Revised Draft

California ISO
Shaping a Renewed Future

2010-2011 Transmission Plan

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Executive Summary

1) Introduction

The 2010/2011 California Independent System Operator Corporation transmission plan presents results from the first cycle of the revised transmission planning process.[1] This ISO transmission plan, which will be updated annually, provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to successfully meet California's policy goals, in addition to examining conventional grid reliability requirements and projects that can bring economic benefits to consumers. In recent years, California enacted policy goals aimed at reducing greenhouse gases and increasing renewable resource development. The state's goal to have renewable resources provide 33% of California's electricity consumption by 2020 has become the principal driver of substantial investment in new renewable generation capacity both inside and outside of California.

The transmission plan describes the transmission necessary to meet the state's 33% RPS goals. Key analytic components of the plan include:

- Identification of transmission needed to support meeting the 33% RPS goals over a diverse range of renewable generation portfolio scenarios, which are based on plausible forecasts of the type and location of renewable resources in energy-rich areas most likely to be developed over the 10 year planning horizon;
- A "least regrets[2]" analysis of transmission infrastructure under development but not yet permitted, as well as policy-driven elements that might be needed to deliver energy from the resources in these portfolios to the ISO grid;
- Evaluation of need for all of the transmission projects submitted into the 2008 and 2009 transmission planning request windows;
- Identification of transmission upgrades and additions needed to reliably operate the network and comply with applicable planning standards and reliability requirements; and
- Economic analysis that considers whether transmission upgrades or additions could provide additional ratepayer benefits.

[1] The Revised Transmission Planning Process (RTTP) was filed on June 4, 2010 by the ISO at the Federal Energy Regulatory Commission following a lengthy

[2] The "least regrets" approach can be summarized as evaluating a range of plausible scenarios made up of different generation portfolios, and identifying the transmission reinforcements found to be necessary in a reasonable number of those scenarios. It is captured in more detail in the ISO tariff, in section 24.4.6.6.

Our comprehensive evaluation of the areas listed above resulted in the following key findings.

- No new major transmission projects are required to be approved by the ISO at this time to support achievement of California's 33% RPS goals given the transmission projects already approved or progressing through the California Public Utilities Commission approval process because:
    - The major transmission projects already underway accommodate a diverse range of resource portfolios for meeting a 33% RPS goal, including in-state generation, distributed generation, and out of state scenarios;
    - Existing inter-state transmission will have capacity made available as renewable resources displace energy from traditional resources;
    - Approving more transmission under the circumstances and conditions that exist today would increase risk of stranded costs; and
    - The ISO will reassess transmission needs in future annual planning cycles and consider any changed conditions, potential policy changes (e.g., increased emphasis on distributed generation), renewable generation advances utilizing previously approved transmission, and any new factors that may drive future generation development.
- Justification for additional transmission to support out-of-state procurement will need to be addressed through the CPUC renewable energy procurement approval process to determine the specific location, quantity, and type of renewable energy projects.
- Immediate focus now should be on:
    - Obtaining approvals for identified transmission; and
    - Renewable energy procurement
- The ISO evaluated all 41 transmission project proposals submitted in the 2008 and 2009 request windows to determine if they are needed as either policy driven or economically driven transmission projects. One of the projects, reconductoring of the Devers-Mirage 230 kV double circuit line, was found to be needed as a policy driven line to support California's RPS goals.
- The ISO identified 32 transmission projects with an estimated cost of $1.2 billion, as needed to maintain the reliability of the ISO transmission system.
- The ISO performed a transmission congestion study to determine potential areas for transmission reinforcement. These study results led to the detailed evaluation of nine specific congestion

mitigation plans. The analyses compared the cost of the mitigation plans to the expected reduction in production costs, congestion costs, transmission losses, capacity or other electric supply costs resulting from improved access to cost-efficient resources and determined that none of the mitigation plans were economically justified.

The finding that no major new transmission projects are needed at this time to support the California's RPS goals reflects years of effort by California state agencies, participants in the Renewable Energy Transmission Initiative, market participants and the ISO that resulted in the approval and ongoing construction of major transmission projects such as Tehachapi and the Sunrise Powerlink. The ISO recognizes, however, that uncertainty remains regarding how California will ultimately meet its 33% RPS goals in terms of the precise locations, resource mix and quantity of renewable energy resources. While this plan shows that the transmission approved to date can accommodate a diverse range of plausible renewable development scenarios, the ISO will continue to work with state agencies and all stakeholders to evaluate development trends and policy directives beginning with next year's planning cycle and will reassess the transmission needs accordingly.

This year's transmission plan is based on the ISO's recently approved transmission planning process, which involved collaborating with the California Public Utilities Commission (CPUC), California Transmission Planning Group (CTPG), and many other interested stakeholders. Summaries of the RTPP and some of the key collaborative activities are provided below. This is followed by additional details on each of the key study areas and associated findings described above.

2) The Revised Transmission Planning Process

A core responsibility of the ISO is to plan and approve additions and upgrades to transmission infrastructure so that as conditions and requirements evolve over time, it can continue to provide a well-functioning wholesale power market through reliable, safe and efficient electric transmission service. Since it began operation in 1998, the ISO has fulfilled this responsibility through its annual transmission planning process. The State of California's adoption of new environmental policies and goals created a need for some important changes to the planning process. In 2009, the ISO initiated a stakeholder process to design the needed changes, and in June 2010 filed tariff amendments with the Federal Energy Regulatory Commission (FERC) to implement the needed changes. The FERC approved RTPP tariff amendments on December 16, 2010, and the amendments went into effect on December 20, 2010.

The RTPP improves upon the prior transmission planning process in several important ways including:

Establishing a new "policy-driven" category of transmission additions and upgrades that are needed to meet state and federal public policy directives and goals;

Managing the risk of stranded investment associated with transmission additions by creating a distinction between category 1 (transmission elements that will be approved as part of the transmission plan) and category 2 (transmission elements that will be re-evaluated in future cycles);

Providing for collaboration with other transmission planners in California in development of a statewide conceptual transmission plan that will serve as an input into the ISO planning process;

Improving coordination between transmission planning and the Generation Interconnection Procedures (GIP);

Providing more opportunities for stakeholder participation and input to the process;

Allowing all interested project sponsors, including independent developers and existing participating transmission owners, an equal opportunity to propose to construct and own policy-driven and economically-driven transmission facilities included in the plan; and

Enabling the ISO to use its planning resources efficiently to develop a comprehensive annual plan that addresses all categories of identified transmission infrastructure needs.

Most of the planning activities and studies reported in this document were performed in 2010, prior to FERC's December approval of RTPP. During that period, the ISO followed the requirements and provisions specified in its tariff for the then-current transmission planning process, but expanded the scope of its analyses to assess the capability of the grid, augmented by the upgrades already in progress or approved, to support the 33% RPS goals. This proactive approach allowed an expedient transition from the previous transmission planning process to RTPP.

One RTPP enhancement is the development of a conceptual statewide plan, which is developed by the ISO in coordination with neighboring balancing authority areas and planning entities and provided to stakeholders for comment and recommendations to be considered in the ISO's comprehensive analysis. Based on the work of CTPG and other data developed by the ISO, a conceptual statewide plan was developed and released by the ISO on January 17, 2011.

3) Collaborative Planning Efforts

Responding to the need for coordinated action, the ISO, utilities, state agencies and other stakeholders worked closely to assess how to meet the environmental goals established by state policy. The collaboration with these entities is evident in the following initiatives.

Renewable Energy Transmission Initiative (RETI)

A joint initiative between the ISO, CPUC, California Energy Commission (CEC), investor-owned and publicly owned utilities and other stakeholders, RETI identified areas in California and neighboring states with concentrations of high-quality renewable resources that could be delivered to California loads. Much of the data used by the CPUC in developing its generation development scenarios, which the ISO further refined for use in the transmission plan, was initially developed through RETI.

CPUC Long Term Procurement Plan (LTPP)

A memorandum of understanding (MOU) was signed by the CPUC and ISO in May 2010 to formalize coordination between the ISO's RTPP and the CPUC's transmission siting, permitting and the long-term transmission planning processes. The MOU contemplated that the ISO will consider and incorporate the generation scenarios from the LTPP process into its planning process. The CPUC, in turn, will give substantial weight in its siting assessment to project applications that are consistent with the ISO transmission plan. In the later part of 2010, the CPUC released potential renewable procurement portfolios in the LTPP proceeding representing plausible scenarios for meeting 33% RPS goals.

Because of the timing of the development of the CPUC cases, the four resource portfolios documented in this transmission plan are not identical to the CPUC portfolios released in the LTPP. However, the ISO was able to utilize the preliminary CPUC information to develop its portfolios.[3] As was done during the 2010/2011 planning process, the CPUC portfolios will be relied upon as key input into the 2011/2012 planning cycle.

California Transmission Planning Group (CTPG)

The CTPG was formed in the fall of 2009 to conduct joint transmission planning by transmission owners (investor owned utilities and publicly owned utilities) and the ISO. During the 2010/2011 planning cycle the California ISO worked closely with the CTPG to develop a statewide approach to the transmission needed to meet the 33% RPS targets by 2020. During their individual 2010 planning cycles, CTPG members completed a significant amount of technical analyses to develop a framework for preparing a statewide transmission plan. CTPG evaluated alternative renewable resource portfolios based on participant interest, which reflected input from RETI, other stakeholders, and state agencies. Their intent was to develop a conceptual least regrets transmission plan that CTPG members who are the planning entities for their balancing authority areas would assess in greater detail as part of their own respective planning processes. The CTPG statewide transmission plan was completed in early January 2011 and presented a list of high potential and medium potential transmission elements that were identified for further consideration by all CTPG members in their development of their own 2020 RPS planning goals. The ISO performed its own independent analysis and found that the high potential transmission elements identified by CTPG were found to be needed in the ISO's 33% RPS transmission plan.

4) 33% RPS Generation Portfolios and Transmission Assessment

The transition to greater reliance on renewable generation creates significant transmission challenges because renewable resource areas tend to be located in places distant from population centers. As a

[3] As part of its analysis in this cycle, the ISO compared the portfolios actually studied to the CPUC portfolios and found that they were reasonably similar to ISO scenarios, as the data used to construct both sets of scenarios is almost identical and the scenarios share many common elements.

result, development in these areas often requires new transmission lines. The ISO is keenly aware that without transmission in place, developers are extremely reluctant to invest in generation. At the same time, an entirely reactive transmission planning process creates its own problems — most significantly, the time required to develop generation is typically much shorter than the time required to develop a new transmission line. In other words, a transmission process that relies on generators making investments first can leave generation without the necessary transmission for a significant period of time.

The RTPP addresses this challenge and uncertainty by creating a structure for considering a range of plausible generation development scenarios and identifying transmission elements needed to meet the state's 2020 RPS goals. Commonly known as a least regrets methodology, the portfolio approach allows the ISO to consider resource areas (both in-state and out-of-state) where generation build-out is most likely to occur; evaluate the need for transmission to deliver energy to the grid from these areas; and identify any additional transmission upgrades that are needed under one or more portfolios. The ISO 33% RPS assessment is described in detail in chapters 4 and 5 of this plan.

The scenario development methodology is straightforward and begins with evaluating the probability of renewable resource build-out using criteria set forth in the tariff[4]:

Commercial interest in geographic locations evidence by signed purchase power and interconnection agreements;

The results of the CPUC procurement proceedings, as well as similar proceedings sponsored by other regulatory agencies;

Planning level cost estimates of transmission required for alternative resource locations;

Potential energy and capacity values of resources located in various zones;

Publicly available environmental information about the resource locations as well as potential environmental, economic and reliability impacts of additional transmission elements needed to access such resources;

Potential future connections to alternative resource locations;

Potential resource integration requirements;

The effect of other transmission upgrades and additions being considered for approval during the planning process; and

The effects of uncertainty on any of the other criteria that could increase the risk of stranded investment.

[4] Section 24.4.6.6

By weighing the LTPP discounted core[5] procurement information, as well as previously identified transmission projects in various stages of approval, permitting and construction against the tariff criteria, the ISO developed four resource portfolios and populated each one with sufficient generation to meet the 33% RPS goals. Additional transmission was then added to each portfolio as needed to deliver the generation to the ISO grid.

The ISO portfolios cover a broad range of plausible generation possibilities including relatively high levels of internal resources, out-of-state generation and distributed smaller generation, as well as a hybrid portfolio that reflects a balance of potential sources of traditional and renewable energy. The generation resources comprising these four portfolios reflect the latest and best available information on the commercial interests of transmission customers, as measured by interconnection queue positions and whether the resources have signed power purchase agreements with California load-serving entities. Other factors such as cost, procurement policies, permitting, environmental assessments conducted by RETI, and resource financing capabilities were part of the metrics used to evaluate each portfolio. The hybrid portfolio represents an amount of out-of-state renewable procurement that tends to maximize the use of existing import transmission; an amount of distributed generation that exceeds the amount in the CPUC's discounted core, but is plausible, especially given emerging state policies; and a moderate build-out of large in-state renewable generation areas that are already farthest along in development. Given these attributes, the hybrid portfolio was designated as our base case because it is considered the more likely scenario to occur.

According to the tariff and the least regrets methodology, the additional transmission elements added to each portfolio to support the 33% RPS goals were considered to be policy-driven and were placed into category 1 or category 2.

In addition to transmission already approved by the ISO through the transmission planning process, the ISO considered Large Generator Interconnection Procedures (LGIP) network upgrades required to serve renewable resources that either have or were expected to have signed generator interconnection agreements. As such, these transmission upgrades and additions form a core part of the ISO analysis methodology.

The ISO assessment of the transmission projects identified above indicate that those projects with some additional minor system upgrades are sufficient to meet the 33% RPS target by 2020. These transmission upgrades were tested under the four ISO generation portfolios and all of the projects identified above were determined to be needed.

For this transmission plan, the ISO has concluded that some upgrades to WECC Path 42 are also needed to deliver renewable resources under development in Imperial County that are modeled in the base case portfolio.

[5] The CPUC chose projects for the discounted core based on two publicly available criteria that adequately demonstrate developer interest: projects must have a signed power purchase agreement (PPA), and a permitting application submitted to the responsible permitting entity (CEC, BLM) must be judged data adequate.

The ISO also identified other upgrades that are potentially needed but require further analysis in the next transmission planning cycle as more information becomes available regarding renewable generation development and integration requirements. For example, environmental concerns are growing over the level of development occurring in the California desert. Some of the facilities below would allow development to increase in areas where already disturbed land is available for possible renewable resource development.

Table E1 provides a summary of the various transmission elements of the 2010/11 transmission plan for supporting California's RPS goals. These elements are composed of the following categories:

- Major transmission projects that have been previously approved by the ISO and are fully permitted by the CPUC for construction;
- Additional transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the approval process;
- One policy-related transmission project; and
- Policy-related projects that are potentially needed but will be carried forward for evaluation in the next transmission planning cycle.

Table E1: Elements of the 2010/11 ISO Transmission Plan Supporting Renewable Energy Goals

Transmission Facility	Potential Renewable energy Delivery	Renewable Deliverability potential with upgrade
	(TWh)	(MW)
Transmission Facilities Approved and Permitted For Construction		
Sunrise Powerlink	4.1	1,700
Tehachapi Transmission Project	18.2	5,500
Colorado River - Valley 500 kV line	2.9	1,600
Eldorado – Ivanpah 230 kV line	3.6	1,400
Additional LGIP Network Transmission not Permitted		
Borden Gregg Reconductoring	2	800
South of Contra Costa Reconductoring	0.8	300
Pisgah - Lugo	4.1	1,750

West of Devers Reconductoring	5.7	3,100
Carrizo Midway Reconductoring	2.1	900
Coolwater - Lugo 230 kV line	1.4	600
Needed Policy-Driven Transmission Elements		
Mirage-Devers 230 kV reconductoring (Path 42)	3.6	1,400
Potentially Needed Policy-Driven Transmission Elements		
Midway-Gregg 500 kV line		
Gregg - Herndon 230 kV line Reconductoring		
Warnerville - Wilson 230 kV line Reconductoring		
Barton - Herndon 115 kV line Reconductoring		
Manchester - Herndon 115 kV line Reconductoring		
Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)		
400 MVAr reactive power support at Sycamore, Mission, and Talega 230 kV substations		
The third Miguel 500 kV transformer		
Total	48.5	19,050

5) Reliability Assessment

The reliability studies necessary to ensure compliance with North American Electric Reliability Corporation (NERC) and ISO planning standards are a foundational element of the transmission plan. During the 2010/2011 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with applicable NERC reliability standards. The analysis was performed across a 10-year planning horizon and modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities across a voltage bandwidth of 60 kV to 500 kV, and where reliability concerns were identified, the ISO identified mitigation plans to address these concerns. These mitigation plans include upgrades to the transmission infrastructure, implementation of new operating procedures and installation of automatic special protection schemes. All ISO analysis, results and mitigation plans are documented in the transmission plan.

It is the ISO responsibility to conduct its transmission planning process in a manner that ensures planning is appropriately coordinated across its controlled grid as well as its connections with neighboring systems. The analysis that is required to prepare this transmission plan is complex and entails processing a significant amount of data and information. In total, this plan proposes approval of 32 reliability driven transmission projects, representing an investment of approximately $1.2 billion in infrastructure additions to the ISO controlled grid. The majority of these projects (28) cost less than $50 million and has a combined cost of $573 million. The remaining four projects with costs greater than $50 million have a combined cost of $629 million. These reliability projects are necessary to ensure compliance with the NERC and ISO planning standards. A summary of the number of projects and associated total costs in each of the four major transmission owners' service territories is listed below in table E2. Because PG&E and SDG&E have lower voltage transmission facilities (i.e., 138 kV and below) under ISO operational control, a number of projects were identified mitigating reliability concerns in those utilities' areas, compared to none for SCE.

In arriving at these projects, the ISO and transmission owners performed power system studies to measure system performance against the NERC reliability standards and ISO planning standards as well as to identify reliability concerns that included among other things, facility overloads and voltage excursions. Mitigation measures were then evaluated and cost-effective solutions were recommended by ISO staff to management and the Board of Governors for approval.

Table E2 – Summary of Approved Reliability Driven Transmission Projects in the ISO 2010/2011 Transmission Plan

Service Territory	Number of Projects	Cost
Pacific Gas & Electric (PG&E)	23	$683M
Southern California Edison Co. (SCE)	0	$0M
San Diego Gas & Electric Co. (SDG&E)	9	$515M
Total	32	$1,198M

The majority of identified reliability concerns are related to facility overloads or low voltage. Therefore, many of the specific projects that comprise the totals in the table above include line reconductoring and facility upgrades for relieving overloading concerns, as well as installing voltage support devices for mitigating voltage concerns. Additionally, some projects involve building new load-serving substations to relieve identified loading concerns on existing transmission facilities. Several initially identified reliability concerns were mitigated with non-transmission solutions. These include generation redispatch and, for low probability contingencies, possible load curtailment.

6) Economic Studies

Economic studies of transmission needs are another fundamental element of the ISO transmission plan. The objective of these studies is to identify transmission congestion and analyze if the congestion can be cost effectively mitigated by network upgrades. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load. Resolving congestion bottlenecks is cost effective when ratepayer savings are greater than the cost of the project. In such cases, the transmission upgrade can be justified as an economic project.

The ISO economic planning study was performed after evaluating all policy-driven transmission (i.e., meeting RPS targets) and reliability-driven transmission. Network upgrades determined by reliability and renewable studies were modeled as an input in the economic planning database to ensure that the economic driven transmission needs are not redundant and are beyond the reliability- and policy-driven transmission needs. The engineering analysis behind the economic planning study was performed using a production simulation and traditional power flow software.

Grid congestion was identified using production simulation and congestion mitigation plans were evaluated through a cost-benefit analysis. Economic studies were performed in two steps: 1) congestion identification; and 2) congestion mitigation. In the congestion identification phase, grid congestion was simulated for 2015 (the 5th planning year) and 2020 (the 10th planning year). Congestion issues were identified and ranked by severity in terms of congestion hours and congestion costs. Based on these results, the worst congestion issues were identified and ultimately selected as high-priority studies. Compared to the 2009/2010 planning analysis, the 2010/2011 planning results indicated that congestion levels identified in the worst areas were less severe. The change is attributed to a lower load forecast and lower net-short renewable energy requirements used in this year's study.

In the congestion mitigation phase, congestion mitigation plans were analyzed for the worst congestion issues. A total of nine congestion mitigation proposals were evaluated. Stakeholders submitted 41 economic and renewable delivery project proposals through the ISO 2008/09 request window. Seven of the stakeholder proposals aligned with the worst congestion areas and were analyzed in detail. In addition, the ISO identified three other potential congestion mitigation options that were analyzed in detail.

Based on the costs-benefits analyses performed by the ISO for all of the proposed congestion mitigation proposals, the ISO determined that none of the proposed projects demonstrated a positive net benefit. Therefore, the ISO is not recommending any economic upgrades as part of the 2010/2011 planning cycle.

7) Evaluation of the 2008/09 Request Window

As part of the 2010 RTPP planning cycle, the ISO reviewed 41 projects submitted in the 2008 and 2009 request windows. Those projects comprise all request window submissions other than reliability project submissions that the ISO carried forward into the 2010 planning cycle.

The RTPP tariff modifications contemplated that the ISO would evaluate these 2008 and 2009 request window transmission project proposals to determine if they are needed as either policy driven or economically driven transmission projects. These analytic efforts were integrated into the overall transmission planning studies, and relied on the study assumptions, generator portfolio development, methodology, and analysis used in the overall 2010/2011 planning process.

A key consideration in developing these portfolios was to incorporate commercial interest in resources in geographic areas across the ISO grid as well as information from the CPUC and local regulatory authorities' resource planning processes. The renewable portfolio development work performed in CPUC resource planning process included a cost comparison of these resources and as such, the base portfolio information from that work was incorporated in the ISO portfolios. The environmental evaluation data from that process for the zones that the transmission would be interconnecting was also extensively incorporated in the ISO portfolio development process.

The request window projects, excluding seven that were submitted as information only, were evaluated in five areas to determine if they would provide net economic benefits to ratepayers. Those categories are:

Reduction in production cost or other congestion benefits;

Capacity or other electric supply cost benefits;

Transmission system loss reduction benefits;

Emission reduction benefits; and

Policy need.

The results of this analysis found that one of the submissions — the reconductoring of the Devers-Mirage 230 kV double circuit transmission line — is needed as a policy-driven transmission element. This upgrade is part of an overall transmission plan that is coordinated with upgrades planned by Imperial Irrigation District to WECC Path 42.

8) Conclusions and Recommendations

The 2010/2011 ISO transmission plan presents comprehensive results from the first cycle of the ISO's RTPP. This ISO transmission plan, which will be updated annually, provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately meet California's policy goals, in addition to examining conventional grid reliability requirements as well as projects that can bring economic benefits to consumers. This year's plan identified 32 transmission projects, estimated to cost a total of approximately $1.2 billion, as needed to maintain the reliability of the ISO transmission system. While this plan shows that the transmission approved to date can accommodate a diverse range of plausible renewable development scenarios, the ISO will continue to work with state agencies and all stakeholders to evaluate development trends and policy directives beginning with next year's planning cycle and will reassess the transmission needs accordingly.

Chapter 1 Overview of the Revised Transmission Planning Process and the 2010/2011 Transmission Planning Cycle

1.1 INTRODUCTION

The ISO instituted enhancements to its Order 890 transmission planning process that were proposed to FERC in June, 2010 and became effective on December 20, 2010. As the first comprehensive transmission plan presented to the Board of Governors under this revised process, the 2010/2011 comprehensive transmission plan outlines upgrades and additions needed for reliable service, as well as transmission required to meet the state's 33% Renewables Portfolio Standard (RPS) goal. Additionally, to ensure that the transmission plan provides economic efficiency, the ISO conducted production simulation and congestion studies to determine whether ratepayers would benefit from the addition of economically-driven transmission elements. Where appropriate, the ISO also considered non-transmission alternatives and took into account demand response programs that meet required ISO criteria.

The plan is organized into the following chapters:

Chapter 1 – Overview of the Revised Transmission Planning Process and the 2010 – 2011 Transmission Planning Cycle

Chapter 2 – Reliability Assessment – Study Assessment, Methodology and Results

Chapter 3 – Study Results for Other Transmission Studies

Chapter 4 – Study Methodology for Identifying Transmission Needed to Meet the 33% Renewables Portfolio Standard

Chapter 5 – Planning Assessment for 33% RPS Transmission

Chapter 6 – Economic Planning Studies

Chapter 7 – Evaluations of the 2008/09 Request Window Project Submittals

Chapter 8 – Updated Project Schedules and Listing Summary of 2010 Request Window Submittals

Because the modifications to the ISO transmission planning process became effective after the 2010/2011 cycle was well under way, the 2010/2011 transmission planning cycle was initiated under the previous process but will conclude in 2011 under the revised transmission planning process (RTPP). Chapter 1 provides an overview of the revised planning process, the 2010/2011 planning and stakeholder process, and next steps for the 2011/2012 planning cycle.

1.2 THE REVISED TRANSMISSION PLANNING PROCESS

1.2.1. Need for transmission planning process enhancements

On June 4, 2010, following a ten-month stakeholder process, the ISO submitted to FERC a comprehensive proposal to revise its transmission planning process. This proposal, known as RTPP, was motivated by the recognition that most transmission additions and upgrades over the next decade will be driven by the need to access renewable electricity supply resources in response to California's 33% RPS. The existing transmission planning processes and rules simply were not well suited to the new world in which infrastructure needs are driven by environmental policies that trigger major changes in the supply fleet over a ten-year period – a relatively short time for normal transmission planning and development.

A crucial challenge for transmission planning in the new environmental policy-driven context is to develop sufficient transmission on a timetable that supports the 33% RPS goals and to develop such transmission efficiently – and in the right places – so ratepayers are not saddled with high costs of under-utilized transmission. Contributing to this challenge is the great uncertainty about which of the identified areas rich in renewable energy potential will realize the most generation development. The revised planning process: 1) identifies and approves transmission projects that have the highest likelihood of being fully utilized; 2) identifies, for later reevaluation, projects that could be highly utilized but whose approval must await stronger evidence of committed generation development; 3) addresses the more conventional requirements of transmission planning such as reliability needs and congestion reduction; and 4) organizes all these elements into an annual comprehensive plan that accommodates 33% renewable energy portfolios by 2020.

A second major factor affecting the RTPP design was the need for a new public policy-driven category of transmission additions and upgrades. The prior ISO planning rules provided for reliability and economic projects, as well as more narrowly defined transmission categories, to be submitted for evaluation through a request window. In order to be eligible for cost recovery through the ISO transmission access charge (TAC) a project had to meet the criteria for one of these project categories. For example, a reliability project must be shown to be the preferred cost effective solution to a reliability problem identified through annual reliability studies. An economic project must be shown to offer economic benefits, such as reducing system production costs through mitigation of chronic congestion identified in the annual congestion studies, with savings that exceed the project's costs. In contrast, transmission elements needed to meet the 33% RPS goals typically would not qualify for either of these categories because they are explicitly identified to meet needs that are neither reliability- nor economic-based. Thus, in order to enable the transmission planning process to identify such projects and approve them for cost recovery through the TAC, the ISO had to amend its tariff to include the public policy-driven category.

The third major factor driving the RTPP enhancements was the infeasibility of the request window structure for economic projects. As it was structured prior to the RTPP modifications, the request window allowed any party to submit a project proposal irrespective of any previously identified need and required the ISO to allocate substantial staff resources to evaluate such submissions even when there was little likelihood that the project would be needed. Under the prior request window process for economic projects, the project proponent retained the right to build the project if the ISO determined that the project or something very similar was needed under the existing criteria, thus encouraging parties to submit as many project proposals as possible in order to establish rights to build TAC-based transmission. With the state's adoption of the RPS goals and the resulting potential need for substantial new transmission over the next ten years, the inefficiency of the request window would have increased because of the greater incentive for parties to submit more project proposals to establish rights to build and the complexity involved in evaluating these proposals.

Fourth, although the request window structure was problematic, a need existed to involve independent transmission developers in the planning process and provide them explicit, well-defined opportunities to build needed transmission under the TAC-based cost recovery paradigm (in addition to the merchant transmission paradigm). In practical terms, certain types of transmission additions and upgrades are most appropriately and efficiently built by incumbent Participating Transmission Owners (PTOs), most notably to address reliability problems on their own systems or when upgrading an existing facility is the most economical solution. In other instances, however, it is important to allow competition among interested and capable developers. The new transmission planning process provides for such competition by conducting an open request for proposals to build and own, under TAC cost recovery, transmission elements in the economic and policy-driven categories that are found to be needed in the comprehensive transmission plan.

The fifth major driver of the RTPP design was the need to better coordinate transmission planning with generator interconnection procedures (GIP), so that the planning and approval of new transmission for the ISO grid could be more holistic and comprehensive. Under the GIP, the ISO and the PTOs are required to provide the network upgrades needed for interconnection customers for which certain GIP milestones are completed (i.e., the phase 2 interconnection studies and the posting of required security by the customer). But prior to the RTPP, however, there were no provisions for ISO planners to evaluate the identified network upgrades within the broader context of transmission planning to identify more efficient upgrades and additions that could meet other planning objectives as well as the needs of the interconnection customers. For example, there were no provisions for enhancing or expanding these GIP-driven upgrades to anticipate the interconnection of additional generation that is in the interconnection queue to be studied in later clusters. At the same time, in the 33% renewable policy context, it is important that the transmission planning process anticipate the needs of the generators in these later queue positions in order to identify cost-efficiency opportunities.

Moreover, due to the expected concentration of renewable generation in a number of promising geographic areas, it is likely that the most efficient way to develop transmission to meet the 33% goal will be to expand or enhance network upgrades identified in the GIP. In other words, the most efficient strategy for developing transmission under the new public policy-driven category will likely be to use this category as a basis for approving enhancements to GIP-driven network upgrades. But this meant that the two processes – the GIP and transmission planning – had to be coordinated more explicitly than in the past.

1.2.2 Similarities and differences between the prior transmission planning process and RTPP

The ISO RTPP retains some elements of the former transmission planning process. Under the RTPP, the ISO will still hold a stakeholder process at the beginning of each planning cycle (in the first quarter of each calendar year) to establish unified planning assumptions and a study plan. The ISO will perform its reliability studies, publish the results and propose solutions to identified reliability problems, require PTOs to propose solutions to problems identified on their systems, and accept additional solution proposals from other parties before conducting a stakeholder process to discuss all the elements. The ISO will conduct congestion studies and identify areas of the grid where congestion is substantial and where an economic transmission project may be justified on a cost-benefit basis. The ISO will identify any issues with the feasibility of long-term congestion revenue rights and will propose solutions. The ISO will continue to accept, evaluate, and act on proposals for locational constrained resource interconnection (LCRI) projects and merchant projects.

The ISO will discuss all the elements of the planning cycle with stakeholders through an open process. The comprehensive transmission plan will be presented to the ISO Board in the fifteenth month of the planning cycle.

The substantial differences between the prior process and RTPP include the following:

- The new planning cycle has three phases.[6] Phase three begins after the ISO Board approves the comprehensive transmission plan and encompasses the competitive solicitation process for policy-driven category 1 and economically-driven elements found to be needed in the plan.
- The request window is limited to reliability projects, merchant projects, LCRI projects and projects proposed to maintain the feasibility of long-term CRRs.
- Request window project submissions, other than merchant projects, will not confer a right to build on the sponsor of the submission. Rather, once the ISO determines which projects should be approved, the rights or obligations to build and own projects will be determined through the applicable tariff rules for each project category.
- During phases one and two, the ISO will develop a conceptual statewide plan, including information from neighboring balancing authorities and planning entities, and solicit stakeholder comment. This plan and stakeholder comments will be inputs into the comprehensive plan that the ISO develops for its footprint.
- The comprehensive plan will identify policy-driven and economically-driven elements that, upon approval by the Board, will be the basis for the competitive solicitation in phase three in which both non-incumbent transmission developers and PTOs may participate.
- Starting with the 2011/2012 cycle, the ISO will evaluate certain network upgrades identified in GIP as part of the transmission planning process.
- During the 2010/2011 cycle, the ISO evaluated economic projects submitted in the 2008 and 2009 request windows. If any of those projects lined up with policy-driven or economically-driven needed elements, the project proponent would have the right to finance, own and construct such project.

1.2.3 Blending the Old and the New

[6] Under RTPP terminology, the new process is divided into “phases” rather than the “stages” used in the prior planning process. However, the purpose of the “phases” is similar to the “stages” in that each phase provides a demarcation of the process milestones and triggers certain stakeholder activities.

The ISO's proposed modifications to the transmission planning process were suspended by FERC on July 26, 2010 and became effective on December 20, 2010. In anticipation that the 2010/2011 cycle would be governed by two different tariff processes, the ISO took several steps to align its planning activities with the milestones under each process by:

- Seeking (and receiving) a waiver from FERC from the prior requirement that economic projects be submitted into the 2010 request window;
- Amending the request window dates in its Business Practice Manual (BPM) for transmission planning to allow time for FERC to act on the waiver request.
- Utilizing the flexibility under the prior tariff to conduct a comprehensive analysis of system needs using resource scenarios that accomplish the 33% by 2020 renewable generation policy objective;
- Posting base cases and holding an additional stakeholder meeting in early December to discuss the preliminary results of its 33% renewable and economic studies; and
- Issuing a conceptual statewide plan and soliciting stakeholder comment prior to posting this plan.

The 2010/2011 process details are discussed in section 1.3.

1.2.4 Collaborative Planning Efforts

The ISO, utilities, state agencies and other stakeholders are working closely to assess how to meet the environmental goals established by state policy. Their collaboration is visible in several recent initiatives:

- **Renewable Energy Transmission Initiative (RETI):** This is a joint initiative between the ISO, California Public Utilities Commission (CPUC), California Energy Commission (CEC), investor-owned and publicly-owned utilities and other stakeholders. RETI identified areas in California and neighboring states with concentrations of high-quality renewable resources that could be delivered to California loads. Much of the data used by the CPUC in developing its discounted core projects and its defined generation development scenarios as well as the ISO generation development scenarios were initially developed through RETI. The RETI effort was also a major input into the California Transmission Planning Group (CTPG) effort.

- **Reformed Long-Term Procurement Planning:** In 2008, the CPUC began a process of reforming its Long Term Procurement Plan process to better support the need to meet state policy goals. This effort resulted in standards that the IOUs need to meet in their 2010 plans. Those standards include a set of the following four renewable resource scenarios: cost-constrained, time-constrained, environmentally-constrained, and trajectory. While these cases are not identical to the four resource scenarios developed by the ISO, the data used to construct both sets of scenarios is almost identical and the scenarios share many common elements.

- **California Transmission Planning Group (CTPG):** This group was formed in the fall of 2009 to conduct joint transmission planning by transmission owners (investor and publicly owned utilities) and the ISO. These parties have the technical capability to perform detailed transmission planning and the statutory obligation to provide reliable transmission service to serve California consumers within their service territories. The 2010 statewide plan produced by the CTPG is intended to be conceptual rather than a prescriptive plan for meeting the state's 33% RPS goals. The ISO considered the study methodologies and findings from the CTPG effort and incorporated them into its studies. However, one major difference between the ISO and CTPG study methodologies was the ISO use of a security-constrained production simulation model to establish major transmission path flows and conventional generation dispatch assumptions. This difference resulted in greater utilization of existing and proposed transmission. As a result, the scope of the ISO transmission plan for achieving the 33% RPS goals is smaller than what CTPG has projected.

- **CPUC-ISO Memorandum of Understanding.** The CPUC and ISO signed a Memorandum of Understanding in May 2010 that formalized coordination between the ISO revised transmission planning process and CPUC's transmission siting, permitting and long-term procurement planning processes. Specifically, the ISO will consider and incorporate the generation scenarios from the procurement process into its planning process to identify transmission needed to access the renewable energy produced by those generators. The CPUC, in turn, will give substantial weight in its siting assessments to projects approved in the ISO comprehensive transmission plan. However, the ISO had to stay on schedule for completing its comprehensive transmission plan by the end of 2010 while the CPUC portfolio development process was not completed until almost the end of 2010. Therefore, the ISO had to use preliminary CPUC information and anticipate what the CPUC portfolios would ultimately be. Once the CPUC completed their portfolios in late 2010, the ISO compared portfolios it studied to the CPUC portfolios and found that they were generally similar. Further description of the ISO's scenario development can be found in chapter 4.

1.3. The 2010/2011 Transmission Planning Cycle

1.3.1 Process and Stakeholder Schedule

The 2010/2011 annual planning cycle began in December, 2009 when the ISO staff reached out to neighboring balancing authorities and other regional planning entities seeking information that could be incorporated into the unified planning assumptions and study plan. The draft study plan was posted for stakeholder review on February 5, 2010 and a meeting was held on February 12, 2010. Following the meeting and an opportunity for comments, the final draft planning assumptions and study plan were posted on March 31, 2010.[7]

The ISO completed the technical study base cases and posted them on its secured website on April 19, 2010. Stakeholders were given an opportunity to provide input via conference call on April 26, 2010. Following the call, all other planning data was posted on the secured website on May 3, 2010.

[7] The Unified Planning Assumptions and Study Plan can be found at http://www.caiso.com/276a/276af0692d6e0.pdf.

On September 10, 2010, the ISO posted the technical study results for long-term CRR feasibility and the system reliability assessments. This posting triggered the 30 day period within which PTOs must submit reliability projects through the request window responding to the reliability concerns identified in the studies. As noted briefly above, for the 2010-2011 cycle, the ISO revised the dates for the request window through the BPM change management process so that the window would open on the date that the PTOs submitted reliability projects and close 60 days later. Because the technical studies were posted on September 10, the request window opened on October 10 and closed on December 10, 2010.

A stakeholder meeting was held on October 26 and 27, 2010 to discuss the ISO technical study results and the PTO reliability projects. The ISO also arranged two other stakeholder engagements prior to posting this draft comprehensive plan on March 24, 2011. On December 2, 2010, the ISO held a stakeholder meeting to address preliminary results of the 33% RPS portfolio evaluation and the preliminary results of the congestion studies. A follow-up conference call was held on December 16, 2010 to provide an opportunity for additional questions and discussion.

In order to complete the process steps required by RTPP, the ISO issued a conceptual statewide plan on January 17, 2011 and solicited stakeholder comments that were submitted on February 23, 2011. The ISO also advised stakeholders, in a market notice issued on February 18, 2011, that in order to allow sufficient time to evaluate stakeholder input and develop this comprehensive plan, the plan would be presented to the Board for approval at the May 2011 meeting. Stakeholders were also advised that the draft plan would be posted on March 24, 2011 and that a final stakeholder meeting was scheduled for March 30, 2011.

1.3.2 Unified Planning Assumptions and Study Plan

For the 2010/2011 cycle, the study plan contained a description of the study assumptions for the ISO reliability assessments, the long-term CRR feasibility study, the short term operational studies, a description of the locational capacity studies and a brief reference to economic planning study requests. In addition, the study plan described the once through cooling (OTC) study being conducted in conjunction with the CPUC and the CEC.

In the study plan, the ISO described the development of the base case assumptions for its reliability assessments. Specifically, the ISO explained that in light of the state's 33% RPS by 2020, a 33% RPS scenario for renewable resources should be modeled in the planning base cases in this planning cycle. The ISO proposed to rely on information from its generation interconnection process to determine the amount and location of renewable resources in the reliability base cases. Specifically, for the GIP serial study group the ISO used renewable generation and associated transmission that had been identified in interconnection agreements. For renewable generation in the transition cluster, the ISO included generation projects and associated transmission upgrades in the phase two cluster studies.[8]

[8] Study Plan at pages 11-12.

The study plan also identified all of the other assumptions for the reliability studies and the other technical studies to be conducted during phase 2 of the planning cycle. As noted above, technical study results, with the exception of economic and congestion study results, were posted on September 10, 2010.

1.3.3 Comprehensive Transmission Planning

Once the reliability studies and other technical assessments were completed, the ISO moved forward with developing the 33% RPS portfolio scenario that would be used for a comprehensive look at the needs of the system over a ten year planning horizon. The reliability assessment results and reliability projects determined to be needed during this cycle, as well as other request window projects proposed for approval, formed the basis for this comprehensive system study. GIP network upgrades were also included as baseline assumptions in the comprehensive study.[9] The 33% RPS scenario base cases were posted to the ISO's secure website on September 15, 2010, and later with updated 33% RPS portfolio cases on November 29, 2010.

1.3.4 Analysis of the 2008/2009 Economic Request Window Submissions

During the 2008 and 2009 planning cycles, participants in the ISO transmission planning process submitted economically-driven projects through the request window. The ISO concluded that an appropriate analysis of these projects must be based on a comprehensive view of system needs in light of the 33% RPS and included a specific tariff provision addressing the evaluation of these submissions as part of the revised transmission planning process enhancements.

Although the revised tariff language was not yet in effect, the ISO nonetheless advised FERC and its stakeholders that these projects would be evaluated in the 2010/2011 cycle. Accordingly, the ISO conducted an economic analysis of the 2008 and 2009 request window submissions based on the comprehensive plan study scenarios. The results of the economic analyses for the 2008 and 2009 request window submissions are described in chapter 7.

1.4 2010-2011 Transmission Planning Process External Inputs

1.4.1 Sub-Regional Planning Coordination

Regional and sub-regional coordination is one of the Order No. 890 principles and is required by both the tariff and BPM. In addition to soliciting information for the unified planning assumptions when the cycle is initiated each year, the ISO is a member of Western Electricity Coordinating Council (WECC) and its Transmission Expansion Planning Policy Committee (TEPPC) and actively participates in the development of the database used throughout the western interconnection.

[9] In the 2010/2011 planning cycle the ISO did not evaluate GIP-driven network upgrades for potential efficiency-improving enhancement. In accordance with the FERC-approved RTPP the ISO will begin to perform this type of evaluation in the 2011/2012 cycle.

During this cycle, the ISO also worked closely with the CTPG to develop a statewide approach to the transmission needed to meet the 33% RPS. CTPG includes transmission owners with service territories and transmission operators (i.e., parties that have both the responsibility for transmission planning and the technical capabilities to perform the required activities). CTPG evaluated alternative renewable resource portfolios based on participant interest and reflecting input from RETI, other stakeholders and state agencies. One explicit CTPG objective is to identify opportunities for joint transmission projects, which the ISO believes is an important focus and potential benefit of developing a statewide 33% renewable transmission plan. The ISO used some of the data developed by CTPG in the 33% RPS scenarios studied in the comprehensive planning study.

1.4.2 Coordination with Regulatory Agencies

The CPUC and the CEC participated in the 2010/2011 transmission planning process and provided input that was reflected in the development of the 33% RPS scenarios. Additionally, the ISO used data from the CPUC long-term procurement proceedings and coordinated its scenario development with the scenarios developed by the CPUC staff for use in that proceeding. Further description of the ISO's scenario development can be found in chapter 4.[10]

1.4.3 Coordination with RETI

Analysis developed by RETI was incorporated into the ISO work through the CPUC's development of portfolios, and through the CTPG reliance on RETI analysis in advancing the comprehensive plan as discussed earlier. Also the ISO utilized RETI environmental impact scores, as refined by Aspen Environmental Group, in the development of its four 33% RPS portfolios.

1.5 Next Steps under RTPP 2011/2012 Planning Cycle

Phase 1 of the 2011/2012 planning cycle is currently underway. Under RTPP, during phase 1 and the development of the unified planning assumptions and study plan, stakeholders will be given an opportunity to submit economic planning study requests, demand response programs and generation alternatives for consideration as study assumptions in the study plan. The ISO will also identify and seek stakeholder input on the policy objectives that will form the basis for its comprehensive evaluation of the need for policy-driven projects. It is anticipated that the ISO will propose that the 33% RPS by 2020 policy goal is used in the 2011/2012 cycle. The ISO also expects to include, as a related policy objective for the RTPP, that renewable resources imported from outside the ISO balancing authority, as identified in the appropriate ISO 33% RPS baseline scenario, be fully deliverable for resource adequacy (RA) purposes. This will enable broader competition for the supply of economical renewable resources.

[10] The ISO also participates in CPUC proceedings and is currently developing modeling techniques that will assist load serving entities in making procurement decisions regarding resources needed to integrate renewable resources into the ISO grid. ISO 33% RPS Integration Study Production Simulation models are posted in the following website (**http://www.caiso.com/23bb/23bbc01d7bd0.html**)

Chapter 2 Reliability Assessment - Study Assumptions, Methodology and Results

2.1 Overview of the ISO Reliability Assessment

The ISO reliability assessment is a comprehensive annual study that includes:

- Power flow studies;
- Transient stability analysis; and
- Voltage stability studies.

The focus of the annual reliability assessment is to identify facilities that indicated a potential of not meeting the applicable performance requirements specifically outlined in section 2.2.

The study used WECC full-loop power flow base cases and was performed as part of the ISO's annual transmission planning process that is defined in the BPM for the transmission planning process[11].

2.1.1 Backbone (500 kV and select 230 kV) system area assessment

For the backbone system assessment, conventional and governor power flow studies and stability studies were performed to evaluate the system performance under normal conditions and following the contingencies of power system equipment of voltage levels 230 kV and above. The backbone transmission system studies include:

- Northern California-PG&E system;
- Southern California-SCE system; and
- Southern California-SDG&E system.

2.1.2 Local area assessments

For the local area non-simultaneous assessments, conventional and governor power flow studies were performed under normal system conditions and contingency system conditions of power system equipment of voltage levels 60 kV through 230 kV. These assessments were performed for eight local PG&E service territory areas listed below.

- Humboldt area;
- North Coast and North Bay area;
- North Valley area;
- Central Valley area;
- Greater Bay area;

[11] https://bpm.ISO.com/bpm/bpm/version/000000000000105

- Greater Fresno area;
- Kern area; and
- Central Coast and Los Padres area.

2.2 Reliability Standards Compliance Criteria

This 2010/2011 transmission plan spanned a 10 year planning horizon and was performed to ensure the ISO's balancing authority area is in compliance with the North American Electric Reliability Corporation (NERC), WECC and ISO reliability standards across the 2011 through 2020 planning horizon. Sections 2.2.1 through 2.2.4 describe how these planning standards were applied in the 2010/2011 study.

2.2.1 NERC Reliability Standards

NERC reliability standards[12] set forth criteria for meeting system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the ISO as a registered NERC planning coordinator and were considered in the reliability assessment:

- 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).

2.2.2 WECC Reliability Standards

The WECC reliability standards[13], like the NERC reliability standards, set forth additional criteria for meeting system performance requirements that must be met under a varied but specific set of operating conditions. These WECC Reliability Standards are applicable to the ISO as a member of the WECC.

2.2.3 Low Voltage Requirements

The low voltage requirements for NERC and WECC Categories B and C contingencies are established by the Participating Transmission Owner (PTO) responsible for each service territory. Table 2.2-1 provides the voltage guidelines that were used in the assessment.

[12] http://www.nerc.com/page.php?cid=2%7C20
[13] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71

Table 2.2-1: Voltage Guidelines Utilized in the Assessment

ISO / PTO	Voltage level kV	Normal Conditions		Contingency Conditions		Category D	WECC Voltage Deviation Criteria	
		Vmin	Vmax	Vmin	Vmax		Category B	Category C
PG&E	115 kV and below	0.90 p.u.	1.1	0.90 p.u.	1.1 but not clear standard	checked for voltage collapse, stability issues, and cascading outages	-	-
	230 kV and above (500 kV)	N/A – Generally, normal voltage on the 500 kV system is higher 1 PU at the starting point	1.1	N/A – Already captured by voltage deviation criteria	N/A – Already captured by voltage deviation criteria	Checked for voltage collapse, stability issues, and cascading outages	≤5%	≤10%
SCE	bellow 220	0.95	1.05	0.9	1.1			
	220	Bulletin #17	1.05	0.9	1.1	evaluate for risks and consequences	≤7%	≤10%
	500	Bulletin #17	1.07	0.9	1.1	evaluate for risks and consequences	≤7%	≤10%
SDG&E	69-230 kV	SDG&E Operating Procedure TMC1005				evaluate for risks and consequences	≤5%	≤10%
	500	SDG&E Operating Procedure TMC1005					≤5%	≤10%

2.2.4 California ISO Grid Planning Standards

The California ISO Grid Planning Standards (ISO standards)[14] specify the planning standards to be used in the planning of ISO transmission facilities. These standards:

- Address specifics not covered in the NERC reliability and WECC planning standards;
- Provide interpretations of the NERC reliability and WECC planning standards specific to the ISO grid; and

[14] http://www.ISO.com/docs/09003a6080/14/37/09003a608014374a.pdf

- Identify whether specific criteria should be adopted that are more stringent than the NERC/WSCC planning standards.

At this point the ISO standards define a more stringent requirement for all TPL-002 disturbances than is specified by the NERC reliability and WECC planning standards. For the ISO, acceptable system performance for the TPL-002 standard is bound by loss of a single bulk electric system element when one generator is already out-of-service, where NERC and WECC define the TPL-002 standard as system performance following loss of a single bulk electric system element[15].

2.2.5 Nuclear Plant Interface Requirements (NUC-001-2)

The purpose of this standard[16] is to ensure coordination between the nuclear plant generator operators and transmission entities to ensure safe operation of the nuclear plant. The NUC-001-2 standard requires the transmission planners to perform planning studies and analyses in accordance to the Transmission Control Agreements (Appendix E)[17] with the Nuclear Plant Generator Operators. The Transmission Control Agreements provides voltage requirements, as well as stability requirements, for the off-site power supply to the Diablo Canyon and San Onofre nuclear generating station (SONGS) under various generating or transmission contingency conditions.

2.2.6 Observing System Operating Limits Standard Requirements (FAC-014-2)

The purpose of this standard is to ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the bulk electric system are determined based on an established methodology. SOLs used in planning studies follow and comply with the NERC and WECC reliability standards.

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15 Section II of http://www.ISO.com/docs/09003a6080/14/37/09003a608014374a.pdf

16 http://www.nerc.com/files/NUC-001-2.pdf

17 http://www.ISO.com/docs/09003a6080/25/a3/09003a608025a385.pdf

2.3 STUDY METHODOLOGY AND ASSUMPTIONS

Sections 2.3.1 and 2.3.2 summarize the study methodology and assumptions used for the reliability assessment.

2.3.1 Study Methodology

As noted earlier, the assessment of the backbone and local areas were performed using conventional analysis tools and widely accepted generation dispatch approaches. These methodology components are briefly described below.

2.3.1.1 Generation Dispatch

All generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels. Qualifying Facilities (QFs) and self-generating units were modeled based on their historical generating output levels.

2.3.1.2 Power Flow Contingency Analysis

Conventional and governor power flow contingency analyses were performed on all backbone and local areas consistent with NERC TPL-001 through TPL-004, WECC, and ISO standards as outlined in section 2.2. Transmission line and transformer bank ratings in the power flow cases were updated to reflect the rating of the most limiting component or element. All power system equipment ratings were consistent with information in the ISO Transmission Register.

Based on historical forced outage rates of combined cycle power plants on the ISO controlled grid, the G-1 contingencies of these generating facilities were classified as an outage of the whole power plant that could include multiple units. Examples of such power generating facilities are the Delta Energy Center (DEC) which is comprised of three combustion turbines and a single steam turbine.

2.3.1.3 Post Transient Analyses

For the ISO balancing authority area backbone system assessment, post transient analyses were performed to ascertain compliance with the WECC post transient voltage deviation standards, with one exception being the SCE system. For the SCE system, consistent with the SCE guidelines for 7% deviation requirements for N-1 contingencies, the 7% and 10% voltage deviation guidelines were applied for the N-1 and N-2 contingency analyses respectively. The WECC standards specify maximum post-transient voltage deviation of 5% and 10% for Categories B and C contingencies, respectively, for impacts caused on other systems. The SCE's post-transient voltage deviation guidelines apply to its own system and not to other systems. For impacts caused on other systems, all PTOs follow WECC standards on post-transient voltage deviations.

2.3.1.4 Transient Stability Analyses

Transient stability simulations were also performed as part of the backbone system assessment ensures system stability and positive damping of system oscillations for critical contingencies. This ensured that the transient stability criteria for performance levels B and C as shown in table 2.3-1 were met.

Table 2.3-1: WECC transient stability criteria

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

2.3.2 Study Assumptions

The following study horizon and assumptions were modeled in the 2010/2011 ISO transmission planning analysis.

2.3.2.1 Study Horizon

The NERC standards, TPL-001 through TPL-003 (given in section 2.2.1) and compliance related studies were performed for both the near-term (i.e., year 2015) and long-term (i.e., year 2020) scenarios. Additional studies for the NERC TPL-004 standards which relate to extreme system events were performed for the near-term (2015) scenarios only.

2.3.2.2 Peak Demand

In 2010 the ISO balancing authority area peak demand was 47,350 MW and occurred on August 25, 2010 at 4:20 p.m. The peak demands for PG&E occurred on the same date and time at 21,297 MW. However, SCE and SDG&E peak demands occurred on a different date and times: (a) for SCE, it occurred on September 27, 2010, at 2:51 p.m. with 23,678 MW; and (b) for SDG&E, it also occurred on September 27, 2010, however, at 3:25 p.m. with 4,684 MW.

Most of the ISO balancing authority area experiences summer peaking conditions. Hence, summer peak conditions were mainly considered in all studies. For areas that experienced highest demand in the winter season, or where historical data indicated other conditions may require separate studies, winter peak and summer off-peak studies were also performed. Examples of such areas are Humboldt, Greater Fresno and the Central Coast in the PG&E service territory. Table 2.3-2 summarizes these study areas and the corresponding peak scenarios for the reliability assessment.

Table 2.3-2: Summary of study areas, horizon and peak scenarios for the 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 Winter Peak	Summer Peak Winter Peak
Northern Califronia (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

2.3.2.3 Stressed Import Path Flows

As part of the interconnected transmission system in California, the ISO balancing authority area is interconnected with neighboring balancing authority areas through interconnections over which power can be imported or exported to and from the ISO balancing authority area. The power that flows across these import paths are an important consideration in developing the study base cases. For the 2010/2011 planning study and consistent with operating conditions for a stressed system, high import path flows were modeled to serve the ISO's balancing authority area load. These import paths are discussed in more detail *in section 2.3.2.10.*

2.3.2.4 Contingencies

In addition to studying the system under TPL-001 (normal operating conditions), the following provides additional detail on how the TPL-002, TPL-003, and TPL-004 standards were evaluated.

TPL-002

For this standard, loss of a single BES element which included loss of one generator (G-1), one transformer (T-1), one transmission line (L-1), DC lines, and a selected loss of one generator, one transmission line (G-1/L-1), all outages of transmission facilities in the ISO balancing authority area of voltage levels 115 kV and above, and most of the 60 kV, 69 kV and 70 kV facilities were studied. The outages of transmission facilities that comprise the import paths with neighboring balancing authority areas were also studied. The list of contingencies was provided on the ISO secured website.

TPL-003

For this standard, loss of two or more BES elements which included loss of two transmission facilities in the same corridor, DCTL outages, loss of two nuclear units and a large number of two element outages (i.e., C-3 contingencies) were studied. In general, because many of the transmission facilities evaluated under the TPL-003 standard are major paths designed to transfer large amounts of power, the results of the analysis was considered to be more severe, and therefore more critical than many of the other Category C outages studied as part of the 2010/2011 study. The impact of outages of two or more elements that resulted from a combination of two Category B outages at voltage levels of 60 kV and above were also evaluated for a number of the local area studies;

TPL-004

For this standard, selected extreme events were studied. However, during the 2008/2009 planning process, the ISO performed a detailed assessment of the most severe Category D outages in the ISO balancing authority area. The results from this analysis were documented in the 2010 transmission plan[18]. The results documented in this report satisfy the TPL-004 standard requirement 1.3.1 as well as the requirement for this 2010/2011 transmission plan.

2.3.2.5 Generation Projects

The ISO modeled a 20% renewable energy scenario for the 2015 renewable focus reliability study case. Specifically, the ISO included in its 20% RPS portfolio for the 2015 study case the renewable generation and associated transmission in the ISO queue that was in the following stages of interconnection process and was expected to be in service by 2015:

- For serial interconnection studies, both the large generation 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 the process of signing their interconnection agreement; and
- All remaining renewable projects in phase II of the ISO Transition Cluster (after posting of financial securities).

For 2020 renewable transmission studies, the ISO evaluated various renewable scenarios to determine needed transmission to access and deliver renewable generation to meet 33% RPS goals. Chapters 4 and 5 include detailed study assumptions, methodology and results for the 2020 33% RPS transmission studies.

2.3.2.6 Transmission Projects

[18] 2010 Final California ISO Transmission Plan at http://www.ISO.com/2771/2771e57239960.pdf

The study included all existing transmission projects in service and the expected future transmission projects that have been approved by the ISO for interconnection in accordance with the project approval status list in the 2010 transmission plan. In addition, generation interconnection transmission related projects that were included in executed Large Generator Interconnection Agreements (LGIA) prior to the final posting of the 2011 transmission plan study plan on March 31, 2010, were included in the study cases. Refer to Appendix C of this report for the list of transmission projects modeled in the base cases.

2.3.2.7 Load Forecast

The local area load forecasts used in the study were developed by the corresponding PTOs using the CEC-approved load forecast in December 2009[19] as the starting point as the load forecast from the CEC did not provide the bus-level demand projections. The 1-in-10 load forecasts were modeled in each of the local area studies. The 1-in-5 coincident peak load forecasts were used for the northern area backbone system assessment as it covers a vast geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

Light Load Conditions

The assessment evaluated the light load conditions in various parts of the ISO balancing authority area to satisfy NERC compliance requirement 1.3.6 for TPL-001, TPL-002 and TPL-003. The ISO light load conditions in various local areas of the system ranged from 35% to 50% of the summer peak load in that area. In most cases, the impacts under light load conditions were less severe than those under peak load conditions.

Some of the local areas were not evaluated for light load conditions because they were known through documentary evidence to have less severe impacts or no impacts on the system as compared to impacts under peak load conditions. The ISO staff used the discretion allowed under requirement 1.3.1 of TPL-001 and 1.3.2 of TPL-002 and TPL-003 to limit evaluation of such areas only for peak load conditions.

2.3.2.8 Reactive Power Resources

Existing and new reactive power resources were modeled in the base cases for the study to ensure realistic reactive power support capability. These resources include generators, capacitors, static var compensators (SVC) and other devices. A list of generation plants and corresponding assumptions related to each of the eight local areas are provided in further details of this chapter. Appendix C also provides a list of several key reactive power resources that were modeled in the studies. For a complete list of these resources, refer to the base cases available at the ISO Market Participant Portal secured website (https://portal.ISO.com/tp/Pages/default.aspx)[20].

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[19] **http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html**

[20] This site is available to Market Participant who has submitted a Non-Disclosure Agreement (NDA) and is approved to access the portal by the ISO.

2.3.2.9 Operating Procedures

ISO operating procedures for both the system under normal (pre-contingency) and emergency (post-contingency) conditions were observed in this study. Table 2.3-3 summarizes major operating procedures that are utilized in the ISO controlled grid.

Table 2.3-3: 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
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)

2.3.2.10 Firm Transfers

Power flow on the major power transmission paths was considered and modeled as a firm transfer on the major import paths into the ISO BAA. In general, the northern California system has two major power transfer paths (i.e., Path 66 and Path 26). Table 2.3-4 lists the transfer capability and power flows that were modeled in each scenario on these paths in the northern area assessment for both the 2015 and 2020 base cases.

Table 2.3-4: Major Paths and Power Transfer Capabilities in the Northern California Assessment

Import Path	2015 Summer Peak	2015 Summer Off-Peak	2020 Summer Peak	2020 Summer Off-Peak
California-Oregon Intertie Flow (N-S) (MW)	4800	-3631	4800	-3665
Pacific DC Intertie Flow (N-S) (MW)	3000	-1855	3100	-1857
Path 15 Flow (S-N) MW	-534	5350	-62	5380
Path 26 Flow (N-S) MW	4000	-1052	4000	-674
Northern California Hydro % dispatch of nameplate	80%	n/a	80%	n/a

Table 2.3-5 lists the major paths in the SCE service territory in southern California and the corresponding power transfer capabilities (MW) under various system conditions as modeled in the base cases for the assessment.

Table 2.3-5: Major paths and power transfer capabilities for the SCE area assessment

Import Path	2015 Summer Peak	2015 Spring Off-Peak	2020 Summer Peak
Path 26 Flow (N-S)	3135	1942	3004
West of River	8542	7055	8048
East of River	7447	5945	6575
PDCI	3000	3000	3100
SCIT	17170	14499	15885

Table 2.3-6 lists the major paths in the SDG&E service territory in southern California and the corresponding power transfer capabilities (MW) under various system conditions as modeled in the base cases for the assessment.

Table 2.3-6: Major paths and power transfer capabilities for the SDG&E area assessment

Import Path	Path Flow (MW)	
	2015 Summer Peak	2020 Summer Peak
Midway-Los Banos (Path 15)	1038	1633
Arizona-California (Path 21)	3206	3685
Northern-Southern California (Path 26)	1180	936
IPP DC (Intermountain-Adelanto)	1823	1702
Sylmar-SCE	149	-26
IID-SCE	229	10
North of San Onofre	1809	1444
South of San Onofre	341	706
ISO-Mexico (CFE)	3	3
West of Colorado River (WOR)	4644	5969
East of Colorado River (EOR)	3474	3914
Lugo-Victorville 500 kV line	1331	1696
Eldorado-Mc Cullough 500 kV line	-137	-66
Perkins-Mead 500 kV line	310	166

2.3.2.11 Protection Systems

To help ensure reliable operation of the system, many remedial action schemes (RAS) or Special Protection System (SPS) have been installed in certain areas of the system. These protection systems trip load and/or generation upon detection of system overloads by strategically tripping circuit breakers under selected contingencies. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies. Table 2.3-7 lists major new and existing SPS that were included in the study.

Table 2.3-7: A sample of protection systems modeled for the reliability assessment

No.	RAS / SPS Name	Descriptions	Study Area
1	Middletown UVLS	Trip Middletown substation load under low voltages conditions.	PG&E - North Coast/North Bay
2	Humboldt SPS	Trip load in Humboldt under low voltages conditions	PG&E - Humboldt Area
3	Alameda Overload SPS	Drops City of Alameda load following the overload of Oakland cables.	PG&E - Greater Bay Area
4	Bay Area UVLS	Trip local distribution load. When detects low 230 kV voltage at Newark, Monta Vista, San Mateo.	PG&E - Greater Bay Area
5	Bay Meadows OL SPS	Trip one or two Bay Meadows distribution feeders. After loss of any San Mateo - Bay Meadows 115 kV line.	PG&E - Greater Bay Area
6	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.	PG&E - Greater Bay Area
7	Evergreen - San Jose B OL	Trip San Jose CBs 112, 122 following the OL on Evergreen - San Jose B	PG&E - Greater Bay Area
8	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.	PG&E - Greater Bay Area
9	Grant - Eastshore OL SPS	Trip Grant feeder breakers 1105 & 1108 if OL on Grant - Eastshore #1, #2	PG&E - Greater Bay Area
10	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.	PG&E - Greater Bay Area
11	Metcalf SPS	Trip load and curtail generation following the loss of Moss Landing - Metcalf or Metcalf – Tesla	PG&E - Greater Bay Area
12	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.	PG&E - Greater Bay Area
13	Moraga - Oakland J OL SPS	Trip Oakland J CB 122 (Jenny) if load > 750 A on Moraga – J	PG&E - Greater Bay Area

No.	RAS / SPS Name	Descriptions	Study Area
14	Newark Dumbarton OL SPS	Trip Dumbarton CB 132 if OL on Newark - Dumbarton 115	PG&E - Greater Bay Area
15	San Francisco RAS	Trip Area Load after NERC Cat D loss of area generation or transmission.	PG&E - Greater Bay Area
16	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.	PG&E - Greater Bay Area
17	Paso Robles UVLS	Drops load at Paso Robles Substaion to mitigate any voltage collapse concerns for the loss of Paso Robles - Templeton 70 kV line	PG&E - Los Padres Area
18	SCE's "MWD Eagle Mountain Thermal Overload Protection Scheme"	The thermal overload relay will trip Eagle Mountain-Julian Hinds if an overload is detected on the Iron Mountain-Eagle Mountain 230 kV line.	SCE
19	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 configuration	SCE
20	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.	SCE
21	Mariposa UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley
22	Ashlan 230 kV UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley
23	McCall 230 kV UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley
24	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.	PG&E - Stockton Area

25	Blythe RAS	There is an existing Blythe RAS 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-tie line. This RAS is used 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.	SCE
26	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 500 kV (or Lugo-Rancho Vista, after Lugo-Serrano is looped in).	SCE
27	Yolo 115 kV UVLS	Trip load in the Woodland area if under voltages detected	PG&E Scramento Area
28	Figarden 230 kV UVLS	Trip load in the area if under voltages detected	PG&E San Joaquin Valley
29	500 kV TL 50001 IV Generator SPS	Trip generation at CLR II and TDM under contingency conditions	SDG&E
30	Miguel transformer protection	Monitors the loss of transformer and the loading on the remaining transformer	SDG&E
31	Otay Mesa – Tijuana SPS	A redundant scheme is installed to protect the line from loading above its continuous rating	SDG&E
32	TL 649 69 kV SPS	An SPS to protect TL 649 from thermal overload for an outage of TL 6910	SDG&E
33	Cascade Thermal Overload Scheme	An SPS to open the Crag View-Cascade 115 kV intertie to protect thermal overload on the Cascade-Benton-Deschutes 60 kV line.	PG&E North Valley Area
34	Caribou PH Thermal Overload Scheme	An SPS to protect the Caribou-Palermo 115 kV line from thermal overload by tripping generation in the Caribou area.	PG&E North Valley Area

2.3.2.12 Control Devices

Several control devices were also modeled in the study. These control devices were:

- All shunt capacitors in the SCE service territory;

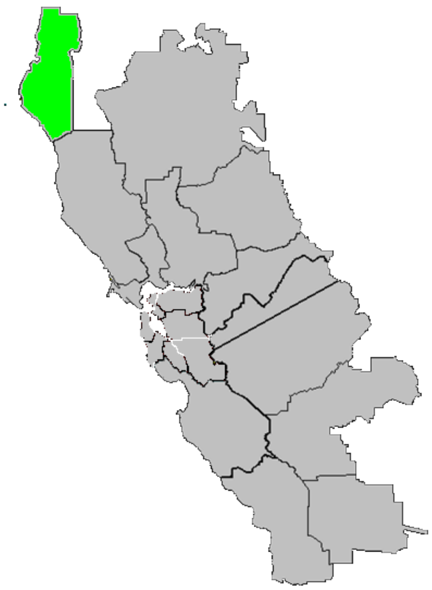
- Static var compensators at several locations such as Potrero, Newark, Rector, and Devers substations; and
- DC transmission lines such as the Pacific Direct Current Interface (PDCI), Inter-Mountain power plant direct current (IPPDC), and the Trans Bay projects.

For complete details of the control devices that were modeled in the study, please refer to the base cases that are available through the ISO Market Participant Portal secured website.

2.4 HUMBOLDT AREA

2.4.1 Area Description

The Humboldt area covers approximately 3,000 square miles in the northwestern corner of PG&E's service territory. Some of the larger cities that are served in this area include Eureka, Arcata, Garberville and Fortuna. The highlighted area in the adjacent figure provides an approximate geographical location of the Humboldt area.



Humboldt's electric transmission system is comprised of 60 kV and 115 kV transmission facilities. Electric supply to this area is provided primarily by generation at Humboldt Bay power plant, local QF generation units, and transmission imports via two 100 mile, 115 kV circuits from the Cottonwood substation east of this area and one 80 mile 60 kV circuit from the Mendocino substation south of this area.

Historically, the Humboldt area experiences its highest demand during the winter season. For the 2010/2011 transmission planning studies a summer peak and winter peak assessment was performed. For the summer peak assessment, a simultaneous area load of 178 MW and 191 MW in the 2015 and 2020 time frame was assumed. For the winter peak assessment, a simultaneous area load of 208 MW and 224 MW in the 2015 and 2020 time frame was assumed. An annual load growth for both summer and winter peak of approximately 3 MW per year was also assumed.

2.4.2 Area-Specific Assumptions and System Discussion

The Humboldt area study was performed in accordance with the general study assumptions and methodology described in section 2.3. The ISO secured website lists the contingencies that were evaluated as a part of this assessment. Specific assumptions and methodology applied to the Humboldt area study are provided below. Finally, since Humboldt is the only winter peaking area within PG&E, a detailed assessment was performed for both winter and summer peak conditions for the years 2011, 2012, 2013, 2014, 2015 and 2020.

Generation

Generation resources in the Humboldt area consist of market, Qualifying Facilities (QFs) and self-generating units. Notable resource model modifications for this area include the addition of the *Humboldt Bay Re-powering Project* which started commercial operation during the 2010 summer timeframe. This new plant replaced the existing Humboldt power plant which was retired in November 2010. In addition, the 12 MW *Blue Lake Power Biomass Project* was placed into commercial operation on August 27, 2010. This project mitigated many voltage concerns that were identified in the previous reliability assessments of the Humboldt area.

Table 2.4-1 lists generation plants in the Humboldt area.

Table 2.4-1: Generation plants in the Humboldt area

Generation Plant	Max. Capacity
Humboldt Bay	166
Kekawaka	4.9
Pacific Lumber	32.5
LP Samoa	25
Fairhaven	17.3
Blue Lake	12
Generation Total	258

The studies assumed that a new 50 MW wind generation project will be added in 2015. This project plans to connect to the Rio Dell 60 kV substation.

Load Forecast

Loads within the Humboldt area reflect a coincident peak load for 1-in-10-year heat wave conditions of each study year. Tables 2.4-2 and 2.4-3 summarize loads modeled in the studies for Humboldt area in the PG&E system.

Table 2.4-2: Load Forecasts modeled in Humboldt area assessment, summer peak

1- IN- 10 YEAR HEAT WAVE NON-SIMULTANEOUS LOAD FORECAST SUMMER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
HUMBOLDT	168	170	172	175	178	191

Table 2.4-3: Load Forecasts modeled in Humboldt area assessment, winter peak

NON-SIMULTANEOUS LOAD FORECAST WINTER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
HUMBOLDT	197	200	203	206	208	224

2.4.3 Study Results and Discussions

TPL 001: System Performance under Normal Conditions
For the winter peak and summer peak cases, there were no facilities identified with thermal overloads and no facilities identified with low voltage concerns under the Category A performance requirement.
TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (N-1/G-1)
For the winter peak cases, there were no facilities identified with thermal overload under the Category B performance requirement and no facilities identified with low voltage concerns or high voltage deviations under the Category B performance requirement.
For the summer peak cases, there were five facilities identified with thermal overloads and there were no facilities identified with low voltage concerns or high voltage deviations under the Category B performance requirement. Five facilities identified as overloaded included two sections of the same transmission line.
TPL 003: System Performance Following Loss of Two or More BES Elements
For the winter peak cases, there were 12 facilities identified with thermal overloads and 10 buses identified with low voltage concerns under the Category C performance requirement. In addition, voltage deviation concerns were also identified on 10 buses. Out of 12 facilities that had thermal overloads, five were separate sections of the two transmission lines. Voltage concerns included two diverged cases.
For the summer peak cases, there were 14 facilities identified with thermal overloads. Seven buses were identified with low voltage concerns, and eight buses were identified with voltage deviation concerns under the Category C performance requirement. Out of 14 facilities that had thermal overloads, 11 were separate sections of five transmission lines.
Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak and winter peak conditions along with the corresponding proposed solutions.

2.4.4 Recommended solutions for identified thermal overloads and voltage concerns

Based on this year's reliability assessment results of the PG&E Humboldt area, the ISO identified needed solutions to address system performance results that did not meet the thermal and voltage performance requirements under Categories B and C contingency conditions. These solutions are needed to maintain or enhance system reliability in a manner consistent with the applicable planning standards and the BPM for the transmission planning process.

2.4.4.1 Thermal Overload Mitigations

Humboldt Bay– Humboldt 60 kV #1

The Humboldt Bay-Humboldt 60 kV #1 transmission line consists of two sections: Humboldt-Humboldt Junction and Humboldt Junction-Humboldt Bay. This line is paralleled by the Humboldt Bay-Humboldt 60 kV line #2 and the Humboldt-Eureka, Eureka-Humboldt Bay 60 kV lines. The summer analysis results indicated that the Humboldt-Humboldt Junction portion of the line would exceed its emergency rating for both Category B and Category C contingencies of the parallel transmission lines and also Category C contingencies of any two transmission lines in the Cottonwood-Bridgeville – Humboldt area starting from 2015 for Category B and 2011 for Category C. The Category B overloads are not expected until 2015, and Category C overloads are expected starting in 2011. The Humboldt Junction-Humboldt Bay portion of the line has a higher rating and will exceed its emergency rating only for Category C contingencies of the parallel transmission lines between Humboldt and Humboldt Bay starting from 2011.

The winter analysis results indicated that the Humboldt-Humboldt Junction portion of the line would exceed its emergency rating for Category C contingencies of the parallel transmission lines: the Humboldt Bay-Humboldt 60 kV line #2 and the Eureka-Humboldt Bay starting from 2011. Line overloads for Category B contingencies of either one of these parallel transmission lines were not found in this analysis. This is because of the higher transmission line ratings that were assumed for the winter conditions.

Power flow studies modeled the new Humboldt Bay power plant generating at full output. An overload on the Humboldt Bay– Humboldt 60 kV #1 transmission line was caused by high output of the six generation units of the Humboldt Bay power plant connected to the 60 kV bus. A new wind generation project that plans to connect to the Rio Dell 60 kV substation significantly impacted the observed overload.

Humboldt Bay-Humboldt 60 kV line #1 will be upgraded in 2012 as a part of the PG&E's *Infrastructure Replacement Project*, which is a maintenance project that does not require ISO approval. If the line is not reconductored, then an SPS to trip some of the Humboldt Bay generation will be needed by 2015. The ISO will follow with PG&E on the maintenance project of the line reconductoring and/or the SPS installation.

In the short-term, the ISO proposes addressing these loadings concerns by applying the PG&E action plan to reduce generation from the Humboldt Bay 60 kV power plant following the first contingency. This action plan was approved by the ISO. Under the worst scenario, for the Category B overload it is sufficient to trip one unit or reduce generation by 16.6 MW in 2020 if the line is not upgraded. For the Category C overload it is sufficient to trip 4 units or reduce generation by 62 MW in 2020 if the line is not upgraded.

Humboldt Bay– Humboldt 60 kV #2

An overload of this line is expected only during summer peak under Category C contingencies with an outage of the two parallel transmission lines such as any two lines out of the Humboldt Bay-Humboldt 60 kV line #1, the Humboldt-Eureka-Humboldt Bay 60 kV line and Humboldt Bay-Bridgeville 60 kV line starting from 2011.

An SPS to trip some of the Humboldt Bay 60 kV generation or an operational procedure to reduce output of the Humboldt Bay power plant units connected to the 60 kV bus after first contingency will mitigate this overload. The mitigation is required by summer 2011.

The ISO proposes addressing these Category C concerns by utilizing the PG&E's existing action plan. This action plan will reduce the Humboldt Bay power plant generation after the first contingency and thus will mitigate the Category C overloads.

Humboldt-Eureka 60 kV #1

The section of this transmission line between Harris and Eureka will exceed its emergency rating for certain Category C contingencies during summer peak starting from 2011 and under winter peak conditions starting from 2020. An SPS to trip some of the Humboldt Bay 60 kV generation or an operational procedure to reduce output of the Humboldt Bay power plant units connected to the 60 kV bus after first contingency will mitigate this overload. The mitigation is needed by summer 2011. The ISO proposes addressing these Category C concerns by utilizing the PG&E's existing action plan. This action plan will reduce the Humboldt Bay power plant generation after the first contingency and thus will mitigate the Category C overloads.

Humboldt Bay-Eureka 60 kV #1

This transmission line will exceed its emergency rating for certain Category B contingencies (such as Humboldt Bay-Humboldt 60 kV line #2 alone or together with any one generation unit in the area) during the summer peak starting from 2015 and under Category C contingencies beginning in 2011 both in summer and winter. For Category B conditions, the ISO proposes to install an SPS to trip a new wind power plant that plans to connect to the Rio Dell 60 kV substation. For Category C conditions, an operating procedure to reduce output of the Humboldt Bay power plant units connected to the 60 kV bus after first contingency will mitigate this overload. The ISO proposes addressing these Category C concerns by utilizing the PG&E's existing action plan. This action plan will reduce the Humboldt Bay power plant generation after the first contingency and thus will mitigate the Category C overloads. The ISO will follow with PG&E on the SPS installation to trip the new wind project by the time this project is constructed.

Humboldt Bay-Rio Dell Junction 60 kV #1

The section of this line between Newburg and Rio Dell Junction will exceed its emergency rating for certain Category B (Carlotta-Bridgeville 60 kV line) and Category C (Humboldt 60 kV bus) contingencies during summer peak starting from 2015 for Category B and 2011 for Category C. For Category B conditions, the ISO proposes to install an SPS to trip a new wind power plant that plans to connect to the Rio Dell 60 kV substation. A PG&E maintenance project to upgrade the Humboldt 60 kV bus to a breaker-and–a-half configuration will mitigate the overload under Category C conditions (an outage of the Humboldt 60 kV bus). Upgrade of the Humboldt 60 kV bus will also mitigate overload of the sections between Newburg and Eel River and between Eel River and Humboldt Bay. The ISO will follow with PG&E on the SPS installation to trip the new wind project by the time this project is constructed and on the maintenance project to upgrade the Humboldt 60 kV bus that is currently scheduled for December 2013. Prior to the upgrade of the Humboldt 60 kV bus, the PG&E action plan to reduce the Humboldt Bay power plant generation will mitigate the overload in case of the Humboldt 60 kV bus outage.

Rio Dell Junction – Bridgeville 60 kV #1

All three sections of this transmission line will exceed it emergency rating for certain Category B (Humboldt-Bridgeville 60 kV line or Humboldt Bay-Eel River 60 kV line) and Category C contingencies during summer peak starting from 2015 for Category B and 2011 for Category C and under Category C conditions during winter peak starting from 2011. The ISO-proposed SPS to trip a new wind power plant that plans to connect to the Rio Dell 60 kV substation described above will mitigate the Category B and some of the Category C overloads. The PG&E maintenance project to upgrade the Humboldt 60 kV bus to a breaker-and–a-half configuration will mitigate the overload that may occur with an outage of this bus both in summer and in winter. Category C overloads that may occur prior to the new wind generation project coming into service (estimated in 2015) will be mitigated by the existing PG&E action plan to reduce output of the Humboldt Bay power plant units connected to the 60 kV bus after first contingency.

Bridgeville-Garberville 60 kV #1

All three sections of this transmission line will exceed their emergency ratings for certain Category C contingencies during summer peak starting from 2015. The ISO-proposed SPS to trip the new wind power plant that will be connected to the Rio Dell 60 kV substation and the PG&E maintenance project to upgrade the Humboldt 60 kV bus will mitigate these overloads. The ISO will follow with PG&E on the SPS installation to trip the new wind project by the time this project is constructed and on the maintenance project to upgrade the Humboldt 60 kV bus.

Essex Junction-Arcata-Fairhaven 60 kV Line #1

Both sections of this transmission line will exceed their emergency ratings for certain Category C contingencies (Humboldt #1 60 kV & Humboldt-Arcata 60 kV #1 lines) during winter peak starting from 2013. Utilizing the PG&E operational procedure to disable load transfer from Janes Creek substation to this transmission line for a double outage of the Humboldt #1 and Humboldt-Arcata #1 60 kV lines will mitigate this overload. With this procedure, the Janes Creek load will be lost, however it is acceptable for Category C contingencies.

Fairhaven – Humboldt 60 kV #1

The section of this transmission line between Arcata Junction #2 and Humboldt will exceed its emergency rating for certain Category C contingencies (Humboldt #1 60 kV & Humboldt-Arcata 60 kV #1 lines) during winter peak starting from 2020. The PG&E operational procedure to disable load transfer from Janes Creek described in the previous paragraph will mitigate this overload with the loss of Janes Creek load which is acceptable for Category C contingencies.

Bridgeville 115/60 kV #1 Transformer

This transformer will exceed its emergency rating for certain Category C contingencies both in summer and in winter starting from 2011 in winter and 2015 in summer. PG&E plans a maintenance project to replace the Bridgeville transformer in December 2011 with a new transformer that will have a higher rating. The new transformer will have 90 MVA rating that will be sufficient to mitigate the overloads. The ISO will follow with PG&E on the Bridgeville transformer replacement. In interim, an existing operational procedure to open a circuit breaker 42 at the Bridgeville 60 kV bus after first contingency will mitigate the overload.

Humboldt 115/60 kV Transformer Banks #1 and #2

These transformers will exceed their emergency rating for certain Category C contingencies during winter peak starting from 2012. Replacement of these transformers with the ones with the higher ratings was approved by the ISO in the 2009 ISO transmission plan and is planned for the year 2012 for the first bank and 2013 for the second one. The transformer replacement will mitigate the overloads. In interim, tripping some of the Humboldt Bay power plant 115 kV generation will be required. The ISO will follow with PG&E on developing an SPS or an operating procedure that is needed by winter of 2012.

2.4.4.2. Voltage Concern Mitigations

Low voltages and high voltage deviations were observed for the Category C outage of the Bridgeville 115/60 kV transformer and either Rio Dell 60 kV Tap or Humboldt Bay-Eel River 60 kV line both in summer and winter starting from 2015. In the system model of 2020, an outage of the Bridgeville 115/60 kV transformer and Rio Dell Tap 60 kV line did not converge. High voltage deviations were also observed with an outage of the Bridgeville 115/60 kV transformer and Carlotta-Pacific Lumber 60 kV line in 2020 both under summer and winter peak conditions. For the winter peak cases, an outage of the Bridgeville 115/60 kV transformer and the Garberville-Kekawaka 60 kV line also resulted in the diverged power flow case for the system model of 2020. To mitigate these problems, the PG&E existing operating procedure to open circuit breaker 42 at the Bridgeville 60 kV bus with the Bridgeville 115/60 kV transformer outage needs to be applied. Opening this circuit breaker will sectionalize the 60 kV system between Bridgeville and Garberville so that the Fruitland and Fort Seward substations will be served from the North Coast area through Garberville. No load shedding is expected with this operational procedure after the first contingency; however some local load shedding (at Carlotta substation) may occur with the second contingency. With this procedure, the voltage concerns were mitigated and the diverged cases were solved.

2.4.5 Key Conclusions

The ISO study of the Humboldt area yielded the following conclusions:

- No overloads would occur under normal conditions;
- Five overloads would occur for five Category B contingencies under summer peak conditions starting in 2015 and no overloads would occur for single contingencies under winter peak conditions;
- No low voltages or voltage deviation concerns would occur under summer or winter peak conditions caused by single contingencies;
- 14 overloads would occur for various multiple contingencies under summer peak conditions starting in 2011, and 12 overloads driven by various multiple contingencies under• winter peak conditions also starting in 2011; and
- No low voltages or voltage deviations would occur for multiple contingencies if existing PG&E operating procedures are utilized.

The identified overloads will be addressed by the operational procedures and SPS mitigation solutions discussed above. No new transmission projects for the Humboldt area are required, and the ISO did not receive any new transmission projects through the request window.

2.5 NORTH COAST AND NORTH BAY AREAS

2.5.1 Area Description

The highlighted areas in the adjacent figure provide an approximate geographical location of the North Coast and North Bay areas.

The North Coast area covers approximately 10,000 square miles north of the Bay Area and south of the Humboldt area along the northwest coast of California. It has a population of approximately 850,000 people in Sonoma, Mendocino, Lake and a portion of Marin counties and extends from Laytonville in the north to Petaluma in the south. The North Coast area has both coastal and interior climate regions. Some substations in the North Coast area are summer peaking, and some are winter peaking. For the summer peak assessment, a simultaneous area load of 809 MW and 870 MW in the 2015 and 2020 time frame was assumed. For the winter peak assessment, a simultaneous area load of 635 MW and 676 MW in the 2015 and 2020 time frame was assumed. An annual load growth for both summer and winter peak of approximately 12 MW per year was also assumed.. A significant amount of North Coast generation is from geothermal (The Geysers) resources. The North Coast area is connected to the Humboldt area by the Garberville-Laytonville 60 kV line, to the North Bay by the 230 kV and 60 kV lines between Lakeville and Ignacio and to the East Bay by 230 kV lines between Lakeville and Vaca Dixon and 115 kV lines between Eagle Rock and Mendocino and Cortina.

North Bay encompasses the area just north of San Francisco. This transmission system serves the counties of Marin, Napa and portions of Solano and Sonoma Counties. Some of the larger cities that are served in this area include Novato, San Rafael, Vallejo and Benicia. North Bay's electric transmission system is comprised of 60, 115, and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento, and Bay Area.

For the summer peak assessment, a simultaneous area load of 790 MW and 838 MW in the 2015 and 2020 time frame was assumed. For the winter peak assessment, a simultaneous area load of 707 MW and 748 MW in the 2015 and 2020 time frame was assumed. An annual load growth for both summer and winter peak of approximately 10 MW per year was also assumed. The same as the North Coast, North Bay area has both summer peaking and winter peaking substations. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and winter peak conditions that reflect different load conditions mainly in the coastal areas.

2.5.2 Area-Specific Assumptions and System Conditions

The North Coast and North Bay area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO's secured website lists the contingencies that were performed as part of this assessment. Specific assumptions and methodology applied to the North Coast and North Bay area studies are provided below. Finally, since the North Coast and North Bay areas have both summer peaking and winter peaking substations, a detailed assessment was performed for both winter and summer peak conditions for the years 2011, 2012, 2013, 2014, 2015 and 2020.

Generation

Generation resources in the North Coast and North Bay areas consist of market, QFs and self-generating units. Table 2.5-1 lists generating plants in the North Coast and North Bay areas.

Table 2.5-1: Generator in North Coast and North Bay areas

Plant Name	Max Capacity (MW)
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
Bottle Rock	55
Geysers 17	118
Geysers 18	118
Geysers 20	118
SMUD Geo	72
Potter Valley	11
Geo Energy	20
Indian Valley	3
Sonoma Landfill	6
Exxon	54
Monticello	12
Generation Total	**1619**

Load Forecast

Loads within the North Coast and North Bay areas reflect a coincident peak load for 1-in-10-year heat wave conditions of each study year. Tables 2.5-2 and 2.5-3 summarize the substation loads assumed in the studies for North Coast and North Bay areas under summer and winter peak conditions.

The studies also modeled two future renewable generation projects. A new 66 MW wind generation project was assumed to be on-line in 2015 connected to the Eagle Rock-Cortina 115 kV transmission line. The second project, 35 MW geothermal plant was modeled connected to the Geysers #3-Cloverdale 115 kV line. It was also assumed to be on-line in 2015.

Table 2.5-2: Load forecasts modeled in North Coast and North Bay area assessments, summer peak

1- IN- 10 YEAR HEAT WAVE NON-SIMULTANEOUS LOAD FORECAST						
SUMMER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
NORTH COAST	764	777	789	798	809	870
NORTH BAY	756	765	777	783	790	838

Table 2.5-3: Load forecasts modeled in North Coast and North Bay area assessments, winter peak

NON-SIMULTANEOUS LOAD FORECAST						
WINTER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
NORTH COAST	598	607	616	623	635	676
NORTH BAY	678	685	695	701	707	748

2.5.3 Study Results and Discussions

TPL 001: System Performance under Normal Conditions
For the summer peak cases, there were no facilities identified with thermal overloads and no facilities identified with low voltage concerns under the Category A performance requirement.
However, the Bridgeville-Garberville 60 kV transmission line was heavily loaded (from 97% to 99% of its normal rating depending on the line section) in the 2020 summer peak case.
For the winter peak cases, there were no facilities identified with thermal overloads and no facilities identified with low voltage concerns under the Category A performance requirement.
TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (N-1/G-1)
For the summer peak cases, there were four facilities identified with thermal overloads under the Category B performance requirement. Out of these four facilities, two were sections of the same transmission line. There were no low voltage concerns, but four buses were identified as having voltage deviation concerns.
For the winter peak cases, there were two facilities identified with thermal overloads, no facilities with low voltage concerns and two buses with high voltage deviation under the Category B performance requirement.
TPL 003: System Performance Following Loss of Two or More BES Elements
For the summer peak cases under the Category C performance requirements, there were 34 facilities identified with thermal overloads, including 21 separate sections of seven transmission lines. 32 facilities were identified with low voltage concerns and 42 facilities with high voltage deviations.
For the winter peak cases, there were 12 facilities identified with thermal overloads, 10 facilities with low voltage concerns and 14 facilities with high voltage deviations under the Category C performance requirement.

Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak and winter peak conditions along with the corresponding proposed solutions.

2.5.4 Recommended solutions for identified thermal overloads and voltage concerns

Based on this year's reliability assessment results of the PG&E North Coast and North Bay areas, the ISO identified needed solutions to address system performance results that did not meet the thermal and voltage performance requirements under Categories B and C contingency conditions. These solutions are needed to maintain or enhance system reliability in a manner consistent with the applicable planning standards and the BPM for the transmission planning process.

The proposed recommended solutions for the identified thermal overloads and voltage concerns are set forth below as well as information about the expected in-service dates of the proposed mitigation with the goal to achieve the required system performance over the planning horizon.

2.5.4.1 Thermal Overload Mitigations

Ignacio-San Rafael 115 kV Line

This transmission line is expected to overload under Categories B and C emergency conditions. For the summer peak, the overload is expected to start in 2020, and for the winter peak the overload is expected to start in 2011. The higher loading in winter is explained by higher load on the San Rafael substation in winter than in summer. The limiting element on this line is a disconnect switch which is rated for 600 A. The ISO proposes to mitigate this overload by replacing the disconnect switch with one rated at least for 800 A. The switch should be replaced as soon as possible to mitigate the overload, or else the potential exists for some of the load on San Rafael or Las Gallinas substations to be tripped. With the line conductor as the limiting element, the Ignacio-San Rafael 115 kV line may overload under winter peak emergency conditions starting from 2020. In addition to the disconnect switch replacement, the ISO recommends reconductoring the Ignacio-San Rafael 115 kV line in 2020 if the overload is identified in the next year's assessment with the updated load forecast. The ISO will coordinate with PG&E the replacement of the disconnect switch, as well as the line reconductoring later on.

Mendocino - Redbud 115 kV Line #1

The section of this transmission line between Red Bud and Red Bud Junction 1 may overload under Category C emergency conditions during summer peak starting in 2011. No overload on this line is expected in winter. The overload is not expected to occur after 2016 when the *Middletown 115 kV Project* (Clear Lake 60 kV System Reinforcement) will come on line. To mitigate the overload in interim, the ISO proposes that the re-rate of the line be considered or that an SPS or operating procedure to trip some load in the North Geysers area for the second contingency be developed. The ISO will work with PG&E on the interim solution to this overload.

Eagle Rock - Redbud 115 kV #1

This line consists of five sections, three of which may overload under Category C emergency conditions during summer peak starting in 2011. No overload on this line is expected in winter.

The *Middletown 115 kV Project* (Clear Lake 60 kV System Reinforcement) will mitigate overload of the section between Red Bud Junction 2 and Cache. However, in the interim, an operating procedure to drop the load in the north Geysers area for the second contingency should be implemented in 2011 to mitigate any overload on the two remaining overloaded sections. PG&E has a procedure that is included in the PG&E Summer 2010 Action Plan for N-1-1 overloads. The procedure disables automatic load transfer at Lucerne 115 kV substation and drops up to 8 MW of load at Redbud 115 kV substation following the first contingency. Applying this action plan will mitigate the Category C overloads.

Geysers 3 - Cloverdale 115 kV Line #1

Overload on Cloverdale-MPE Tap section of this transmission line is expected for Category B contingency conditions during summer peak starting in 2015 and during winter peak starting in 2020, as well as for Category C contingency conditions starting from 2011 during both summer and winter peaks.

The proposed solution to mitigate these overloads is to develop an SPS to trip a new geothermal project that is proposed to be connected to the Geysers #3-Cloverdale 115 kV line, in case of the contingency overload. Tripping generation will be sufficient to mitigate Category B overload. However, it will not be sufficient for some of the Category C overloads. Tripping generation at Geysers and also some load at Ukiah in summer will be required for the Eagle Rock-Red Bud-Cortina and Cortina-Mendocino 115 kV double line outage. In winter, no load tripping will be required for Category C outages.. ISO will follow with PG&E on the SPS installation.

Fulton - Santa Rosa 115 kV Line #1 and Fulton - Santa Rosa 115 kV Line #2

These lines are expected to overload under Category C contingency conditions starting in 2011 during summer peak.

The ISO proposes to develop an SPS to drop the load supplied from these lines under contingency conditions to mitigate these overloads. The study results show that this mitigation plan is needed in 2011. PG&E has an Action Plan to re-adjust the system after the first contingency and curtail some load as a final option. However, load curtailment after the first contingency is not an acceptable solution. The ISO will follow with PG&E on installation of the SPS.

Santa Rosa - Corona 115 kV Line #1, Corona - Lakeville 115 kV Line #1, and Sonoma - Pueblo 115 kV Line #1

These transmission lines may overload under Category C contingency conditions for an outage of both Fulton 230/115 kV transformer banks starting in 2011 during summer peak. These transmission lines are not expected to overload in winter.

The proposed solution to mitigate these overloads is to add a third Fulton 230/115 kV transformer. The ISO proposes to install the third transformer bank and not an SPS due to the high cost of the SPS that is comparable with the cost of the project. In addition, the SPS would be complicated due to the need of tripping load at multiple locations and the need to monitor three transmission lines for overloads, 19 substations for low voltages and 28 substations for high voltage deviations.

In interim, an existing PG&E operating plan to perform system sectionalizing and load switching can be utilized. This plan may include load tripping after first contingency which is not an acceptable solution. The ISO will discuss with PG&E the interim plan.

Fulton - Pueblo 115 kV Line #1

The section of this line between Pueblo and Pueblo Junction is expected to overload following an outage of a 115 kV double circuit Lakeville-Sonoma tower line (Category C contingency) starting from 2013 under summer peak conditions.

The proposed solution to mitigate this overload is to utilize the existing SPS to trip load at Pueblo 115 kV substation.

Hopland 115/60 kV Transformer Bank #2

This transformer may overload for the Category C contingency with an outage of two Mendocino 115/60 kV banks both under summer or winter peak load conditions.

The proposed solution to mitigate this overload is to develop an SPS to trip generation from the Geo Energy power plant and from the new geothermal project that plans to connect to the Geysers #3-Cloverdale 115 kV line. This SPS is needed by winter 2011. The ISO will work with PG&E on development of the SPS.

Eagle Rock 115/60 kV Transformer Bank #1

This transformer may overload under Category C contingency conditions during summer peak starting from 2011. *Middletown 115 kV Transmission Project* (Clear Lake 60 kV System Reinforcement) that was approved by the ISO in the 2009 transmission plan will mitigate this overload. Since this project is not expected to come on-line until 2016, as interim solution, an operating procedure to open a circuit breaker CB22 at the Clear Lake 60 kV substation (to Mendocino) and close normally opened circuit breaker at Middletown 60 kV (to Calistoga) will mitigate the overload. This interim solution is included in the PG&E action plan.

Bridgeville - Garberville 60 kV Line #1

This transmission line consists of 3 sections: between Bridgeville and Fruitland Junction, Fruitland Junction-Fort Seward Junction and Fort Seward Junction and Garberville. The line is expected to be loaded up to 99% in 2020 under summer normal conditions. Two sections of the line are expected to overload under Category B contingencies during summer peak starting from 2020, and all sections of the line are expected to overload under Category C contingencies during summer peak starting in 2011.

No overload on the Bridgeville - Garberville 60 kV Line #1 is expected in winter.

Based on the current data, the preferred solution to mitigate these overloads would be to re-rate or upgrade the line in 2020. Given that the need does not arise until 2020, the ISO will continue to monitor the situation and adopt any appropriate mitigation solution in a future transmission plan. For Category C contingencies, it is needed to open a circuit breaker CB 42 at Garberville (to Laytonville) after the first contingency to mitigate the overload. Opening this breaker will separate Garberville substation from Mendocino and significantly reduce loading on the Bridgeville-Garberville 60 kV line. PG&E has an existing operating procedure to open this circuit breaker.

Mendocino - Clear Lake 60 kV Line #1

All three sections of this transmission line are expected to overload under Category C contingency conditions during summer peak starting from 2011, and one section is expected to overload under Category C contingencies during winter peak starting from 2014.

The *Middletown 115 kV Project* (Clear Lake 60 kV System Reinforcement) planned to be in service in 2016 will mitigate these overloads. In the interim, an operating procedure to open a circuit breaker CB22 at the Clear Lake 60 kV substation (to Mendocino) and close the normally opened circuit breaker at Middletown 60 kV (to Calistoga) will mitigate the overload. The ISO will follow with PG&E on this interim solution.

Mendocino-Philo-Hopland 60 kV Line

All three sections of this transmission line may overload under Category C contingency conditions during summer peak starting from 2011 and one section may overload under Category C contingency during winter peak starting from 2020.

The proposed solution to mitigate these overloads is to utilize the existing SPS that opens Hopland 115/60 kV transformer bank and trips Ukiah and Cloverdale 115 kV load for an overload on the Mendocino-Philo-Hopland 60 kV line for these contingencies.

Clear Lake - Eagle Rock 60 kV Line #1

Both sections of this transmission line are expected to overload under Category C contingency conditions both during summer and winter peak starting from 2011.

The *Middletown 115 kV Project* (Clear Lake 60 kV System Reinforcement) planned to be in service in 2016 will mitigate overload on the section between Eagle Rock and Konocti, but will exacerbate the overload on the section between Konocti and Clear Lake. The permanent solution to this overload will include reconductoring of the Clear Lake –Konocti 60 kV line as a part of the *Middletown 115 kV Project*. In the interim, an operating procedure to open a circuit breaker CB22 at the Clear Lake 60 kV substation (to Mendocino) and close normally open circuit breaker at Middletown 60 kV (to Calistoga) will mitigate the overload. However, keeping the Middletown-Calistoga 60 kV line normally open after the *Middletown 115 kV Project* is completed will mitigate the overload on this line that might occur with another Category C outage (Eagle Rock-Fulton-Silverado 115 kV and Geysers #9-Lakeville 230 kV double outage) after 2016.

The ISO will work with PG&E on the solution to this overload and propose the optimal solution in the next transmission plan.

Ignacio - Alto 60 kV Line #1

The section of this transmission line between Ignacio and Greenbrae is expected to overload with an outage of the parallel double-circuit tower line (Category C contingency) starting in 2011 both under summer and winter peak load conditions. The ISO proposes to install an SPS that would trip the load at Alto 60 kV substation to mitigate this overload. An alternative plan to reconductor the line proposed by PG&E is not recommended due to its higher cost compared to the SPS and the fact that overload is expected to occur only for a Category C contingency. The amount of tripped load is up to approximately 30 MW in 2020. The ISO will follow with PG&E on the SPS installation.

Ignacio-Alto-Sausalito 60 kV Lines #1 and 2

The sections of these transmission lines between Ignacio and Hamilton Field are expected to overload under Category C contingency conditions with an outage of the parallel two lines starting from 2011 both during summer and winter peak.

The proposed mitigation plan is for PG&E to replace switches that are the limiting elements. The lines are comprised from the 477 ACSS conductor that is not expected to overload. In interim, the recommendation is to trip load at Alto or at Greenbrae 60 kV substations with the second contingency. The ISO will follow with PG&E on the replacement of the switches.

Lakeville #2 60 kV Line #1

Three sections of this transmission line are expected to overload under Category C contingency conditions starting from 2011 during summer peak, and one section is expected to overload under the same conditions during winter peak.

The proposed solution to mitigate these overloads is to utilize the existing SPS to trip load at the Petaluma 60 kV substation in case of the line overload.

2.5.4.2 Voltage Concern Mitigations

The contingency that caused widespread low voltages and high voltage deviations was an outage of two Fulton 230/115 kV transformer banks. To mitigate these concerns, and also to mitigate multiple overloads that may occur with this outage, the ISO recommends that PG&E installs a third 230/115 kV transformer bank at the Fulton substation. The need for the third Fulton 230/115 kV transformer is also described above in the discussion of the Santa Rosa - Corona 115 kV line #1, Corona - Lakeville 115 kV line #1 and Sonoma - Pueblo 115 kV line #1 overloads.

Low voltages and high voltage deviations were also observed at the Alto and Greenbrae 60 kV substations for double contingencies of 60 kV lines between Ignacio, Alto and Sausalito (Category C contingencies). The mitigation plan is to install an SPS to trip load at the Alto substation for Category C voltage deviations. The same SPS will also mitigate the overloads that are expected for Category C contingencies. The SPS was described in the section discussing the Ignacio-Alto 60 kV line #1 overload.

Other voltage concerns may be mitigated by existing SPS or operational procedures. These concerns and the mitigation plans are summarized in Appendix A.

2.5.5 Key Conclusions

Based on the ISO study assessment, the North Coast/North Bay areas had:

- No overloads under normal conditions, although one transmission line may reach 99% of its rating by 2020; no buses with normal voltages below 0.90;
- Four overloads caused by three critical single contingencies under summer peak conditions; two overloads caused by two critical single contingencies under winter peak conditions;
- 34 overloads caused by 29 critical multiple contingencies under summer peak conditions and 12 overloads caused by 12 critical multiple contingencies under winter peak conditions; and
- Multiple voltage concerns under Category C contingencies.

In order to address the identified overloads, the ISO proposed one transmission upgrade project (addition of the third Fulton 230/115 kV transformer), replacement of switches on Ignacio-San Rafael 115 kV line and on Ignacio-Alto-Sausalito 60 kV lines, one transmission line re-rate (Bridgeville-Garberville 60 kV) and 10 SPS or operational procedures.

ISO received six proposed transmission projects through the 2010 request window. The ISO determined that one project, *Addition of the Third Fulton 230/115 kV Transformer*, was consistent with the ISO's proposed mitigation solution and is needed to mitigate identified reliability concerns. The ISO recommends installing an SPS in lieu of PG&E's proposed project, *Reconductoring of the Ignacio-Alto 60 kV Line* which was therefore determined not to be needed.

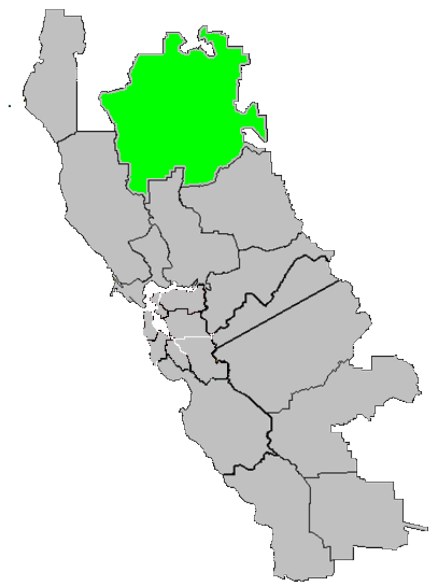
In addition, the following projects, submitted through the 2010 request window, are not needed because in the previous planning cycles, the ISO has approved transmission projects to mitigate the same identified reliability concerns:

- *Garberville Interim Solution* - the ISO approved Garberville Voltage Support Project which solves the same reliability concern;
- *Maple Creek Interim Solution* - the ISO approved Maple Creek Voltage Support Project which solves the same reliability concern;
- *Tulucay 60 kV Energy Storage Project* - the ISO approved reconductoring the Vaca Dixon-Lakeville 230 kV lines #1 and 2 which solves the same reliability concern; and
- *Ignacio 115 kV Energy Storage Project* - the ISO approved reconductoring the Ignacio-San Rafael 115 kV lines #1 and 2 which solves the same reliability concerns.

2.6 NORTH VALLEY AREA

2.6.1 Area Description

The North Valley area is located in the northeastern corner of the PG&E's service area and covers approximately 15,000 square miles. This area includes the northern end of the Sacramento Valley, and parts of the Siskiyou and Sierra mountain ranges and the foothills. Chico, Redding, Red Bluff and Paradise are some of the cities in this area. The figure below depicts the approximate geographical location of the North Valley area.



North Valley's electric transmission system is comprised of 60 kV, 115 kV, 230 kV, and 500 kV transmission facilities. The 500 kV facilities are part of the Pacific Intertie between California and the Pacific Northwest. The 230 kV facilities, which complement the Pacific Intertie, also run north to south with connections to hydroelectric generation facilities. The 115 kV and 60 kV facilities serve the local electricity demand. In addition to the Pacific intertie, there is one other external interconnection to the PacifiCorp system. The internal transmission system connections to the Humboldt and Sierra areas are via Cottonwood, Table Mountain, Palermo, and Rio Oso substations.

Historically, North Valley experiences its highest demand during the summer season, however there are very few and small areas in the mountains that experience highest demand during the winter season. Load forecasts indicate North Valley should reach a summer peak demand of 1021 MW by 2020 assuming load is increasing at approximately 11 MW per year.

Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions. Table 2.6-2 includes load forecast data.

2.6.2 Area-Specific Assumptions and System Conditions

The North Valley area study was performed consistent with the general study methodology and assumptions described in Section 2.3. The ISO secured website (i.e. ISO Market Participant Portal) lists contingencies that were performed as part of this assessment. Additionally, specific methodology and assumptions that are applicable to the North Valley area study are provided below.

Generation

Generation resources in the North Valley area consist of market, QFs and self-generating units. There are over 2,000 MW of hydroelectric generation facilities in this area. These hydroelectric facilities are fed from the following river systems: Pit River, Battle Creek River, Cow Creek, North Feather River, South Feather River, West Feather River and Black Butt. Pit, James Black, Caribou, Rock Creek, Cresta, Butt Valley, Belden, Poe, and Bucks Creek are some of the large powerhouses on the Pit River and the Feather River watersheds. The largest generation facility in the area is the Colusa County generation plant. This plant consists of a combined total capacity of 717 MW, and is interconnected to the four Cottonwood-Vaca Dixon 230 kV. A list of all the generating facilities in the North Valley area is given in table 2.6-1.

Table 2.6-1: Generation in the North Valley Area

No.	Generation Facility	Type	Max. Capacity (MW)
1	Pit River	Hydro	752
2	Battle Creek	Hydro	17
3	Cow Creek	Hydro	5
4	North Feather River	Hydro	736
5	South Feather River	Hydro	123
6	West Feather River	Hydro	26
7	Black Bute	Hydro	11
8	CPV Colusa	Thermal	717
9	Hatchet Ridge Wind	Wind	103
10	QFs	Co-Gen	353
	Total Generation		2843

Load Forecast

Loads within the North Valley area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.6-2 shows loads modeled for the North Valley area assessment as well as other local areas within PG&E system.

Table 2.6-2: Load forecasts modeled in the North Valley area assessment

1- IN- 10 YEAR HEAT WAVE NON-SIMULTANEOUS LOAD FORECAST						
SUMMER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
NORTH VALLEY	915	928	939	951	961	1,021

2.6.3 Study Results and Discussions

A summary of the study results of facilities in the North Valley area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

- All facilities met the thermal loading and voltage performance requirements under the normal conditions.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

- The ISO identified two facilities as not meeting the required thermal loading performance and eight substations as not meeting the required voltage performances under the Category B contingency conditions.

TPL 003: System Performance Following Loss of Two or More BES Elements

- The ISO identified 14 facilities as not meeting the required thermal loading performance and five substations as not meeting the required voltage performances under the Category C contingency conditions; and
- The ISO also identified power flow case divergence for three Category C contingencies.

Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak condition along with the corresponding proposed solutions.

2.6.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

Based on this year's reliability assessment results of the PG&E North Valley area, the ISO initially recommended solutions that address each of the identified facilities that did not meet the thermal and voltage performance requirements under Categories A (normal), B and C contingency conditions. The ISO then evaluated the initial recommended solutions as well as submissions made through the request window process.

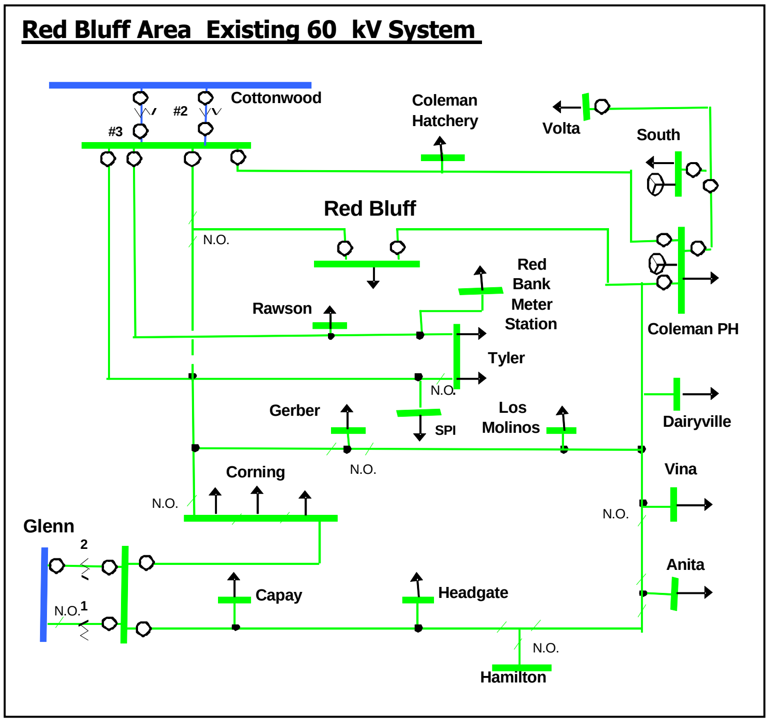
The following discussion addresses the analysis and the projects the ISO determined were needed to address the thermal and voltage performance requirements. This includes information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.6.4.1 Thermal Overload Mitigations

Red Bluff Area 230/60 kV Substation and Cottonwood – Red Bluff No. 2 60 kV Line

The Coleman-Red Bluff 60 kV line is approximately 18.4 miles long and serves load at Red Bluff, Dairyville, Los Molinos, and Vina substations. The Cottonwood-Red Bluff 60 kV line is approximately 16.5 miles long and has connections to Gerber and Anita substations that are normally open. The 2011 projected peak load in the Red Bluff area is approximately 94 MW and is forecast to increase at a rate of 2.1 MW/yr. Figure 2.6-1 below shows the one-line diagram of the existing Red Bluff 60 kV system.

Figure 2.6-1: Red Bluff 60 kV System



This year's assessment identified the following facilities in the Red Bluff area as not meeting the thermal and voltage performance requirements:

- Coleman – Red Bluff 60 kV line (existing overloads under Categories B & C);
- Cottonwood – Red Bluff 60 kV line (Category B overload starting 2017 and existing overload under Category C);
- Red Bluff area 60 kV substations (low voltages starting 2014 under Category B and existing low voltages under Category C); and
- Red Bluff area 60 kV substations (existing voltage deviations under Categories B & C).

To mitigate these overloads and voltage issues, PG&E submitted a project through the 2010 request window, the *Red Bluff Area 230/60 kV Substation and Cottonwood – Red Bluff No. 2 60 kV Line Project*, which proposes to build a new 230/60 kV substation and a small section of the Cottonwood – Red Bluff 60 kV line. Specifically, this project scope includes the following:

Cottonwood-Red Bluff No.2 60 kV Line (in-service date: May 2014)

- Build a new span from Red Bluff Jct. to Red Bluff substation and connect the new short line to the existing Cottonwood No. 2 60 kV line. This change will convert this back-up line into another dedicated source to Red Bluff 60 kV substation (to be named Cottonwood-Red Bluff No.2 60 kV);
- Convert Red Bluff to Ring Bus and add an extra breaker position for use in the second phase (below); and
- Upgrade all other equipment to achieve the maximum conductor rating.

Red Bluff area New 230/60 kV Substation Project (in-service date: May 2016)

- Build a new 230/60 kV substation under 230 kV corridor (Cottonwood - Vaca Dixon 230 kV lines) which is 1 mile away from Red Bluff substation;
- Install a three-phase 230/60 kV transformer rated to handle at least 420 MVA;
- Build a new one mile 60 kV line from the new substation to Red Bluff substation;
- Build a new seven mile 60 kV line from new substation to Tyler substation; and
- Upgrade all other equipment to achieve the maximum conductor rating.

Figure 2.6-2 shows the one-line diagram of the proposed project.

The project is expected to cost between $43M and $57M. The ISO determined that this project is needed to mitigate identified thermal overloads and voltage issues. In the interim, operating solutions such as utilizing short-term ratings, seasonal load transfer, and radializing certain system elements will be used to address these overloads and low voltages from occurring until the project is completed. The ISO staff will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

An alternative project considered included reconductoring certain 60 kV lines, installing a new 230/60 kV transformer bank and adding voltage support was considered. Specifically, this alternative is comprised of 35 miles of 60 kV line reconductoring, one new 230/60 kV transformer bank at Cottonwood substation, an upgrade of Cottonwood 230 and 60 kV bus configurations, an upgrade of Red Bluff 60 kV bus, and 10 MVAr of shunt capacitors installed at the Red Bluff 60 kV substation. This alternative is expected to cost between $50 million and $70 million. Figure 2.6-3 below shows the one-line diagram of the alternative solution considered.

Figure 2.6-2: Proposed Project

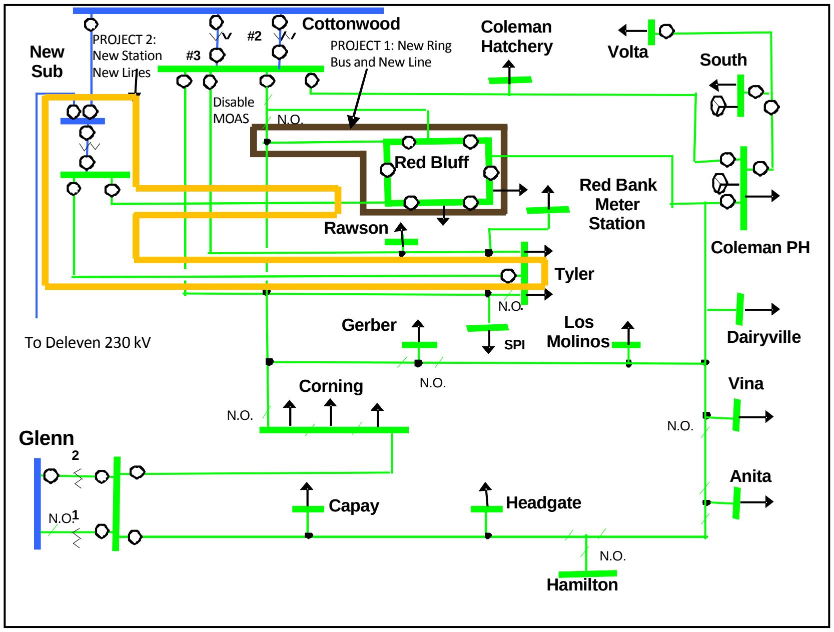
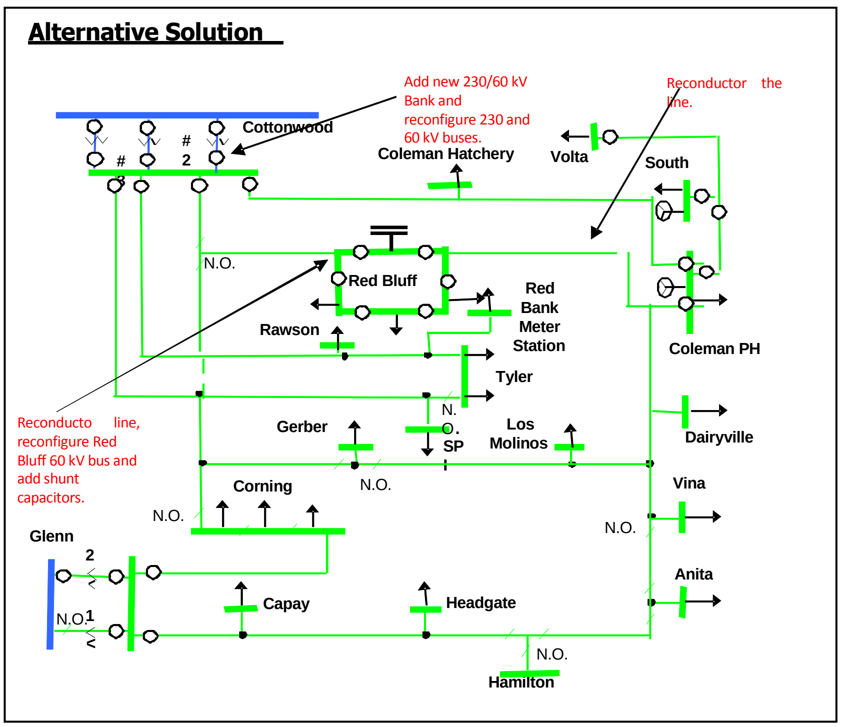


Figure 2.6-3: Alternative Red Bluff Area Solution



The power flow analysis showed that both solutions mitigate all the Red Bluff area thermal overloads and voltage issues identified in 2020. However, the new 230/60 kV substation solution resulted in better thermal loadings and voltages performances compared to the reconductoring alternative. Furthermore, the load-serving capability analysis showed that the new 230/60 kV substation option provides a higher load serving capability compared to the reconductoring alternative. Table 2.6-3 below shows the load-serving capabilities for the new 230/60 kV substation project along with the alternative considered.

Table 2.6-3: Summary of Load Serving Capability by Alternative

Alternative	Cost	Load Serving Capability (MW)	Limiting Element	Worst Contingency
SQ	$0M	70MW	Voltage and Thermal O/L Coleman-Redbluff 60 kV Line	Cottonwood-Red Bluff 60 kV Line and Cottonwood No.2 230/60 kV Transformer outage
Build New 230/60 kV Substation	$55M	128MW	Thermal O/L Cottonwood-Redbluff 60 kV Line (Red Bluff jct to Red Bluff)	NewSub-Redbluff and NewSub-Tyler 60 kV Line outage
Alternative: Reconductor and Shunt Caps	$70M	105MW	Voltage	Coleman-Cottonwood and Cottonwood-Red Bluff 60 kV Line outage

Request Window Submission - Red Bluff 60 kV Energy Storage Project

Western Grid Development, LLC (WGD) proposed an energy storage reliability-driven project, the *Red Bluff 60 kV Energy Storage Project*, to address the same reliability concerns addressed by the PG&E-submitted 2010 request window proposal to build a second Cottonwood-Red Bluff 60 kV line and a new 230/60 kV substation in Red Bluff area. The cost of the PG&E proposed project is between $43 million to $57 million. The WGD's proposed project has an initial capital cost of $22.5 million for 15 MW of storage capacity. WGD proposed to build and own the energy storage project and turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO staff considered the proposed energy storage project as an alternative to building a new 230/60 kV substation and the second Cottonwood – Red Bluff 60 kV line to determine whether PG&E should instead be directed to install energy storage facilities. The PG&E proposed project has a Category B local area load serving capability of more than 175 MW. At this load level, the size of the energy storage device would need to be about 43 MW to alleviate line overloads under Category B contingency conditions. Using the WGD provided cost; a 43 MW energy storage device is estimated to cost around $64 million. Furthermore, the energy storage device would also require augmenting an SPS to mitigate the loss of the energy storage device combined with some transmission lines in the area. This will further increase the cost of the energy storage project to ensure a comprehensive solution for the area. Hence, the ISO determined that the *Red Bluff 60 kV Energy Storage Project* is not needed.

Cottonwood-Benton No. 1 60 kV Line

The Cottonwood-Benton No. 1 60 kV line was identified with existing overloads under Category C contingency conditions. To mitigate this overload, PG&E submitted a project through the 2010 request window, *Cascade 115/60 kV No. 2 Transformer and Cascade-Benton 60 kV Line*, which consists of installing a new 115/60 kV transformer bank at the Cascade substation. The project has an in-service date of May 2014. The ISO determined that this project is needed to mitigate identified overloading concerns.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that the necessary operating procedures will be in place to meet reliability needs in 2011.

Request Window Submission - Cascade 60 kV Reliability Solution

Transmission Technology Solutions, LLC (TTS) proposed a SVC project, the *Cascade 60 kV Reliability Solution*, to address the same reliability concerns addressed by PG&E's proposed project to add a second Cascade 115/60 kV transformer and to build a second Cascade-Benton 60 kV line. The cost of the PG&E proposed project is between $20 million to $30 million. TTS's proposed project has a capital cost of $7.5 million. TTS proposed to build and own the SVC project, to turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO considered the proposed SVC project as an alternative to adding the second Cascade 115/60 kV transformer and building a second Cascade-Benton 60 kV line to determine whether PG&E should be directed to install SVC. TTS's proposed SVC project only mitigates the voltage concerns but not the thermal overloads in the Cascade area. PG&E's proposed project would still be needed to mitigate the thermal overloads in the Cascade system even with the TTS's proposed SVC in place. PG&E's proposed second Cascade-Benton 60 kV line would also mitigate the voltage problem in the area and, hence, voltage support provided by the SVC would not be needed. Hence, the ISO determined that the *Cascade 60 kV Reliability Solution* is not needed.

Keswick-Cascade and Keswick-Trinity-Weaverville 60 kV Lines

This line was identified as overloading under Category C contingency conditions in the 2015 and 2020 cases. This overload was mainly due to the additional renewable generation modeled the Humboldt area in these cases. The excess power generated in the Humboldt area flows towards Trinity and Cascade following an outage of the two Humboldt 115 kV tie lines. At this point, the ISO recommends that a short-term rating and operating procedure be developed by 2015 to reduce the Humboldt area generation following the first contingency to address this problem. This plan, and other possible options, will be assessed further and included in a future ISO transmission plan.

Table Mountain/Chico Area 115 kV Lines

All four 115 kV lines emanating from the Table Mountain substation serving the Chico/Sycamore area have been identified with existing thermal overloads under the various Category C contingency conditions. To mitigate these overloads, PG&E submitted a project through the 2010 request window, *the Table Mountain-Sycamore 115 kV Line Project,* which consists of building a new 115 kV line from the Table Mountain to Sycamore substation. The project has an in-service date of May 2015. The ISO determined that this project is needed to mitigate identified overloading concerns. The ISO also considered an SPS alternative to mitigate all

Category C overloads identified in this area and found that the SPS is not feasible as it is required to monitor number of contingencies more than the SPS guideline would allow. The ISO further considered another alternative, a feasible SPS combined with required upgrades to mitigate all overloads, and found this option to be more expensive compared to the *Table Mountain-Sycamore 115 kV Line Project*.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

2.6.4.2. Voltage Concern Mitigations

Eight substations were identified as not meeting the required voltage performances under the Category B contingency conditions, and five substations were identified as not meeting the required voltage performances under the Category C contingency conditions. In addition, three Category C contingencies have been found to result in the power flow case divergence.

The substations identified as not meeting the voltage performance requirements together with the three Category C contingencies resulting in the diverged power flow solution will be addressed upon implementation of projects discussed above under the thermal overload mitigation section.

Other Request Window Submissions

Request Window Submission - Cottonwood Interim Solution

TTS proposed an SVC project, the *Cottonwood Interim Solution*, to address a need identified in the PG&E 2007 reliability assessment. TTS proposed to build and own the SVC project, and to lease the equipment to PG&E. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition. The ISO does not have the tariff authority to direct PTOs to enter into leasing arrangements with specified vendors, as is being proposed in this request window submission. See ISO tariff section 24.4.6.2.

The need targeted by the *Cottonwood Interim Solution* is not identified in the ISO's 2010/2011 reliability assessment, and the project proponent did not identify a current need for the proposal. The *Cottonwood Interim Solution* was also evaluated in the ISO's 2009 transmission plan and the need targeted by this project was also not identified in that cycle. Hence the *Cottonwood Interim Solution* was determined not to be needed.

Request Window Submission - Trinity Interim Solution

TTS proposed a SVC project, the *Trinity Interim Solution*, to address a need identified in PG&E 2007 reliability assessment. TTS proposed to build and own the SVC project, and to lease the facilities to PG&E ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition. The ISO does not have the tariff authority to direct PTOs to enter into leasing arrangements with specified vendors, as is being proposed in this request window submission. See ISO tariff section 24.4.6.2.

The need targeted by the *Trinity Interim Solution* is not identified in the ISO 2010/2011 reliability assessment, and the project proponent did not identify a current need for the proposal. The *Trinity Interim Solution* was also evaluated in the ISO's 2009 transmission plan and deemed not needed then as the Western and Trinity PUD's project to remove the Trinity PUD load from the PG&E system could mitigate the identified voltage concerns in the Trinity 60 kV system. Western and Trinity PUD's project is now implemented and hence voltage concerns in the Trinity 60 kV system were not identified in the ISO 2010/2011 reliability assessment. Hence, the ISO determined that the *Trinity Interim Solution* is not needed**.**

2.6.5 KEY CONCLUSIONS

The 2011 reliability assessment of the PG&E North Valley area identified several reliability concerns. These concerns consist of thermal overloads and low voltages under Categories B as well as Category C contingency conditions. In addition, a few of the Category C contingencies resulted in the power flow divergence indicating potential area-wide voltage collapse.

A number of these concerns were identified in last year's studies, and will be addressed by the construction of the following three projects that the ISO determined to be needed during the 2010 cycle:

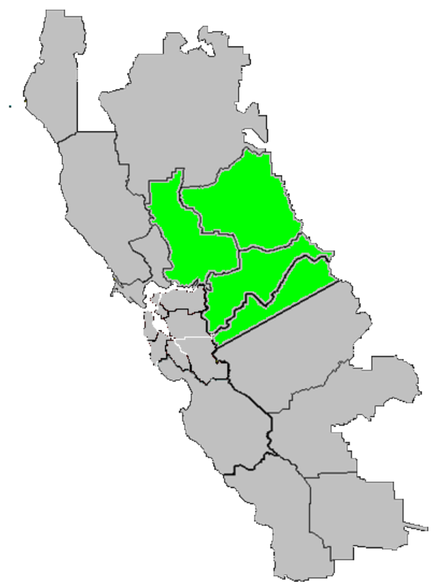
- Red Bluff Area new 230/60 kV substation and two new 60 kV lines;
- New Cascade 115/60 kV Bank and a second Cascade-Benton 60 kV line; and
- New Table Mountain-Sycamore 115 kV line.

Until these projects are completed, operating procedures will be relied upon. Although addressed by operating procedures, the reliability concerns will continue to be identified in annual planning studies for study years prior to the forecast in-service dates of these projects. Two request window submissions proposed as alternatives to the previously approved projects were found not to be needed.

2.7 CENTRAL VALLEY AREA

2.7.1 Area Description

Central Valley area is located in the eastern part of PG&E's service territory. This area includes the central part of the Sacramento Valley, and it is comprised of the Sacramento, Sierra, Stockton and Stanislaus divisions as shown in the figure below.



Sacramento covers approximately 4,000 square miles of the Sacramento Valley, but excludes the service territory of Sacramento Municipal Utility District (SMUD) and Roseville. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system is comprised of 60, 115, 230 and 500 kV transmission facilities. Two sets of 230 and 500 kV transmission paths make up the backbone of the system.

Sierra is located in the Sierra-Nevada area of California. Yuba City, Marysville, Lincoln, Rocklin, El Dorado Hills and Placerville are some of the major cities located within this area. Sierra's electric transmission system is comprised of 60, 115, and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 and 230 kV facilities transmit generation resources from the north to the south. Generation units located within the Sierra area are primarily hydroelectric facilities located on the Yuba and American River water systems. Transmission interconnections to the Sierra transmission system are from Sacramento, Stockton, North Valley, and the Sierra Pacific Power Company (SPP) in the State of Nevada (Path 24).

Stockton is located east of the Bay Area. Electricity demand in this area is concentrated around the cities of Stockton and Lodi. The transmission system is comprised of 60, 115, and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. The City of Lodi is a member of the Northern California Power Agency (NCPA) and it's the largest city that is served from the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus is located between the Greater Fresno and Stockton systems. Newman, Gustine, Crows Landing, Riverbank and Curtis are some of the cities in the area. The transmission system is comprised of 230, 115, and 60 kV facilities. The 230 kV facilities connect Bellota to Wilson and Borden substations. The 115 kV transmission network is located in the northern portion of the area and has connections to QF generation located in the San Joaquin Valley. The 60 kV network located in the southern part of the area is a radial network. It supplies the Newman and Gustine areas and has a single connection to the transmission grid via a 115/60 kV transformer bank at Salado.

Historically, Central Valley experiences its highest demand during the summer season. Load forecasts indicate Central Valley should reach its summer peak demand of 4,587 MW by 2020 assuming load is increasing at approximately 61 MW per year.

Accordingly, system assessments in these areas included technical studies using load assumptions for these summer peak conditions. Table 2.7-5 includes load forecast data.

2.7.2 Area-Specific Assumptions and System Conditions

The Central Valley area study was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO secured website lists contingencies that were performed as part of this assessment. Additionally, specific methodology and assumptions that are applicable to the Central Valley area study are provided below.

Generation

Generation resources in the Central Valley area consist of market, QFs and self-generating units. These are shown in tables 2.7-1 to 2.7-4. The total installed capacity is about 3459 MW with another 530 MW of North Valley generation being connected directly to the Sierra division. The following table summarizes the generation capacity in the Sacramento area. Over 800 MW of capacity listed below (Lambie, Creed, Goosehaven, EnXco, Solano, High Winds and Shiloh) is connected to the new Birds Landing Switching Station and mostly serves the Bay Area loads.

Table 2.7-1: Generation in the Sacramento Area

Chapter 3 No.	**Chapter 4** Generation Facility	**Chapter 5** Type	**Chapter 6** Max. Capacity (MW)
1	Wadham	Biomass	27
2	Woodland Biomass	Biomass	25
3	UC Davis Co-Gen	Co-Gen	4
4	Cal-Peak Vaca Dixon	CT	49
5	Wolfskill Energy Center	CT	60

6	Lambie, Creed and Goosehaven	CT	143
7	EnXco	Wind	60
8	Solano	Wind	100
9	High Winds	Wind	200
10	Shiloh	Wind	300
	Total Generation		968

The following table summarizes the generation capacity in the Sierra area. There is about 1,247 MW of internal generating capacity within the Sierra Division, and over 530 MW of hydro generation listed under North Valley that flows directly into the Sierra electric system. Over 75% of this generating capacity is from hydro resources. The remaining 25% of the capacity is from QFs, and co-generation plants. The Colgate Powerhouse (294 MW) is the largest generating facility in the Sierra Division.

Table 2.7-2: Generation in the Sierra Area

Chapter 7 No.	**Chapter 8** Generation Facility	**Chapter 9** Type	**Chapter 10** Max. Capacity (MW)
1	Bowman Power House	Hydro	4
2	Camp Far West (SMUD)	Hydro	7
3	Chicago Park Power House	Hydro	40
4	Chili Bar Power House	Hydro	7
5	Colgate Power House	Hydro	294

6	Deer Creek Power House	Hydro	6
7	Drum Power House	Hydro	104
8	Dutch Flat Power House	Hydro	49
9	El Dorado Power House	Hydro	20
10	Feather River Energy Center	Hydro	50
11	French Meadows Power House	Hydro	17
12	Green Leaf No. 1	QF/Co-Gen	73
13	Green Leaf No. 2	QF/Co-Gen	50
14	Halsey Power House	Hydro	11
15	Haypress Power House	Hydro	15
16	Hellhole Power House	Hydro	1
17	Middle Fork Power House	Hydro	130
18	Narrows Power House	Hydro	66
19	Newcastle Power House	Hydro	14
20	Oxbow Power House	Hydro	6
21	Ralston Power House	Hydro	83

22	Rollins Power House	Hydro	12
23	Spaulding Power House	Hydro	17
24	SPI-Lincoln	QF/Waste	18
25	Ultra Rock (Rio Bravo-Rocklin)	Biomass	25
26	Wise Power House	Hydro	20
27	Yuba City	CT	49
28	Yuba City Energy Center	QF/Co-Gen	61
	Total Generation		1247

The Stockton area has about 950 MW of internal generating capacity. The following table summarizes the generation resources within the area.

Table 2.7-3: Generation in the Stockton Area

Chapter 11 No.	**Chapter 12** Generation Facility	**Chapter 13** Type	**Chapter 14** Max. Capacity (MW)
1	Altamont Co-Generation	QF/Co-Gen	7
2	Camanche Power House	Hydro	11
3	Co-generation National POSDEF	QF/Co-Gen	44
4	Electra Power House	Hydro	101

5	Flowind Wind Farms	Wind	76
6	GWF Tracy Peaking Plant	CT	192
7	Ione Energy	QF/Co-Gen	18
8	Lodi Stigg (NCPA)	QF/Co-Gen	21
9	Pardee Power House	Hydro	29
10	Salt Springs Power House	Hydro	42
11	San Joaquin Co-Generation	QF/Co-Gen	55
12	Simpson Paper Co-Generation	QF/Co-Gen	50
13	Stockton Co-Generation (Air Products)	QF/Co-Gen	50
14	Stockton Waste Water Facility	QF/Co-Gen	2
15	Thermal Energy	QF/Biomass	21
16	Tiger Creek Power House	Hydro	55
17	US Wind Power Farms	Wind	158
18	West Point Power House	Hydro	14
	Total Generation		946

The Stanislaus area has about 590 MW of internal generating capacity. Over 90% of this generating capacity is from hydro resources. The remaining capacity consists of QFs and co-generation plants. The Melones power plant is the largest generating facility in the area. The following table summarizes the generation facilities.

Table 2.7-4: Generation in the Stanislaus Area

No.	Generation Facility	Type	Max. Capacity (MW)
1	Beardsley Power House	Hydro	11
2	Donnells Power House	Hydro	68
3	Fiberboard (Sierra Pacific)	QF/Co-Gen	6
4	Melones Power Plant	Hydro	119
5	Pacific Ultra Power Chinese Station	QF/Waste	22
6	Sand Bar Power House	Hydro	15
7	Spring Gap Power House	Hydro	7
8	Stanislaus Power House	Hydro	83
9	Stanislaus Waste Co-gen		24
10	Tulloch Power House	Hydro	17
	Total Generation		323

Load Forecast

Loads within the Central Valley area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.7-5 shows loads modeled for the Central Valley area assessment as well as other local areas within PG&E system.

Table 2.7-5: Load forecasts modeled in the Central Valley area assessment

1- IN- 10 YEAR HEAT WAVE NON-SIMULTANEOUS LOAD FORECAST						
SUMMER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
SACRAMENTO	1,149	1,166	1,181	1,195	1,209	1,292
SIERRA	1,222	1,251	1,280	1,307	1,334	1,486
STOCKTON	1,377	1,400	1,418	1,433	1,451	1,550
STANISLAUS	226	230	234	237	241	260

2.7.3 Study Results and Discussions

A summary of the study results of facilities in the Central Valley area that were identified as not meeting thermal loading and voltage performance requirements under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

- The ISO identified four facilities as not meeting the required thermal loading performance and 10 substations as not meeting the required voltage performances under the normal conditions.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

- The ISO identified 22 facilities as not meeting the required thermal loading performance and 35 substations as not meeting the required voltage performances under the Category B contingency conditions.

TPL 003: System Performance Following Loss of Two or More BES Elements

- The ISO identified 60 facilities as not meeting the required thermal loading performance and 69 substations as not meeting the required voltage performances under the Category C contingency conditions; and
- The ISO also identified power flow case divergence for one Category C contingency.

Appendix A documents the worst thermal loading and low voltage profiles of facilities not meeting the performance requirements for the summer peak condition along with the corresponding proposed solutions.

2.7.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

Based on this year's reliability assessment results of the PG&E Central Valley area, the ISO initially recommended solutions that address each of the identified facilities that did not meet the thermal and voltage performance requirements under Categories A (normal), B and C contingency conditions. The ISO then evaluated the initial recommended solutions as well as submissions made through the request window process.

The following discussion addresses the analysis and the projects the ISO determined were needed to address the thermal and voltage performance requirements. This includes information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.7.4.1 Sacramento Division Thermal Overload Mitigations

Vaca Dixon – Davis Voltage Conversion

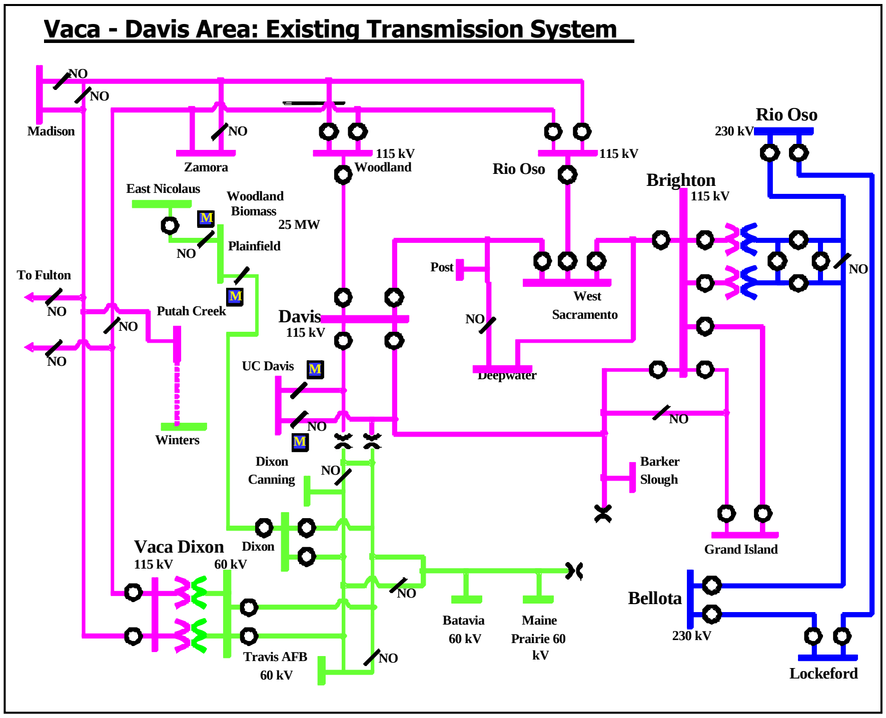
The Davis/Yolo area is located in Yolo County. Electric power is transmitted from the grid to the Davis area via Rio Oso and Vaca Dixon substations and delivered via a network of two 230 kV, three 115 kV and three 60 kV transmission lines to serve customers in this area. These transmission lines are listed below.

- Rio Oso-Brighton 230 kV line;
- Brighton-Bellota 230 kV line;
- Rio Oso-West Sacramento 115 kV line;
- Rio Oso-Woodland Nos. 1 and 2 115 kV lines;
- Dixon-Vaca Nos. 1 and 2 60 kV lines; and
- Vaca-Plainfield Junction 60 kV line.

The electric transmission network within the Davis area is comprised of a 60 kV and a 115 kV system which are separated by normally open breakers between Dixon Canning and University of California – Davis (UCD). These two systems serve 11 distribution substations and five customer-owned substations. Travis Air Force Base (AFB), the Cities of Dixon, Winters, and Plainfield as well as various other electric customers in the area are served from Vaca Dixon substation via three 60 kV lines. The Rio Oso substation serves the 115 kV system (UCD and the Cities of Davis, Woodland, and West Sacramento) via one 230 kV and three 115 kV lines. The area also includes a local generation facility, Woodland Biomass (25 MW), in the City of Woodland which is tapped onto the Woodland-Davis 115 kV line.

The 2011 projected peak load in the Red Bluff area is approximately 509 MW and is forecast to increase at a rate of 7.3 MW/yr. Figure 2.7-1 below shows the one-line diagram of the existing Vaca Dixon 115/60 kV and Davis 115 kV system.

Figure 2.7-1: Vaca – Davis Area Transmission System



This year's assessment identified the following facilities in the Vaca Dixon and Davis areas as not meeting the thermal and voltage performance requirements:

- Brighton – Davis 115 kV line (starting 2013 under Category B and existing overload under Category C);
- Vaca Dixon 115/60 kV Bank No. 5 (existing overloads under Categories B and C);
- Brighton 230/115 kV Bank No. 9 (starting 2013 under Category C);
- Rio Oso – West Sacramento 115 kV line (existing overload under Category C);
- Vaca Dixon 230/115 kV Bank Nos. 2 & 2A (existing overload under Category C);
- West Sacramento – Brighton 115 kV line (starting 2020 under Category C);
- West Sacramento – Davis 115 kV line (starting 2012 under Category C);
- Woodland – Davis 115 kV line (existing overload under Category C); and
- Brighton/Davis/West Sacramento Area 115 kV Voltages (existing low voltages and potential voltage collapse starting 2020 under Category C).

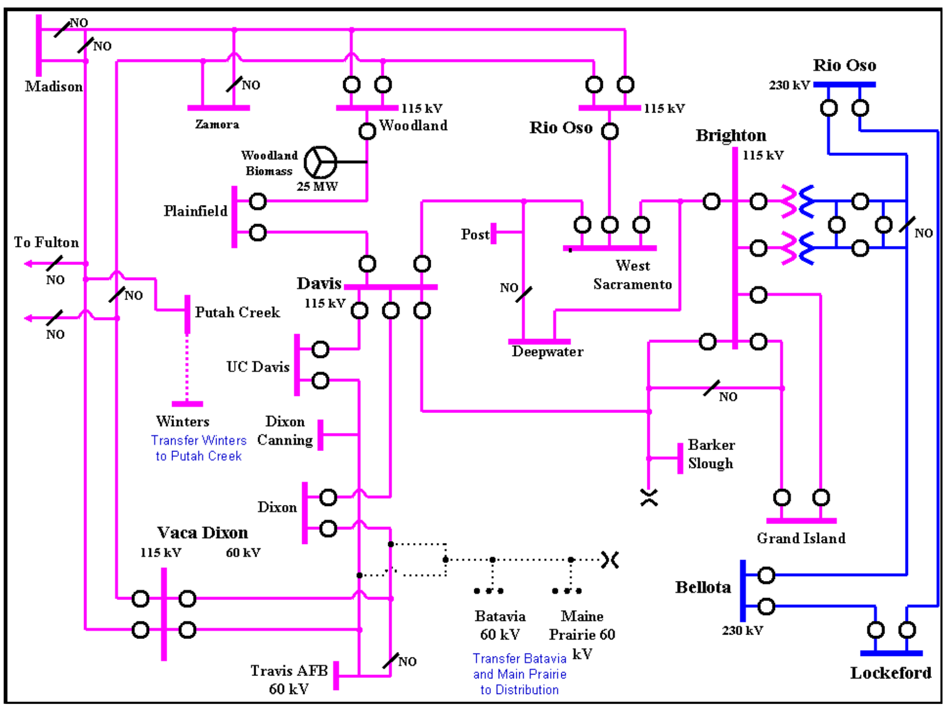
To mitigate these overloads and voltage issues, PG&E submitted a project through the 2009 request window, the *Vaca Dixon – Davis Voltage Conversion Project*, which proposes to convert the Vaca Dixon 60 kV system to 115 kV operation and connect to the Davis 115 kV system. Specifically, this project scope includes the following:

- Reconductor and convert the two 60 kV lines between UC Davis and Vaca-Dixon to 115 kV operation with larger conductor whose emergency capability is at least 1400 A;.
- Reconductor the two 115 kV lines between UC Davis and Davis with larger conductor whose emergency capability is at least 1200 A;

- Construct a new 115 kV switching station at Davis to accommodate the voltage conversion work;
- Convert Dixon substation to 115 kV operation and loop into the Dixon-Vaca No. 2 115 kV line;
- Construct a switching station at UC Davis, looping into the Dixon-Vaca No. 1 115 kV line;
- Convert Plainfield substation to 115 kV operation and loop into the Woodland-Davis 115 kV line;
- Transfer Batavia and Maine Prairie substations to distribution service;
- Transfer the Winters substation distribution load to Putah Creek substation;
- Dixon Canning, Travis AFB and Travis AFB Hospital are customer owned substations and are responsible for upgrading their equipment;
- Connect Travis AFB and Travis AFB Hospital to the Dixon-Vaca Nos. 1 and 2 115 kV lines in a double-tap arrangement;
- Replace Vaca Dixon 230/115 kV Transformer Nos. 2 and 2A with a three-phase, 420 MVA transformer;
- Replace limiting switches and re-rate the Woodland-Davis 115 kV line (Woodland-Plainfield and Davis-Plainfield 115 kV lines) with a higher wind speed rating; and
- Reconductor the limiting sections of the West Sacramento-Davis (1.5 miles) 115 kV lines with higher capacity conductors that are rated to handle at least 1,100 A under emergency conditions.

Figure 2.7-2 below shows the one-line diagram of the proposed Vaca Dixon-Davis conversion.

Figure 2.7-2: Proposed Vaca Dixon – Davis Conversion

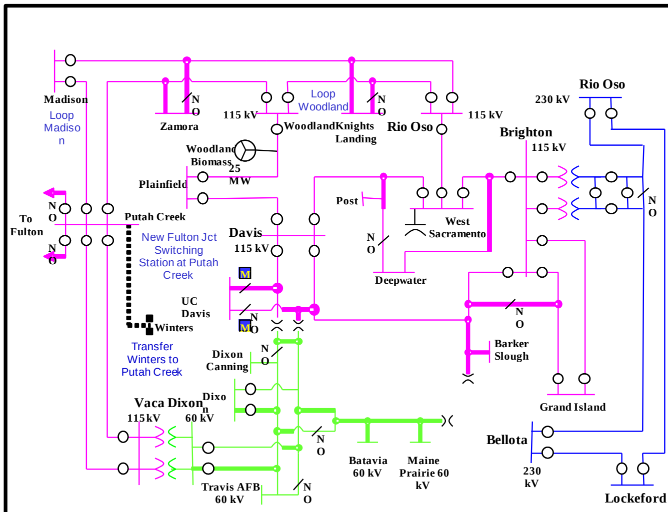


The project is expected to cost between $70M and $107M and has an in-service date of May 2015. The ISO determined that this project is needed to mitigate the identified thermal overloads and voltage issues identified in the area. In the interim, operating solutions such as utilizing short-term ratings, seasonal load transfer, and radializing certain system elements will be used to prevent these overloads and low voltages from occurring until the project is placed into service. The ISO will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

Three other alternatives were considered along with the Vaca Dixon – Davis voltage conversion.

Alternative 1: Tie Vaca Dixon-Fulton Jct-Woodland 115 kV Systems

Figure 2.7-3: Alternative 1



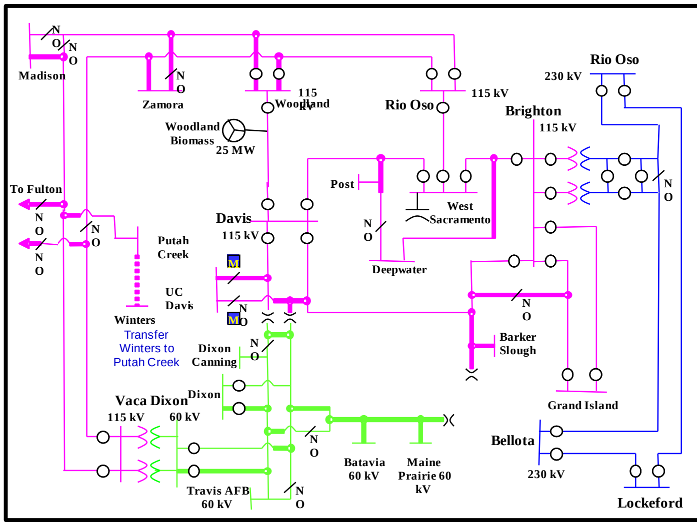
Scope

- Construct a new 115 kV Switching Station at Putah Creek and Fulton Jct.
- Install circuit breakers at Madison, terminating the Vaca-Madison 115 kV Line.
- Loop Woodland into the Rio Oso-Woodland No. 2 line, creating the Vaca-Putah Creek-Woodland, Rio Oso-Woodland, and Rio Oso-Madison 115 kV lines.
- Reconductor the Vaca-Madison (23 miles) and Vaca-Fulton Jct (11.5 miles) 115 kV lines with higher capacity conductors that are rated to handle at least 1,100 Amps under emergency conditions.
- Reconductor the Rio Oso-Woodland Nos. 1 and 2 115 kV lines (58 miles total) with higher capacity conductors that are rated to handle at least 1,100 Amps under emergency conditions.
- Covert Plainfield substation to 115 kV operation and loop into the Woodland-Davis 115 kV Line.
- Transfer the Winters Substation distribution load to Putah Creek Substation.
- Reconductor the Brighton-Davis (28 miles), West Sacramento-Davis (1.5 miles), Rio Oso-West Sacramento (30 miles), and Woodland-Davis (Woodland-Plainfield and Davis-Plainfield: 25 total miles) 115 kV lines with higher capacity conductors that are rated to handle at least 1,100 Amps under emergency conditions.
- Install at least 100 MVAR of voltage support at West Sac Substation.

Costs: $145M - $222M

Alternative 2: Reinforce existing 60 and 115 kV Systems

FIgure 2.7-4: Alternative 2



Scope

•Reconductor the Brighton-Davis (28 miles), West Sacramento-Davis (1.5 miles), Rio Oso-West Sacramento (30 miles), and the Rio Oso-Woodland Nos. 1 and 2 (58 miles total) 115 kV lines with higher capacity conductors that are rated to handle at least 1,100 Amps under emergency conditions.

•Covert Plainfield substation to 115 kV operation and loop into the Woodland-Davis 115 kV Line.

•Replace limiting switches and re-rate the Woodland-Davis 115 kV Line (Woodland-Plainfield and Davis-Plainfield 115 kV lines) with higher wind speed assumptions.

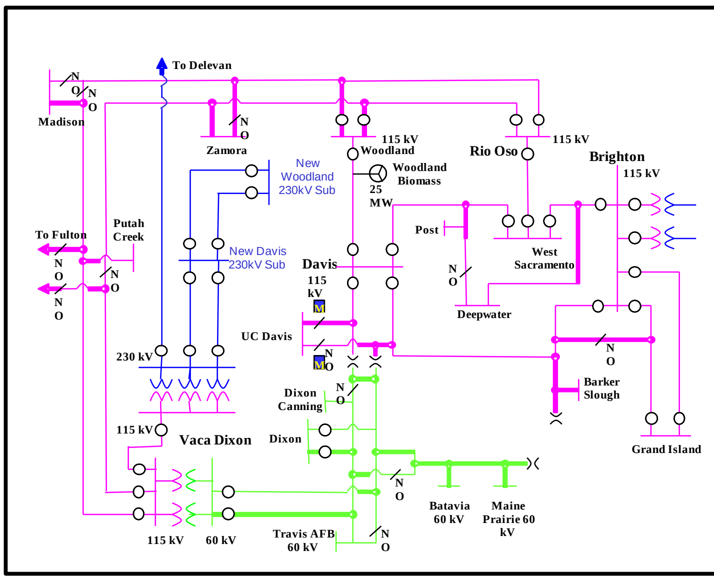
•Replace Vaca Dixon 115/60 kV Transformer No. 5 with a three-phase, 200 MVA transformer.

•Install at least 100 MVAR of voltage support at West Sac Substation.

Costs: $77M - $120M

Alternative 3: New 230 kV DCTL from Vaca Dixon to a new 230 kV substation in Davis area

Figure 2.7-5: Alternative 3



Scope

•Extend the Vaca-Dixon 230 kV Bus to acquire two new 230 kV lines.

•Construct a 20 mile DCTL extending north from Vaca-Dixon Substation to the Davis/Woodland area.

•Construct a new substation west of the city of Davis and interconnect to the 230 kV DCTL from Vaca-Dixon Substation.

•Construct a new substation south of the city of Woodland and interconnect to the 230 kV DCTL from the new Davis 230 kV Substation.

•Offload 70 MW from Davis Substation on to the new 230 kV Davis substation.

•Offload 60 MW from Woodland Substation and 10 MW from Plainfield Substation onto the new 230 kV Woodland substation.

•Replace limiting switches and re-rate the Woodland-Davis 115 kV Line (Woodland-Plainfield and Davis-Plainfield 115 kV lines) with a higher wind speed rating.

Costs: $77M - $120M

The power flow analysis showed that even though alternatives 1 and 2 mitigate most of the thermal overloads, the Brighton/Davis/West Sacramento area 115 kV system low voltages would still occur. Also, for alternative 3, the 115 kV system low voltages would still occur as well as overloading of certain facilities for some Category B & C contingencies in 2020. Furthermore, the load-serving capability analysis showed that the Vaca Dixon – Davis voltage conversion option provides the highest load serving capability among all alternatives considered. The load-serving capabilities for the voltage conversion project along with the three alternatives considered are shown in table 2.7-6 below.

Table 2.7-6: Summary of Load Serving Capability by Alternative

Alternative	Cost	Load Serving Capability (MW)	Limiting Element	Worst Contingency
Status Quo	$0	390 MW	Deepwater 115 kV Bus	Rio Oso-Brighton & Brighton-Bellota 115 kV Lines (N-1-1)
Voltage Conversion	$70-107M	840 MW	Deepwater 115 kV Bus	Rio Oso-Brighton & Brighton-Bellota 115 kV Lines (N-1-1)
Alternative 1	$145-222M	470 MW	Deepwater 115 kV Bus	Rio Oso-Brighton & Brighton-Bellota 115 kV Lines (N-1-1)
Alternative 2	$77-120M	390 MW	Deepwater 115 kV Bus	Rio Oso-Brighton & Brighton-Bellota 115 kV Lines (N-1-1)
Alternative 3	$75-113M	460 MW	Deepwater 115 kV Bus	Rio Oso-Brighton & Brighton-Bellota 115 kV Lines (N-1-1)

Request Window Submission - Vaca Dixon 60 kV Energy Storage Project

WGD proposed an energy storage reliability-driven project, the *Vaca Dixon 60 kV Energy Storage Project*, to address the same reliability concerns addressed by the PG&E proposed Vaca Dixon-Davis Voltage Conversion. The cost of the PG&E proposed project is between $70 million and $107 million. WGD's proposed project has a capital cost of $6 million for the initial installation of 4 MW of storage capacity. WGD proposed to build and own the energy storage project and turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO staff considered the proposed energy storage project as an alternative to the PG&E proposed Vaca Dixon-Davis voltage conversion to determine whether PG&E should be directed to install the energy storage. WGD's proposed energy storage project only mitigates the overloads on the Vaca 115/60 kV transformer #5 and does not mitigate any thermal overloads or voltage issues in the Vaca-Davis area. The PG&E proposed voltage conversion project would still be needed to mitigate other thermal overloads and voltage problems in the Vaca-Davis area even with the WGD proposed energy storage in place. However, the PG&E proposed voltage conversion project would eliminate the 60 kV system at Vaca Dixon, thereby eliminating the need to mitigate the Vaca Dixon 115/60 kV transformer #5 overload. Hence, the ISO determined that the *Vaca Dixon 60 kV Energy Storage Project* is not needed.

Cortina 230/115/60 kV Transformer and Cortina No. 3 60 kV Line

The ISO identified an existing overload on the Cortina 230/115/60 kV transformer under a Category B contingency condition. To mitigate this overload the ISO previously approved a PG&E project – the *Cortina 60 kV Reliability Project* - with an in-service date of May 2012.

The ISO also identified an existing overload on the Cortina No. 3 60 kV line under a Category B contingency condition. To mitigate this overload, PG&E submitted a project through the 2010 request window, the *Cortina No.3 60 kV Line Reconductoring Project*, which consists of reconductoring a 5.6 miles on the Cortina No.3 60 kV line from Cortina substation to Wadham Jct. The project has an in-service date of May 2013. The ISO determined that this project is needed to mitigate identified overloading concerns

In the interim, the ISO recommends that short-term ratings and operating procedures be developed to address any potential reliability concerns. The ISO will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

Request Window Submission - Cortina 60 kV Energy Storage Project

WGD proposed an energy storage reliability-driven project, the *Cortina 60 kV Energy Storage Project*, to address the same reliability concerns addressed by the previously approved *Cortina 60 kV Reliability Project* and the PG&E-submitted 2010 request window project, Cortina #3 60 kV line reconductoring project. The cost of the reconductoring project is between $4 million to $7 million. The WGD's proposed project has a capital cost of $7.5 million for the initial installation of 5 MW of storage capacity. WGD proposed to build and own the energy storage project and turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO considered the proposed energy storage project as an alternative to the 60 kV line reconductoring project to determine whether PG&E should be directed to install the energy storage. WGD's proposed energy storage project does not mitigate the overload on the Cortina #3 60 kV line. Furthermore, mitigating the line overload in 2020 would require about 7 MW of energy storage. Using the WGD provided cost for the 5 MW of energy storage, the 7 MW energy storage would cost about $10.5 million which is higher than the cost of reconductoring. Hence, the ISO determined that the *Cortina 60 kV Energy Storage Project* is not needed.

Vaca-Suisun-Jameson 115 kV

The ISO identified an overload on the Vaca-Suisun-Jameson 115 kV line under a Category B contingency starting in 2019. Currently there is also one Category C contingency that was forecast to overload this line and an SPS is used to trip load as mitigation. The ISO identified solution would include reconductoring about 18 miles of this line. There is ample time for permitting, procurement and installation of a project before 2019. Accordingly, the ISO will assess this and other mitigation plans further in a future ISO transmission plan.

Other Request Window Submissions

Request Window Submission - Madison 115 kV Energy Storage Project

WGD proposed an energy storage reliability-driven project; *the Madison 115 kV Energy Storage Project*, to address a need identified in the ISO's 2009 annual assessments. WGD proposed to build and own the energy storage project, to turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The need targeted by the *Madison 115 kV Energy Storage Project* is not identified in the ISO 2010/2011 reliability assessment. The *Madison 115 kV Energy Storage Project* was also evaluated in the ISO's 2009 transmission plan and deemed not needed then as the overload could be mitigated by rerating the line at minimal cost. The need targeted was not identified in the ISO's 2010/2011 reliability assessment because of the decrease in the load forecast. Hence, the ISO determined that the *Madison 115 kV Energy Storage Project* is not needed.

2.7.4.2 Sacramento Division Voltage Concerns Mitigations

Sacramento Area 115 kV Substations

The ISO identified existing low voltages in the Sacramento area 115 kV substations following a Category C contingency of losing both the 230 kV lines coming into the Brighton substation. The *Vaca-Davis Voltage Conversion Project* discussed in the preceding section will also mitigate these voltage concerns in the Sacramento area 115 kV system. The project has an in-service date of May 2014. The ISO recommends that an operating procedure be developed to address any potential reliability concern in the interim. The ISO staff will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

Plainfield 60 kV Substation

The ISO identified normal low voltage in the Plainfield 60 kV bus starting in year 2020. The *Vaca-Davis Voltage Conversion Project* discussed above will also mitigate this voltage concern.

Cortina 60 kV Substations

The ISO identified existing low voltages in the Cortina area 60 kV substations under a Category C contingency of losing both the 230 kV lines coming into the Cortina substation. The ISO recommends that PG&E develop an operating procedure to address these low voltage issues. The ISO staff will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

Brighton 230 kV Substation

The Brighton 230 kV bus was identified to have normal voltage below 0.95 pu starting in year 2020. The solution includes installing voltage support or bringing new 230 kV source in to Brighton. There is ample time for permitting, procurement and installation before 2020. This plan and other options will be assessed further in a future ISO transmission plan.

Request Window Submission - Brighton 230 kV Reliability Solution

TTS proposed a SVC project, the *Brighton 230 kV Reliability Solution*, to address the low voltage concern at Brighton 230 kV bus. TTS proposed to build and own the SVC project, to turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO will consider the SVC project, along with other possible options, in future ISO planning cycles to determine what facilities PG&E should be required to construct to meet the reliability needs in this area.

Other Request Window Submissions

Request Window Submission - Great Basin HVDC Project

Great Basin Energy Development, LLC (GEBD) proposed an HVDC project, the *Great Basin HVDC Project*, targeting the Sacramento Area low voltage problem as reliability need. GBED proposed to build and own the HVDC project and turn the facilities over to the ISO's operational control. ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

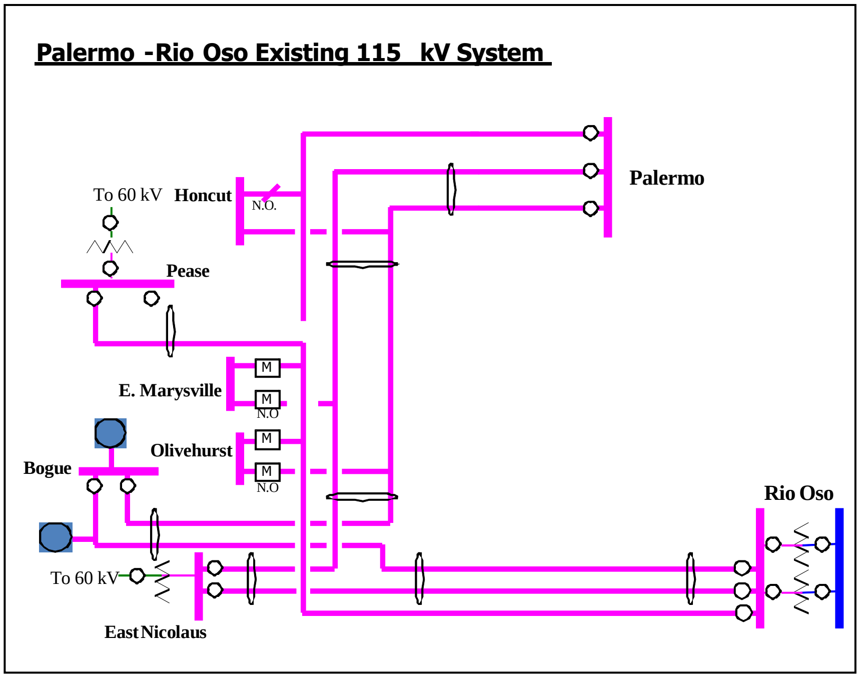
The proposed *Great Basin HVDC Project* does not mitigate the voltage concerns identified in the Sacramento area in the ISO's 2010 reliability assessment**.** Hence, the ISO determined that the *Great Basin HVDC Project* is not needed for reliability purposes.

2.7.4.3 Sierra Division Thermal Overload Mitigations

South of Palermo 115 kV Reinforcement

There are three Palermo – Rio Oso 115 kV lines located in the Yuba and Sutter counties. These lines range in length from 46 to 57 miles and provide transmission power to the Honcut, Pease, East Marysville, Olivehurst, Bogue and East Nicolaus distribution substations. Figure 2.7-6 below shows the one-line diagram of the existing Palermo-Rio Oso 115 kV system.

Figure 2.7-6: Palermo-Rio Oso Existing 115 kV System



In addition to providing 115 kV transmission power to local area electric customers, the Palermo – Rio Oso 115 kV lines also serve as a transmission path for a significant amount of hydro generation energy to flow into PG&E's local area network. The hydro plants in the area include facilities along the Feather River between Lake Almanor and Lake Oroville and are connected to Table Mountain, Palermo and Rio Oso substations. A portion of the output from these power plants flows through the Table Mountain substation to load centers in the Sacramento area through the Palermo – Rio Oso 115 kV lines. The ISO, in its 2008 transmission plan, approved the *Palermo – Rio Oso 115 kV Line Reconductoring Project* which would reconductor the northern sections of the existing Palermo-Rio Oso 115 kV double circuit tower line by 2012. This reconductoring work includes a 40-mile section between Palermo and East Nicolaus substations and a 30-mile section between Palermo and Bogue Junction.

This year's assessment identified that the Pease – Rio Oso 115 kV line will exceed its normal rating with all lines in-service and its emergency rating for certain Category B and Category C contingencies. Similarly, the Bogue – Rio Oso 115 kV line will exceed its emergency ratings in 2014 for certain Category B and Category C contingencies. Furthermore, a section of the Palermo – Bogue 115 kV line will exceed its emergency rating in 2020 for certain Category B contingencies and the Palermo – Pease 115 kV line and Rio Oso – Nicolaus 115 kV lines will exceed their emergency ratings in 2015 and 2020, respectively, for certain Category C contingencies.

To mitigate these overloads, PG&E submitted the *South of Palermo 115 kV Reinforcement Project* through the 2010 request window. The project proposes to reconductor the southern portions of the Palermo – Rio Oso 115 kV lines #1 and #2 as well as the entire Palermo – Pease and Pease – Rio Oso 115 kV lines with 1113 kcmil aluminum conductor:

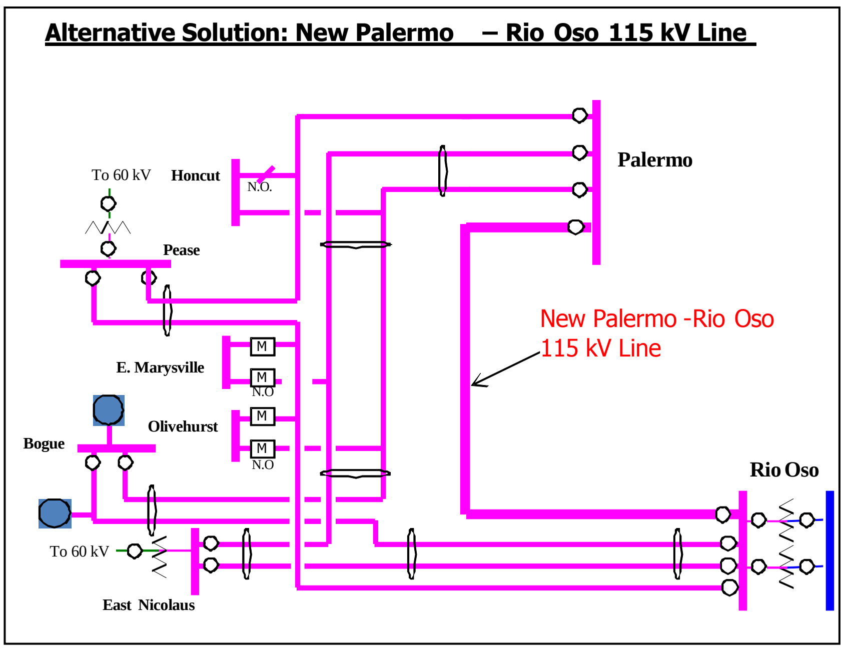
- Bogue – Rio Oso 115 kV line (21.5 miles);

- Palermo – Bogue 115 kV line (8 miles) between Olivehurst and Bogue substations;
- Palermo – Pease 115 kV line (26.5 miles);
- Pease – Rio Oso 115 kV line (28 miles); and
- Rio Oso – Nicolaus 115 kV line (5.5 miles).

The project is expected to cost between $80M and $100M and has an in-service date of May 2014. The ISO determined that this project is needed to mitigate identified thermal overloads. Until this project is placed in-servce seasonal load transfers will be done to prevent these overloads from occurring. The ISO staff will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

An alternative solution considered building a new 115 kV line from Palermo to Rio Oso substation. The new line would be sized with 715 Al conductors and extend approximately 45 to 55 miles. This alternative would also require Honcut substation to be normally served from the Palermo-Pease 115 kV line as well as transferring the alternate feed to East Marysville substation from the Palermo - Nicolaus 115 kV line to the new Palermo - Rio Oso 115 kV line. This alternative is expected to cost between $70 million and $100 million. Figure 2.7-7 shows the one-line diagram of the alternative solution considered.

Figure 2.7-7: Alternative Solution – New Palermo-Rio Oso 115 kV Line



The power flow analysis showed that for the new 115 kV line solution, the Pease – Rio Oso line would still experience normal overloads and the Bogue – Rio Oso line would exceed its emergency rating for certain Category C contingencies in 2020. The remaining line sections also showed high (>80%) loading under various Category C contingencies. Because this alternative does not mitigate all the overloads identified and also has significant uncertainties in transmission line permitting requirements, this alternative is not recommended.

Placer 115/60 kV Transformer, Del Mar-Atlantic 60 kV Line and Gold Hill-Horseshoe Nos. 1 & 2 115 kV Lines

Under normal conditions, the Placer 115/60 kV transformer was identified to overload starting in year 2017. Also under normal conditions, there are substations in the area with voltages below 0.95 pu starting in year 2018. In addition, the Del Mar-Atlantic 60 kV line overloads under Category C contingency condition starting in year 2014 and the Gold Hill-Horseshoe Nos. 1 & 2 115 kV lines have existing overloads under Category C contingency conditions. These overloads and voltage concerns in the area can be mitigated by upgrading the Atlantic-Rocklin-Del Mar-Penryn-Placer 60 kV system to 115 kV operation. This would be achieved by upgrading the existing Atlantic-Del Mar No.1 and No.2 60 kV to 115 kV operation, as well as rebuilding Placer-Del Mar to a 115 kV DCTL. The most feasible implementation timeline for this upgrade is 2017 due to permitting and lead times.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address the Category C overloads on the Gold Hill-Horseshoe 115 kV lines. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Request Window Submission - Auburn 60 kV Energy Storage

WGD proposed an energy storage reliability-driven project, the *Auburn 60 kV Energy Storage Projec*t, to address some of the reliability concerns in the Placer area. WGD proposed to build and own the energy storage project and turn the facilities over to the ISO's operational control. However, ISO tariff section 24.1.2 provides that the PTO with service territory in which any proposed transmission upgrade or addition deemed necessary is located shall be the project sponsor with the responsibility to construct, own, finance and maintain the upgrade or addition.

The ISO will evaluate the energy storage project to determine whether PG&E should be directed to install such facility to address reliability needs in the area. The Placer area is very complex with both peak and off-peak transmission constraints driven by load, hydro and import patterns. Due to these factors, the operation of this system is extremely dynamic, with multiple constraints that need to be mitigated throughout the day. The ISO considers all the possible reliability problems in the area as being inter-related and any solution or solutions adopted to address these needs must complement each other and assure full compliance with reliability standards. In other words, this area requires a comprehensive long-term solution to address all the concerns. The ISO will consider the Atlantic - Placer voltage upgrade and the Auburn battery storage project, along with other possible options in a future ISO transmission planning cycle to determine what facilities PG&E should be required to construct to meet the reliability needs in this area.

Drum-Bell 115 kV Line

The ISO identified an overload on the Drum-Bell 115 kV line under a Category B contingency condition starting year 2015 and experience an existing overload under a Category C contingency condition. The *Atlantic-Placer Voltage Conversion Pro*ject described above mitigates this overload as well. The most feasible implementation timeline for this upgrade is 2017 due to permitting and lead times.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern.

Drum-Grass Valley-Weimar 60 kV Line

The ISO identified an existing overload on the Drum-Grass Valley-Weimar 60 kV line under a Category B contingency condition. To mitigate this overload, PG&E submitted a project through the 2010 request window, the *Drum-Grass Valley-Weimar 60 kV Line Reconductor Project.* Although, this project relieves the overload, Grass Valley substation cannot be looped in due to the limitation on the Colgate source. The Grass Valley load could potentially be served from the 115 kV source in the area, which could be a long-term solution for this area. The ISO, working with PG&E, will evaluate possibility of serving Grass Valley from 115 kV source in the area. The most feasible project implementation, due to permitting and lead times is 2014. These plans will be assessed further in a future ISO transmission plan.

In the interim, the ISO recommends deactivating automatics at Grass Valley during peak loading conditions to address this overload.

Rio Oso-Atlantic 230 kV and Rio Oso-Lincoln-Atlantic 115 kV Lines

The Rio Oso-Atlantic 230 kV line was identified to overload starting 2017 under Category B and existing overloads under Category C contingency conditions. There are also existing overloads on the Rio Oso-Lincoln and Atlantic-Lincoln 115 kV lines under a Category C contingency involving the Rio Oso-Atlantic 230 kV. To mitigate these overloads, PG&E submitted a project through the 2010 request window, the *Rio Oso-Atlantic 230 kV Line Project*, which consists of a second 230 kV line between the Rio Oso and Atlantic substations. The project has an in-service date of May 2016. The ISO determined that this project is needed to mitigate the identified overloading concerns.

For the existing Category C overloads, the ISO recommends that a short-term rating and operating procedure be developed in the interim to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Drum-Rio Oso Nos.1 and 2 115 kV Lines

The Drum-Rio Oso Nos.1 and 2 115 kV lines are identified with existing overload under Category C contingency conditions. The ISO recommends developing an operating procedure to curtail generation in Drum area to mitigate these overloads. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Gold Hill Nos. 1 & 2 230/115 kV Transformer

Under multiple contingencies, the Gold Hill Nos.1 and/or 2 230/115 kV transformers overload starting 2013. There is also an existing power flow divergence for the loss of both transformers. Solutions include the addition of a third 230/115 kV 420 MVA bank at Gold Hill plus an SPS for the new Category C contingency.

This solution depends on the options chosen for the Clarksville area reinforcement as well as the upgrade of the Atlantic-Placer system from 60 to 115 kV operations. The most feasible project implementation, due to permitting and lead times is 2016.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Gold Hill-Missouri Flat No.1 115 kV Line

The ISO, in its 2008 transmission plan, approved a project to reconductor the Gold Hill-Missouri Flat 115 kV lines to mitigate then identified Category B overloading concerns. The Gold Hill-Missouri Flat No.1 115 kV line still has an existing overload under a Category C contingency condition. Also the Clarksville substation has close to 200 MW of load and should be looped in. Solutions include upgrading the Clarksville substation to 230 kV operations or building a new 230 kV substation by looping the 230 kV lines in the area. The most feasible project implementation, due to permitting and lead times is 2016.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

2.7.4.4 Sierra Division Voltage Concerns Mitigations

The three 230 kV substations, Rio Oso, Gold Hill and Atlantic, are identified with normal voltage below 0.95 p.u. starting year 2019. The solution includes installing voltage support in the area. There is more than ample time for permitting, procurement and installation before 2019. This plan, and other possible options, will be assessed further in a future ISO transmission plan. The remaining voltage concerns under various Categories B and C contingency conditions will be addressed upon implementation of projects aimed at achieving the thermal loading performance requirements.

Request Window Submission - Westwood Area Upgrades

PG&E submitted a project through the 2010 request window, the Westwood Area Upgrades, which proposes to reconductor 21 miles of the Caribou – Westwood 60 kV line and install two SPSs. These upgrades are driven by interconnection of two new generation projects in the Lassen Municipal Utility District (LMUD) system. LMUD’s 60 kV system is directly connected to PG&E’s Westwood substation via two LMUD-owned 60 kV transmission lines in Lassen County, California. PG&E intends to upfront the cost of these upgrades and recover through the Transmission Access Charge (TAC).

The ISO considers this a unique circumstance. Further evaluation is required.

2.7.4.5 Stockton/Stanislaus Division Thermal Concerns Mitigations

Hammer-Country Club 60 kV Line, Stagg-Country Club Nos. 1 & 2 and Stagg-Hammer 60 kV Lines

An overload of the Hammer-Country Club 60 kV line was identified starting in 2015 under normal conditions and to currently exist under Category C contingency conditions. Existing overloads were identified on the Stagg-Country Club Nos. 1 & 2 and Stagg-Hammer 60 kV lines under Category C contingency conditions of the combined loss of any two out of three lines. To mitigate these overloads, PG&E submitted two projects through the 2010 request window, the Hammer-Country Club 60 kV Switch Project and the *Stagg-Hammer 60 kV Line Project*. The *Hammer-Country Club 60 kV Switch Project* consists of replacing the limiting switch on this line and re-rate a small section at the Country Club end. The *Stagg-Hammer 60 kV Line Project* consists of building a second 60 kV line between Stagg and Hammer substations approximately 4.2 miles in length. The switch replace project has an in-service date of May 2012 and the new line project has an in-service date of May 2014. The ISO determined that these projects are needed to mitigate the identified overloading concerns.

In the interim for the Category C overloads, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Tesla-Weber 230 kV Line

The Tesla-Weber 230 kV line was identified to overload starting year 2018 under normal conditions and starting in 2016 to overload under Categories B and C contingency conditions. Reconductoring this network line could be a solution. The most feasible implementation timeline for this upgrade is 2016 due to permitting and lead times. This plan, and other possible options, will be assessed further and included in a future ISO transmission plan.

Eight Mile – Tesla and Stagg - Tesla 230 kV Lines

The Eight Mile – Tesla and Stagg - Tesla 230 kV lines were identified to overload starting in year 2018 under Categories B and C contingency conditions. Re-rating these network lines could be a solution. There is ample time for the re-rate implementation before 2018. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

Tesla – Manteca Area 115 kV Lines

There are four 115 kV lines emanating from the Tesla substation delivering power towards Salado and Manteca substations. There is a fifth 115 kV line that goes through Tracy and the sixth 115 kV line that connects co-generation in the area. The ISO previously approved the *Tesla 115 kV Capacity Increase Project* for some sections of the Tesla-Schulte and Lammers-Kasson 115 kV lines.

This year's assessment identified existing overloads on the Tesla-Salado-Manteca, Kasson 115/60 kV Transformer, Tesla-Tracy, Tesla-Schulte Switching Station, Tesla-Kasson-Manteca, Vierra-Tracy-Kasson, and Lammers-Kasson 115 kV lines as well as the Kasson-Louise and Manteca-Louise 60 kV lines under various Category C contingency conditions. To mitigate these overloads, PG&E submitted a project through the 2010 request window, *Vierra 115 kV Looping Project*, which proposes to loop the Tesla-Stockton Co-gen 115 kV line in to the Vierra substation. The project has an in-service date of May 2014. The ISO determined that this project is needed to mitigate the identified overloading concerns. The ISO also considered an SPS alternative to mitigate all Category C overloads identified in this area and found that the SPS to be infeasible because it would require monitoring more contingencies than the SPS guideline would allow. The ISO further considered an alternative feasible SPS combined with required upgrades to mitigate all overloads and found this option to be more expensive compared to the *Table Mountain-Sycamore 115 kV Line Project*.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO staff will ensure that necessary operating procedures will be in place to meet reliability needs in 2011.

Lockeford-Industrial, Lodi-Industrial and Lockeford-Lodi 60 kV Lines

The Lockeford/Lodi area 60 kV lines are identified with existing overloads under various Category C contingency conditions. Also for the loss of the Country Club-Hummer 60 kV, the Mosher substation transfers to the Lockeford #1 60 kV line potentially overloading it. The Mosher substation has over 50 MW of load and, as such, it should have a looped service. For these potential overloads, presently there is an ongoing 2010 request window project which proposes to build a new 230/60 kV substation in the vicinity of the existing Industrial substation and also build two new 60 kV lines from the new substation to the Industrial substation. The ISO, working with PG&E, will evaluate different alternatives to bringing additional transmission capacity in to the Lodi area as a long-term solution. The most feasible project implementation, due to permitting and lead times is 2016. These plans will be assessed further in a future ISO transmission plan.

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concerns. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Valley Spring No. 1 60 kV Line

The Valley Spring No. 1 60 kV line is identified to overload starting year 2020 under Category B contingency condition. This overload occurs when the Linden substation is transferred to this line due to an outage of the Weber-Mormon Junction 60 kV line. Reconductoring this line could be a solution. There is ample time for permitting, procurement and installation before 2020. This plan, and other possible options, will be assessed further in a future ISO transmission plan.

West Point-Valley Springs 60 kV Line

The ISO identified an existing overload on the West Point-Valley Springs 60 kV line under a Category B contingency condition. The ISO previously approved a project in the 2010 transmission plan to reconductor this line but since this is a remote radial line built though rough terrain with no back-up sources, the reconductoring work cannot take place without interrupting electric service to customers at Electra, West Point, and Pine Grove for approximately 1-2 months. Because of this issue, PG&E submitted a project through the 2010 request window, the *West Point-Valley Springs 60 kV Line Project*, which consists of building a new 60 kV line from Valley Springs to Pine Grove substation. The project has an in-service date of December 2013. The ISO determined that this project is needed to mitigate identified overloading concerns

In the interim, the ISO recommends that a short-term rating and operating procedure be developed to address any potential reliability concern. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Stanislaus-Manteca No. 2 115 kV Line

The Stanislaus-Manteca No. 2 115 kV line was identified with an existing overload under a Category C contingency. The solution includes developing an operating solution to reduce generation at Stanislaus following the first contingency. The most feasible implementation timeline is 2011.

Stanislaus-Melones-Manteca No. 1 115 kV Line

The Stanislaus-Melones-Manteca No.1 115 kV line was identified with an existing overload under a Category C contingency. Solutions include obtaining a short-term rating and developing an operating solution to reduce generation at Stanislaus following the contingency or to install an SPS for the same action. The most feasible implementation timeline for this upgrade is 2012.

Stockton 'A'-Lockeford-Bellota No. 2 115 kV Line

The ISO identified an existing overload on the Stockton 'A'-Lockeford-Bellota No. 2 115 kV line under a Category C contingency condition. Solution includes developing an operating solution to re-adjust the system following the first contingency or to install an SPS to curtail load following the second contingency. The most feasible implementation timeline for this upgrade is 2012.

2.7.4.6 Stockton/Stanislaus Division Voltage Concerns Mitigations

The ISO identified an existing low voltage at Lockeford 230 kV bus under a Category B contingency condition. The ISO also identified existing low voltages at Stagg and Eight Mile 230 kV buses under Category C contingency conditions. The solution includes installing voltage support in the area. The most feasible implementation timeline for this upgrade is 2015 due to permitting and lead times. In the interim, the ISO recommends that an operating procedure be developed to address any potential reliability concerns.

Request Window Submission - Kirkwood Meadows Public Utility District (KMPUD) 115 kV Interconnection

KMPUD and the Kirkwood Community are physically isolated from any large regional electric service utility. Kirkwood is currently being served by local diesel-fired generators, which are owned and operated by KMPUD. KMPUD's customer base is comprised of residential homes, commercial operations, and the Kirkwood Ski Resort, which is its largest single customer. Due to the increased electric demand, KMPUD is proposing to interconnect to PG&E's transmission system. To facilitate this interconnection, PG&E submitted a project through the 2010 request window, the *KMPUD 115 kV Interconnection Project*, which proposes to interconnect KMPUD's proposed facilities by tapping onto the existing Salt Springs – Tiger Creek 115 kV line adjacent to Salt Springs PH. This tap line will be 2.3 miles long. The project is expected to cost between $2M and $4M.

The ISO has reviewed the interconnection facilities proposed by PG&E and has determined that they will allow the load to be reliably interconnected to the ISO controlled grid. There are no reliability upgrades or additions to the ISO controlled grid that will be triggered by the tap line and associated facilities. Thus, the ISO has determined that this proposed load interconnection to the PG&E 115 kV system may proceed without modification. The radial tap line will not be under the ISO's operational control.

2.7.5 KEY CONCLUSIONS

The 2010 reliability assessment of the PG&E Central Valley area revealed several reliability concerns. These concerns consist of thermal overloads and low voltages under normal, Categories B and C contingency conditions. Also one Category C contingency resulted in the power flow divergence indicating potential area-wide voltage collapse.

The problems identified in this 2010/2011 assessment are very similar to those found in the last year's assessment. There were three new projects approved in the 2010 transmission plan, which eliminated one normal, one Category B and three Category C overloads identified in the last year's assessment. To address the identified thermal overloads and low voltage concerns, the ISO-proposed a total of 30 transmission solutions and received nine transmission project proposals through the request window. ISO also completed evaluation of one ongoing project from the last year's request window. However, some of these proposed request window projects serve the purpose of more than one ISO-proposed solutions. These are:

- Hammer –Country Club 60 kV Line Switch Replacement Project;
- Cortina No. 3 60 kV Line Reconductoring;
- West Point –Valley Springs 60 kV Line Project;
- South of Palermo 115 kV Reinforcement Project;
- Stagg –Hammer 60 kV Line Project;
- Vierra 115 kV Looping Project;
- Rio Oso –Atlantic 230 kV Line Project;
- Vaca Dixon-Davis Voltage Conversion;
- Lodi Area 230 kV Substation Project; and
- Drum –Grass Valley –Weimar 60 kV Line Project.

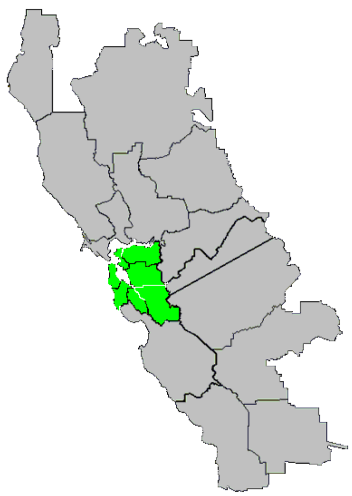
The ISO has determined eight projects to be needed (1 through 8 in the list above), and the remaining two (9 and 10 in the list above) have ongoing status requiring further information.

The projects determined to be needed will carry forward into the 2011/2012 planning cycle and will be included in the planning assumptions.

2.8 GREATER BAY AREA

2.8.1 Area Description

The Greater Bay Area (or Bay Area) is at the center of PG&E's service territory. This area includes Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties as shown in the adjacent illustration. For ease of conducting the performance evaluation, the Greater Bay Area is divided into three sub-areas: 1) East Bay, 2) South Bay and 3) San Francisco-Peninsula.



The East Bay sub-area includes cities in Alameda and Contra Costa Counties. Major cities include Concord, Berkeley, Oakland, Hayward, Fremont and Pittsburg. This area primarily relies on its internal generation to serve electricity customers.

The South Bay sub-area covers approximately 1,500 square miles and includes the Santa Clara County. Major cities include San Jose, Mountain View, Morgan Hill and Gilroy. Los Esteros, Metcalf, Monta Vista and Newark are the key substations that deliver power to this sub-area. The South Bay sub-area encompasses the De Anza and San Jose divisions, and the City of Santa Clara. Generation units within this sub-area include the Calpine's Metcalf Energy Center, Los Esteros Energy Center, Gilroy Units, and SVP's Donald Von Raesfeld power plant. In addition, this sub-area has key 500 kV and 230 kV interconnections to the Moss Landing and Tesla substations.

Finally, the San Francisco-Peninsula sub-area includes the San Francisco and San Mateo Counties. These counties comprise the cities of San Francisco, San Bruno, San Mateo, Redwood City, and Palo Alto. The San Francisco-Peninsula area presently relies on transmission line import capabilities, including the new Trans Bay cable, to serve its electricity demand. Electric power is imported from Pittsburg, East Shore, Tesla, Newark, and Monta Vista substations to support the sub-area loads.

Trans Bay Cable Project becomes operational in 2011. It is a uni-directional, controllable, 400 MW HVDC land and submarine-based electric transmission system. The project employs Voltage Source Converter ("VSC") technology which will transmit real power from the Pittsburg 230 kV substation in the City of Pittsburg to the Potrero 115 kV substation in the City and County of San Francisco.

In addition, as a result of the re-cabling of the Martin-Bayshore-Portrero lines (A-H-W #1 and A-H-W #2 115 kV cable), it has replaced the two existing 115 kV cables between Martin-Bayshore-Potrero with new cables and resulted in increased ratings on these facilities. The new ratings provided by this project will increase transmission capacity between Martin-Bayshore-Potrero and relieve congestion.

As these two projects become in service and are proven reliable, Potrero Unit 3, 4 5 and 6 will no longer be needed for Reliability Must Run services.

2.8.2 Area-Specific Assumptions and System Conditions

In addition to the general assumptions described in section 2.3, the following are some of the area-specific assumptions used for the Greater Bay Area studies.

Generation

Table 2.8-1 lists major generating plants that were modeled in the base cases when the Greater Bay Area analysis was performed.

Table 2.8-1: Generators in the Greater Bay Area

Power Plant Name	Maximum Capacity (MW)
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
Metcalf Energy Center	575
Moss Landing Power Plant	1500
Oakland C Gas Turbines	165
Donald Von Raesfeld Power Plant	182
Pittsburg Power Plant	1360
Riverview Energy Center	61
Ox Mountain	13
United Cogen	30
Gateway Generating Station	599
Russell City Energy Center (Modeled in 2020)	614

Load Forecast

Loads within the Greater Bay Area reflect a coincident peak load for 1-in-10-year heat wave conditions. Table 2.8-2 shows the area load levels modeled for each of the PG&E local area studies including the Greater Bay Area.

Table 2.8-2: Summer Peak load forecasts for Greater Bay Area assessment

1- IN- 10 YEAR HEAT WAVE NON-SIMULTANEOUS LOAD FORECAST SUMMER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
EAST BAY	897	909	919	925	931	977
DIABLO	1,727	1,743	1,763	1,777	1,794	1,888
SAN FRANCISCO	942	948	954	959	965	998
PENINSULA	938	960	974	987	996	1,055
MISSION	1,296	1,320	1,339	1,352	1,366	1,478
DE ANZA	985	1,019	1,060	1,069	1,080	1,143
SAN JOSE	1,735	1,760	1,789	1,806	1,823	1,927

2.8.3 Study results and Discussions

Based on the studies performed for the Bay Area, the following results were observed:

TPL 001: System Performance under Normal Conditions

- There is no facility with an identified thermal overload under the Category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and ISO Category B: (G-1/L-1)

- There are six facilities with identified thermal overloads.

TPL 003: System Performance Following Loss of Two or More BES Elements

- There are 64 facilities with identified thermal overloads, 13 facilities with identified low voltage and five facilities with voltage deviation concerns under the Category C performance requirement.

Appendix A documents the thermal overloads and voltage concerns identified for the summer peak conditions along with ISO-proposed solutions.

2.8.4 Recommended Solutions for Facilities Not Meeting Thermal and Voltage Performance Requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

2.8.4.1 San Francisco Division

The Trans Bay cable and re-cabling projects of the A-H-W 1&2 115 kV cables are complete in 2011. With these projects being in place and proven reliable, ISO analysis has concluded that Potrero units 3, 4, 5 and 6 can be released from their RMR agreement. The results of this analysis based on the completion of both Trans Bay cable and re-cabling projects are documented in the following:

TPL 001-System Performance under Normal Conditions

- No overloads were found under normal operating conditions

TPL 002-System Performance Following Loss of a Single BES Element

- **Potrero-Mission (AX) 115 kV Cable Overload**

  This overload would be caused by outage of Potrero-Larken #2 (AY-2) 115 kV cable during the 2011 summer peak conditions if the Trans Bay cable is at its full capacity of 400 MW. Reducing the Trans Bay cable transfer into San Franscisco to the minimum of 210 MW will reduce the flow on the Potrero-Mission (AX) 115 kV cable below its emergency rating.

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Potrero–Larkin #1 (AY-1) 115 kV Cable Overload**

  Develop an operating procedure to transfer loads among relevant substations. It should be noted that reducing the Trans Bay cable output does not solve this particular problem

The following two elements are found overloaded under different L-1-1 conditions for which a common solution is recommended. Overloaded elements are:

- Potrero–Larkin #2 (AY-2) 115 kV cable; and
- Potrero–Mission (AX) 115 kV cable.

The ISO recommends the following mitigation procedure for each of the above overloads:

- Develop an operating procedure to transfer loads among relevant substations and/or reduce Trans Bay cable output upon detection of an overload and the contingencies that are causing it.
- If the overload still exists, drop a calculated amount of load either manually or through an SPS. For manual load dropping, short-term emergency (STE) ratings must be developed and the line loading must be within STE ratings.

The ISO is working with PG&E to develop and implement this proposed mitigation procedure before the 2011 summer operating period.

Loss of Embarcadero Load

Embarcadero substation is served by two 230 kV cables. Loss of both 230 kV cables supplying Embarcadero substation will result in the curtailment of approximately 250 MW of San Francisco downtown load. The ISO is contemplating to reconductor the existing cables or to add a third 230 kV line into Embarcadero substation in order to significantly reduce the risk of curtailing San Francisco downtown load and increase operating flexibility for future infrastructure replacement.

2.8.4.2 Peninsula Division

TPL 001: System Performance under Normal Conditions

- No overloads were found under normal operating conditions.

TPL 002: System Performance Following Loss of a Single BES Element

- **Jefferson-Stanford 60 kV Line #1 Overloading**

  This overload would be caused by a loss of Cooley Landing-Stanford 60 kV Line with Cardinal Co-Gen off-line at the expected load level of summer 2012. ISO recommends building a new Jefferson-

Stanford #2 60 kV line. It should be noted that reconductoring the existing line is not feasible due to logistic constraints.

TPL 003-System Performance Following Loss of Two or More BES Elements

Ravenswood-Palo Alto 115 kV Line #1 Overloading

This overload would be caused by a bus fault at Ravenswood 115 kV substation bus 2E or the loss of Ravenswood-Palo Alto 115 kV #2 line and Ravenswood–Cooley Landing 115 kV #2 line at the expected load level of summer 2011. The ISO recommends developing an STE rating and operating procedures before the summer of 2011 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Ravenswood-Palo Alto 115 kV Line #2 Overloading

This overload would be caused by loss of two transmission lines on separate towers, Ravenswood-Palo Alto #1 and Cooley Landing-Palo Alto 115 kV lines; or the combination of Ravenswood–Cooley Landing #2 115 kV line and Ravenswood–Palo Alto #1 115 kV line at the expected load level of summer 2011. The ISO recommends re-rating the overloaded line and also developing the STE rating. If re-rating is not applicable or it does not eliminate the overload, then the ISO recommends developing operating procedures before the summer of 2011 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Cooley Landing-Palo Alto 115 kV Line #1 Overloading

This overload would be caused by loss of a double circuit tower line, Ravenswood-Palo Alto 115 kV line #1 and #2 at the expected load level of summer 2011. The ISO recommends re-rating the overloaded line and also developing the STE rating. If re-rating is not applicable or it does not eliminate the overload, then the ISO recommends developing operating procedures before the summer of 2011 to drop a calculated amount of load either manually or through SPS to mitigate the overload.

Ravenswood-Cooley Landing 115 kV Line #2 Overloading

This overload would be caused by loss of a double circuit tower line, Ravenswood-Palo Alto 115 kV line #1 and #2 at the expected load level of summer 2011. The ISO recommends re-rating the overloaded line and also developing the STE rating. If re-rating is not applicable or it does not eliminate the overload, then the ISO recommends developing operating procedures before summer of 2011 to drop a calculated amount of load either manually or through SPS to mitigate the overload.

Ravenswood-San Mateo 115 kV Line #1 Overload

This overload would be caused by loss of a double circuit tower line, Ravenswood-San Mateo 230 kV line #1 and #2 at the expected load level of summer 2011. The ISO recommends re-rating the overloaded line and also developing the STE rating. If re-rating is not applicable or it does not eliminate the overload, then the ISO recommends developing operating procedures before the summer of 2011 to drop a calculated amount of load either manually or through SPS to mitigate the overload. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

San Mateo-Belmont 115 kV Line #1 Overload

This overload would be caused by loss of a double circuit tower line, Ravenswood-Bair 115 kV line #1 and #2 at expected load level of summer 2020 or the combined loss of Ravenswood 230/115 kV Bank 1&2 at the expected load level of summer 2013. ISO recommends re-rating the overloaded line and also developing the STE rating. If re-rating is not applicable or it does not eliminate overload, then develop operating procedures before summer of 2011 to drop calculated amount of load either manually or through SPS to mitigate the overload. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Bair 115/60 Transformer #1 Overloading

This overload would be caused by loss of Ravenswood–Cooley Landing #1 115 kV line and Cooley Landing 115/60 kV transformers #2 at the expected load level of summer 2011. The ISO recommends replacing a transformer or dropping a calculated amount of load to relieve overloading. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Bair-Cooley Landing 60 kV Line #1 Overloading

This overload would be caused by loss of Bair–Cooley Landing #2 60 kV line and Bair 115/60 kV transformers #1 at the expected load level of summer 2020. ISO recommends dropping a calculated amount of load to relieve overloading. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Bair-Cooley Landing 60 kV Line #2 Overloading

This overload would be caused by loss of San Mateo-Bair 60 kV line and Bair 115/60 kV transformers #1 at the expected load level of summer 2013. The ISO recommends load curtailment to relieve overloading. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

San Mateo 230/115 Transformer #7 Overloading

This overload would be caused by loss of San Mateo 230/115 kV transformers #5 and #6 at the expected load level of summer 2020. Since overloading is less than 10%, ISO recommends re-rating the overloaded transformer and developing STE ratings. If re-rating is not achievable or does not relieve the overload, the ISO recommends add cooling fans to increase transformer capacity. If cooling fans are not feasible then require load curtailment may be required to relieve overloading.

2.8.4.3 East Bay Division

TPL 001-System Performance under Normal Conditions

- No overloads were found under normal operating conditions (Category A)

TPL 002-System Performance Following Loss of a Single BES Element

- **Oleum-North Tower-Christie 115 kV Line Overload**

This overload would be caused by loss of a Christie-Sobrante 115 kV line and Union CH Generation at the expected load level of summer 2020. ISO recommends re-rating or reconductoring the line.

TPL 003-System Performance Following Loss of Two or More BES Elements

- **Oleum-North Tower-Christie 115 kV Line Overload**

This overload would also be caused by combination of loss of two BES elements. The ISO recommends re-rating or reconductoring the line.

- **Christie-Sobrante 115 kV Line Overload**

  This overload would be caused by loss of a double circuit tower line Sobrante-G #1 and #2 115 kV lines at the expected load level of summer 2011. ISO recommends re-rating or reconductoring the line. For an interim solution, ISO recommends SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

2.8.4.4 Diablo Division

TPL 001: System Performance under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002: System Performance Following Loss of a Single BES Element

Contra Costa PP-Contra Costa Sub 230 kV Line Overload

This overload would be caused by a line outage of Birds Landing-Contra Costa PP 230 kV line at the expected load level of summer 2020. The ISO recommends using congestion management or SPS to curtail load.

Birds Landing-Contra Costa 230 kV Line Overload

This overload would be caused by a line outage of Contra Costa PP - Contra Costa Sub 230 kV line at the expected load level of summer 2020. The ISO recommends using congestion management or SPS to curtail load.

TPL 003: System Performance Following Loss of Two or More BES Elements

Pittsburg-Clayton #1 115 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying Pittsburg-Clayton #3 and #4 115 kV lines at the expected load level of summer 2011. The ISO recommends using SPS to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Pittsburg-Clayton #3 115 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying Pittsburg-Clayton #1 and #4 115 kV lines at the expected load level of summer 2011. The ISO recommends using SPS to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Pittsburg-Clayton #4 115 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying Pittsburg-Clayton #1 and #3 115 kV lines at the expected load level of summer 2011. The ISO recommends using SPS to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Lakewood-Meadow Lane-Clayton 115 kV Line Overload

This overload would be caused by the double line outage of Clayton-Meadow Lane 115 kV and Lakewood-Clayton 115 kV lines or bus fault of Clayton 115 kV section #1 at the expected load level of summer 2011. The ISO recommends using SPS to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Moraga-Lakewood 115 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying Lakewood-Clayton and Lakewood-Meadow Lane-Clayton 115 kV lines at the expected load level of summer 2011. The ISO recommends using SPS to drop a calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Moraga-Oakland J 115 kV Line Overload

This overload would be caused by a bus fault at San Leandro 115 kV bus D at the expected load level of summer 2011. The ISO recommend using SPS to drop a calculated amount of load as an interim solution. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

The ISO had approved the *Moraga-Oakland "J" SPS Project* in the 2010 transmission plan as the cost effective solution for the reliability problems found in this area. However, the ISO will evaluate PG&E's proposed Oakland Area Long Term plan in the next planning cycle to address the long-term transmission needs in the East Bay.

Moraga-San Leandro 115 kV Line #1 Overload

This overload would be caused by loss of Moraga-San Leandro 115 kV line #2 & #3 115 kV line at the expected load level of summer 2011 or Moraga-Oakland J 115 kV line & Moraga-San Leandro 115 kV line #3 115 kV line at the expected load level of summer 2011. For an interim solution, the ISO recommend SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS is in place on time.

The ISO had approved the *Moraga-Oakland "J" SPS Project* in the 2010 transmission plan. In addition, the ISO also will evaluate Oakland Area Long Term plan in the next planning cycle to mitigate this specific and many other potential overloads in the East Bay.

Moraga-San Leandro 115 kV Line #2 Overload

This overload would be caused by loss of Moraga-San Leandro 115 kV line #1 & #3 at the expected load level of summer 2011 or Moraga-Oakland J 115 kV line & Moraga-San Leandro 115 kV line #3 at the expected load level of summer 2011.

The ISO had approved the *Moraga-Oakland "J" SPS Project* in the 2010 transmission plan. In addition, the ISO is also evaluating Oakland Area Long Term plan in the next planning cycle to mitigate this specific and many other potential overloads in the East Bay.

Moraga-San Leandro 115 kV Line #3 Overload

This overload would be caused by loss of Moraga-San Leandro 115 kV line #1 & #2 at the expected load level of summer 2011 or Moraga-Oakland J 115 kV line & Moraga-San Leandro 115 kV line #2 at the expected load level of summer 2015.

The ISO had approved the *Moraga-Oakland "J" SPS Project* in the 2010 transmission plan. In addition, the ISO is also evaluating the Oakland Area Long-Term plan in the next planning cycle to mitigate this specific and many other potential overloads in the East Bay.

Christie-Sobrante 115 kV Line Overload

This overload would occur with loss of a double circuit tower line carrying Sobrante-G #1 and #2 115 kV lines at the expected load level of summer 2011. The ISO recommends SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Oleum-Martinez 115 kV Line Overload

This overload would occur with loss of a double circuit tower line carrying Sobrante-G #1 and #2 115 kV lines at the expected load level of summer 2011. The ISO recommends SPS be incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Moraga-Castro Valley 230 kV Line Overload

This overload would be caused by double line outage of Contra Costa-Las Positas 230 kV Line and Contra Costa-Lonetree 230 kV line at the expected load level of summer 2011. The ISO recommends SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures or SPS are in place on time.

Contra Costa PP- Contra Costa Sub 230 kV Line Overload

This overload would be caused by double line outage of Contra Costa-Gateway and Birds Landing-Contra Costa 230 kV lines at the expected load level of summer 2020 or Lambie-Birds Landing 230 kV line and Peabody-Birds Landing 230 kV line at the expected load level of summer 2020. The ISO recommends congestion management.

2.8.4.5 Mission Division

TPL 001: System Performance under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002: System Performance Following Loss of a Single BES Element

No overloads were found under Category B contingency conditions

TPL 003: System Performance Following Loss of Two or More BES Elements

Moraga-San Leandro 115 kV Line #1 Overload

This overload would be caused by a bus outage San Leandro 115 kV section E or double circuit tower line carrying Moraga-Oakland J and Moraga-San Leandro #3 115 kV lines or double line contingencies of Moraga-San Leandro #2 and Moraga-San Leandro #3 115 kV lines at the expected load level of summer 2011. The ISO recommends developing flow gate limit in the operating procedure. The ISO will work with PG&E to ensure that the operating procedures is in place on time.

Moraga-San Leandro 115 kV Line #2 Overload

This overload would be caused by double circuit tower line carrying Moraga-Oakland J and Moraga-San Leandro #3 115 kV lines or double line contingencies of Moraga-San Leandro #1 and Moraga-San Leandro #3 115 kV lines at the expected load level of summer 2011. The ISO recommends developing flow gate limit in the operating procedure. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Moraga-San Leandro 115 kV Line #3 Overload

This overload would be caused by double line contingencies of Moraga-San Leandro #1 and Moraga-San Leandro #2 115 kV lines at the expected load level of summer 2011. The ISO recommends developing flow gate limit in the operating procedure. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark-Ames 115 kV Line #1 Overload

This overload would be caused by double line contingencies of Newark-Ravenswood 230 kV line and Tesla-Ravenswood 230 kV line at the expected load level of summer 2011. The ISO recommends SPS or RAS be incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark-Ames115 kV Line #2 Overload

This overload would be caused by double line contingencies of Newark-Ravenswood 230 kV line and Tesla-Ravenswood 230 kV line at the expected load level of summer 2011. The ISO recommends SPS or RAS be incorporated in the operating procedures to drop some calculated amount of load. . The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark-Ames 115 kV Line #3 Overload

This overload would be caused by double line contingencies of Newark-Ravenswood 230 kV line and Tesla-Ravenswood 230 kV line at the expected load level of summer 2011. The ISO recommends SPS or RAS be incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark-Ames Distribution 115 kV Line Overload

This overload would be caused by double line contingencies of Newark-Ravenswood 230 kV line and Tesla-Ravenswood 230 kV line at the expected load level of summer 2011. The ISO recommends SPS or RAS be incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Moraga-Castro Valley 230 kV Line Overload

This overload would occur for outage of Contra Costa-Las Positas 230 kV line and Tesla-Newark #2 230 kV line at the expected load level of summer 2011 or Contra Costa-Las Positas 230 kV line and Contra Costa-Lonetree 230 kV line at the expected load level of summer 2011. The ISO recommends SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

East Shore 230/115 kV Bank #1 Overload

This transformer overload would be caused by Dumbarton-Newark 115 kV line and East Shore 230/115 kV Bank #2 at the expected load level of summer 2012. The ISO recommends SPS or RAS be incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

East Shore 230/115 kV Bank #2 Overload

This transformer overload would be caused by Dumbarton-Newark 115 kV line and East Shore 230/115 kV Bank #1 at the expected load level of summer 2011. ISO recommends SPS or RAS be incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Newark 115/60 kV Bank #1 Overload

This overload would be caused by double contingencies of San Ramon 230/60 kV Bank #1 and Las Positias 230/60 kV Bank#4 at the expected load level of summer 2020. The ISO recommends congestion management.

Grant-East Shore #1 115 kV Line Overload

This overload would occur for outage of San Leandro-Oakland J 115 kV line and Grant-East Shore #2 115 kV line at the expected load level of summer 2020. The ISO recommends congestion management.

Grant-East Shore #2 115 kV Line Overload

This overload would occur for outage of San Leandro-Oakland J 115 kV line and Grant-East Shore #2 115 kV line at the expected load level of summer 2020. The ISO recommends congestion management.

East Shore-Dumbarton 115 kV Line Overload

This overload would be caused by an outage of Pittsburg-East Shore and East Shore-San Mateo 230 kV lines at the expected load level of summer 2020. The ISO recommends congestion management.

Las Positas-Newark 230 kV Line Overload

This overload would be caused by an outage of Tesla-Newark #1 & #2 230 kV lines at the expected load level of summer 2015. The ISO recommends mitigation by congestion management.

Castro Valley-Newark 230 kV Line Overload

This overload would be caused by an outage of Contra Costa-Las Positas 230 kV line and Tesla-Newark #2 230 kV line at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Low Voltages

A low voltage concern was identified beginning in year 2011 in the 60 kV system including a numerous 60 kV bus under Category C with loss of San Ramon 230/60 kV Bank #1 and Las Positas 230/60 kV Bank #4. The ISO recommends installing reactive support device in the 60 kV system. In the meantime, the ISO recommends an interim operating procedure. The ISO will work with PG&E to ensure that the operating procedure is in place on time.

Voltage Drop

A concern of voltage drop was identified for more than 10% beginning in year 2011 in the 60 kV system including a numerous 60 kV bus under Category C with loss of San Ramon 230/60 kV Bank #1 and Las Positas 230/60 kV Bank #4. The ISO recommends installing reactive support in the 60 kV system. In the meantime, the ISO recommends an interim operating procedure. The ISO will work with PG&E to ensure that the operating procedures is in place on time.

2.8.4.6 San Jose Division

TPL 001: System Performance under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002: System Performance Following Loss of a Single BES Element

Newark-Dixon Landing 115 KV Line Overload

This overload would be caused by an outage of Piercy-Metcalf 115 kV line at the expected load level of summer 2011. PG&E has scheduled a reconductor project by 2012. For an interim solution, the

ISO recommends SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the interim operating procedure is in place on time.

TPL 003: System Performance Following Loss of Two or More BES Elements

Metcalf 230/115 kV Bank #1 Overload

This overload would be caused by the outage of Metcalf 230/115 kV Bank #2 and Metcalf 230/115 kV Bank #4 at the expected load level of summer 2015. The ISO recommends mitigation by congestion management.

Metcalf 230/115 kV Bank #2 Overload

This overload would be caused by the outage of Metcalf 230/115 kV Bank #1 and Metcalf 230/115 kV Bank #3 at the expected load level of summer 2011 or loss of Metcalf 230 kV Bus #1 D at the expected load level of summer 2011. The ISO recommends mitigation by congestion management.

Metcalf 230/115 kV Bank #3 Overload

This overload would be caused by the outage of Metcalf 230/115 kV Bank #2 and Metcalf 230/115 kV Bank #4 at the expected load level of summer 2015 or loss of Metcalf 230 kV Bus #1 D at the expected load level of summer 2015. The ISO recommends mitigation by congestion management.

Metcalf 230/115 kV Bank #4 Overload

This overload would be caused by the outage of Metcalf 230/115 kV Bank #1 and Metcalf 230/115 kV Bank #2 at the expected load level of summer 2015. The ISO recommends mitigation by congestion management.

Piercy-Metcalf 115 kV Line Overload

This overload would be caused by the outage of Metcalf-Evergreen #1 & #2 115 kV lines at the expected load level of summer 2015. The ISO recommends mitigation by congestion management.

Evergreen-Mabury 115 kV Line Overload

This overload would be caused by the outage of Newark-Metcalf #2 115 kV line and Piercy-Metcalf 115 kV at the expected load level of summer 2012. The ISO recommends SPS or RAS be incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Metcalf 500/230 kV Bank #13 Overload

This overload would be caused by the outage of Metcalf 500/230 kV Bank #11 & #12 at the expected load level of summer 2013. The ISO recommends mitigation by congestion management.

Newark-Milpitas #2 115 kV Line Overload

This overload would be caused by the outage of Newark-Milpitas #1 115 kV line and Swift-Metcalf 115 kV line at the expected load level of summer 2011. The ISO recommends SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Metcalf-LLagas 115 kV Line Overload

This overload would be caused by the outage of Metcalf-Morgan Hill 115 kV line and LLagas-Gilroy Foods 115 kV line at the expected load level of summer 2012. The ISO recommends SPS or RAS incorporated in the operating procedures to drop some calculated amount of load. The ISO will work with PG&E to ensure that the operating procedures are in place on time.

Metcalf-Morgan Hill 115 kV Line Overload

This overload would be caused by the outage of Metcalf-Morgan Hill 115 kV line and LLagas-Gilroy Foods 115 kV line at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Hicks-Metcalf 230 kV Line Overload

This overload would be caused by the outage of Metcalf-Monta Vista #3 230 kV line and Monta Vista-Coyote Sw Sta 230 kV line at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Monta Vista-Hicks 230 kV Line Overload

This overload would be caused by the outage of Metcalf-Monta Vista #3 230 kV line and Monta Vista-Coyote Switching Station 230 kV line at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Trimble-San Jose B 115 kV Line Overload

This overload would be caused by outage of Los Esteros-Montague115 kV lines and Los Esteros-Trimble115 kV lines at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

2.8.4.7 De Anza Division

TPL 001: System Performance under Normal Conditions

No overloads were found under normal operating conditions (Category A)

TPL 002: System Performance Following Loss of a Single BES Element

No overloads were found under Category B contingency conditions

TPL 003: System Performance Following Loss of Two or More BES Elements

Monta Vista-Saratoga 230 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying Metcalf-Monta Vista #3 and Monta Vista-Coyote Switching Station 230 kV lines at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Monta Vista-Hicks 230 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying Metcalf-Monta Vista #3 and Monta Vista-Coyote Switching Station 230 kV lines at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Saratoga-Vasona 230 kV Line Overload

This overload would be caused by loss of a double circuit tower line carrying Metcalf-Monta Vista #3 and Monta Vista-Coyote Switching Station 230 kV lines at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Monta Vista 230/115 kV Transformer #4 Overload

This transformer overload would be caused by the outage of Monta Vista 230/115 kV Bank #2 and #3 at the expected load level of summer 2020. The ISO recommends mitigation by congestion management.

Monta Vista 230/115 kV Transformer #2 Overload

This transformer overload would be caused by the outage of Monta Vista 230/115 kV Bank #3 and #4 at the expected load level of summer 2020. The ISO recommends congestion management as a mitigation plan.

2.8.5 Key Conclusions

The ISO proposed a total of 32 upgrades (see Appendix A) to address identified reliability concerns. After considering all the plausible alternatives, the following two projects are determined to be needed by the ISO:

- *New Jefferson-Stanford #2 60 kV Line*: This Category B overload was identified as starting to show up in 2012 and the proposed in-service date given by PG&E is 2014; and
- *Moraga-Castro Valley 230 kV Capacity Increase*: This project mitigates Category C overloads on Moraga-Castro Valley 230 kV and Castro Valley-Newark 230 kV lines. The overloads are expected to start in 2011 and the proposed in-service date is 2013.

The following six projects submitted in the request window are determined not to be needed:

- *Moraga-San Leandro / Oakland "J" 115 kV Line Reconductor*: Implementing a SPS is a more cost effective solution for this overload. Hence the reconductor project is determined not to be needed;
- *Pittsburg-Clayton #2, Moraga-Lakewood & Lakewood-Meadow Lane-Clayton 115 kV Line Reconductor:* Implementing a SPS is a more cost effective solution for this overload. Hence the reconductor project is determined not to be needed;
- *Potrero 115 kV Energy Storage*: ISO's reliability assessment studies did not demonstrate the reliability need for this project (WGD based this project on the out-of-date LCR report for SF with 25 MW in 2010, 15 MW in 2011 and 10 MW in 2013). Hence the project is determined not to be needed;
- *New High Temperature Cable*: The ISO has approved and completed the project to re-cable the existing San Francisco 115 kV cables. This eliminated the need for any similar alternative. Hence the project is determined not to be needed;
- *Collinsville Substation Project*: The need for this project was not identified in ISO's reliability assessment studies. Hence the project is determined not to be needed; and
- *Bay Area Reactive Support – Pittsburg SVC Project*: The need for this project was not identified in ISO's reliability assessment studies. Hence the project is determined not to be needed.

The following two projects will be evaluated in future planning cycles:

- *New Embarcadero-Potrero 230 kV Line*: This is a $130-170 million project. ISO is coordinating with PG&E to carry out a study to evaluate this project. This is a project driven by Category C concerns; and
- *New Ames-Palo Alto 115 kV Line*: Preliminarily, implementing an SPS was considered a more cost effective solution for the overloading concern. However, ISO is coordinating with PG&E to further evaluate the overall transmission needs for the local area.

During this year's reliability assessment, the one Category B problem observed was addressed by project submitted through request window. After considering all the alternatives the ISO has determined two projects to be needed. Out of the six projects not being approved during this planning cycle, three projects are alternatives to the projects determined to be needed.

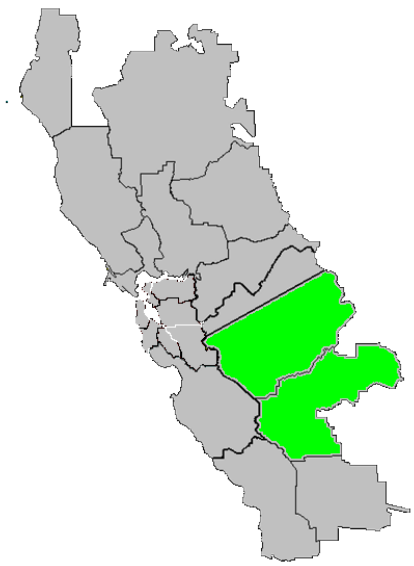
- *Potrero 115 kV Energy Storage* is not needed as the alternative to the S.F. re-cabling project which has been approved and completed;
- *New High Temperature Cable* is not needed as the alternative to the S.F. re-cabling project which has been approved and completed;
- *Bay Area Reactive Support* – Pittsburg SVC Project is not needed as the alternative to the Trans Bay cable project which has been approved and completed.

Remaining projects which are not deemed to be needed at this point will be further evaluated during future planning cycles. The projects determined to be needed during this planning cycle will be included as planning assumptions for the next planning cycle.

2.9 GREATER FRESNO AREA

2.9.1 Area Description

The Greater Fresno Area is located in the central to southern PG&E service territory. This area includes Madera, Mariposa, Merced, and Kings Counties located within the San Joaquin Valley Region. The figure below depicts the geographical location of the Fresno area.



The Greater Fresno area electric transmission system is comprised of 70 kV, 115 kV, and 230 kV transmission facilities. Electric supply to the Greater Fresno area is provided primarily by area Hydro generation (largest of which is Helms Pump/Gen), a number of market, and few QF units. It is supplemented by transmission imports from the North Valley and the 500 kV along the West and South parts of the Valley. Greater Fresno Area is comprised of two primary load pockets, one being the Yosemite area in the northwest portion of the shaded region in figure 4-6. The rest of the shaded region represents the Fresno area.

The Greater Fresno area interconnects to the bulk PG&E transmission system by thirteen transmission circuits which are ten 230 kV lines, one 230/115 kV bank, two 230/70 kV banks, and one 70 kV line served from the Gates substation in the south, Moss Landing in the West, Los Banos in the Northwest, Bellota in the Northeast, and Templeton in the Southwest. Historically, the Greater Fresno area experiences its highest demand during the summer season but also experience high loading due to the potential of 900 MW of pump load at Helms during off-peak. Load forecasts indicate the Greater Fresno area should reach its summer peak demand of approximately 3,529 MW and summer off-peak of load exceeding 1,760 MW (excluding the Helms pump load) by 2020 assuming load is increasing at a rate of 35 MW per year. In addition, this area has a maximum capacity of about 3,405 MW of local generation. The largest generation facility within the area is the Helms Pump Storage Plant (PSP) with 1,212 MW of generation capability. Accordingly, system assessments in this area include the technical studies for the scenarios under summer-peak and off-peak conditions that reflect different operating conditions of the Helms PSP.

2.9.2 Area-Specific Assumptions and System Conditions

The Greater Fresno area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO secured website provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions and methodology applied to Fresno area study are provided below in this section.

Generation

Generation resources in the Greater Fresno area consist of market, QF and self-generating units. Table 2.9-1 list all generating plants in Greater Fresno and Yosemite areas modeled in the study.

Table 2.9-1: Generation units in the Greater Fresno-2014 peak analysis

Plant Name	Max Capacity (MW)
Fresno Cogen-Agrico	79.9
Balch 1 PH	31
Mendota Biomass Power	25
Balch 2 PH	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
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
Haas PH Unit 1 & 2 Aggregate	146.2
Helms Pump-Gen	1212
Herndon Synch Condenser	0
J.R. Wood	10.8
Kerkhoff PH 1	32.8
Kerkhoff PH 2	142
Kingsburg Cogen	34.5
Kings River Hydro	51.5
Kings River Conservation District	112
Madera	28.7
McCall Synch Condensers	0
Mc Swain 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
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
Generation Total	**3405**

Load Forecast

Loads within the Fresno and Yosemite area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.9-2 shows the substation loads assumed in these studies under summer peak and off-peak conditions. These tables also show loads modeled for neighboring local areas in PG&E system in the Fresno and Yosemite area assessment as well.

Table 2.9-2: Load Forecasts modeled in Fresno and Yosemite area assessment

1- IN- 10 YEAR HEAT WAVE NON-SIMULTANEOUS LOAD FORECAST						
SUMMER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
YOSEMITE	901	912	923	932	944	1,005
FRESNO	2,275	2,302	2,329	2,352	2,379	2,524

2.9.3 Study Results and Discussions

TPL 001: System Performance under Normal Conditions

- For the summer peak cases, there are three facilities with identified thermal overloads and no facilities with low voltage concerns under the Category A performance requirement; and
- For the summer off-peak cases, there is one facility with identified with thermal overloads and no facilities with low voltage concerns under the Category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and ISO Category B: (G-1/L-1)

- For the summer peak cases, there are three facilities with identified thermal overloads and one facility with identified low voltage concerns under the Category B performance requirement; and
- For the summer off-peak cases, there is one facility with identified thermal overloads and no facilities with low voltage concern under the Category B performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

- For the summer peak cases, there are 21 facilities with identified thermal overloads and 40 facilities with identified with low voltage concerns under the Category C performance requirement.
- For the summer off-peak cases, there are four facilities with identified thermal overloads and no facilities with low voltage concern under the Category C performance requirement.

Appendix A documents the worst thermal overloads and low voltage concerns identified for the summer -peak and summer off-peak conditions along with ISO-proposed solutions.

2.9.4 *Recommended solutions for facilities not meeting thermal and voltage performance requirements*

Based on the 2011 - 2020 reliability assessment results of the PG&E Fresno local area, the ISO recommended solutions that address each of the identified facilities that did not meet the thermal and low voltage performance requirements under Categories A,, B and C contingency conditions. Also included in this section is a discussion on the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were to ensure secured power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- Reinforcing or upgrading the system to avoid area wide voltage collapse;
- Installing new and additional transformer banks;
- Build new transmission lines;
- Converting low voltage lines to higher ones;
- Re-rating facilities, reconductoring, network looping and reconfiguring stations; and
- Installing shunt capacitor banks for voltage support.

The following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. It provides information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.9.4.1 Thermal Overload Mitigations for Summer Peak Cases

Borden-Gregg 230 kV line

Borden-Gregg 230 kV was identified as overloaded under NERC Category A and C conditions in the 2020 peak case to 107% and 104% respectively. The mitigation plan is to reconductor this line by 2017. This project, *Borden-Gregg 230 kV Line Reconductoring Project*, was proposed through the 2010 request window. However, reconductoring the line was also identified as a needed network upgrade in LGIP Transition Cluster Phase II process. Therefore, implementation of the reconductoring project will proceed on the timeline established in the GIA(s).

Leprino Tap 70 kV

The line between Lemoore 70 kV to Leprino TP 70 kV Ckt #1 was identified as overloaded under NERC Category A conditions in the 2015 and 2020 summer peak cases to 104% and 117%, respectively. The mitigation plan is to replace limiting components at Lemoore Substation by 2015. Specifically, replace disconnect switches 21, 23, and 25 with disconnects rated for 1200 A or higher. Accordingly, the PG&E *Lemoore 70 kV Disconnect Switches Project* was proposed through the 2010 request window. The ISO finds this project is needed to meet reliability concerns.

Oakhurst Tap 115 kV

The line between Corsgold 115 kV To Oakh_Jct 115 kV Ckt #1 was identified as overloaded under NERC Category A, B, and C conditions in the 2020 summer peak case to 116%, 102%, and 100%, respectively. The mitigation plan is to build a new line from Kerckhoff PH #2 to Oakhurst substation and upgrading limiting substation equipment as necessary in the 2016 to 2020 time frame. Accordingly, the PG&E *Kerckhoff PH #2 - Oakhurst 115 kV Line Project* was proposed through the 2010 request window. The ISO finds this project is needed to meet reliability concerns.

Oro Loma – Mendota 70 kV Line

Oro-Loma-Mendota 70 kV line was identified as overloaded up to 111% and 225% under NERC Category B and C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases. The mitigation plan is to convert the Oro Loma - Mendota 70 kV line to 115 kV operation by 2015. In the interim period, between the years 2011 and 2015, NERC compliance is provided by conducting operator switching actions following the first contingency in preparation for the next outage. The ISO staff will ensure that necessary operating procedures will be in place to meet reliability needs in 2011. The PG&E *Oro Loma - Mendota 70 to 115 kV Conversion Project* was proposed through the 2010 request window. The ISO finds this project is needed to meet reliability concerns.

California Ave-McCall 115 kV Line

California-Ave-McCall 115 kV line was identified as overloaded under NERC Category C3 (N-1-1) conditions in the 2020 summer peak case to 103%. The mitigation plan is to re-rate the line by 2017. This plan will be assessed further and included in the next annual ISO transmission plan.

Panoche-Schindler 115 kV Line #1

Panoche-Schindler 115 kV line #1 was identified as overloaded under NERC Category C3 (N-1-1) conditions in the 2020 summer peak case to 109%. A PG&E maintenance related project will replace Panoche Bank 1 with a 420 MVA bank and reconfigure the network. No ISO approval is required for maintenance projects.

Barton-Airways-Sanger 115 kV line

Barton-Airways-Sanger 115 kV line was identified as overloaded under NERC Category C3 (N-1-1) conditions only in 2011 summer peak case to 108%. After the new Herndon 230/115 kV transformer #3, approved by the ISO in the previous 2009 transmission plan, is placed in service in 2012, the overload will be mitigated. In the interim period, between the years 2011 and 2012, NERC compliance is provided by conducting operator switching actions following the first contingency in preparation for the next outage. The ISO staff will ensure that necessary operating procedures are in place to meet reliability needs in 2011.

Panoche-Mendota 115 kV Line

Panoche Mendota 115 kV line was identified as overloaded up to 134% under NERC Category C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases. In addition, it was overloaded under NERC Category B and C5 (DCTL) conditions in the 2020 summer peak cases to 101% and 112%. A PG&E maintenance-related project will replace Mendota Switch Nos. 171, 173, 181, 183, and 187 with a 1200 A switch by December 2011. No ISO approval is required for maintenance projects.

Wilson 115 kV Area

Wilson-Atwater 115 kV line #2 was identified as overloaded up to 117% under NERC Category C3 (N-1-1) conditions in the 2015 to 2020 summer peak cases.

Wilson-Le Grand 115 kV line was identified as overloaded up to 175% under NERC Category C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases.

Le Grand - Dairyland 115 kV line was identified as overloaded up to 106% under NERC Category C3 (N-1-1) conditions in the 2014 to 2020 summer peak cases.

Wilson-Oro Loma 115 kV line was identified as overloaded up to 142% under NERC Category C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases.

Panoche-Oro Loma 115 kV line was identified as overloaded up to 134% under NERC Category C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases.

Planning studies have concluded that an outage of the two existing 230/115 kV transformers at Wilson substation would result in thermal overload conditions on the Wilson-Le Grand, Panoche-Oro Loma and Wilson-Oro Loma 115 kV lines in 2011. Studies have also indicated that the Wilson-Atwater #2 line will experience an overload for the outage of the Atwater-Merced and El Capitan-Wilson 115 kV lines in 2015. The mitigation plan through *Wilson 115 kV Area Reinforcement Project* is included as follows:

- Construct a new 230 kV substation that is looped into the Melones-Wilson 230 kV line approximately 8.5 circuit miles north of Wilson Substation;
- Construct a 115 kV bus and install a three-phase 230/115 kV transformer rated to handle at least 420 MVA at the new 230 kV substation;
- Construct a 4 mile 115 kV double circuit tower line from the new substation to El Capitan substation;
- Obtain any necessary environmental and land permits to construct the new line and substation
- Disable the Atwater SPS; and
- If needed, update the Helms RAS.

In the interim period, between the years 2011 and 2015, NERC compliance is provided by the Atwater SPS and by conducting operator switching actions following the first contingency in preparation for the next outage. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011. The *Wilson 115 kV Area Reinforcement Project* was proposed by PG&E through the 2010 request window and was evaluated and compared with SPS and operating procedures for load curtailment and found to be cost comparable in addressing reliability concerns. The ISO finds this project is needed to meet reliability concerns.

Oro-Loma 70 kV Area

Oro Loma – Canal 70 kV line #1 was identified as overloaded up to 267% under NERC Category C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases.

Los Banos-Canal-Oro Loma 70 kV line was identified as overloaded up to 117% under NERC Category C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases.

Los Banos-Livingston Jct. - Canal 70 kV line was identified as overloaded up to 109% under NERC Category C3 (N-1-1) conditions in the 2014 to 2020 summer peak cases.

Oro Loma 115/70 kV transformer bank #2 was identified as overloaded up to 133% under NERC Category C3 (N-1-1) conditions in the 2011 to 2020 summer peak cases.

Los Banos 230/70 kV transformer bank #3 was identified as overloaded under NERC Category C3 (N-1-1) conditions in the 2020 summer peak case to 104%.

Planning analysis has indicated that there are numerous contingencies, especially Category C contingencies that will overload lines and transformers in the Oro Loma Area up to 267%. The mitigation plan is to build a new 230/70 kV substation near Mercy Springs Junction and convert a single pole line into a double circuit tower line to create a new 70 kV line from Mercy Springs to Canal. In the interim period, between the years 2011 and 2015, NERC compliance is provided by conducting operator switching actions following the first contingency in preparation for the next outage. The ISO will ensure that necessary operating procedures are in place to meet reliability needs in 2011. The *Oro Loma 70 kV Area Reinforcement Project* was proposed by PG&E through the 2010 request window and was evaluated and compared with SPS and operating procedures for load curtailment and found to be cost comparable in addressing reliability concerns. The ISO finds this project is needed to meet reliability concerns.

2.9.4.2 Thermal Overload Mitigations for Summer Off-peak Cases

McCall-Sanger 115 kV Line #3

McCall-Sanger 115 kV line #3 was identified as overloaded under NERC Category C5 (DCTL) conditions in the 2020 summer off-peak case to 104%. The mitigation plan is to re-rate the line by 2017.

McCall-Henrietta, Panoche-Helm and Helm-McCall 230 kV Lines

The above three lines were identified as overloaded under NERC Category C5 (DCTL) conditions only in 2011 summer off-peak case up to 114%. Reconductoring the three lines have been approved in the ISO 2010 transmission plan and will be finished in 2012 to 2014 time frame. In the interim, the mitigation plan is to use interim temperature adjusted rating.

2.9.4.3 Voltage Concerns Mitigations

There are 28 substations that were identified as not meeting the low voltage performance requirements together with the area-wide voltage collapse experienced under Categories B and C conditions as shown in Appendix A for Fresno area. Of these, the low voltage concerns at 23 substations would be addressed upon implementation of projects aimed at achieving the thermal loading performance requirements. Another five substations with low voltage concerns would be addressed in PG&E's 2011 action plan.

2.9.5 Key Conclusions

Based on the ISO study assessment, the Fresno Area had:

- Four overloads under normal conditions for summer peak and summer off-peak cases;
- Three overloads caused by three critical single contingencies under summer peak conditions and one overload caused by one single contingencies under summer off-peak conditions; and
- Numerous overloads caused by numerous critical multiple contingencies under summer peak and off-peak conditions.

The ISO proposed solutions to address all of the identified overloads and received seven project proposals through the 2010 request window by PG&E for the remaining overloads:

- Six request window projects were determined to be needed; these are the *Oro Loma - Mendota 70 to 115 kV Conversion Project, Kerckhoff PH #2 - Oakhurst 115 kV Line Project, Lemoore 70 kV Disconnect Switches Project, Wilson 115 kV Area Reinforcement Project, Oro Loma 70 kV Area Reinforcement Project and Gill Ranch Gas Storage 115 kV Interconnection.* This interconnection project is a load interconnection project with network upgrades.
- *Midway – Gregg 500 kV Line Project*, submitted by PG&E in the 2010 request window as a reliability project, is not needed as a reliability project in this planning cycle. The electrical needs for transmission additions or upgrades in this area were assessed also as part of the ISO's 33% renewable energy evaluation. Please see chapter 5 for further discussion.
- Some of the overloads will be resolved by a planned maintenance project to replace Panoche Bank 1 with a 420 MVA bank and reconfigure network. Another project is to replace Mendota switches.

- For the remaining two Category C overloads PG&E has proposed a re-rate as an interim solution. The ISO will coordinate with PG&E to achieve a more permanent solution, which will be assessed further and included in the next ISO transmission plan.

The Guernsey 70 kV Energy Storage Project, a reliability-driven battery storage project, was re-submitted by WGD to connect an initially sized 7 MW battery to the Guernsey 70 kV bus in order to mitigate the Corcoran bank overload based on 2009 ISO reliability assessment results. This project was determined not to be needed because there was no need identified in this ISO transmission plan. The previously approved PG&E project *Corcoran 115/70 kV Bank #2 Replacement* has been modeled in the base cases for studies. The *Guernsey 70 kV Energy Storage Project* was also evaluated in the 2010 transmission plan and deemed not needed because the cost and the complex operating requirements for the battery project makes the Corcoran transformer replacement project a superior, more cost effective choice. The *Corcoran Transformer Bank #2 Replacement Project* has been identified a simpler design to solve the reliability need. Thus ISO approved the *Corcoran Transformer Bank #2 Replacement Project* in the 2010 ISO transmission plan.

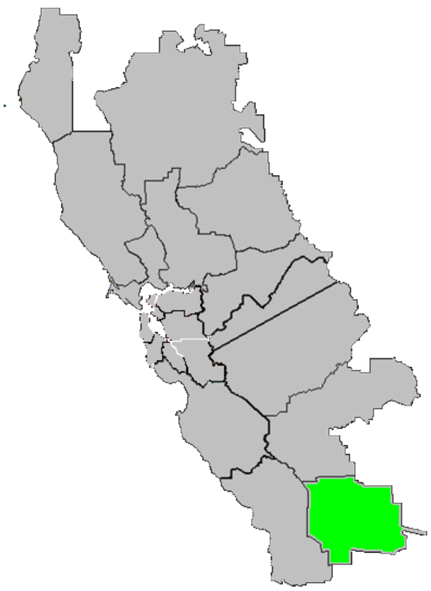
WGD re-proposed another battery storage reliability-driven project, the *Coppermine 70 kV Energy Storage Project*, to address low voltage at Coppermine 70 kV area based on PG&E's 2009 expansion plan. This project was determined not to be needed because there was no reliability need identified in last two ISO transmission plans. The *Coppermine 70 kV Energy Storage Project* was also evaluated in the 2010 transmission plan and deemed not needed then as the Coppermine-Tivy Valley-Reedley 70 kV reconductoring (a PG&E maintenance project) was completed on September 30, 2008.

TTS proposed a reliability-driven SVC installation project, *Shepherd Interim Solution*, to address the low voltage at Shepherd and Woodward 115 kV substations for Category B contingency based on PG&E's 2008 expansion plan. This project was determined not to be needed because there was no need identified in this transmission plan. The *Shepherd Interim Solution* was evaluated in the 2009 transmission plan and was deemed having no interim reliability need because a distribution-level substation that was proposed by PG&E would include a shunt 50 MVAr capacitor that will address potential voltage issues due to load growth in the area.

2.10 KERN AREA

2.10.1 Area Description

The Kern area is located south of the Yosemite-Fresno area and north of SCE's service territory. Midway substation, one of the largest substations in the PG&E system is located in Kern Division and has connections to PG&E's Diablo Canyon, Gates, and Los Banos substations as well as SCE's Vincent substation. The figure below depicts the geographical location of the Kern area.



The bulk of the power that interconnects at Midway substation transfers onto the 500 kV systems. A substantial amount also reaches neighboring transmission systems through Midway's 230 and 115 kV interconnections to the local areas. These interconnections include 115 kV lines to Yosemite-Fresno (north) as well as 115 and 230 kV lines to Los Padres (west). Electric customers in the Kern area are served primarily through the 230/115 kV transformers at Midway and Kern power plant substations and through local generation power plants connected to the lower voltage transmission network.

Load forecasts indicate that the Kern area should reach its summer peak demand of 1802 MW by 2015 and 1913 MW by 2020. Load is increasing at a rate of about 20 MW per year. Accordingly, system assessments in this area include the technical studies for the scenarios under these load assumptions for summer peak conditions.

2.10.2 Area-Specific Assumptions and System Conditions

The Kern area study was performed in a manner consistent with the general study methodology and assumptions described in section 2.3. The ISO secured website lists the contingencies that were studied as part of this assessment. In additional, specific assumptions and methodology applied to the Kern area study are provided below in this section

Generation

Generation resources in Kern area consist of market, QF and self-generating units. Table 2.10-1 lists all generating plants in the Kern area and modeled parameters for the 2014 and 2019 peak analysis respectively.

Table 2.10-1: Generator in the Kern Area

Plant Name	Max Capacity (MW)
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
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
Total	**3532**
Kern Area Pumping Plants	
Wheeler Ridge Pumping Plant	53
Wind Gap Pumping Plant	130
Buena Vista Pumping Plant	58
Total	**241**

Load Forecast

Loads within the Kern area reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.10-2 shows loads modeled for neighboring local areas in PG&E system in the Kern area assessment as well.

Table 2.10-2: Summer Peak Load Forecasts modeled in Kern area assessment

1- IN- 10 YEAR HEAT WAVE NON-SIMULTANEOUS LOAD FORECAST						
SUMMER PEAK (MW)						
PG&E AREA NAME	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
KERN	1,714	1,737	1,763	1,781	1,802	1,913

2.10.3 Study Results and Discussions

TPL 001: System Performance under Normal Conditions

- For the summer peak cases, there are no facilities with identified thermal overloads and three facilities with voltage concerns under the Category A performance requirement.

TPL 002: System Performance Following Loss of Single BES Elements and ISO Category B: (G-1/L-1)

- For the summer peak cases, there is 1 facility with identified thermal overloads and three facilities with voltage concerns under the Category B performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

- There are nine facilities with identified thermal overloads and 21 facilities with identified voltage concerns under the Category C performance requirement.

Appendix A documents the worst thermal overloads and voltage concerns identified for the summer peak conditions along with ISO-proposed solutions.

2.10.4 Recommended Solutions for Facilities Not Meeting Thermal and Voltage Performance Requirements

Based on the 2011 - 2020 reliability assessment results of the PG&E Fresno local area, the ISO recommended solutions that address each of the identified facilities that did not meet the thermal and low voltage performance requirements under Categories A (normal), B and C contingency conditions. Also included in this section is a discussion on the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were to ensure secured power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- Reinforcing or upgrading the system to avoid area-wide voltage collapse;
- Installing new and additional transformer banks;
- Building new transmission lines;
- Converting low voltage lines to higher ones;
- Re-rating facilities, reconductoring, network looping and reconfiguring stations; and
- Installing shunt capacitor banks for voltage support.

A discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns is set out below. It provides information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.10.4.1 Thermal Overload Mitigations

KERN 230 kV System

Midway-Kern 230 kV line #3 was identified as overloaded up to 120% under NERC Category C5 (DCTL) conditions in the 2012 to 2020 summer peak cases. The mitigation plan is to replace the limiting substation equipment at Kern and Midway substations such as, disconnect switches, wave traps, jumper conductors limiting the Midway-Kern No. 1, 3 and 4 230 kV lines with equipment rated for 2800 A or higher by 2013. In the interim period, between the years 2012 and 2013, NERC compliance is provided by conducting operator switching actions following the first contingency in preparation for the next outage. The equipment replacement project was proposed by PG&E through the 2010 request window. It was evaluated and compared with SPS and operating procedures for load curtailment and found to be more cost effective in addressing reliability concerns. The ISO finds this project is needed to meet reliability concerns.

KERN 115 kV System

Kern-Lamont 115 kV line was identified as overloaded under NERC Category B and C conditions in the 2020 peak case to 104% and 105% respectively;

Kern-Magunden-Witco 115 kV line was identified as overloaded up to 122% under NERC Category C5 (DCTL) conditions in the 2013 to 2020 summer peak cases;

Westpark-Magunden 115 kV line was identified as overloaded under NERC Category C5 (DCTL) conditions in the 2020 summer peak case to 101%;

Kern-Westpark 115 kV line #2 was identified as overloaded up to 119% under NERC Category C3 (N-1-1) conditions in the 2013 to 2020 summer peak cases; and

Kern Westpart 115 kV line #1 was identified as overloaded up to 120% under NERC Category C3 (N-1-1) conditions in the 2013 to 2020 summer peak cases.

The mitigation plan for the above five Kern 115 kV system overloads is the *Wheeler Ridge Junction 230 kV Substation Project* by 2020, which includes:

- Building a new 230/115 kV substation with two 230/115 kV transformers at Wheeler Ridge Junction;
- Converting the Kern-Lamont, Kern-Stockdale, Tevis Tap #1 and #2 115 kV lines and the Stockdale and Tevis 115 kV distribution substations to 230 kV operation, which will require replacing two distribution banks at Tevis and one at Stockdale;
- Building a new 230 kV line from Wheeler Ridge Junction to Wheeler Ridge substation.
- Bringing a new 115 kV line from Wheeler Ridge Junction into Magunden utilizing an idle 115 kV line; and
- Building a new 115 kV line tap off the Wheeler Ridge-Lamont 115 kV line to connect Wheeler Ridge Junction to Weedpatch, which will also require building a 115 kV bus and installing a 115/70 kV transformer at Weedpatch.

In the interim period, the ISO recommends establishing a 15 minute rating, an operating procedure and installing Supervisory Control and Data Acquisitions (SCADA), if necessary, to curtail load within 15 minutes after the second contingency by 2013 or re-rate by 2013. The *Wheeler Ridge Junction 230 kV Substation Project* was proposed through the 2010 request window by PG&E as a new conceptual project not requiring ISO approval in the 2010/2011 cycle. -It will be assessed further in the next transmission plan.

KERN 70 kV System

Wasco-Famoso 70 kV line was identified as overloaded under NERC Category C3 (N-1-1) conditions in the 2020 summer peak case to 102%. The mitigation plan is to establish a 15 minute rating, an operating procedure and installing SCADA, if necessary, to curtail load within 15 minutes after the second contingency by 2020.

2.10.4.2 Voltage Concern Mitigations

There are 21 substations in total identified as not meeting the low voltage performance requirements under Categories A, B and C conditions (only four contingencies involved). The mitigation plan is to build SPS to trip load for the four contingencies by 2011 for Category C concerns. The ISO will ensure that necessary operating procedures will be in place to meet Categories A, B reliability needs in 2011. If SCADA installation is required then the implementation date may need to be delayed from 2011 to 2012 and load shedding would need to be performed in 2011 by proactively sending operators to load tripping locations, as needed. There will be a long-term solution to address both the thermal and low voltage concerns. The final long-term solution will be proposed in the next planning cycle. In the long run, these low voltage issues will be resolved upon implementation of projects aimed at achieving the thermal loading performance requirements.

2.10.5 Key Conclusions

Based on the ISO study assessment, the northern Kern area had:

- No overloads but three voltage concerns under normal conditions;
- One overload and three voltage concerns under single contingency conditions; and
- A few overloads and voltage concerns caused by numerous critical multiple contingencies under summer peak conditions.

The ISO proposed solutions to address all of the identified overloads and received one project proposal through the request window. Operational solutions were submitted by PG&E for the remaining overloads. One request window project was determined to be needed, which is *Midway-Kern PP 230 kV Lines No 1, 3 and 4 Capacity Increase*. PG&E also proposed *Wheeler Ridge Junction 230 kV Substation Project* through the 2010 request window as a new conceptual project, which will be assessed further and included in the next ISO transmission planning cycle. The projects determined to be needed during this planning cycle will be included as planning assumptions for the next planning cycle.

WGD re-proposed a battery storage reliability-driven project, the *Weedpatch 70 kV Energy Storage Project*, to address Category B overload on San Bernard-Stalin Jct. 70 kV line based on 2009 ISO reliability assessment results. This project is determined not to be needed because there is no need identified in this ISO reliability assessment after applying an existing operating procedure to open Weedpatch CB 42 in summer. Even without applying the operating procedure, there is no overload on San Bernard-Stalin Jct. 70 kV line until 2018; thus no project is needed at this time. The *Weedpatch 70 kV Energy Storage Project* was also evaluated in the 2010 transmission plan and deemed not needed.

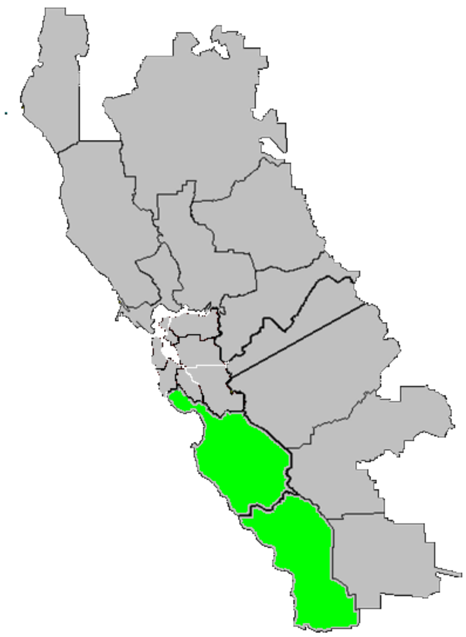
TTS re-proposed a reliability-driven SVC installation project, *Old River Interim Solution*, to address the low voltage at Panama and Old River 70 kV substations for Category C contingency based on PG&E 2008 Expansion Plan. This project is determined not to be needed because a previously approved PG&E's project, *Kern–Old River 70 kV #1 and #2 Lines Reconductoring*, has a close in-service date with this TTS project (only a two month difference). The *Old River Interim Solution* was also evaluated in the 2009 ISO transmission plan and deemed not needed because PG&E's proposed solution, which involves reconductoring 35 miles of Kern-Old River lines 1 and 2, is a more cost effective solution that will address both thermal and under-voltage reliability violations.

2.11. CENTRAL COAST AND LOS PADRES AREAS

2.11.1 Area Description

The Central Coast Area is located south of the Greater Bay Area and extends along the Central Coast from Santa Cruz to King City. The Central Coast transmission system serves Santa Cruz, Monterey and San Benito counties. The green shaded portion in the figure below depicts the geographic location of the Central Coast and Los Padres areas.

The Central Coast electric transmission system is comprised of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Most of the customers in the Central Coast are supplied via local transmission system out of the Moss Landing power plant substation. The local transmission systems are: a) Santa Cruz - Watsonville, Monterey - Camel and Salinas - Soledad - Hollister sub-areas which are supplied via 115 kV double circuit tower lines (DCTL), b) King City, an area supplied by 230 kV lines from the Moss Landing and Panoche substations and c) Burns - Point Moretti sub-area which is supplied by a 60 kV line from the Monta Vista substation in Cupertino. Besides the 60 kV connection between the Salinas and Watsonville substations, the only connection among the sub-areas is at the Moss Landing substation. The Central Coast transmission system is tied to the San Jose and De Anza systems in the north, and the Greater Fresno system in the east.



The Los Padres Division is located in the southwestern portion of PG&E's service territory (south of the Central Coast division). San Luis Obispo, Santa Maria, Paso Robles and Atascadero are among the cities PG&E provides electric service to within this division. The City of Lompoc, a member of the NCPA is also located here. Counties in the area include San Luis Obispo and Santa Barbara. The Diablo Canyon nuclear power plant is also located in Los-Padres. Most of the power generated from the Diablo Canyon power plants are exported to the north and east through bulk 230 kV and 500 kV transmission lines, hence it has very little impact on the Los Padres area operation. There are several transmission ties to the Fresno and Kern systems, with the majority of these interconnections at the Gates and Midway substations. Local customer demand is served through a network of 115 kV and 70 kV circuits.

Load forecasts indicate that the Central Coast and Los Padres areas should reach their summer peak demand of 807.8 MW and 627 MW, respectively, by 2015. By 2020 the loading for these two areas would be 854 MW and 686.4 MW, respectively. Winter peak demands in the Central Coast are also expected to grow. The peak load forecast for 2015 and 2020 are approximately 704.3 MW and 743.7 MW, respectively. As this area is along the coast, it has a dominant winter peak profile in certain pockets (e.g., the Monterey - Carmel sub-area). Winter peak demands could be as high as 10% more than summer peak demands.

Accordingly, system assessments in these areas included technical studies using load assumptions for summer and winter peak conditions. Table 2.11-2 includes load forecast data for the Central Coast as well as the Los Padres area.

2.11.2 Area Specific Assumptions and System Conditions

The Central Coast and Los Padres areas study was performed consistent with the general study methodology and assumptions that are described in section 2.3. The ISO secured website lists the contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the Central Coast and Los Padres areas study are provided below.

Generation

Generation resources in the Central Coast and Los Padres areas consist of market, QF and self-generating units. A list of all the generating facilities in the Central Coast and Los Padres areas is given in table 2.11-1. These were modeled for the 2011 through 2105 and 2020 summer and winter peak reliability assessment.

Table 2.11-1: Generation in the Central Coast and Los Padres Areas

No.	Generation Facility	Type	Max. Capacity (MW)	Division
1	Moss Landing Power Plant	Large Gas-Fired Units	2600	Central Coast
3	Basic Energy Cogen (King City)	Co-Gen	120	Central Coast
3	King City Peaker	Simple-Cycle Gas Turbine	61	Central Coast
4	Sargent Canyon Cogen (Oilfields)	Co-Gen	50	Central Coast
5	Salinas River Cogen (Oilfields)	Co-Gen	50	Central Coast
6	Diablo Canyon Power Plant	Nuclear	2,400	Los Padres
7	Morro Bay Power Plant	Thermal	1014	Los Padres
8	Union Oil (Tosco)	Thermal	6	Los Padres
9	Santa Maria	Co-Gen	8	Los Padres
10	Vandenberg Air Force Base		15	Los Padres
	Total Generation		**6324**	**CC & LP**

Load Forecast

Loads within the Central Coast and Los Padres areas reflect a coincident peak load for 1-in-10-year heat wave conditions of each peak study scenario. Table 2.11-2 shows loads modeled for the Central Coast and Los Padres areas assessment as well as other local areas within the PG&E system.

Table 2.11-2: Load forecasts Modeled in the Central Coast and Los Padres Area Assessment

	Simultaneous Load Forecast (MW)						
	PG&E Area Name	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
Summer Peak (MW)	Central Coast	761.9	780.1	791	795.4	807.8	854
	Los Padres	592.3	601.2	610.2	617.9	627	686.4
	Total Summer Forecast	**1354.2**	**1381.3**	**1401.2**	**1413.3**	**1434.8**	**1540.4**
Winter Peak (MW)	Central Coast	665.1	680.6	689.9	693.7	704.3	743.7
	Los Padres	485.8	492.8	500	506	513.2	560.2
	Total Winter Forecast	**1150.9**	**1173.4**	**1189.9**	**1199.7**	**1217.5**	**1303.9**

2.11.3 Study Results and Discussions

A summary of the study results of facilities in the Central Coast and Los Padres areas that were identified as not meeting thermal loading and low voltage performance requirements under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

- For both the summer and winter peak conditions studied, there were no facilities identified as not meeting either the thermal or voltage performance requirements under NERC Category A contingency conditions.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

- Two facilities were identified as not meeting the thermal loading performance requirements and 60 substations identified as not meeting the required low voltage performance under Category B contingency and summer peak conditions;
- 22 substations were identified as not meeting voltage deviation performance requirements under Category B contingency and summer peak conditions;
- No facilities in the Central Coast area were identified as not meeting the thermal loading performance requirements under Category B contingency and winter peak conditions;
- Nine substations were identified as not meeting the required low voltage performance under Category B contingency and winter peak conditions; and
- 13 substations were identified in the Central Coast area as not meeting voltage deviation performance requirements under Category B contingency and winter peak conditions.

TPL 003: System Performance Following Loss of Two or More BES Elements

- 26 facilities were identified as not meeting the thermal loading performance requirements and 22 substations identified as not meeting the required low voltage performance under Category C contingency and summer peak conditions;
- 22 substations were identified as not meeting voltage deviation performance requirements under Category C contingency and summer peak conditions;

- Eight facilities in the Central Coast area were identified as not meeting the thermal loading performance requirements under Category C contingency and winter peak conditions;
- 15 substations were identified as not meeting the required low voltage performance under Category C contingency and winter peak conditions;
- 16 substations were identified in the Central Coast area as not meeting the required voltage deviation performance under Category B contingency and winter peak conditions; and
- Five Category C contingencies were identified as causing area-wide voltage collapse in the Los Padres area under summer peak conditions, hence not meeting the required performance criteria.

Appendix A documents facilities that experience the worst thermal loading, low voltage and voltage deviation profiles that were identified as not meeting the performance requirements for the summer and winter peak conditions along with the corresponding solutions.

2.11.4 Recommended Solutions For Facilities Not Meeting Thermal and Voltage Performance Requirements

Based on this year's reliability assessment of the Central Coast and Los Padres areas, the ISO recommended solutions that address each of the identified facilities that did not meet the thermal and voltage performance requirements under NERC Categories A , B and C contingency conditions. Also included in this section is a discussion of the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were to ensure secured power transfer and adequate load serving capability of the transmission system.
These solutions generally include, but are not limited to, the following:

- Reinforcing or upgrading the system to avoid area-wide voltage collapse;
- Installing new and additional transformer banks.
- Re-rating, reconductoring and upgrading associated substation equipment in order to achieve maximum rating of the reconductored facilities.
- Installing voltage support schemes (shunt capacitors, Static Var Compensators, voltage conversion projects, UVLS, etc.).

The following are a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. It provides information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.11.4.1 Thermal Overload Mitigations

T239SWST - Midway #1 230 kV, and T239SWST - Midway #2 230 kV Lines

For these two facility concerns expected to occur in 2015, the ISO recommends reconductoring of the Morro Bay – Midway 230 kV #1 & 2 lines to address the thermal overloads under Categories B, C and summer conditions.

Area-wide Voltage Collapse in the Los Padres 230 kV and 115 kV Transmission System

There are a number of Category C contingencies (Templeton-Gates and Morro Bay-Gates #1 230 kV lines, Morro Bay-Diablo and Morro Bay-Mesa 230 kV lines, Morro Bay-Mesa 230 kV and Diablo-Mesa 230 kV lines, Mesa-Divide #1 115 kV and Mesa-Divide #2 115 kV lines; as well as Mesa 230/115 kV Bank #2 and Mesa 230/115 kV Bank #3) that will result in severe low voltages resulting potentially in area-wide collapse as well as causing thermal overload conditions on the San Luis Obispo-Santa Maria, San Luis Obispo-Callender switching station 115 kV lines. During the summer peak conditions, these events could result in loss of over 250 MW of customer load.

The *Morro Bay-Mesa 230 kV Line Project* was submitted through the 2010 request window. This project was proposed to mitigate Category C (N-2 and DCTL) concerns. It adds a new Morro Bay-Mesa 230 kV line, installs a new three-phase transformer 230/115 kV bank and bus sectionalizing circuit breakers at the Mesa substation. The proposed in-service date is May 31, 2017. The ISO has determined that this project is not needed.

Also submitted through the 2010 request window to address the area-wide voltage collapse concern was the *Mesa-Divide Line Project*. This project was proposed to mitigate Category C (N-2 and DCTL) area-wide voltage collapse concerns. It adds a new third Mesa-Divide 115 kV line. The proposed in-service date is May 31, 2014. The ISO has determined that this project is not needed.

For the identified Category C contingencies, the ISO has recommended load dropping consistent with ISO standards. The *Los Padres Transmission Project* (SPS at Mesa and Santa Maria) approved in 2009 drops 250 MW load.

Mesa-Sisquoc 115 kV and Santa Maria-Sisquoc 115 kV Lines

The Mesa 115 kV system serves a large portion of the southern PG&E Los Padres Division including Santa Maria, Sisquoc and Fairway substations. The Mesa-Sisquoc 115 kV line is limited by a 4.1-mile 397.5 AAC conductor. It experiences thermal overloads upon Category C5 contingency conditions (loss of Mesa-Santa Maria and San Luis Obispo-Santa Maria 115 kV lines).

In order to mitigate against the Category C contingency conditions, the ISO has recommended reconductoring the Mesa-Sisquoc 115 kV line and upgrading the associated substation equipment to accommodate the reconductored line rating. Thus, the ISO has determined that the *Mesa-Sisquoc 115 kV Line Reconductor Project* submitted by PG&E through the 2010 request window is needed to address this NERC Category C concern. An alternative option will be to drop approximately 40 MW of customer load at the Fairway substation in addition to dropping load tap changing transformer bank #3 (33 MW of load) at the Santa Maria substation. As dropping load (banks #2 and #3) at Sisquoc will not mitigate the identified overload, the load dropping mechanism will require installing communication from the Sisquoc substation to both Santa Maria and Fairway substations. This was not found to be a cost effective approach.

Furthermore, in 2009, the ISO approved the *Santa Maria-Sisquoc* and *Mesa-Santa Maria 115 kV Line Reconductoring Projects* to address reliability problems in the area. The projects have an expected in-service date of May 2011, or earlier. Other projects such as the San Luis Obispo-Santa Maria 115 kV line reconductoring with expected in-service date of May 2012 will also address some of the potential thermal overload concerns in the Los Padres area. Additionally, in 2010 the ISO approved the *Los Padres*

Transmission Project, and *Divide 115 kV SPS* projects with in-service date of May 2011 that will drop 250 MW and 92 MW respectively.

As a result of the two SPS projects (*Los Padres Transmission and Divide 115 kV SPS*) already approved for the area, and to also avoid the complications of operating a third SPS scheme to drop load at a higher cost, the ISO has determined that the *Mesa-Sisquoc 115 kV Line Reconductor Project* submitted through the 2010 request window was needed. It reconductors the 4.1 mile limiting line section of the Mesa-Sisquoc 115 kV line at a cost of $5 to 10 million. The proposed in-service date is May 31, 2014. The project mitigates the identified Category C (N-2 and DCTL) concerns as well as increasing the load serving capability of the system especially when the Santa Maria cogeneration unit is off-line.

In the short-term, the ISO has recommended that an operating procedure be developed to address any potential reliability concern.

Green Valley - Watsonville 115 kV, and Watsonville - Hollister 115 kV Lines

The Watsonville 60 kV to 115 kV conversion project was approved in 2008 with an expected in-service date of May 31, 2012. The project encompasses upgrading the existing 60 kV substations from Green Valley through Watsonville to Hollister substations to a 115 kV infrastructure.

In the interim, the ISO recommends the use of an operating procedure to curtail load within 15 minutes for this NERC Category C voltage concern.

Templeton-Morro Bay #1 230 kV Line

This facility is projected to experience a thermal overload under Category C contingency conditions (loss of Q239SWST-Midway #1 & #2 230 kV lines) beginning summer 2015. The ISO recommends the use of an operating procedure to curtail load within 15 minutes.

Crazy Horse - Natividad SWS - Lagunitas 115 kV Line

This facility is projected to experience thermal overload beginning summer 2011 upon loss of Moss Landing-Green Valley #1 and #2 lines as well as Moss Landing-Salinas #1 and #2 115 kV lines (DCTL). There exists a plan to curtail load within 15 minutes.

Atascadero-San Luis Obispo #1 70 kV Line and Atascadero-Cayucos 70 kV Line

This facility is projected to experience thermal overload beginning summer 2015. The ISO recommends the use of an operating procedure to curtail load within 15 minutes.

Moss Landing #1, #2, #8 & #10 230/115 kV Transformer Banks

These Category C overloads result from lack of bus-paralleling and bus-sectionalizing circuit breakers on the 230 kV and 115 kV bus sections. For an outage of either 230 kV bus sections (D or E), which will result in the loss of one large transformer and one small transformer, the two remaining transformers are expected to overload starting from summer 2011.

There exists a plan to curtail load within 15 minutes for the NERC Category C concerns.

2.11.4.2 Central Coast and Los Padres Areas Voltage Concern Mitigation

Central Coast 60 kV and 115 kV System

The study results showed that the Central Coast 60 kV and 115 kV systems experience general voltage conditions below 0.90 p.u. under both Categories B and C contingency conditions, particularly substations along the Green Valley-Watsonville and Watsonville-Hollister lines as well as the Oil Fields and its interconnecting substations. These substations were identified as not meeting the required voltage performance criteria under Categories B, C contingency for the summer and winter peak conditions. Other substations identified as not meeting the required voltage performance criteria are those along Green Valley-Paul Sweet and Green Valley-Camp Evers-Paul Sweet lines.

The ISO received the following two projects through the 2010 request window with the purpose of addressing NERC Category B voltage concerns.

- The *Watsonville Interim Solution* with in-service date of November 30, 2012. The project proposes to install a direct connect -40/+50 MVAr capacity SVC at the PG&E's Watsonville 60 kV substation at a cost of $11 million. The proposed in-service date is November 30, 2012 with a five-year lease term. The ISO determined that this project is not needed as there were no Category B voltage concerns identified for the study horizon; and
- The *Camp Evers Interim Solution* with in-service date of November 30, 2012. The project proposes to install a direct connect -40/+50 MVAr capacity SVC at the PG&E's Camp Evers 115 kV substation at a cost of $15 million. The proposed in-service date is November 30, 2012 with a five-year lease term. The ISO has determined that this project is not needed because there are no Category B voltage concerns identified for the study horizon.

For the identified voltage concerns there are mitigation plans in place such as the Watsonville Under Voltage Load Shedding (UVLS) scheme and proposed operating procedures that address the concern.

Los Padres 70 kV and 115 kV System

The San Luis Obispo 70 kV system is fed by the Templeton-Atascadero 70 kV line and San Luis Obispo #3 115/70 kV transformer bank. These two supply sources combined, serve over 17,600 customers in northern San Luis Obispo County.

Study results show that the Los Padres 70 kV and 115 kV system experience general voltage conditions below 0.90 pu under both Categories B and C contingency conditions, particularly substations along the Atascadero-Cayucos-Cambria, San Luis Obispo-Cayucos and Atascadero-San Luis Obispo 70 kV corridors. Other substations identified as not meeting the required voltage performance criteria are the Vandenberg Air Force Base 70 kV, Morro Bay 115 kV, These substations were identified as not meeting the required voltage performance criteria under Category B and C contingencies for the summer and winter peak conditions.

In order to meet the required voltage performance, the ISO has determined that the *Cayucos 70 kV Shunt Capacitor Project* submitted by PG&E through the 2010 request window is needed. This project is proposed to mitigate both Category B (loss of San Luis Obispo 115/70 kV transformer bank #3) and C concerns. The project includes 25 MVAr reactive support at the Cayucos 70 kV substation as well as re-rating the San Luis Obispo-Mustang 70 kV line at a cost of $5-10 million. The expected in-service date is May 31, 2014. In the interim, *The Summer 2010 Los Padres Area Action Plan* exists to curtail load within 15 minutes for the NERC Category C voltage concerns.

2.11.5 Key Conclusions

The 2011 summer and winter peak reliability assessment of the PG&E Central Coast and Los Padres areas revealed several reliability concerns. These concerns consist of thermal overloads, low voltages and voltage deviations under Category B and C contingency conditions. Also area-wide voltage collapse was observed in the Mesa area under five Category C contingency conditions.

The problems identified in the year's annual assessment are very similar to those found in last year's assessment. However, it was observed that previously approved projects mitigated the corresponding concerns. To address the identified Category B thermal overloads, low voltage and voltage deviation concerns, the ISO determined that a total of four transmission solutions are needed. Six transmission project proposals were submitted through the 2010 request window by project proponents. Consistent with the ISO standards, the ISO determined that operating procedures and load shedding schemes are needed for addressing the identified NERC Category C concerns. The 2010 request window projects that are determined to be needed will be included as planning assumptions for the next planning cycle.

The ISO has determined that the following projects, submitted through the 2010 request window, are needed to mitigate the identified reliability concerns:

- *Mesa-Sisquoc 115 kV Line Reconductor Project* with in-service date of March 31, 2014; and
- *Cayucos 70 kV Shunt Capacitor Project* with in-service date of March 31, 2014.

The ISO has determined that the following projects, submitted through the 2010 request window are not needed for mitigation of the identified reliability concerns:

- *Morro Bay-Mesa 230 kV Line Project* with in-service date of May 31, 2017;
- *Mesa-Divide 115 kV Line Project* with in-service date of May 31, 2014;
- *Watsonville Interim Solution* with in-service date of November 30, 2012 with a five-year lease term; and
- *Camp Evers Interim Solution* with in-service date of November 30, 2012 with a five-year lease term.

2.12 PG&E Bulk Transmission System Assessment

2.12.1 PG&E Bulk Transmission System Description

The 500 kV bulk transmission systems in northern California consist of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue past Bakersfield in the south. This system transfers power between California and other states in the northwestern part of the United States and western Canada. The transmission system is also a gateway for excess resources located in the sparsely populated portions of northern California, and the system typically delivers these resources to population centers in the Greater Bay Area and Central Valley. Also, there are a large number of generation resources in the central California area that are delivered over the 500 kV systems into southern California. The typical direction of power flow through Path 26 is from north to south during on-peak load periods and in the reverse direction during off-peak load periods. As a result of this bi-directional power flow pattern on the 500 kV Path 26 lines, both the summer peak (N-S) and off-peak (S-N) flow scenarios were analyzed. Transient stability and post transient contingency analyses were also performed for both flow patterns and scenarios.

2.12.2 Study Assumptions and System Conditions

The northern area bulk transmission system study was performed consistent with the general study methodology and assumptions described in chapter 2. The ISO secured website lists the contingencies that were performed as part of this assessment. In addition, specific methodology and assumptions that are applicable to the northern area bulk transmission system study are provided below in the next sections.

Generation and Path Flows

The bulk transmission system studies used the same set of generation plants that were modeled in the local area studies. In this planning cycle, the study plan contemplates the scope of the study that includes exploring the impacts of meeting 20% and 33% RPS goals in addition to the conventional study that models new generators according to the guidelines for modeling new generation interconnection projects (http://ISO.com/docs/2001/06/25/20010625134406100.pdf). Therefore, additional amount of renewable resources were modeled in the 2015 and 2020 base cases according to the information in the ISO Large Generation Interconnection Queue. The following table lists the queue number and maximum capacity of these resources in northern California. Note that several of these projects have been modeled in the starting base cases from WECC. Consequently, the only changes to these existing projects are the different output levels due to the dispatch methodology.

Table 2.12-1: Additional Renewable Resources Modeled in the Study

No	Queue Number	Maximum Capacity (MW)	Type of Resources
1	39	200	Wind
2	74	102	Wind
3	108	128	Wind
4	111	16	Biomass
5	113	30	Wind
6	166	210	Solar
7	184	35	Geothermal
8	194	190	Solar
9	212	50	Wind
10	222	78	Wind
11	239	250	Solar
12	242	150	Solar
13	250	66.2	Wind
14	261A	5	Solar
15	272	25/125	Natural Gas/Solar
16	304	50	Solar
17	356	40	Solar
18	417	14	Wind

The table following table lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in the area.

Table 2.12-2: Major import flow for the northern area bulk study

Parameter	2015 Summer Peak	2015 Summer Off-Peak	2020 Summer Peak	2020 Summer Off-Peak
California-Oregon Intertie Flow (N-S) (MW)	4800	-3631	4800	-3665
Pacific DC Intertie Flow (N-S) (MW)	3000	-1855	3100	-1857
Path 15 Flow (S-N) MW	-534	5350	-62	5380
Path 26 Flow (N-S) MW	4000	-1052	4000	-674
Northern California Hydro % dispatch of nameplate	80%	n/a	80%	n/a

Load Forecast

Per the ISO planning criteria for regional transmission planning studies, the demand within the ISO area reflects a coincident peak load for 1-in-5-year heat wave conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50% of the 1-in-5 summer peak load level. Table 2.12-3 shows the assumed load levels for selected areas under summer peak and off-peak conditions.

Table 2.12-3: Load modeled in the bulk transmission system assessment

Scenario	Area	Load (MW)	Loss (MW)	Total (MW)
2015 Summer Peak	PG&E	29784	1128	30912
	SDG&E	5182	159	5341
	SCE	26771	575	27346
	ISO	61737	1862	63599
2015 Summer Off-Peak	PG&E	14299	591	14890
	SDG&E	2784	47	2831
	SCE	12713	246.5	12960
	ISO	29796	884.5	30681
2020 Summer Peak	PG&E	31735	1241	32976
	SDG&E	5672	178	5850
	SCE	27852	549	28401
	ISO	65259	1968	67227
2020 Summer Off-Peak	PG&E	15280	682	15962
	SDG&E	2784	47	2831
	SCE	12703	242	12945
	ISO	30767	971	31738

Existing Protection Systems

There are extensive SPS or RAS that are installed in the northern California area 500 kV systems to ensure reliable system performance. These systems were modeled and included in the contingency studies. A comprehensive detail of these protection systems are provided in various ISO operating procedures, engineering and design documents. For details, refer to table 2.3-7.

2.12.3 Study Results and Discussion

The studies were performed under normal and emergency system conditions and various scenarios with the primary focus on transmission systems in northern and central California.

The 2015 and 2020 summer peak and summer off-peak cases were all found to satisfy the transient and post-transient performance criteria. However, some thermal limits were exceeded during post-transient contingency conditions in all three cases.

NUC-001: Nuclear Plant Interface Requirements (NPIRs)

The technical studies were conducted in compliance with the NUC-001 standards annually as part of the transmission plan. Post-transient governor power flow and transient stabilities were conducted to assess the performance related to the Diablo Canyon power plant under normal and emergency conditions. In this planning cycle, the studies were conducted on the following scenarios:

- 2015 summer peak; and
- 2015 summer off-peak.

There were 51 contingencies in the bulk system studies, which included:

- Loss of single Diablo unit (G-1;)
- Loss of two Diablo units (G-2);
- Loss of one load block at Larkin substation (largest load block in PG&E service territory according to the information in the base case);
- Loss of entire load at Larkin substation; and
- Loss of critical 500 kV transmission lines that include transmission lines that connect Diablo PP with such as Gates – Diablo 500 kV line, Diablo – Midway 500 kV line, and other major intertie such as Malin – Round Mountain 500 kV.

The base cases modeled three transmission circuits to DCPP 500 kV switchyard and two transmission circuits to DCPP 230 kV switchyard with the status normally in-service. The study results showed that:

- The steady state voltage at DCPP 230 kV switchyard was 238 kV under 2015 summer peak conditions and 230 kV under 2015 summer off-peak conditions;
- The steady state voltage at DCPP 500 kV switchyard was 532 kV under 2015 summer peak conditions and 526 kV under 2015 summer off-peak conditions;
- The DCPP generator output voltage was operated at 1.01 per unit under 2015 summer peak conditions and 1.00 per unit under 2015 summer off-peak conditions;
- The 500 kV interface consists of 3 500 kV transmission lines. Each line has the normal rating of 1931 MVA;
- The steady state frequency of the system is approximately at 60.0 Hz; and
- The study results shows no thermal overload, voltage or stability concerns related to the DCPP.

The study results from various studies show that there are no thermal overloads, voltage or stability concerns related to Diablo Canyon units under normal or emergency conditions. Figures 2.12-1 and 2.12-2 show voltage magnitude at Diablo 500 kV bus under summer peak and summer off-peak conditions. In addition, figures 2.12-3 to 2.12-8 show voltage and frequency at this bus following the loss of two generators, two transmission lines, and entire load at Larkin.

Figure 2.12-1: Bus Voltage at Diablo 500 kV bus under normal summer peak conditions

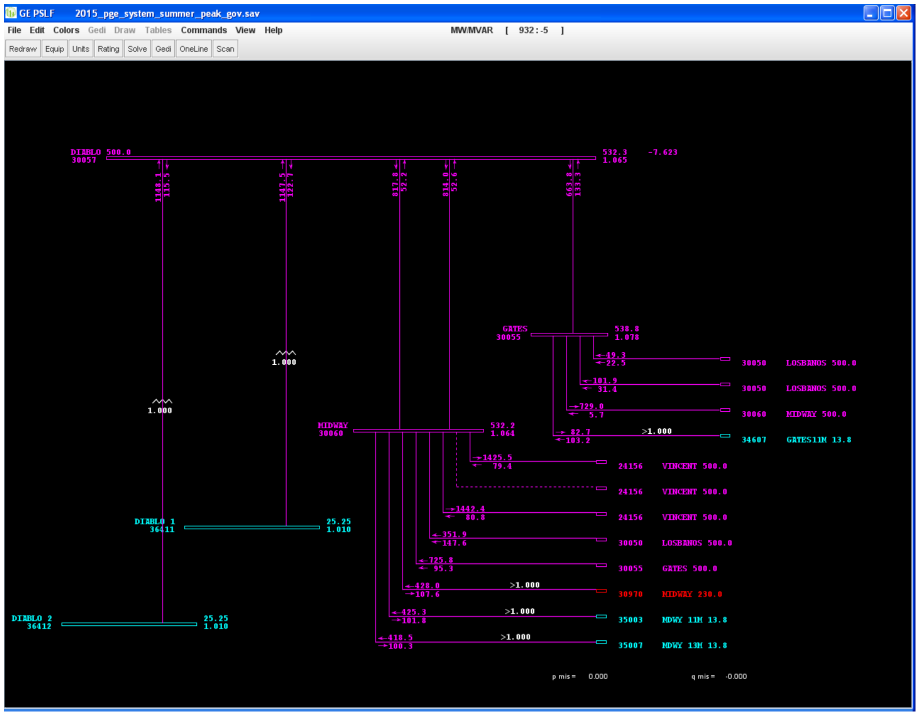


Figure 2.12-2: Bus Voltage at Diablo 500 kV bus under normal summer off-peak conditions

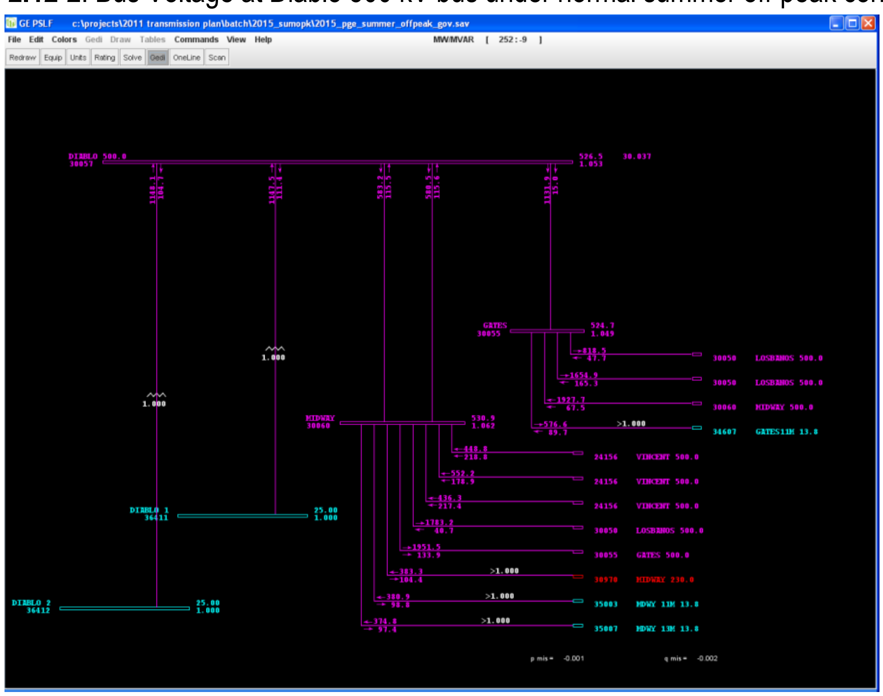


Figure 2.12-3: Voltage and frequency at Diablo 500 kV following the outage of Diablo G-2 under summer peak conditions

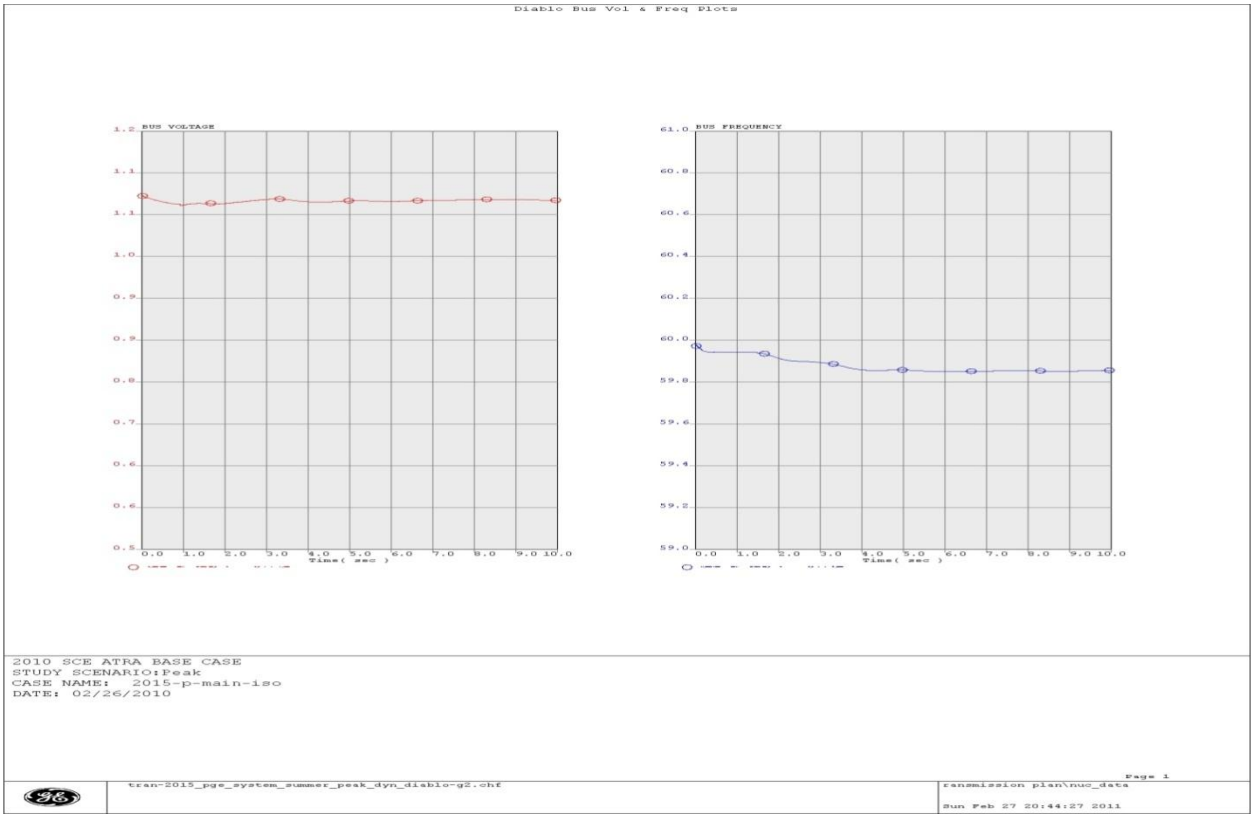


Figure 2.12-4: Voltage and frequency at Diablo 500 kV following the outage of Diablo G-2 under summer off-peak conditions

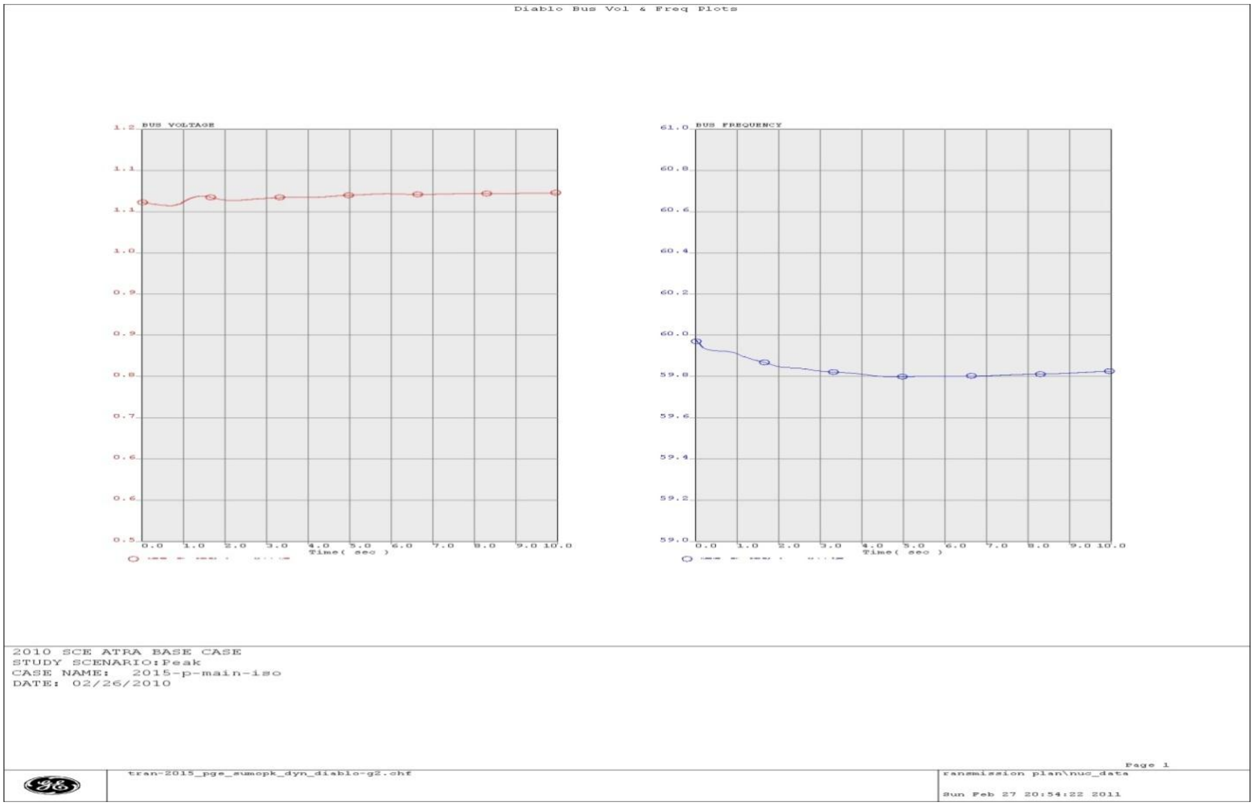


Figure 2.12-5: Voltage and frequency at Diablo 500 kV following the outage of Malin - Round Mountain DLO under summer peak conditions

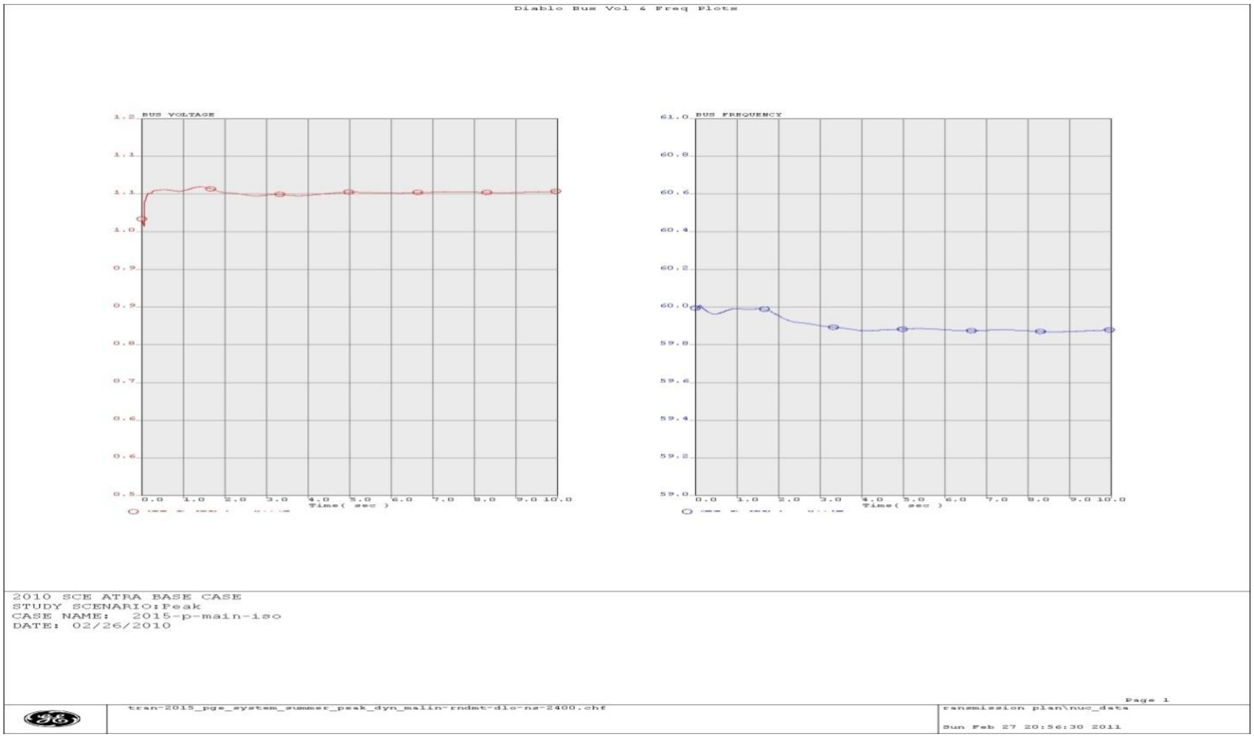


Figure 2.12-6: Voltage and frequency at Diablo 500 kV following the outage of Malin - Round Mountain DLO under summer off-peak conditions

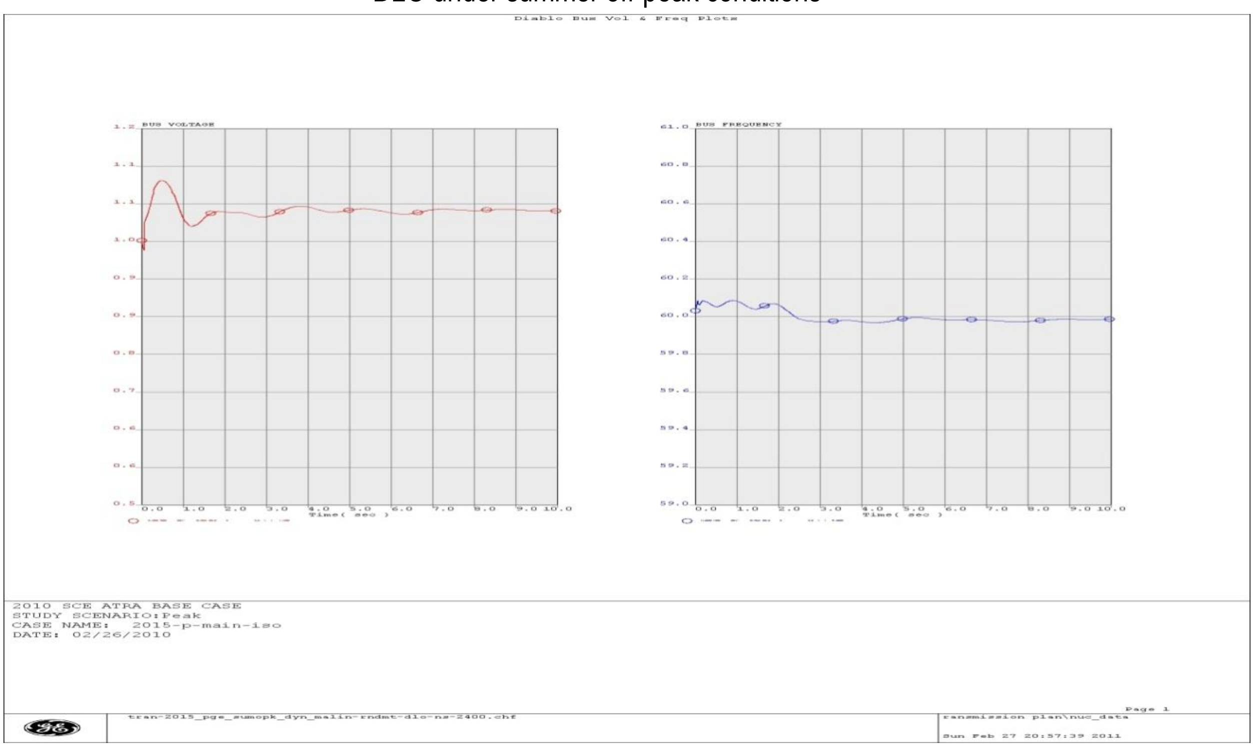


Figure 2.12-7: Voltage and frequency at Diablo 500 kV following the outage of entire load at Larkin substation under summer peak conditions

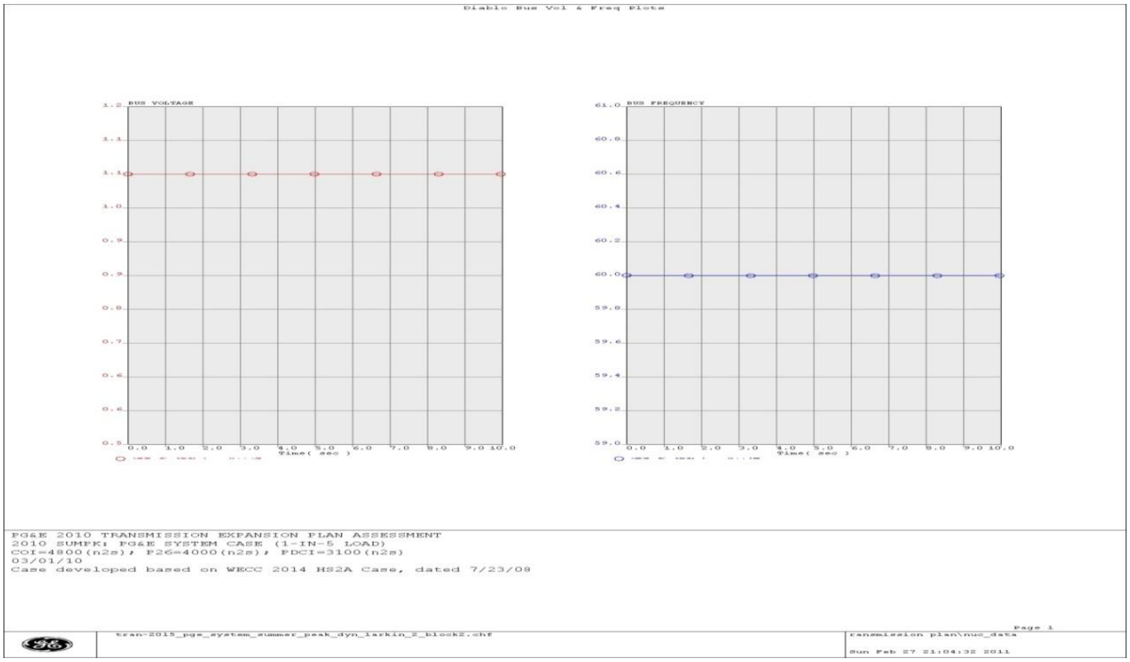
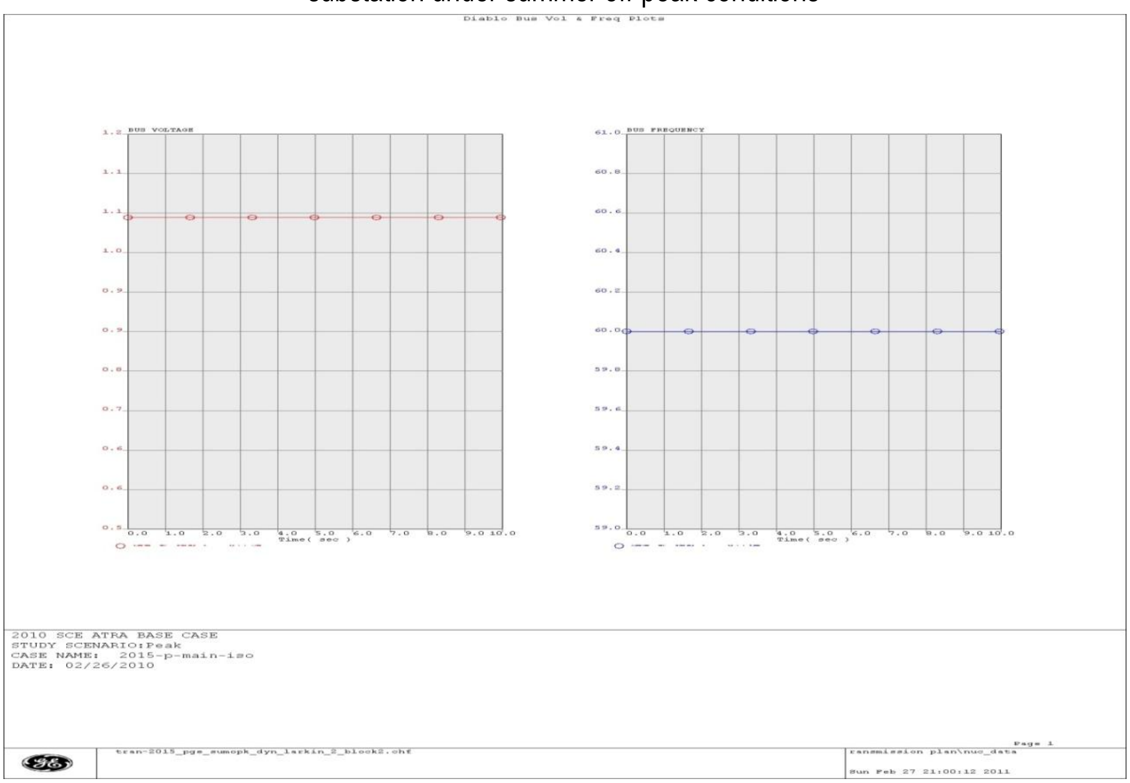


Figure 2.12-8: Voltage and frequency at Diablo 500 kV following the outage of entire load at Larkin substation under summer off-peak conditions



TPL 001: System Performance under Normal Conditions

- For the summer peak cases, there was one overload identified under normal conditions in the 2020 study scenario. Voltages on the 500 kV system buses were within the acceptable limits according to PG&E operating procedure O-59. In general, this operating procedure provides a guideline that voltage ranges on the 500 kV buses in PG&E system should be maintained between 495-551 kV. Transient simulation did not identify stability concerns under normal conditions; and
- For the summer peak cases, there was no overload identified. Voltages on the 500 kV system buses were within the acceptable limits. Transient simulation did not identified stability concerns under normal conditions.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (L-1/G-1)

- For the summer peak cases, there is no overload identified under several category B contingencies. No facilities were identified with voltage concerns under the Category B performance requirement. The system was stable following these contingencies, there was no transient voltage or frequency violation; and
- For the summer off-peak cases, there were two overloads identified under several Category B contingencies and no facilities identified with voltage concerns under the Category B performance requirement. The system remained stable following these contingencies, there was no transient voltage or frequency violation.

TPL 003: System Performance Following Loss of Two or More BES Elements

- For the summer peak cases, there were two overloads identified under several Category C contingencies and no facilities identified with voltage concerns under the Category C performance requirement. The system remained stable following these contingencies, there was no transient voltage or frequency violation; and
- For the summer off-peak cases, there were two facilities identified with thermal overloads and no facilities identified with voltage concerns under the Category C performance requirement. The system remained stable following these contingencies, there was no transient voltage or frequency violation.

Appendix A documents the worst thermal overload and low voltage concerns identified under summer peak and summer off-peak conditions along with the corresponding proposed solutions.

2.12.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

The following are proposed solutions for the facilities not meeting thermal and voltage performance requirements.

Borden – Gregg 230 kV Line was overloaded 105% in 2020 summer peak scenario under both normal and contingency conditions. The loading on this line is anticipated to reach 100% rating in 2016. The proposed mitigation for this overload is to reconductor this line. This overload is also identified in the Transition Cluster Phase II Large Generation Interconnection study and should be addressed as part of the generation interconnection process.

Moraga – Castro Valley 230 kV Line was overloaded 104% in 2015 and 109% in 2020 summer peak conditions. The local area assessment in the Greater Bay area also identified this overload. Please refer to the Greater Bay area section for more details on the mitigation plan for this facility.

Las Positas - Newark 230 kV Line was overloaded 104% in 2020 summer peak conditions with loading on this facility is anticipated to reach 100% of its emergency rating in 2012. The local area assessment in the Greater Bay area also identified this overload. Please refer to the Greater Bay area section for more details on the mitigation plan for this facility.

Cottonwood – Olinda 230 kV Lines #1 and #2 were overloaded 111% in 2020 summer off-peak study results with anticipated 100% emergency loading in 2012. These overloads are the results of load growth and recent rating reductions due to terminal equipment limitations. The mitigation plan to alleviate these overloads is to operate the California-Oregon Intertie (COI) within its nomogram or replacing the terminal equipment. The ISO will continue to work with Western Area Power Administration (WAPA), PG&E and stakeholders on the appropriate mitigation plan.

Westley – Los Banos 230 kV Line #1 has the highest emergency loading of 107% in 2020. The mitigation plan for this overload is to use short-term rating which is already in place. With the short-term rating, power flow on this line will stay well below 100% emergency rating.

12.2.5 Key Conclusions

Based on the ISO study assessment, the northern bulk system had:

- One overload under normal summer peak conditions;
- Two overloads under caused by one multiple contingency under summer peak conditions; and
- Two overloads caused by one single contingency under summer off-peak conditions.

The Borden-Gregg and Cottonwood–Olinda 230 kV lines are new overloads that were identified in this year. However, these overloads were identified from the long-term studies (i.e., 2020 time frame). Although mitigation plans have been proposed to address these issues, there is adequate time to refine the appropriate scope and timing of the proposed upgrades. Meanwhile, these facilities need to be monitored closely or require more work and coordination with PTO and neighboring entities in the development of the mitigation plans. The study also identified similar overloads that were reported last year, but these overloads can be mitigated by the short-term ratings that have been implemented.

Out of the six overloads described in this section, two of the overloaded facilities were also identified from the local area assessment. The mitigation plans that have been submitted as part of the local area assessment can be used to mitigate these overloads as well.

2.13 SOUTHERN CALIFORNIA EDISON AREA (BULK TRANSMISSION)

2.13.1 Area Description

Southern California Edison (SCE) serves over 13 million people in a 50,000 square mile area of central, coastal and southern California, excluding the city of Los Angeles, and certain other cities. In 2010, the SCE system load peaked at 23,628 MW on September 27, 2010. The bulk transmission system consists of 500 kV and 230 kV transmission facilities. Most of the SCE load is located within the Los Angeles Basin. However, fastest load growth occurs in the eastern part of SCE service territory in the Inland Empire area. The SCE service area is shown in map on the left. The CEC's load growth forecast for the entire SCE area is about 350 MW per year. The CEC's 1-in-10 heat wave load forecast includes the SCE service area, Pasadena Water and Power Department and the California Department of Water Resources pump load. The 2015 and 2020 summer peak forecast loads are 27,362 MW and 29,240 MW, respectively. Most of the SCE area load is served by local generation that includes nuclear, QFs, hydro, and oil/gas-fired power plants. The remaining demand is served by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and Desert Southwest.

In general, the SCE transmission system includes 500 kV and 230 kV facilities, with small pockets of 115 kV and 66 kV network transmissions. The bulk system includes five areas: Metro, Big Creek/Antelope, North of Lugo, East of Lugo and eastern. The Metro area consists of the major load centers in Orange, Riverside, San Bernardino, Los Angeles, Ventura and Santa Barbara counties. The boundary of the Metro area is marked by Vincent, Lugo and Alberhill 500 kV substations. The Big Creek/Antelope area is composed of 500 kV, 230 kV and 66 kV transmission system north of Vincent. North of Lugo consists of 230 kV and 115 kV transmission system stretching from Lugo to Kramer and Inyokern and into Nevada. East of Lugo consists of 500 kV, 230 kV and 115 kV transmission system from Lugo to Eldorado. The eastern area includes 500 kV, 230 kV and 115 kV transmission system from Valley to Devers and Palo Verde in Arizona and 230 kV transmission system from Vista to Devers to Mirage.

Consistent with the ISO planning assumptions outlined in its tariff, the performance of the SCE main 500 kV and 230 kV transmission system under the 2011 through 2020 heavy summer conditions was evaluated using applicable reliability criteria as outlined in section 2.2.

2.13.2 Area-Specific Assumptions and System Conditions

The SCE area study was performed consistent with the general study methodology and assumptions described in section 2.3. The bulk SCE system was assessed under the summer peak and spring off-peak conditions for each year from 2011 to 2015 and under the summer peak condition for 2020.

The contingencies that were performed as part of this assessment are listed on the ISO secure website. In addition, specific assumptions and methodology applied to the SCE area study are provided below.

Generation

Table 2.13-1 lists the major generation plants in the SCE area.

Table 2.13-1: List of the major generation plants in the SCE area.

Generation Plants	Max. Capacity (MW)
Alamitos	2010
Big Creek Hydro	1020
Blythe	493
Cool Water	628
El Segundo	670
High Desert	830
Huntington Beach	904
IEEC	810
Long Beach	260
Mandalay	560
Mountain View	1050
Mountain Vista	640
Ormond Beach	1516
Pastoria	750
Redondo Beach	1355
San Onofre Nuclear Generating Station (SONGS)	2250 MW (SCE's Share = 1720 MW)

Seven generation plants in the SCE area, including Alamitos, El Segundo, Huntington Beach, Mandalay, Ormond Beach, Redondo Beach and SONGS, use the OTC technology. The total capacity of the OTC units is 9265 MW. A state policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling has become effective on October 1, 2010 (see discussion below). The policy will apply to these OTC units to reduce the harmful effects associated with cooling water intake structures on marine and estuarine life. The fossil-fueled power plants will submit proposed implementation plans by April 1, 2011. The SCE area reliability assessment did not take into account of the impact of this policy and potential implementation plans by the OTC units. Such impact was considered in the 33% renewable transmission plan studies because the retirement or re-power of OTC units highly interacts with the transmission plan to achieve 33% RPS goal.

On May 4, 2010 the State Water Resources Control Board (State Water Board) adopted this policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy). The administrative record for the policy was approved by the Office of Administrative Law (OAL) on September 27, 2010. The policy became effective on October 1, 2010 when the California Environmental Quality Act Notice of Decision was submitted to the Secretary of Resources.

The policy establishes technology-based standards to implement federal Clean Water Act section 316(b) and reduce the harmful effects associated with cooling water intake structures on marine and estuarine life. The policy will apply to the 19 existing power plants state wide (including two nuclear plants) that currently have the ability to withdraw over 15 billion gallons of water per day from the State's coastal and estuarine waters using a single-pass system, also known as OTC.

Nuclear units may also seek to establish site specific requirements for best technology available. The policy directs PG&E and SCE to conduct special studies to investigate alternatives for the nuclear units to meet the requirements of the policy, including the costs for these alternatives.

The ISO staff has been working with the State Water Board, the CPUC and the CEC to coordinate study efforts for evaluating reliability impacts to the transmission system due to compliance to the policy. The ISO, in conjunction with state energy agencies, initiated a scenario tool for further reliability analysis to assess if and when gas-fired generation using OTC may come off-line to retrofit, re-power or retire in the 10 year planning horizon. This analysis will use a range of planning scenarios and assumptions[21], consistent with California Clean Energy Future's assumptions, which span a 10 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 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 OTC 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.

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.13-2 provides a summary of the SCE substation load in the summer peak assessment. Two summer peak base cases were used for each study year (1) the dispatch of all thermal and hydro units, and (2) the loss of the largest generating unit (SONGS). System re-adjustment was performed for the base case with the largest generating unit out-of-service. Case 1 was utilized for performing double element contingencies (N-2) and beyond, while case 2 was utilized for assessment of single element contingencies (N-1).

The ISO spring off-peak base cases assume 60% of the summer peak load.

[21] http://www.ISO.com/1c58/1c58e7a3257a0.html

Table 2.13-2: Summer peak load forecasts modeled in the SCE area assessment

SCE Coincident A-Bank Load Forecast (MW) Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
Alamitos 220/66	191	190	192	193	189	195
Alberhill 500/115	0	0	0	421	434	482
Antelope-Bailey 220/66	676	685	702	717	731	817
Barre 220/66	721	716	723	732	734	766
Big Creek 220/220	12	12	12	12	12	12
Blythe (Walc) 161/33	60	60	60	61	61	65
Camino 220/66	2	2	2	2	2	2
Center 220/66	457	458	462	466	468	482
Chevmain 220/66	166	166	166	167	167	169
Chino 220/66	735	741	862	882	896	1000
Cima 220/66	3	3	3	3	3	3
Del Amo 220/66	593	592	605	609	620	667
Devers-Mirage 220/115	1002	1008	1023	1035	1048	1123
Eagle Mountain 220/66	2	2	2	2	2	2
Eagle Rock 220/66	207	209	227	237	244	281
El Casco 220/115	111	195	191	192	196	205
El Nido 220/66	413	422	423	429	432	450
Eldorado 220/115	13	13	13	13	13	12
Ellis 220/66	704	709	717	718	725	766
Etiwanda 'Ameron' 220/66	18	18	18	18	18	18
Etiwanda 220/66	739	749	762	773	784	863
Goleta 220/66	307	308	312	313	314	324
Goodrich 220/33 (City of Pasadena)	293	289	289	289	288	287
Gould 220/66	136	136	138	140	143	156
Hinson 220/66	504	500	502	503	505	520
Johanna 220/66	511	525	584	600	605	661
La Cienega 220/66	522	521	517	520	523	541
La Fresa 220/66	722	718	728	730	740	768
Laguna Bell 220/66	667	670	671	672	672	684
Lewis 220/66 (City of Anaheim)	536	537	544	547	553	559
Lighthipe 220/66	503	501	499	500	503	512
Mesa 220/66	631	630	636	638	644	663
Mira Loma 220/66	694	703	620	630	645	702
Moorpark 220/66	847	851	862	872	881	937
Olinda 220/66	388	388	393	397	403	432
Padua 220/66	620	611	619	624	628	642
Rector 220/66	746	749	779	795	819	881
Rio Hondo 220/66	701	699	703	708	711	737
San Bernardino 220/66	648	650	650	655	666	660
Santa Clara 220/66	608	614	624	632	641	692
Santiago 220/66	851	862	884	898	913	662
Saugus 220/66	797	928	949	970	990	1141

SCE Coincident A-Bank Load Forecast (MW) Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	2011	2012	2013	2014	2015	2020
Springville 220/66	271	271	268	283	288	315
Valley 500/115	1099	1128	1168	783	806	844
Kramer 220/115	196	199	202	206	209	229
Vestal 220/66	212	211	214	215	217	229
Victor-Kramer-Inyo 220/115	535	546	560	571	581	620
Viejo 220/66	375	377	382	387	392	772
Villa Park 220/66	745	747	710	708	713	725
Vista 220/115	381	374	375	376	377	376
Vista 220/66	913	960	973	607	617	641
Walnut 220/66	649	647	653	654	659	681
Wilderness 220/66 (City of Riverside)	0	0	0	377	378	387
VALLEYSC	733	752	778	803	826	866
Total	**25168**	**25550**	**25953**	**26281**	**26630**	**28479**

Major Transmission Projects

The following planned transmission projects that have been approved by ISO were included in the assessment:

- Tehachapi Renewable Transmission Project (in-service date: 2010 ~ 2015);
- Valley – Devers – Colorado River No.2 500 kV Transmission Line (in-service date: 2013);
- Alberhill 500 kV Substation Plan of Service (in-service date: 2014);
- Devers – Mirage System Split (in-service date: 2011);
- San Joaquin Cross Valley Loop Transmission Project (in-service date: 2014); and
- East Kern Wind Resource Area 66 kV Reconfiguration Project (in-service date: 2013)

Major Path Flows

The major path flows assumed in the assessment are provided in the following tables.

Table 2.13-3: Major path flows modeled in the summer peak assessment

Path Flows (MW)	2011	2012	2013	2014	2015	2020
Midway-Vincent	3070	2838	2516	3051	3135	3004
West of River	7121	7722	7014	7605	8542	8048
East of River	6145	6484	5351	6484	7447	6575
PDCI	3000	3000	3000	3000	3000	3100
SCIT	15743	16092	15041	16156	17170	15885

Table 2.13-4: Major path flows modeled in the spring off-peak assessment

Path Flows (MW)	2011	2012	2013	2014	2015
Midway-Vincent	3964	2969	3240	3214	1942
West of River	4834	6317	6468	6290	7055
East of River	3652	5586	5771	5664	5945
PDCI	3097	3000	3078	3000	3000
SCIT	14481	14324	14712	14504	14499

Power Factor

In SCE area assessment, an active to reactive power (MW to MVAr) ratio of 25 to 1 or a power factor of 0.999 measured at the high side of the A-Bank (230/115 kV or 230/66 kV) was assumed for the SCE transmission substation loads. The value of this ratio recorded during the annual peak loads for the last six years ranges from 12.2 to 1 in 2000 to 56.0 to 1 in 2008.

The increase in the MW to MVAr ratio was the result of SCE's 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 MW to MVAr ratio of 25 to 1. Table 2.13-5 shows the MW to MVAr ratio recorded for the SCE transmission substation loads during the annual peak loads for the last five years.

Table 2.13-5: Active to reactive (MW to MVAr) power ratios recorded for SCE transmission substation loads during annual non-coincidental peak loads

Year of peak substation load	MW/MVAr (-)
2009	54
2008	56
2007	52
2006	28.9
2005	38

2.13.3 Study Results and Discussions

The study results of facilities in the SCE area under normal and various Category B and C contingency conditions are discussed in the following sections. Transient stability studies of the bulk 500 kV and 230 kV systems were performed as part of the studies.

A summary of the study results of facilities in the SCE area under Category D conditions is given below. Study results for Categories A through C are provided in each area section for the SCE area.

TPL 004: System Performance under Extreme Events

Loss of entire Lugo 500/230 kV substation was assessed for Category D performance. The system is unstable following the event. To restore synchronism of the system, extensive generation tripping in the North of Lugo area and load tripping in LA Basin are required. Loss of Lugo substation will trigger the operation of Kramer SPS, High Desert power plant SPS and South of Lugo SPS. But manual load tripping and restoring is still needed.

A summary of the study results related to the nuclear generating facilities is given below.

NUC 001: System Performance under scenarios that can affect SONGS

The technical studies were conducted in compliance with the NUC-001 standards annually as part of the transmission plan. Post-transient governor power flow and transient stabilities were conducted to assess the performance related to SONGS under normal and emergency conditions. In this planning cycle, the studies were conducted on the following scenarios:

- 2011 summer peak; and
- 2015 summer peak.

Several contingencies were run in the SCE area for thermal, voltage and stability concerns. These contingencies included:

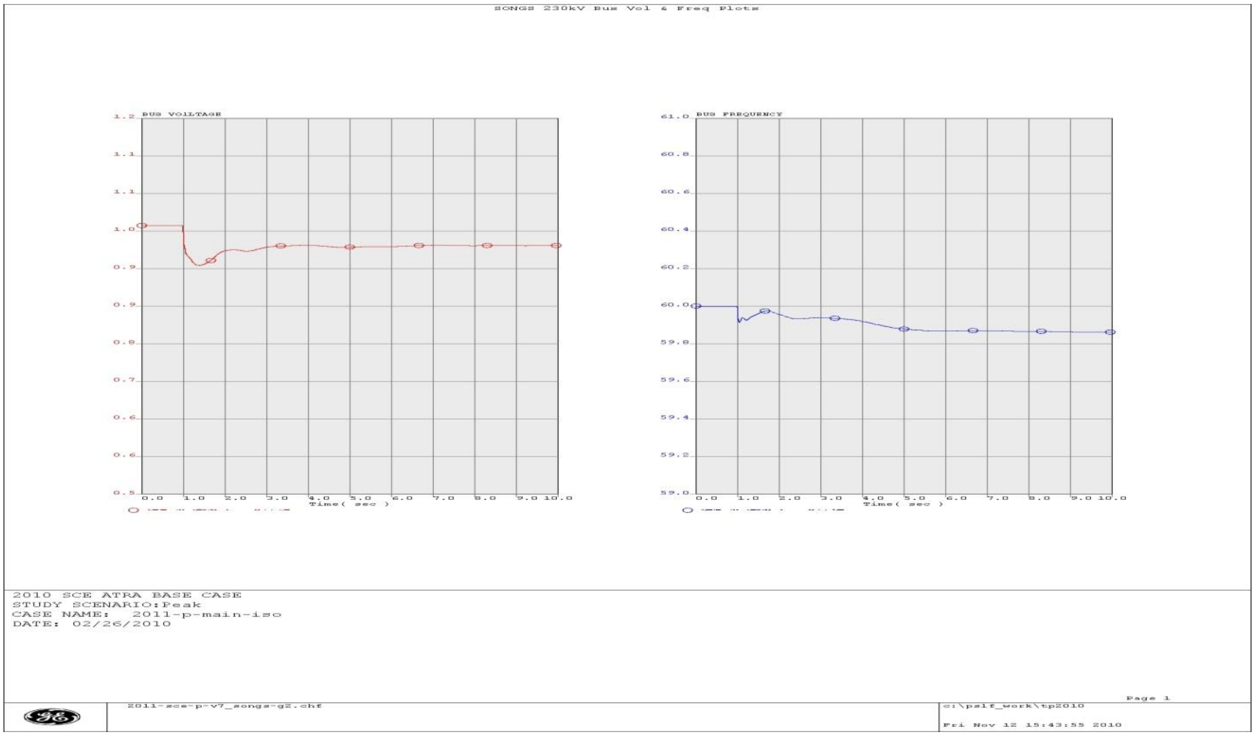
- Loss of a single SONGS unit (G-1);
- Loss of two SONGS units (G-2);
- All critical contingencies of transmission lines connected to SONGS (Category B, C and D);
- Loss of major generation plants in the SCE area;
- Loss of critical transmission lines and interties in the SCE system; and
- Loss of entire load at Santiago substation (largest load block in LA Basin according to the information provided in the base case).

The base cases modeled all transmission circuits connected to SONGS switchyard with the status normally in-service. The study results showed that:

- The steady state voltage at SONGS 230 kV switchyard was 230 kV under 2011 summer peak conditions and 230 kV under 2015 summer peak conditions. This is within the range specified by Transmission Control Agreement for SONGS (218 kV to 234 kV).
- The SONGS generator is regulating the 230 kV bus voltage to 1.00 per unit in 2011 summer peak case and in 2015 summer peak case.

The study results from various studies show that there are no thermal overloads, voltage or stability concerns related to the SONGS units under normal or emergency conditions. Following plots for two of the most severe contingencies and for a sudden loss of load demonstrate that there are no stability concerns related to SONGS units.

Figure 2.13-1: Bus Voltage and Frequency for SONGS (G-2) Contingency (2011 & 2015)



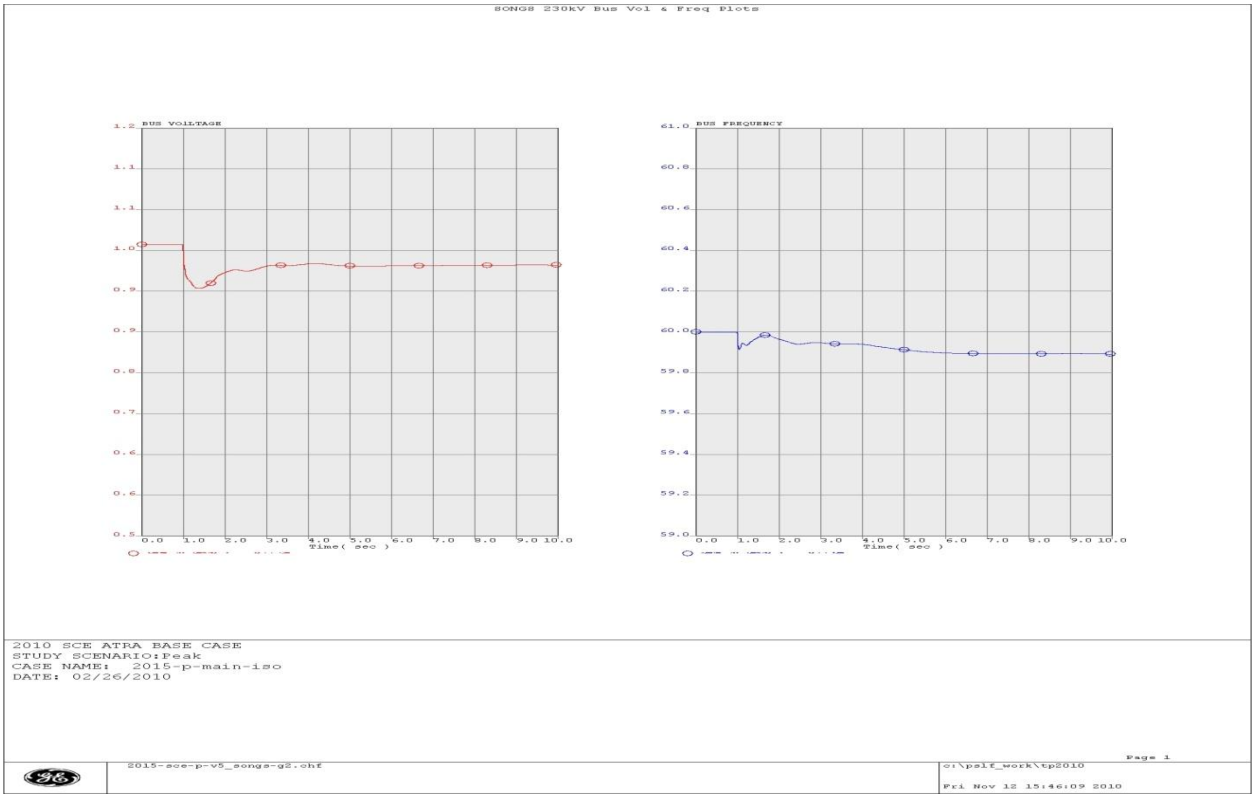
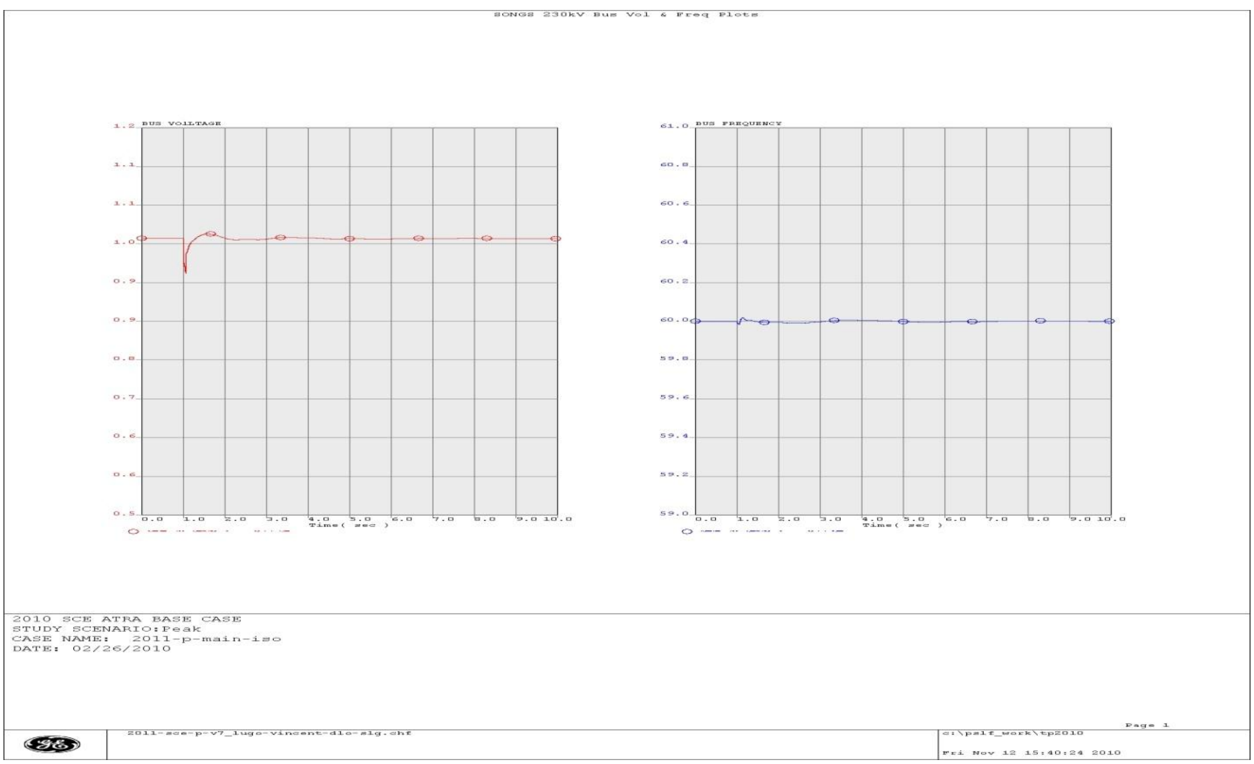


Figure 2.13-2: Bus Voltage and Frequency for Lugo – Vincent (N-2) Contingency (2011 & 2015)



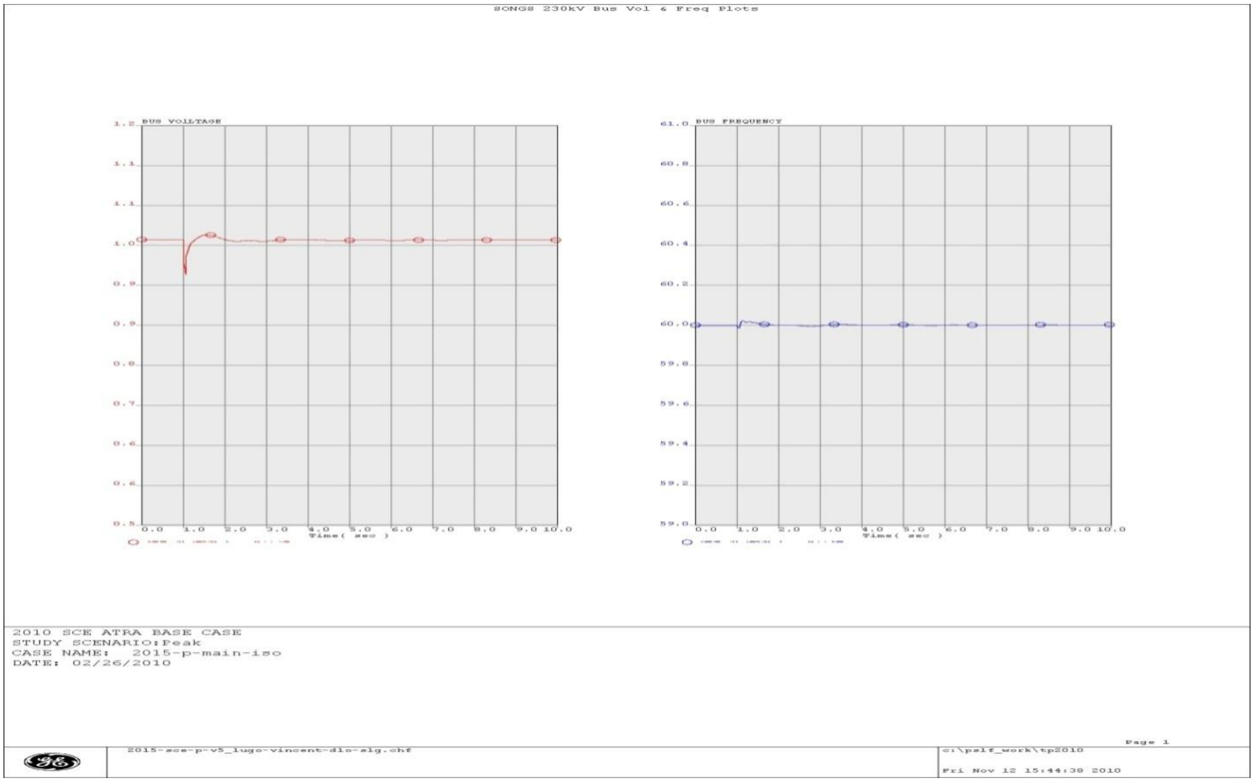
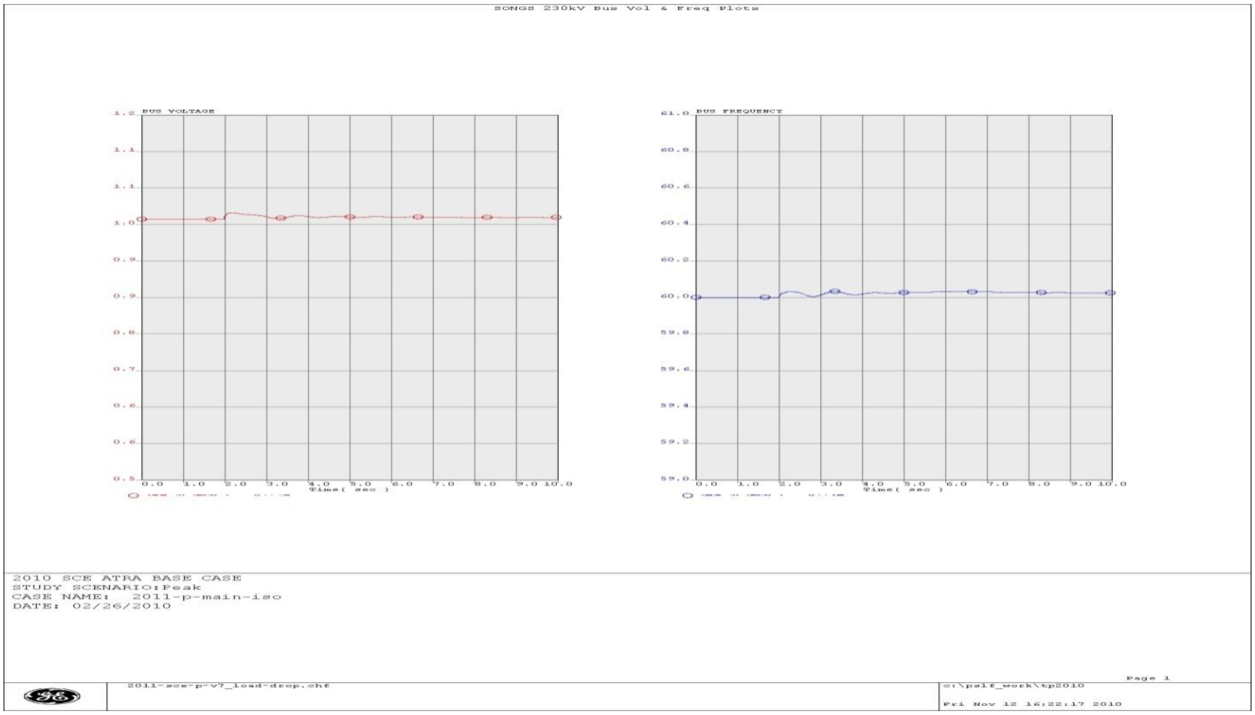
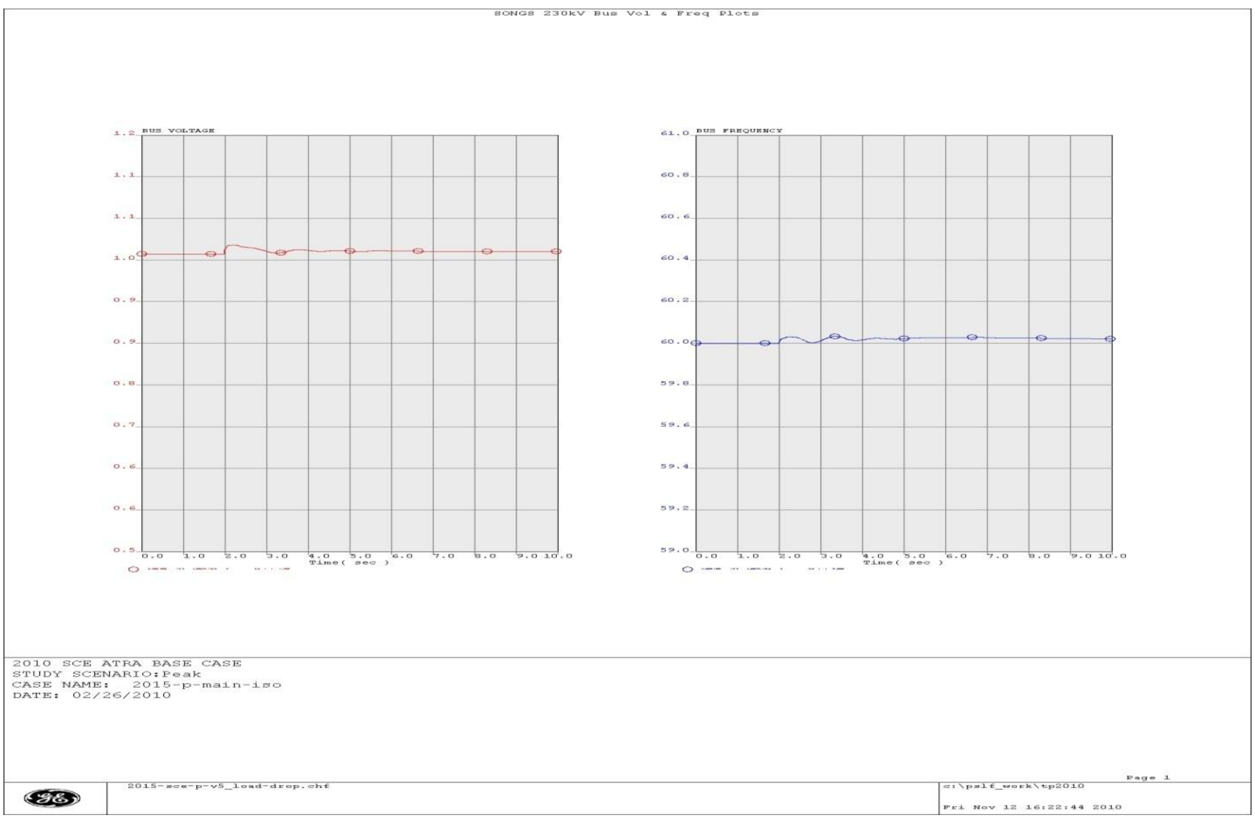

SONGS 230kV Bus Vol & Freq Plots
BUS VOLTAGE
BUS FREQUENCY
Time(sec)
Time(sec)
2010 SCE ATRA BASE CASE
STUDY SCENARIO:Peak
CASE NAME: 2015-p-main-iso
DATE: 02/26/2010
2015-sce-p-v5_lugo-vincent-dlo-alg.chf
c:\pslf_work\tp2010
Fri Nov 12 15:44:38 2010
Page 1

Figure 2.13-3: Bus Voltage and Frequency for Load Drop (2011 & 2015)





2.13.4 Recommended Solutions for Facilities Not meeting Thermal and Voltage Performance Requirements

Recommended solutions that address each of the identified facilities that did not meet the thermal and low voltage performance requirements under Category A,, B and C contingency conditions are discussed in the following sections for each area within SCE service territory.

2.14. SCE - BIG CREEK / ANTELOPE AREA

2.14.1 Area Description

The Big Creek/Antelope area consists of the SCE transmission system north of Vincent. The Big Creek/Antelope area consists of:

- WECC Path 26 – three 500 kV transmission lines between PG&E's Midway substation and SCE's Vincent substation;
- 230 kV transmission system between Vincent and Big Creek Hydroelectric project; and
- Antelope/Bailey 66 kV system.

Figure 2.14-2: Big Creek/Antelope Area Illustration

There are three major transmission projects that have been approved in prior cycles by the ISO in this area:

- San Joaquin Cross Valley Loop Transmission Project (in-service date: 2014);
- Tehachapi Renewable Transmission Project (in-service date: 2010 ~ 2015); and
- East Kern Wind Resource Area 66 kV Reconfiguration Project (in-service date: 2013).

Once the transmission projects are in-service, the area consists of:

- WECC Path 26 – three 500 kV transmission lines between PG&E's Midway substation and SCE's Vincent and Whirlwind substations;
- 500 kV substations, i.e. Whirlwind, Windhub, Antelope and Vincent, and transmission lines;
- 230 kV transmission system between Vincent and Big Creek Hydroelectric project; and
- Antelope/Bailey/Windhub 66 kV system.

2.14.2 Area-Specific Assumptions and System Conditions

The Big Creek/Antelope area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology applied to the SCE area study are provided below.

Generation

Table 2.14-2 lists the major existing generation plants in the Big Creek/Antelope area. There are several generation projects currently under development in this area. The development of generation in this area and the transmission upgrades associated with this generation development is discussed in the 33% renewable transmission plan section of this report.

Table 2.14-1: List of the major generation plants in the Big Creek/Antelope area

Generation Plants	Max. Capacity (MW)
Big Creek Hydro	1020
Omar/Sycamore	600
Ultragen	41
Pando	55
Pastoria	750
Antelope Area Wind and Hydro	389
Vincent Area Wind	272

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.14-2 provides a summary of the SCE substation load in the summer peak assessment. The substations located in the Big Creek/Antelope area are highlighted in the table.

The ISO spring off-peak base cases assume 60% of the summer peak load.

Table 2.14-2: Summer peak load forecasts modeled in the SCE's Antelope-Bailey area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	2011	2012	2013	2014	2015	2020
Antelope-Bailey 220/66	676	685	702	717	731	817
Big Creek 220/220	12	12	12	12	12	12
Rector 220/66	746	749	779	795	819	881
Springville 220/66	271	271	268	283	288	315
Vestal 220/66	212	211	214	215	217	229

2.14.3 Study Results and Discussions

A summary of the study results of facilities in the Big Creek/Antelope area under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

- All facilities met the performance requirements under Category A conditions from 2011 to 2020.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

- For the summer peak cases, there was one contingency (i.e., Bailey 230/66 kV transformer bank No. 3 outage) causing two facility overloads (i.e., Bailey – Neenach – Westpac 66 kV line and Antelope – Neenach 66 kV line), hence not meeting the required Category B thermal loading performance requirement; and
- For the spring off-peak cases, there was one contingency (i.e., Bailey 230/66 kV transformer bank No. 3 outage) causing two facility overloads (i.e., Bailey – Neenach – Westpac 66 kV line and Antelope – Neenach 66 kV line), hence not meeting the required Category B thermal loading performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

- For the summer peak cases, there were five contingencies causing eight facility overloads, hence not meeting the required Category C thermal loading performance requirement;
- For the summer peak cases, there were three contingency cases that resulted in a diverged power flow solution, hence not meeting the Category C contingency thermal loading and voltage performance requirements;
- For the summer peak cases, there were two contingency cases that resulted in voltage deviation greater than 10%, hence not meeting the Category C contingency voltage performance requirements;
- For the spring off-peak cases, there was one contingency causing one facility overload, hence not meeting the required Category C thermal loading performance requirement;
- For the spring off-peak cases, there was one contingency case that resulted in a diverged power flow solution, hence not meeting the Category C contingency thermal loading and voltage performance requirements; and
- For the spring off-peak cases, there was one contingency case that resulted in voltage deviation greater than 10%, hence not meeting the Category C contingency voltage performance requirements.

Appendix A documents the worst thermal loading concerns and voltage deviations of facilities that do not meet reliability requirements. Proposed solutions are listed next to identified criteria performance concerns. The transient stability analysis of the Big Creek/Antelope area revealed transient voltage dips at several substations that are served from Bailey 230/66 kV substation. The transient stability study results are listed in Appendix A.

2.14.4 Recommended Solutions for Facilities Not Meeting Thermal and Voltage Performance Requirements

Based on the 2011 to 2020 reliability assessment results of the SCE Big Creek/Antelope area, the ISO recommended solutions that address each of the identified facilities that did not meet the thermal and low voltage performance requirements under Category A, B and C contingency conditions. Also included in this section is a discussion on the solutions and plan for achieving the required system performance under the normal and various contingency conditions. The recommended solutions were to ensure secured power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- Energizing available spare transformer bank;
- Installing new or modifying existing SPS; and
- Developing operating procedures.

The following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. It provides information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.14.4.1 Thermal Overload Mitigations

Bailey - Neenach - Westpac 66 kV No. 1 Line and Antelope - Neenach 66 kV No. 1 Line

Both lines are overloaded under one Category B outage (Bailey 230/66 kV transformer bank) and one Category C outage (Pardee - Bailey 230 kV No. 1 line & Pastoria - Bailey 230 kV No. 1 line).

To mitigate the Category B condition overload, the ISO recommends energizing the spare 230/66 kV transformer bank at Bailey substation. To mitigate the Category C condition overload, the ISO recommends installing a new SPS to trip Bailey area load following the second contingency. The mitigation measures are expected to be in-service in 2011.

Del Sur - Lancaster - Rite Aid 66 kV No. 1 Line

The Del Sur leg and Lancaster leg of this multi-terminal tapped line are overloaded under one Category C outage. The ISO recommends installing a new SPS to trip Lancaster load under the simultaneous outage of Antelope - Lanpri - Shuttle - Lancaster 66 kV No. 1 line and Antelope - Oasis - Lancaster 66 kV No. 1 line. The SPS is expected to be in-service in 2011.

Antelope - Anaverde - Helijet 66 kV No. 1 Line, Little Rock - Palmdale - Rockair - Helijet 66 kV No. 1 Line and Lancaster - Little Rock - Piute 66 kV No. 1 Line

Several sections of the three multi-terminal tapped lines are overloaded under one Category C outage. The ISO recommends installing a new SPS to trip Palmdale load under the outage of both Palmdale - Acton - Shuttle 66 kV No. 1 line and Palmdale - Oasis - Quartz Hill 66 kV No. 1 line. The SPS is expected to be in-service in 2011.

Magunden – Vestal 230 kV No. 1 and No. 2 Lines

The two lines are overloaded under one Category C outage in 2011 before the *San Joaquin Cross Valley Loop (SJXVL) Transmission Project* is in-service. The SJXVL project was approved by the ISO in 2004 and is currently expected to be in service in 2014. To mitigate the overloads, the existing Big Creek - San Joaquin Valley SPS needs to be modified to trip more load under the simultaneous outage of Big Creek 1 - Rector 230 kV No. 1 line and Big Creek 3 - Rector 230 kV No. 1 line. The modification is expected to be in-service in 2012. In 2011, the overloads will be mitigated by procedures to roll Rector load to Springville and drop voluntary load with demand side management.

Big Creek 3 - Rector 230 kV No. 1

The line is overloaded under one Category C outage in 2011 and 2012 before the SJXVL project is in-service. The SJXVL project was approved by the ISO in 2004 and is currently expected to be in-service in 2014. To mitigate the overloads, the existing Big Creek - San Joaquin Valley SPS needs to be modified to trip more load under the simultaneous outage of Magunden – Vestal 230 kV No. 1 and No. 2 lines. The modification is expected to be in-service in 2012. In 2011, the overloads will be mitigated by procedures to roll Rector load to Springville and drop voluntary load with demand side management.

2.14.4.2 Voltage Concern Mitigations

The eight substations identified as not meeting the voltage performance requirements together with the voltage collapse experienced under Categories B and C conditions as shown in Appendix A would be addressed upon implementation of projects aimed at achieving the thermal loading performance requirements. Voltage collapse under one Category C condition requires mitigation in addition to those aimed at achieving the thermal loading performance requirements.

Oso, Alamo, Bailey, Frazier Park, Gorman, Neenach and Westpac 66 kV Substations

Voltage deviation greater than 10% was identified under one Category C outage (Pardee - Bailey 230 kV No. 1 line and Pastoria - Bailey 230 kV No. 1 line). Voltage collapse was identified for the same Category B and Category C contingencies in year 2014 and 2020.

In addition, voltage collapse was identified under one Category C outage (Bailey 230/66 kV transformer bank and Antelope - Neenach 66 kV No. 1 line) before the *East Kern Wind Resource Area 66 kV Reconfiguration Project*, approved by the ISO in 2010, is in service.

In last year's assessment, voltage deviation greater than 7% was identified under Category B outage of the Bailey 230/66 kV transformer bank. The issue was deferred to this study cycle to evaluate the feasibility of energizing the spare 230/66 kV transformer bank in Bailey substation. Upon further evaluation of the short circuit duty with two Bailey 230/66 kV transformer bank operating in parallel, the ISO recommends energizing spare 230/66 kV transformer bank at Bailey substation and installing a new SPS to trip Bailey area load for Category C contingencies. The mitigation measures are expected to be in-service in 2011.

Palmdale 66 kV Substation

Voltage deviation greater than 10% was identified under one Category C condition at Palmdale 66 kV Substation. The ISO recommends installing a new SPS to trip Palmdale load under the outage of both Palmdale - Acton - Shuttle 66 kV No. 1 line and Palmdale - Oasis - Quartz Hill 66 kV No. 1 line. The SPS is expected to be in-service in 2011.

Voltage Collapse under Category C Outage of Two Antelope 230/66 kV Transformer Banks

Outage of two Antelope 230/66 kV transformer banks resulted in diverged power flow case in 2020, which indicates a voltage collapse condition. The ISO recommended that SCE develop an operating procedure to close the spare Antelope 230/66 kV transformer bank No. 3 when No.1 or No. 2 or No.4 transformer bank is out. The operating procedure is expected to be in-service in 2013.

Request Window Project Submittal - Neenach Selective Service Project

The Neenach Selective Service Project is proposed by SCE to open the Antelope – Neenach 66 kV line after the EKWRA project is in-service due to SCE Sub-transmission Criteria 4.3.7.5 (a substation served by two lines from two separate systems require the mode of operation to be selective service in which only one line is energized). Since the selective service downgrades the reliability of serving Bailey load, the ISO does not find the need for this project.

Request Window Project Submittal - Cal Cement Interim Solution

The *Cal Cement Interim Solution* is proposed by TTS to mitigate voltage deviation at Cal Cement substation before the East Kern Wind Resource Area (EKWRA) 66 kV reconfiguration project is in service. The ISO identified potential Category B voltage deviation at several 66 kV substations in the northern Antelope – Bailey area of the SCE service territory in the 2010 cycle. A long-term solution for the under-voltage concerns in the area was approved in the 2010 cycle as part of the EKWRA project. Although the proposed *Cal Cement Interim Solution* was identified as a possible short-term mitigation solution prior to the implementation of the long-term solution, SCE has implemented an operating procedure to address the interim gap. The operating procedure, OP 068, would curtail the output of generation resources in the area to mitigate potential overloads and voltage concerns that were identified without dropping the load. Therefore, the ISO does not find the need of the project.

2.14.4.3 Transient Voltage Dip Concern Mitigations

Transient voltage dips were observed at seven substations under one Category B condition. The mitigation measures that address the thermal loading and voltage performance (discussed above) are sufficient to mitigate the transient voltage dip concerns.

Oso, Alamo, Bailey, Frazier Park, Gorman, Neenach and Westpac 66 kV Substations

Transient voltage dips greater than 25% at load substation and 30% at non-load substation were identified. The ISO recommends energizing the spare 230/66 kV transformer bank at Bailey substation and installing a new SPS to trip Bailey area load for Category C contingencies. The mitigation measures are expected to be in-service in 2011.

2.14.5 Key Conclusions

The 2011 to 2020 summer peak and spring off-peak reliability assessment of the SCE Big Creek/Antelope area revealed several reliability concerns. These concerns consist of thermal overloads, large voltage deviations and voltage collapse under Category B and C contingency conditions. Based on the assessment results, the ISO proposes operating procedures to address the identified reliability concerns to meet the ISO Standards for the area. SCE responded by identifying the following seven SPS and operating procedures. Upon review by the ISO, the following have met the ISO reliability concerns, and the ISO has concurred with their implementation.

- *Antelope A Bank Operating Procedure;*
- *Lancaster Operating Procedure and Remedial Action Scheme;*
- *Palmdale Remedial Action Scheme;*
- *Rector RAS Modification;*
- *Bailey Operating Procedure;*
- *Big Creek Existing RAS Modification; and*
- *Path 26 Existing RAS Modification.*

2.15. SCE - NORTH OF LUGO AREA

2.15.1 Area Description

The North of Lugo transmission system serves San Bernardino, Kern, Inyo, and Mono counties. The orange shaded portion in the figure below depicts the geographic location of the North of Lugo area. The area extends more than 270 miles.

The North of Lugo electric transmission system is comprised of 55 kV, 115 kV and 230 kV transmission facilities. In the North, it has inter-ties with LADWP and Sierra Pacific Power. In the South, it connects to the Eldorado substation through the Eldorado-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line. It also connects to the Pisgah substation through the Lugo-Pisgah No.1 and No.2 230 kV lines. There are two 500/230 kV transformer banks at the Lugo substation which provide access to SCE's main system. The North of Lugo area can be divided into the following sub-areas: a) North of Control, b) South of Control to Inyokern, c) South of Inyokern to Kramer, d) South of Kramer, and e) Victor.

SCE's Coincident A-Bank Load Forecast indicates that the North of Lugo area should reach the summer peak demand of 731 MW by 2011. By 2020 the loading for the area would be 849 MW. System assessments in the North of Lugo area included technical studies using load assumptions for the summer peak condition and the spring off-peak condition (60% of the summer peak load). Table 2.15-2 includes load forecast data for the area.

2.15.2 Area-Specific Assumptions and System Conditions

The North of Lugo area study was performed consistent with the general study methodology and assumptions that are described in chapter 2. The ISO's secured website lists the contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the North of Lugo area study are provided below.

Generation

Generation resources in the North of Lugo area consist of market and QF generating units. A list of all the generating facilities in the North of Lugo area is given in table 2.15-1. There are several generation projects currently under development in this area. The development of generation in this area and the transmission upgrades associated with this generation development is discussed in the 33% renewable transmission plan section of this report.

Table 2.15-1: Generation in the North of Lugo Area

No.	Generation Facility	Max. Capacity (MW)
1	Bishop Hydro Units 2 & 6	13.3
2	Bishop Hydro Units 3 & 4	15.9
3	Poole & Lundy	13.9
4	Rush Creek	11.5
5	BLM East & West (Units 7, 8 & 9)	72
6	Borax	45
7	Calgen (Units 1, 2 & 3)	80
8	Kerrgen*	16.9
9	Kerr McGee*	55
10	Luz (Units 8 & 9) – SEGS 8 & 9	160
11	McGen	104.4
12	Mogen	51
13	Navy 2 (Units 4, 5 & 6)	90
14	Casa Diablo	30
15	Oxbow	50
16	SEGS 1	20
17	SEGS 2	29.4
18	Sungen (Units 3, 4, 5, 6 & 7)	139.6
19	Alta Unit 1	65
20	Alta Unit 2	81
21	Alta Unit 3 (combustion turbines)	132

22	Alta Unit 3 (steam turbine)	108
23	Alta Unit 4 (combustion turbines)	132
24	Alta Unit 4 (steam turbine)	108
25	HDPP (Units 1, 2 & 3)	525
26	HDPP (steam turbine)	325
	Total	2473.9

*Note that the maximum net generation export as seen at Searless 115 kV (McGen+Kerrgen-Load) is limited to no more than 26 MW.

Load Forecast

The ISO base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses. Table 2.15-2 shows loads modeled for the North of Lugo area assessment as well as other local areas within the SCE system.

Table 2.15-2: Load forecasts modeled in the North of Lugo area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
Kramer 220/115	**196**	**199**	**202**	**206**	**209**	**229**
Victor-Kramer-Inyo 220/115	**535**	**546**	**560**	**571**	**581**	**620**

2.15.3 Study Results and Discussions

A summary of the study results in the North of Lugo area that were identified as not meeting thermal loading, voltage and stability performance requirements under various system contingency conditions is given below.

Power Flow Study Results

TPL 001: System Performance under Normal Conditions

- For the summer peak cases, no facilities had thermal overloads or voltage performance concerns under the Category A performance requirement; and
- For the spring off-peak cases, no facilities had thermal overloads or voltage performance concerns under the Category A performance requirement.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (G-1/L-1)

- For the summer peak cases, no facilities had thermal overloads or voltage performance concerns under the Category C performance requirement; and
- For the spring off-peak cases, no facilities had thermal overloads or voltage performance concerns under the Category C performance requirement.

TPL 003: System Performance Following Loss of Two or More BES Elements

- For the summer peak cases, there are four facilities with thermal overloads and three facilities with high voltage deviation concerns under the Category C performance requirements; and
- For the spring off-peak cases, there are four facilities with high voltage deviation concerns under the Category C performance requirements.

TPL 004: System Performance under Extreme Events

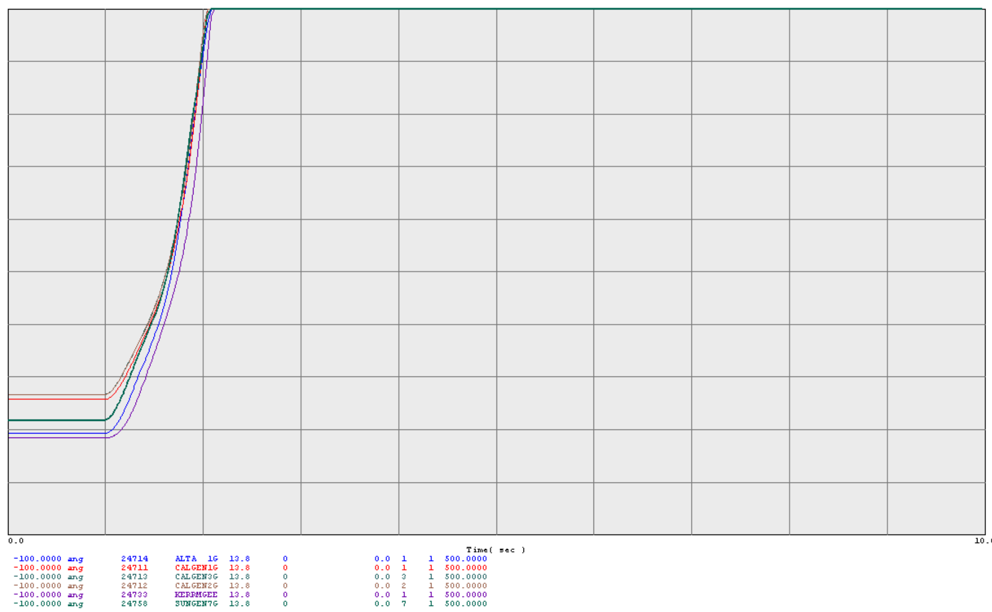
- Loss of the entire Lugo 500/230 kV substation was assessed for Category D performance. The system was unstable following this event.

Appendix A documents the worst thermal loading and voltage deviations of facilities for not meeting reliability performance requirements, along with the corresponding proposed solutions.

Transient Stability Analyses Results

The transient simulation shows that the system is unstable following the Kramer-Lugo 230 kV N-2 contingency and SPS to trip Alta 3, 4, Luz, BLM West, BLM East and Navy 2 generating units. Figure 2.15-1 plots the rotor angles of various generators in the North of Lugo area.

Figure 2.15-1: Transient stability plot of generator rotor angles under the Kramer-Lugo 230 kV N-2 contingency condition (summer 2011 peak load case)



2.15.4 Recommended Solutions for Facilities Not Meeting Thermal and Voltage Performance Requirements

Based on the 2011 to 2020 reliability assessment results of the SCE North of Lugo area, the ISO recommended solutions that address each of the identified facilities that did not meet the thermal or voltage performance requirements or the system stability requirement under the Category C contingency conditions. Also included in this section is a discussion of the solutions and plan for achieving the required system performance under the various contingency conditions. The recommended solutions were to ensure secured power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- Developing operating procedures; and
- Modifying the existing SPS.

The following is a discussion of the recommended solutions for the identified thermal overloads, voltage and system stability concerns. It provides information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.15.4.1 Thermal Overload Mitigations

Control - Inyo 115 kV Line

The Category C overload results from over generation in the North of Lugo area. The ISO recommends that an operating procedure with an in-service date on or before June 1, 2011 to reduce generation be developed to address any potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

Inyo 115 kV Phase Shifter

The Category C overload results from over generation in the North of Lugo area. The ISO recommends that an operating procedure with an in-service date on or before June 1, 2011 to reduce generation be developed to address any potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

Inyokern-Randsburg-Kramer No.1 115 kV Line

The Category C overload results from over generation in the North of Lugo area. The ISO recommends that an operating procedure with an in-service date on or before June 1, 2011 to reduce generation be developed to address any potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

Kramer No. 1 230/115 Transformer Bank

The Category C overload results from over generation in the North of Lugo area. The ISO recommends that an operating procedure with an in-service date on or before June 1, 2011 to reduce generation be developed to address any potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

2.15.4.2 Voltage Concerns Mitigations

The Category C voltage deviations result from over generation in the North of Lugo area. The ISO recommends that an operating procedure with an in-service date on or before June 1, 2011 to reduce generation be developed to address any potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

2.15.4.3 Transient Stability Mitigations

The ISO recommends that SCE evaluate modifications to the existing Kramer SPS to mitigate the transient instability problem under the Category C condition. In the interim, it is recommended that an operating procedure with an in-service date on or before June 1, 2011 be developed to address any potential reliability concern. The ISO will work with SCE to ensure that the operating procedure is in place on time.

2.15.5 Key Conclusions

The summer peak and spring off-peak reliability assessment of the SCE North of Lugo area revealed several reliability concerns. These concerns consist of thermal overloads, large voltage deviations and system instability under Category C contingency conditions.

Based on the assessment results, the ISO proposes operating procedures to address the identified reliability concerns to meet the ISO standards for the North of Lugo area. SCE responded by proposing the North of Lugo Operating Procedure. Upon review by the ISO, the proposed North of Lugo operating procedure met the ISO reliability concerns, and the ISO has concurred that these are needed. The ISO will ensure that the proposed operating procedure will be in place to meet the reliability needs in 2011.

2.16 SCE - EAST OF LUGO AREA

2.16.1 Area Description

The East of Lugo area consists of SCE transmission system between Lugo and Eldorado substations. The East of Lugo area is a major transmission corridor connecting California with Nevada and Arizona. The East of Lugo bulk system consists of:

- 500 kV transmission lines from Lugo to Eldorado and Mohave;
- 230 kV transmission lines from Lugo to Pisgah to Eldorado; and
- 115 kV transmission line from Eldorado to Coolwater.

Figure 2.15-1: East of Lugo Area Illustration

2.16.2 Area-Specific Assumptions and System Conditions

The East of Lugo area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology applied to the East of Lugo area study are provided below.

Generation

There is no major generation located in the East of Lugo area.

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.16-1 provides a summary of the SCE substation load in the summer peak assessment. The substations located in the East of Lugo area are highlighted in the table.

The ISO spring off-peak base cases assume 60% of the summer peak load.

Table 2.16-1: Summer peak load forecasts modeled in the SCE area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
Cima 220/66	3	3	3	3	3	3
Eldorado 220/115	13	13	13	13	13	12

2.16.3 Study Results and Discussions

A summary of the study results of facilities in the East of Lugo area under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

- All facilities met the performance requirements under Category A normal conditions from 2011 to 2020.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

- All facilities met the performance requirements under Category B contingency conditions from 2011 to 2020.

TPL 003: System Performance Following Loss of Two or More BES Elements

- For the summer peak cases, there was one contingency causing two facility overloads, hence not meeting the required Category C thermal loading performance requirement;

Appendix A documents the worst thermal loading of facilities not meeting the performance requirements for the summer peak and spring off-peak conditions along with the corresponding proposed solutions.

2.16.4 Recommended solutions for facilities not meeting thermal and voltage performance requirements

Based on the 2011 to 2020 reliability assessment results of the SCE East of Lugo area, the ISO recommended solutions that address each of the identified facilities that did not meet the thermal performance requirements under Category C contingency conditions. The recommended solutions were to ensure secured power transfer and adequate load serving capability of the transmission system.

2.16.4.1 Thermal Overload Mitigations

Eldorado 500/230 kV Transformer Banks No. 1 and No. 2

The two transformer banks are overloaded under the L-1-1 outage of Eldorado–Moenkopi 500 kV line and Eldorado–McCullough 500 kV line in 2015 and beyond. The recommended solution is to develop emergency ratings for the overloaded transformers. If no emergency rating is achievable, congestion management will be applied following the first contingency to re-adjust the system by reducing import at Eldorado. The solution can be implemented before the summer of 2011.

2.15.5 Key Conclusions

The 2011 to 2020 summer peak and spring off-peak reliability assessment of the SCE East of Lugo area identified thermal overloads on the two Eldorado 500/230 kV transformer banks under one Category C contingency. The solution is to apply congestion management.

2.17. EASTERN AREA

2.17.1 Area Description

The Eastern area includes the 500 kV, 230 kV and 115 kV transmission system from Valley to Devers and Palo Verde in Arizona and 230 kV transmission system from Vista to Devers to Mirage.

Figure 2.17-1: Eastern Area Illustration

There are five major transmission projects that have been approved by ISO in this area:

- Valley – Devers – Colorado River Transmission Project (in-service date: 2013;)
- Devers/Mirage 115 kV Split Project (in-service date: 2011);
- Alberhill 500 kV Substation (in-service date: 2015);
- El Casco 230 kV Substation (in-service date: 2010); and
- Coachella – Devers 230 kV Loop-in to Mirage (in-service date: 2012.)

2.17.2 Area-Specific Assumptions and System Conditions

The Eastern area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology applied to the SCE area study are provided below.

Generation

Table 2.17-1 lists the major existing generation plants in the Eastern area. There are several generation projects currently under development in this area. The development of generation in this area and the transmission upgrades associated with this generation development is discussed in the 33% renewable transmission plan section of this report.

Table 2.17-1: List of the major generation plants in the Eastern area

Generation Plants	Max. Capacity (MW)
Mountain View	1072
Blythe	520
Indigo Thermal	135.9
QF Wind	455
Market Wind	360.5

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.17-2 provides a summary of the SCE substation load in the summer peak assessment. The substations located in the Big Creek/Antelope area are highlighted in the table.

The ISO spring off-peak base cases assume 60% of the summer peak load.

Table 2.17-2: Summer peak load forecasts modeled in the SCE area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	2011	2012	2013	2014	2015	2020
Alberhill 500/115	0	0	0	421	434	482
Blythe (Walc) 161/33	60	60	60	61	61	65
Camino 220/66	2	2	2	2	2	2
Devers-Mirage 220/115	1002	1008	1023	1035	1048	1123
Eagle Mountain 220/66	2	2	2	2	2	2
El Casco 220/115	111	195	191	192	196	205
Valley 500/115	1099	1128	1168	783	806	844
VALLEYSC	733	752	778	803	826	866

2.17.3 Study Results and Discussions

A summary of the study results of facilities in the Eastern area under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

- All facilities under ISO control met the performance requirements under Category A conditions from 2011 to 2020.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

- All facilities under ISO control met the performance requirements under Category B conditions from 2011 to 2020.

TPL 003: System Performance Following Loss of Two or More BES Elements

- For the summer peak cases, there were 11 contingencies causing 26 facility overloads, hence not meeting the required Category C thermal loading performance requirement;
- For the summer peak cases, there were four contingency cases that resulted in voltage deviation greater than 10%, hence not meeting the Category C contingency voltage performance requirements;
- For the spring off-peak cases, there were five contingencies causing five facility overloads, hence not meeting the required Category C thermal loading performance requirement; and
- For the spring off-peak cases, there was one contingency case that resulted in voltage deviation greater than 10%, hence not meeting the Category C contingency voltage performance requirements;

Appendix A documents the worst thermal loading of facilities not meeting the performance requirements for the summer peak and spring off-peak conditions along with the corresponding proposed solutions.

2.17.4 Recommended Solutions for Facilities Not Meeting Thermal and Voltage Performance Requirements

Based on the 2011 to 2020 reliability assessment results of the SCE Eastern area, the ISO recommended solutions that address each of the identified facilities that did not meet the thermal and low voltage performance requirements under Category C contingency conditions. The recommended solutions were to ensure secured power transfer and adequate load serving capability of the transmission system. These solutions generally include, but are not limited to, the following:

- Developing operating procedures to reduce generation following the first contingency and in preparation of the second contingency; and
- Installing new SPS.

The following is a discussion of the proposed recommended solutions for the identified thermal overloads and voltage concerns. It provides information about the expected in-service dates of the mitigation projects and plans with the goal to achieve the required system performance over the planning horizon.

2.17.4.1 Thermal Overload Mitigations

Blythe – Eagle Mountain161 kV Line

The line was overloaded under one Category C condition. The ISO recommends that SCE develop an operating procedure to reduce Blythe generation following the first contingency. The mitigation measure is needed in 2013.

Devers 230/115 kV Transformer Banks No. 1, No. 3 and No.4

Under Category C outage of two Devers 230/115 kV transformer banks, the remaining transformer bank was overloaded. The ISO recommends that SCE develop an operating procedure to reduce Devers 115 kV area generation after the first transformer bank outage.

Farrel – Eisenhower 115 kV Line, Devers – Garnet – Indigo 115 kV Line, Devers – Garnet – Venwind 115 kV Line, Devers – Eisenhower – Thornhill 115 kV Line, Garnet – Farrel 115 kV Line, Devers – Farrel – Buckwind – Altwind – Seawest 115 kV Line and Tamarisk – Thornhill 115 kV Line

These lines were overloaded under eight Category C conditions. The ISO recommends installing new SPSs to trip Devers 115 kV area load under these Category C conditions. The SPSs are needed in 2011.

Mirage – Santa Rosa – Tamarisk 115 kV Line, Mirage – Santa Rosa 115 kV Line, Mirage – Concho 115 kV Line and Mirage 230/115 kV Transformer Banks No. 1, No. 3 and No. 4

These facilities were overloaded under four Category C conditions. The ISO recommends installing new SPS to trip Mirage 115 kV area load under these Category C conditions. The SPS is needed in 2011.

2.17.4.2 Voltage Concern Mitigations

14 substations were identified as not meeting the voltage performance requirements under Category C conditions as shown in Appendix A.

Farrel, Eisenhower, Thornhill, Garnet, Banwind, Renwind, Bottle, Tranwind 115 kV Substations

Voltage deviation greater than 10% was identified at the eight substations under three Category C conditions. The ISO recommends that SCE install new SPSs to trip Devers 115 kV area load under these Category C conditions. The SPSs are needed in 2011.

Banning, Crafthills, Mentone, San Bernadino, Zanja, Maraschi 115 kV Substations

Voltage deviation greater than 10% was identified at the six substations under one Category C condition. The ISO recommends that SCE install new SPSs to trip El Caso 115 kV area load under these Category C conditions. The SPSs are needed in 2020.

2.17.5 Key Conclusions

The 2011 to 2020 summer peak and spring off-peak reliability assessment of the SCE Eastern area revealed several reliability concerns. These concerns consist of thermal overloads and large voltage deviations under Category C contingency conditions.

To address the identified thermal overloads and voltage concerns, the ISO proposed a total of five solutions and SCE identified one operating procedure, *Garnet Operating Procedure.* Upon review by the ISO, the operating procedure met the ISO reliability concerns, and the ISO has concurred with the implementation.

2.18. SCE - METRO AREA

2.18.1 Area Description

The Metro area consists of of the major load centers in Orange, Riverside, San Bernardino, Los Angeles, Ventura and Santa Barbara Counties. The boundary of the Metro area is marked by Vincent, Lugo and Alberhill 500 kV substations.

Figure 2.18-1: Metro Area Illustration

2.18.2 Area-Specific Assumptions and System Conditions

The Metro area study was performed consistent with the general study methodology and assumptions described in section 2.3. In addition, specific assumptions and methodology applied to the Metro area study are provided below.

Generation

Table 2.18-1 lists the major existing generation plants in the Metro area.

Table 2.18-1: List of the major generation plants in the Metro area

Generation Plants	Max. Capacity (MW)
Alamitos	1950
El Segundo	670
Long Beach	260
Mountain Vista	640
Redondo Beach	1280
Mountain View	1072
San Onofre Nuclear Generating Station (SONGS)	2150 MW (SCE's Share = 1720 MW)

Currently the ISO is working with the State Water Board and energy agencies to evaluate reliability impacts to the transmission system in the ISO balancing authority area. Further discussions regarding ongoing reliability assessment efforts are provided in section 2.16.

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year heat wave load forecast. This forecast load includes system losses.

Table 2.18-2 provides a summary of the SCE substation load in the summer peak assessment. The substations located in the Metro area are highlighted in the table.

The ISO spring off-peak base cases assume 60% of the summer peak load.

Table 2.18-2: Summer peak load forecasts modeled in the SCE area assessment

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	2011	2012	2013	2014	2015	2020
Alamitos 220/66	191	190	192	193	189	195
Alberhill 500/115	0	0	0	421	434	482
Barre 220/66	721	716	723	732	734	766
Center 220/66	457	458	462	466	468	482
Chevmain 220/66	166	166	166	167	167	169
Chino 220/66	735	741	862	882	896	1000
Del Amo 220/66	593	592	605	609	620	667
Eagle Rock 220/66	207	209	227	237	244	281
El Nido 220/66	413	422	423	429	432	450
Ellis 220/66	704	709	717	718	725	766
Etiwanda 'Ameron' 220/66	18	18	18	18	18	18
Etiwanda 220/66	739	749	762	773	784	863
Goodrich 220/33 (City of Pasadena)	293	289	289	289	288	287
Gould 220/66	136	136	138	140	143	156
Hinson 220/66	504	500	502	503	505	520
Johanna 220/66	511	525	584	600	605	661
La Cienega 220/66	522	521	517	520	523	541
La Fresa 220/66	722	718	728	730	740	768

Substation Load and Large Customer Load (1-in-10 Year Heat Wave)						
SUBSTATION	2011	2012	2013	2014	2015	2020
Laguna Bell 220/66	667	670	671	672	672	684
Lewis 220/66 (City of Anaheim)	536	537	544	547	553	559
Lighthipe 220/66	503	501	499	500	503	512
Mesa 220/66	631	630	636	638	644	663
Mira Loma 220/66	694	703	620	630	645	702
Moorpark 220/66	847	851	862	872	881	937
Olinda 220/66	388	388	393	397	403	432
Padua 220/66	620	611	619	624	628	642
Rio Hondo 220/66	701	699	703	708	711	737
San Bernardino 220/66	648	650	650	655	666	660
Santa Clara 220/66	608	614	624	632	641	692
Santiago 220/66	851	862	884	898	913	662
Saugus 220/66	797	928	949	970	990	1141
Valley 500/115	1099	1128	1168	783	806	844
Viejo 220/66	375	377	382	387	392	772
Villa Park 220/66	745	747	710	708	713	725
Vista 220/115	381	374	375	376	377	376
Vista 220/66	913	960	973	607	617	641
Walnut 220/66	649	647	653	654	659	681
Wilderness 220/66 (City of Riverside)	0	0	0	377	378	387
VALLEYSC	733	752	778	803	826	866

2.18.3 Study Results and Discussions

A summary of the study results of facilities in the Metro area under normal and various system contingency conditions is given below.

TPL 001: System Performance under Normal Conditions

- All facilities met the performance requirements under Category A normal conditions from 2011 to 2020.

TPL 002: System Performance Following Loss of a Single BES Element and ISO Category B (G-1/L-1)

- All facilities met the performance requirements under Category B contingency conditions from 2011 to 2020.

TPL 003: System Performance Following Loss of Two or More BES Elements

- All facilities met the performance requirements under Category C contingency conditions from 2011 to 2020.

2.18.4 Key Conclusions

The 2011 to 2019 summer peak and spring off-peak reliability assessment of the SCE Metro area resulted in no reliability concerns.

2.19 San Diego Gas & Electric Area

2.19.1 Area Description

SDG&E is a public utility that provides energy service to 3.4 million consumers through 1.4 million electric meters and more than 830,000 natural gas meters in San Diego and southern Orange counties. The utility's service area encompasses 4,100 square miles from Orange County to the Mexican border[22].

Presently, the SDG&E transmission system consists of the 500 kV Southwest Powerlink (SWPL) transmission line (North Gila - Imperial Valley-Miguel) and 230 kV, 138 kV and 69 kV transmission. When the *Sunrise Powerlink Project* is completed, presently scheduled for 2012, SDG&E will have an additional 500 kV line from the Imperial Valley substation to central San Diego to serve its load. SDG&E uses both imports and internal generation to serve the load. The geographical location of the SDG&E system is shown in Figure 2.19-1.

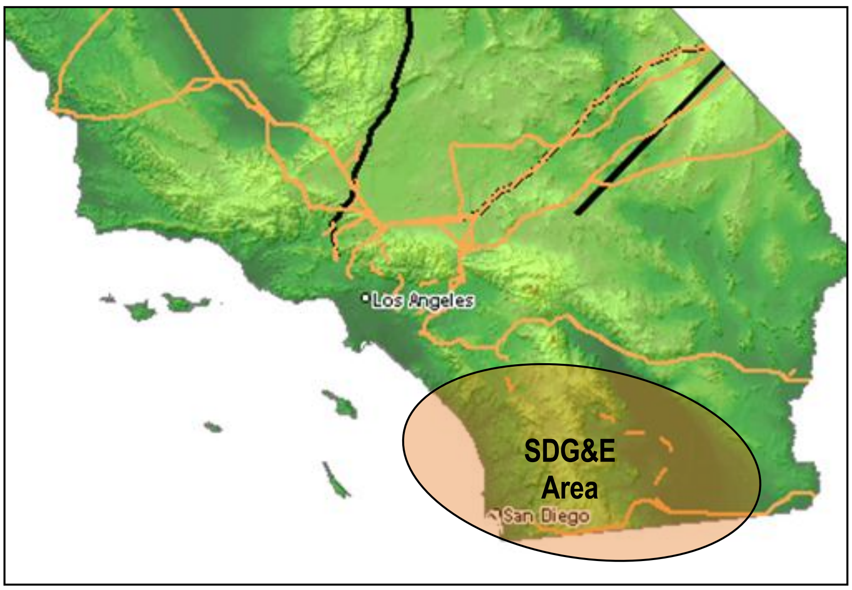


Figure 2.19-1: San Diego Area Illustration

The existing points of import are the South of San Onofre (SONGS) transmission path (WECC Path 44), the Miguel 500/230 kV substation and Otay Mesa –Tijuana 230 kV transmission line.

Historically, the SDG&E import capability was 2850 MW with all facilities in-service and 2500 MW with SWPL out-of-service. When the proposed *Sunrise Powerlink Project* is built (scheduled in-service for June 2012), import capability will be increased by at least another 1000 MW and the cut-plane of import will change by having the Imperial Valley-Suncrest 500 kV line flow added to the import into SDG&E.

22 These numbers are provided by SDG&E in the 2008 Transmission Expansion Plan

In addition to import, the SDG&E area is served by local generation. Existing generation within the SDG&E system is comprised of combustion turbines, QF, steam turbines (ST) at Encina, the combined cycle plants at Palomar Energy (PEN) and Otay Mesa Energy Center and one wind farm. Only generation that is under construction or that has received regulatory approvals was modeled.

The SDG&E transmission system consists of 500 kV SWPL transmission line (North Gila - Imperial Valley-Miguel) and 230 kV, 138 kV and 69 kV transmission. The 500 kV substations include Imperial Valley 500/230 kV and Miguel 500/230/138/69 kV.

The 230 kV system extends from the Talega substation and SONGS in Orange County in the north to the Otay Mesa substation in the south near the Mexican border. 230 kV transmission lines are with an outer loop located along the Pacific coast and around downtown San Diego.

The 138 kV transmission system underlies the 230 kV system from the San Luis Rey 230/138/69 kV Substation in the north to the South Bay and Miguel substations in the south. There is also a radial 138 kV arrangement with five substations interconnected to the Talega 230/138/69 kV substation in Orange County.

SDG&E sub-transmission system consists of numerous 69 kV lines arranged in a network configuration. Rural customers in the eastern part of the San Diego County are served exclusively by a 69 kV system and often by long lines with low ratings.

2.19.2 Area Specific Assumptions and System Conditions

The SDG&E area study was performed in accordance with the general study assumptions and methodology described in section 2.3. The ISO's secured website lists the contingencies that were evaluated as a part of this assessment. In addition, specific assumptions and methodology applied to the SDG&E area study are provided below in this section.

Generation

The studies performed for the heavy summer conditions assumed all available internal generation being dispatched at full output except for the South Bay power plant that was assumed to be retired and Kearney peakers which were assumed to be retired beyond 2014. The Category B contingency studies were also performed for one generation plant being out-of-service. The largest single generator contingencies were assumed to be the whole Otay Mesa Energy Center or PEN Center. These two power plants are combined-cycle plants; therefore, an outage of the whole plant has a high probability.

Existing generation included all five Encina steam units. They were assumed to be available during peak loads. A total of 946 MW of generating capacity can be dispatched based on the maximum capacity of each generating unit. PEN, owned by SDG&E, began commercial operation in April 2006. This plant is modeled at 565 MW for summer peak load reliability assessment.

South Bay power plant (689 MW and a 13 MW gas turbine) was assumed to be retired for the 2011-2015 and 2020 study scenarios. South Bay units 3 and 4 are already retired and the RMR status of units 1 and 2 was terminated on December 31, 2010.

The new combined cycle Otay Mesa power plant started commercial operation in October 2009. It was modeled in the studies with the maximum output of 603 MW.

There are several combustion turbines in San Diego. Cabrillo II owns and operates all but two of the small CTs in SDG&E's territory. Of the two not operated by Cabrillo II, Cabrillo I operates one at the Encina plant and the second was operated by Dynegy at the South Bay power plant. The CT at South Bay was assumed to be retired in the study, since it is scheduled to retire when the South Bay power plant retires. A total of 200 MW of generating capacity from CTs was modeled as dispatched during peak summer conditions.

QFs were modeled with the total output of 180 MW. Power contract agreements with the QFs do not obligate them to generate reactive power. Therefore, to be conservative, all QF generation explicitly represented in power flow cases was modeled with a unity power factor assumption.

Existing peaking generation modeled in the power flow cases included Calpeak Peakers located near Escondido (42 MW), Border (42 MW), and El Cajon (42 MW) substations, two Larkspur peaking units located next to Border substation with summer capacity of 46 MW each, two peakers owned by MMC located near Otay (35.5 MW) and Escondido (35.5 MW) substations, two SDG&E Peakers at Miramar substation (MEF), 46 MW each, El Cajon Energy Center (48 MW) and Cabrillo Power peakers at Miramar (36 MW aggregate) and El Cajon GT (13 MW). New peaking generation modeled in the studies included two units, 94 MW total, at Orange Grove adjacent to 69 kV Pala substation. The Orange Grove peaking plant (94 MW) has currently completed construction and has started commercial operation in 2010.

Renewable generation included in the model is the 50 MW Kumeyaay Wind Farm that began commercial operation in December 2005, Lake Hodges pump-storage plant (40 MW) that is presently under construction and planned to start operation in July 2011, and a future Bull Moose Biomass plant (27 MW) which is planned to be in-service by May 2011. The Bull Moose and Lake Hodges plants were modeled in the power flow cases, but if these projects do not materialize, these units will not be modeled in future study cases.

In addition to the generation plants internal to San Diego, there is 1,070 MW of existing thermal power plants connected to the 230 kV bus of the Imperial Valley 500/230 kV substation. There are several renewable generation projects (solar and wind) expected to be developed in this area. These are modeled and handled in the 33% renewable study carried out as part of this transmission plan.

The SONGS was modeled with two units on-line at maximum output for the summer peak load conditions.

Internal generation in San Diego modeled in the case is summarized in Table 2.19-1.

Table 2.19-1: Generation plants in the SDG&E area

Generation Plants	Max. Capacity (MW)	Note
South Bay 1	145	assumed retired
South Bay 2	149	assumed retired
South Bay 3	174	assumed retired
South Bay 4	221	assumed retired
Encina 1	106	
Encina 2	103	
Encina 3	109	
Encina 4	299	
Encina 5	329	
Palomar	541	
Otay Mesa	573	
South Bay GT	13	assumed retired
Encina GT	14	
Kearny GT1	15	assumed retired
Kearny 2AB (Kearny GT2)	55	assumed retired
Kearny 3AB (Kearny GT3)	57	assumed retired
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	
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	

Generation Plants	Max. Capacity (MW)	Note
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	
Shadowridge	0.1	
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	
Bullmoose (NQC)	27	
Lake Hodges Pumped Storage	40	

Load Forecast

Loads within the SDG&E system reflect a coincident peak load for 1-in-10-year heat wave conditions. The load for the year 2015 was assumed at 5234 MW and transmission losses were 114 MW. The load for the year 2020 was assumed at 5554 MW and transmission losses were 117 MW. SDG&E substation loads were assumed according to the data provided by SDG&E and scaled to represent assumed load forecast. The total load in the power flow cases was modeled based on the load forecast by the CEC. Table 2.19-2 summarizes load in SDG&E and the neighboring areas and SDG&E import modeled for the study horizon.

Table 2.19-2: Load and losses in SDG&E study

PTO	2011		2012		2013		2014		2015		2020	
	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW
SDG&E	4937	97	5034	86	5123	90	5172	102	5234	114	5554	117
SCE	25585	471	26245	408	26245	409	27449	417	27449	412	28432	465

PTO	2011		2012		2013		2014		2015		2020	
	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW	Load, MW	Losses, MW
IID	1056	32	1080	46	1107	47	1131	41	1163	43	1308	45
CFE	2223	32	2935	35	2935	35	2820	34	2820	34	3413	49
SDG&E Import	2101		2255		2365		2302		2472		2787	

Power flow cases for the study modeled a load power factor of 0.992 lagging at nearly all load buses. This number was used because SCADA-controlled distribution capacitors are installed at each substation with sufficient capacity to compensate for distribution transformer losses. The 0.992 lagging value is based on historical system power factor during peak conditions. The exceptions listed below were modeled using power factors indicative of historical values. This model of the power factors was consistent with the modeling by SDG&E for planning studies. Periodic review of historical load power factor is needed to ensure that planning studies utilize realistic assumptions.

- Naval Station Metering (bus 22556): 0.707 lagging (this substation has a 24 MVAr shunt capacitor);
- Creelman (bus 22152): 0.992 leading; and
- Descanso (bus 22168): 0.901 leading.

2.19.3 Study Results and Discussions

The ISO's assessment of the SDG&E transmission system identified two overloads that may occur under normal system conditions with all facilities in-service. One overload was on the Boulevard – Crestwood 69 kV line starting after 2015 under Category A conditions. The other Category A overload was observed on Mesa Heights – Mission 69 kV line starting in 2020.

None of the buses resulted in voltages below the limits specified in the reliability criteria under the Category A performance requirements.

The assessment also identified 25 transmission facilities that may overload under Category B contingency conditions under an assumption that all available generation is dispatched. There were additional 58 facilities that may overload under Category C contingency conditions. Category B contingency conditions included single facilities contingencies, as well as contingencies of single transmission facilities with one generation unit out-of-service. Category C contingencies included contingencies of two facilities and conditions when a transmission facility was out-of-service followed by another single transmission facility outage.

The ISO studies identified voltages below permitted levels on seven 69 kV buses for Category B contingencies. Twelve 69 kV load buses were identified as having voltage deviations that did not meet the reliability criteria for Category B contingencies.

Most of the overloads observed in the analysis of the off-peak case were already seen in the peak case analysis. Only one additional facility did not meet the Category B contingency performance requirement.

Transient stability studies did not show any reliability performance concerns for the Category B and Category C contingencies studied. The studies also did not identify any voltage stability (reactive margin) concerns.

Studies of the extreme contingencies (Category D) did not identify potential cascading contingencies.

2011 through 2015 SDG&E Area Assessment Summary

For the overall SDG&E transmission and sub-transmission systems, the 2015 studies identified the need to:

- Strengthen the 69 kV system in Barrett area;
- Mitigate the 69 kV system issues in El Cajon area using generation;
- Strengthen the 69 kV system in Kearney area;
- Strengthen the 69 kV system in Melrose area;
- Reconductor South Bay – Sweetwater 69 kV line; and
- Mitigate the 69 kV system issues in Sycamore area using Miramar generation.

2020 SDG&E Area Assessment Summary

For the overall SDG&E transmission and sub-transmission systems, the 2020 studies identified the need to implement the following, in addition to the upgrades/mitigations listed in the 2015 studies:

- Dispatch one Orange Grove peaking unit for peak load conditions (to prevent emergency overload of the San Luis Rey-Morro Hill 69 kV line); and
- Consider switching options or reconductoring to mitigate an overload on Talega Tap – Laguna Niguel 138kV line.

The study evaluated the system reliability of SDG&E area under NERC/WECC and the ISO Category A, B, C and D contingencies.

Power Flow Study Results

TPL 001: System Performance under Normal Conditions

For the summer peak cases, there were two 69 kV transmission lines with an identified overload with all facilities in service – Boulevard – Crestwood and Mesa Heights - Mission. The ISO studies showed overloads beyond 2019 over the normal rating.

None of the buses demonstrated voltages below the limits specified in the reliability criteria under Category A performance requirements.

TPL 002: System Performance Following Loss of a Single BES Element, and ISO Category B (N-1[23]/G-1)

For the summer peak cases, there were 25 facilities identified with thermal overloads for contingencies of a single transmission facility or a single transmission facility with one generator out-of-service. The overloaded facilities were the following:

- Boulevard – Crestwood 69 kV line;
- Boulder Creek Tap – Descanso 69 kV line;
- Boulder Creek Tap – Santa Ysabel 69 kV line;
- Descanso – Glencliff Tap 69 kV line;
- Warners – Rincon 69 kV line;
- El Cajon – Los Coches 69 kV line;
- Mesa Heights – Mission 69 kV line;
- Kearney – Mission 69 kV line;
- Mission – Clairmont 69 kV line;
- Melrose – Melrose Tap 69 kV line;
- Melrose – San Luis Rey 69 kV line;
- Morro Hill Tap – San Luis Rey 69 kV line;
- Pendleton – San Luis Rey 69 kV line;
- Pomerado – Sycamore 69 kV line 1;
- Pomerado – Sycamore 69 kV line 2;
- Poway – Rancho Carmel 69 kV line;
- South Bay – Sweetwater 69 kV line;
- South Bay – Montgomery Tap 69 kV line;
- Sweetwater – Montgomery Tap 69 kV;
- Sweetwater – Sweetwater Tap 69 kV line;
- Sycamore – Scripps 69 kV line;
- Talega Tap – Laguna Niguel 138kV line;
- Pala – Monserate Tap 69 kV line;
- Mission 138/69 kV bank 50; and
- Los Coches 138/69 kV bank 50.

These overloads and the proposed mitigation measures are summarized in Appendix A.

For the off-peak cases, there was one additional overload for Category B contingency of Imperial Valley 500/230 kV transformer bank #80. Only two existing 500/230 kV transformer banks were modeled at Imperial Valley. Installation of the third bank to be implemented with a generation project interconnection will mitigate this overload. Prior to the bank installation, the overload may be mitigated by generation dispatch.

[23] N-1 is a single transmission circuit outage.

Under Category B contingencies and the peak load conditions, there were seven 69 kV load buses with voltages below what is allowed by the criteria, and eleven 69 kV load buses with voltage deviations not meeting the criteria requirements.

The following buses had low voltage for Category B contingencies:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Descanso 69 kV;
- Glencliff 69 kV; and
- Crestwood 69 kV.

The following buses had large voltage deviations:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Borrego 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Crestwood 69 kV;
- Descanso 69 kV;
- Glen Cliff 69 kV;
- Narrows 69 kV;
- Santa Ysabel 69 kV;
- Warners 69 kV; and
- Poway 69 kV.

No voltage concerns were identified for the off-peak conditions. These voltage concerns and the proposed mitigation measures are summarized in Appendix A.

TPL 003: System Performance Following Loss of Two or More BES Elements

Category C contingencies studied included:

- Outage of a single transmission facility with generation adjusted followed by another single facility outage (N-1-1);
- Outage of two transmission lines in the same corridor (N-2);
- Stuck circuit breaker; and
- Outage of a bus or a bus section.

For the summer base cases, there are 58 facilities with identified thermal overloads for Category C contingencies in addition to the facilities that overload for Category B contingencies. These overloads and the proposed mitigation measures are summarized in Appendix A.

None of the buses experienced voltages below the standard's requirement for Category C contingency.

TPL 004: System Performance under Extreme Events

As a Category D contingency, a common corridor outage of the transmission lines north of Miguel was studied. This outage is plausible, even if very unlikely, since the lines are in the common corridor. Transmission lines in the North-of-Miguel corridor include:

- Miguel-Sycamore Canyon 230 kV;
- Miguel-Mission #1 and #2 230 kV;
- Otay Mesa-Sycamore Canyon 230 kV;
- Miguel-Los Coches 138 kV and 69 kV; and
- Miguel-Jamacha #1 and #2 69 kV.

The case converged with no indication of cascading failures or major overloads for the system conditions studied.

Another common corridor contingency involving more than two transmission circuits is an outage of transmission lines from San Onofre to San Luis Rey. This transmission corridor includes the following lines:

- San Onofre-San Luis Rey 230 kV #1,2, and 3

The studies of this common corridor Category D contingency for the peak summer conditions of 2020 showed that there would be no cascading contingencies and no overloads for the system conditions studied.

Also, a Category D outage of the transmission lines north of San Onofre was studied. This contingency includes the following transmission lines:

- San Onofre-Talega 230 kV #1 and #2;
- Talega-San Mateo 138 kV;
- Talega-Japanese Mesa 69 kV; and
- San Mateo-Laguna Niguel 138 kV.

The studies did not show any possibility of cascading contingencies. No overloads were observed for this Category D contingency under the assumed system conditions.

Category D contingencies of loss of major power plants in SDG&E were also run as part of the reliability assessment. Loss of Otay Mesa, Palomar, Encina and SONGS generation plants were tested one at a time. These extreme contingencies did not show possibility of cascading contingencies.

NUC-001: System Performance under scenarios that can affect SONGS

The technical studies were conducted in compliance with the NUC-001 standards annually as part of the transmission plan. Post-transient governor power flow and transient stabilities were conducted to assess the performance related to SONGS under normal and emergency conditions. In this planning cycle, the studies were conducted on the following scenarios:

- 2011 summer peak; and
- 2015 summer peak.

Several contingencies were run in SDG&E area for thermal, voltage and stability concerns. These contingencies included:

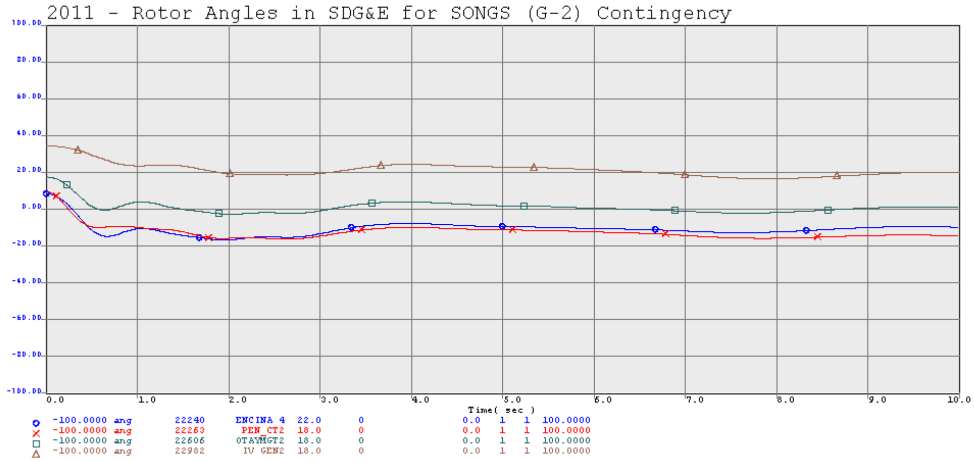
- Loss of a single SONGS unit (G-1);
- Loss of two SONGS units (G-2);
- All critical contingencies of transmission lines connected to SONGS (Category B, C and D);
- Loss of major generation plants in SDG&E area;
- Loss of critical transmission lines and interties in SDG&E system;
- Critical bus section contingencies in SDG&E area; and
- Loss of entire load at Bernardo substation (largest load block in SDG&E's service territory according to the information provided in the base case).

The base cases modeled all transmission circuits connected to SONGS switchyard with the status normally in-service. The study results showed that:

- The steady state voltage at SONGS 230 kV switchyard was 230 kV under 2011 summer peak conditions and 230 kV under 2015 summer peak conditions. This is within the range specified by Transmission Control Agreement for SONGS (218kV to 234kV); and
- The SONGS generator is regulating the 230 kV bus voltage to 1.00 per Unit in 2011 summer peak case and in 2015 summer peak case.

The study results from various studies show that there are no thermal overloads, voltage or stability concerns related to the SONGS units under normal or emergency conditions. The following plots for two of the most severe contingencies and for a sudden loss of load demonstrate that there are no stability concerns related to SONGS units.

Figure 2.19-2: Rotor Angles in SDG&E for SONGS (G-2) Contingency



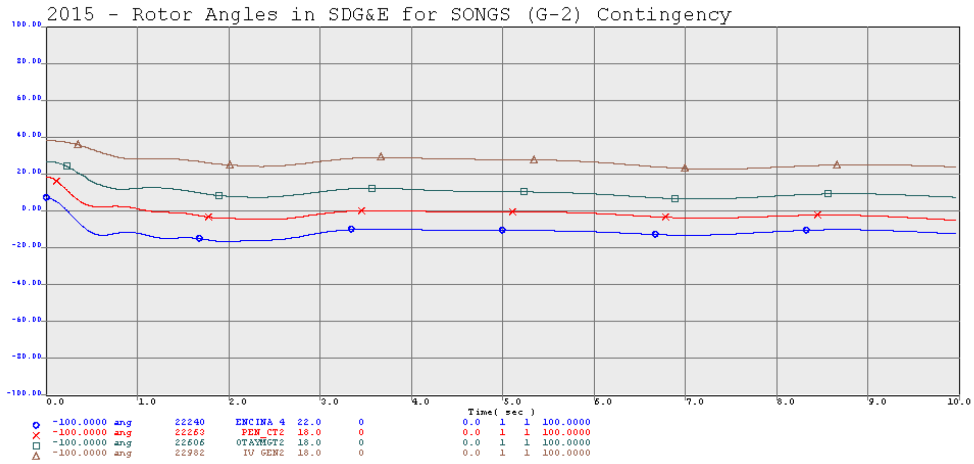


Figure 2.19-3: System Performance under SWPL and (SWPL+Sunrise) Contingency

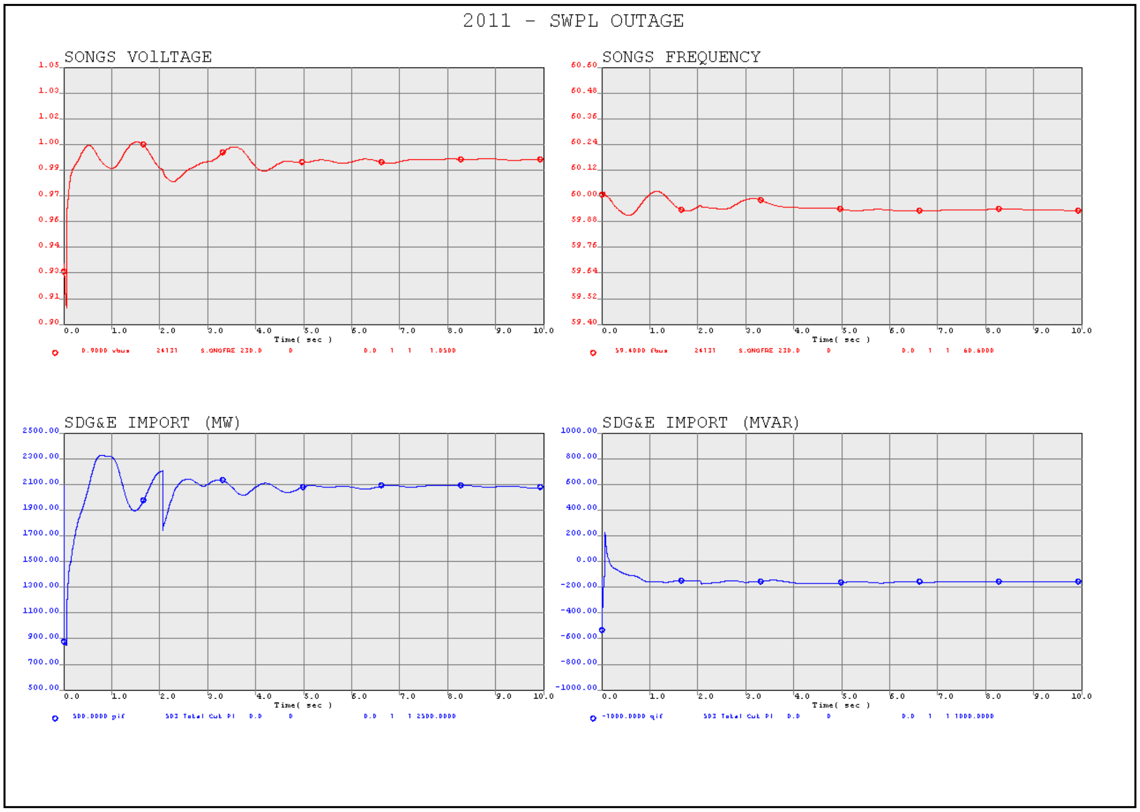
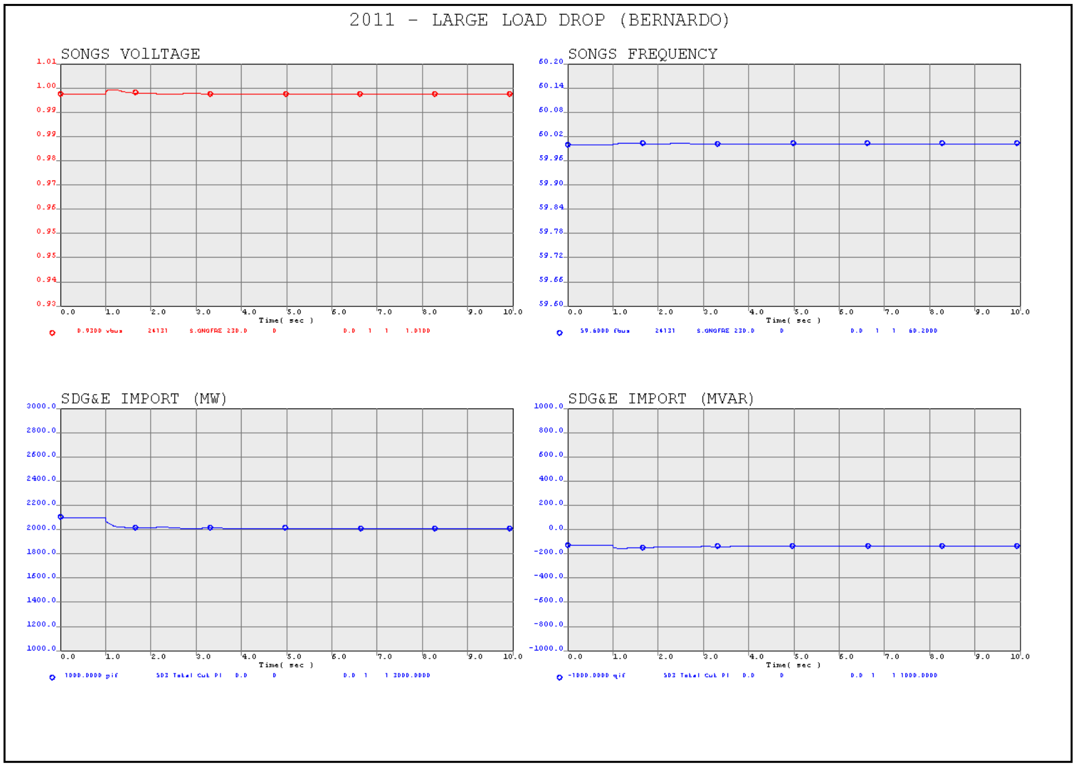
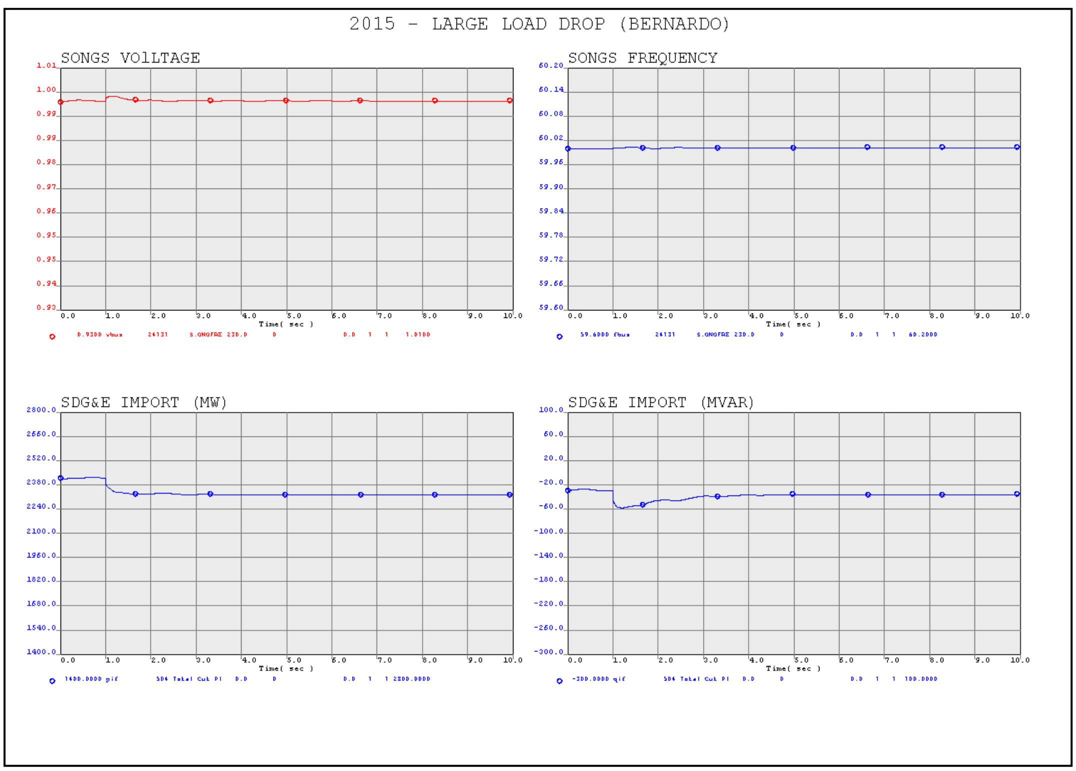


Figure 2.19-4: System Performance under Sudden Loss of Load





Transient Stability Studies

All major 500 kV and 230 kV contingencies were studied for the year 2020. Scenarios analyzed included critical Category B, C, and D contingencies based on historical and expected operation. Three-phase faults were modeled on the sending end bus of transmission lines. Duration of the fault was modeled as four cycles for 500 kV and six cycles for 230 kV. The faults were cleared by opening of the lines. The contingencies that were studied included:

- Imperial Valley-Miguel 500 kV with and without CFE cross trip;
- Hassayampa-North Gila 500 kV;
- Imperial Valley-North Gila 500 kV;
- Palo Verde-Devers 500 kV;
- Imperial Valley-Suncrest 500 kV (planned);
- Intermountain-Adelanto DC;
- Pacific DC Intertie bipolar;
- Sycamore-Suncrest 230 kV (planned) #1 and #2;
- Miguel-Mission #1 and #2;
- North of Miguel corridor;
- Palomar-Escondido #1 and #2 230 kV;
- Palomar-Encina 230 kV;
- Palo Verde-Devers 500 kV;
- Lugo-El Dorado-Mohave 500 kV;
- SONGS generator #2;
- Palo Verde generator #2;
- Diablo generators #1 and 2;
- SONGS generators #2 and #3; and
- Palo Verde generator #1 and #2.

No unacceptable performance levels were found. The analysis indicates acceptable transient stability performance for all of the contingencies.

Studies of the Category D outage North of Miguel simulated a three-phase six-cycle fault on the Miguel 230 kV bus cleared by opening all transmission lines north of Miguel: Miguel-Sycamore Canyon 230 kV, Miguel-Mission #1 and #2 230 kV, Otay Mesa-Sycamore Canyon 230 kV, Miguel-Los Coches 138 kV and 69 kV and Miguel-Jamacha #1 and #2 69 kV. The study showed that the system was stable with acceptable transient stability performance.

Post Transient and Voltage Stability Studies

Post-transient studies for the Imperial Valley-Miguel 500 kV outage did not show any problems for the cases studied even without SPS. This can be explained by the addition of the *Sunrise Powerlink Project*, starting with 2012 period as provided by SDG&E. Studies of all Category B contingencies in the San Diego area with the SDG&E load increased by 5% in 2020 and the import to San Diego increased by 5% in 2020 did not show any need for additional reactive support due to insufficient reactive margin.

Voltage stability analysis was also performed for the Category D outage of North of Miguel. This outage was studied for the case of 2020. This contingency did not show any need for additional reactive support or did not result in any overloads or under-voltage problems.

Impact of the SDG&E Contingencies on the Neighboring Systems

Historically, Imperial Valley-Miguel 500 kV outage caused overloads in the CFE system. These overloads are mitigated by cross tripping either Imperial Valley-La Rosita or Otay Mesa-Tijuana 230 kV lines in case of overload via using an automatic SPS. Addition of the *Sunrise Powerlink Project* will reduce loading concerns in the CFE with the Imperial Valley-Miguel outage. Power flow and post-transient (governor power flow) studies for 2011 through 2015 as well as for 2020 did not show overloads on the CFE system for the Imperial Valley-Miguel outage. Existing RAS for the Imperial Valley-Miguel outage also trips all generation units connected to the Imperial Valley 230 kV bus. The ISO recommends revision of the existing RAS when the *Sunrise Powerlink Project* comes into service because such extensive generation tripping may not be needed with the additional 500 kV transmission line.

2.19.4 Recommended Solutions for Facilities Not Meeting Thermal and Voltage Performance Requirements

In this section, study results and proposed mitigation plans for the San Diego area under each category of the planning standards are shown.

Normal Conditions (TPL 001)

For the summer peak cases, there were two 69 kV transmission lines that were expected to overload with all facilities in service – Boulevard – Crestwood 69 kV line and Mesa Heights – Mission 69 kV line. These lines may overload for Category B and C contingencies as well. Both the overloads show up between 2015 and 2020. The Boulevard – Crestwood 69 kV line overload will be mitigated by a project submitted by SDG&E for looping in TL625 (Loveland – Barrett Tap 69 kV line) line into Loveland substation. This project is needed and described in detail under the Barrett 69 kV Area discussion in the section below. Also, a proposed terminal equipment upgrade will take care of this problem. The Mesa Heights – Mission 69 kV line overload can be mitigated by dispatching Miramar peakers and SDG&E submitted a project to reconductor this line as part of Kearney area upgrades. The project is needed and discussed in detail under Kearney 69 kV Area discussion in the section below.

There were no buses with voltage below the limits specified in the reliability criteria under the Category A performance requirements in 2020.

Emergency Conditions – Loss of a Single BES Element (TPL 002)

Power flow studies were performed for N-1 conditions (Category B) with all major power plants in-service and for N-1, G-1 conditions with the Otay Mesa or PEN generation out. Outage of the Otay Mesa power plant is the largest G-1 contingency in San Diego. Each of Category B contingencies was studied for the years 2011 through 2015 as well as for 2020. The power flow studies of Category B contingencies identified the following overloads.

500/230 kV System

No overloads or voltage concerns were identified on the 500 kV or 230 kV systems in the cases studied.

138 kV System

Orange County Area

Talega Tap – Laguna Niguel 138kV line overload was observed for an outage of the parallel Talega - Pico 138 kV line starting in 2020. SDG&E submitted a project, TL13835B Laguna Niguel, - Talega Tap Mitigation, to reconductor the line. The ISO is considering reconductoring as a conceptual mitigation. Because the overload seen in 2020 is only 1%, the ISO recommends further evaluation in a future planning cycle.

Los Coches 138/69 kV bank #50

Los Coches 138/69 kV bank 50 may experience an overload for the loss of Los Coches 138/69 kV bank 51. The observed Category B overload was 5% in 2020, and will be higher with non-simultaneous peak load in Los Coches area. Existing rating of bank 50 is 180 MVA. The ISO identified Category B overloads starting in 2014 under non-simultaneous peak load assumption. Generation connected to El Cajon is not sufficient to mitigate this problem for the duration of the study window. A project submitted by SDG&E in the 2010 request window, Upgrade Los Coches 138/69 kV Bank 50, will replace the existing 180 MVA bank with a new 224 MVA bank, with proposed in-service date of 2013. The ISO has determined that this reliability project is needed.

69 kV System

Barrett 69 kV Area

This area may experience four overloads for the loss of a single element:

- Boulder Creek Tap - Descanso 69 kV line;
- Boulder Creek Tap – Santa Ysabel 69 kV line;
- Descanso – Glencliff Tap 69 kV line; and
- Warners – Rincon 69 kV line.

All these elements become overloaded for the same contingency of the 3-terminal TL625 (Loveland – Barrett – Descanso 69 kV line) starting in 2015. Low voltages and voltage deviations are also observed due to this contingency. Also, an L-1/G-1 contingency of Loveland – Barrett – Descanso 69 kV line and Otay Mesa power plant causes following undervoltages in this area:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Descanso 69 kV;
- Glencliff 69 kV; and
- Crestwood 69 kV.

Contingency of Loveland – Barrett – Descanso 69 kV line also creates voltage deviations at following buses in this area:

- Barrett 69 kV;
- Boulder Creek 69 kV;
- Borrego 69 kV;
- Boulevard 69 kV;
- Cameron 69 kV;
- Crestwood 69 kV;
- Descanso 69 kV;
- Glen Cliff 69 kV;
- Santa Ysabel 69 kV; and
- Warners 69 kV.

In addition, a contingency of Warners – Narrows 69 kV line creates voltage deviation problem at Narrows 69 kV bus.

The proposed solution is to remove Barrett Tap and create two new lines: Loveland-Descanso 69 kV and Loveland-Barrett 69 kV. This upgrade mitigates overloads as well as undervoltage and voltage deviation problems. This solution appears to be more effective than reconductoring all of the overloaded line sections. SDG&E's proposed in-service date is 2013 which should mitigate this potential problem in time. The ISO has determined that the need to eliminate Barrett tap and loop-in TL625B into Loveland substation exists and is addressed by the *TL625B Loop-in, Loveland – Barrett Tap Project* submitted by SDG&E in the 2010 request window with proposed in-service date of 2013. In the interim the ISO is authorizing the advancement of Barrett and Crestwood 69 kV capacitor installation to mitigate the voltage deviation problem in Barrett area. These capacitors are part of a previously approved project, *New and/or Upgrade 69 kV Capacitors* (approved as a part of 2010 transmission plan).

Request Window Submission – Barrett Interim Solution

Another project submitted in this area was *Barrett Interim Solution* by TTS. The project scope included installation of -40/+50 MVAr SVC at Barrett 69 kV substation (proposed in-service date of October, 2012). The need identified by this project will be mitigated by a long-term project (TL625B loop-in) with a proposed in-service date of June, 2013, which was deemed to be a needed reliability upgrade. ISO tariff section 24.4.6.2 provides that the PTO with service territory in which the transmission upgrade or addition deemed needed under this section 24 will have the responsibility to construct, own and finance and maintain such transmission upgrade or addition. The ISO evaluated the *Barrett Interim Solution* to determine whether SDG&E should pursue this alternative. The ISO found that the interim need is best mitigated by advancing the previously approved installation of capacitors at Barrett 69 kV and Crestwood 69 kV substations. The advancement of capacitors is more cost effective than the *Barrett Interim Solution*, hence the *Barrett Interim Solution* is not needed.

Request Window Submission – TL682 Warner-Rincon Reconductor Project

SDG&E submitted a project, the *TL682 Warner-Rincon: Reconductor Project* to mitigate the overload on Rincon – Warner 69 kV line. The project *TL625B Loop-in, Loveland – Barrett Tap* mitigates this overload and is more cost effective compared to reconductoring the line. Hence the *TL682 Warner-Rincon: Reconductor Project* is not needed.

El Cajon – Los Coches 69 kV line

This line may become overloaded for the contingency of Los Coches – Granite Tap – Miguel 69 kV line starting in 2014. The overload was observed only under a high-import scenario which was higher than the feasible import level observed in the 33% renewable scenario. SDG&E proposed the *Reconductor TL631, El Cajon-Los Coches Project* to mitigate this problem. The ISO studies demonstrated that EL Cajon peakers can sufficiently mitigate this concern for the study horizon. The need for this project will be evaluated in the next planning cycle. Instead of reconductoring this line, the ISO recommends using El Cajon peakers to mitigate any overload issue.

Kearney 69 kV Area

Three lines in Kearney 69 kV area may become overloaded for the loss of a single element.

- Mesa Heights – Mission 69 kV line;
- Kearney – Mission 69 kV line; and
- Mission – Clairmont 69 kV line.

For the loss of one of these three lines, the remaining lines become overloaded starting in 2015. Kearney peakers and Miramar peakers can be used to mitigate these overloads. The site lease for Kearney peakers is going to expire in 2013, and there are no plans to re-power the site. Miramar peakers are sufficient to mitigate this problem only up to 2017. Starting in 2017 and beyond, to mitigate these overloading concerns, SDG&E submitted projects to reconductor 3 lines (Mission - Kearney 69 kV, Mission – Clairmont 69 kV and Mission –

Mesa Heights 69 kV), with a proposed in-service date of 2015. The ISO finds these projects are needed to address the identified reliability concerns.

SDG&E also proposed the *Upgrade Mission 138/69 kV Transformer Banks 51 and 52 Project*. This overload on Mission banks 51 and 52 for the loss of the bank 50 may show up in 2020 as a 3% overload. The proposed in-service date for this project is June 2015, assuming an approval during 2010/2011 planning cycle. Because the overload does not occur until 2020, the ISO will evaluate the proposed project in a future planning cycle.

Melrose 69 kV Area

Two lines in Melrose area overload following the loss of a single element:

- Melrose – Melrose Tap 69 kV line; and
- Melrose – San Luis Rey 69 kV line.

Contingency of San Luis Rey – Melrose 69 kV line causes these overloads starting around 2015. Reconductoring these lines was considered by the ISO, but looping TL694A (San Luis Rey – Morro Hill) into Melrose substation solves these issues as well as one overload in Pendleton 69 kV area. This project was submitted by SDG&E in the 2010/2011 request window as the *TL694A San Luis Rey-Morrow Hills Tap: Reliability Project* with a proposed in-service date of 2012. It is the most cost effective solution and the ISO has determined that the project is needed.

Other reconductor projects proposed by SDG&E and considered by the ISO were the *TL693 San Luis Rey-Melrose: Reconductor Project,* the *TL694A San Luis Rey-Morrow Hills Tap: Reliability* Project and the *TL680B – Melrose-Melrose Tap: Reconductor Project*. These three projects were found not to be needed because *TL694A San Luis Rey-Morrow Hills Tap: Reliability Project* mitigates all these overloads and is more cost effective than reconductoring individual lines.

Pendleton 69 kV Area

This area experienced two overloads for the loss of a single element. The first overload is seen on Morro Hill Tap – San Luis Rey 69 kV line for the loss of Pendleton – San Luis Rey 69 kV line starting in 2013. This overload can be mitigated by dispatching Orange Grove peakers. But the approval of TL694A loop-in into Melrose substation solves this overload issue as mentioned in the Melrose 69 kV area discussion above.

Another overload observed in this area is Pendleton – San Luis Rey 69 kV line for the loss of Monserate – Morro Hill – San Luis Rey 69 kV line. SDG&E submitted a project -’ *TL6912 - Reconductor San Luis Rey-Pendleton*’. This overload may show up in 2020 with an extent of only about 1%. The ISO recommends using Pala generators to mitigate this overload. The need for this upgrade will be evaluated again during the next planning cycle.

Pomerado 69 kV Area

Three lines in this area show overloads for the loss of a single element

- Pomerado – Sycamore 69 kV line 1;
- Pomerado – Sycamore 69 kV line 2; and
- Poway – Rancho Carmel 69 kV line.

Loss of Pomerado – Sycamore 69 kV line 1 or 2 overloads the remaining line. Poway – Rancho Carmel 69 kV line gets overloaded for the loss of Sycamore – Artesian 69 kV line. All these overloads are seen in 2015 study case. The ISO considered the option of reconductoring these three lines. SDG&E also submitted a project to construct a new 69 kV line between Sycamore and Bernardo substations. This line will utilize the vacant side of the towers for TL13820 and 13825. This new Sycamore – Bernardo 69 kV line would eliminate the need to reconductor three aforementioned lines. SDG&E submitted two projects: *TL648, Poway – Rancho Carmel: 69 kV Reconductor Project* and *TL6915 & TL6924 Sycamore-Pomerado #1 & #2: Reconductors Project* to reconductor the three lines mentioned here. Building a new Sycamore – Bernardo 69 kV line is a more cost effective alternative and will improve the outlet capability of Sycamore substation. The ISO has determined that building a new Sycamore – Bernardo 69 kV line, submitted by SDG&E in the 2010-2011 request window with a proposed in-service date of 2015, to be needed and therefore the projects to reconductor the three lines are not needed.

Loss of Poway – Pomerado 69 kV line creates 5% voltage deviation at Poway 69 kV bus. This deviation is observed only in the 2020 study case, and will be further evaluated in future planning cycles.

Sweetwater 69 kV Area

This area experiences four overloads for the loss of a single element. The overloaded lines are –

- South Bay – Sweetwater 69 kV line;
- South Bay – Montgomery Tap 69 kV line;
- Sweetwater – Montgomery Tap 69 kV; and
- Sweetwater – Sweetwater Tap 69 kV line.

South Bay – Sweetwater 69 kV line becomes overloaded for the loss of Montgomery – Sweetwater – South Bay 69 kV line starting in 2013. The rest of the overloads are caused by Silvergate – South Bay 230 kV line contingency. The ISO has determined that the project to reconductor *South Bay – Sweetwater 69 kV Line*, submitted by SDG&E in the 2010-2011 request window with proposed in-service date of 2013 is needed to mitigate reliability concerns. The remaining three overloads will be mitigated by two re-rate/terminal equipment upgrade projects submitted by SDG&E – *TL642A, South Bay – Montgomery Tap – Terminal Equipment* and *TL603B, Sweetwater – Sweetwater Tap – Terminal Equipment*. Both projects were submitted as information only projects and the ISO concurs with these mitigations.

Sycamore 69 kV Area

Sycamore – Scripps 69 kV line may experience overload in 2015 due to the loss of Otay Mesa – South Bay 230 kV line under high import scenario where the import assumption is even higher than the one in 33% renewable study. SDG&E submitted the *TL6916, Sycamore-Scripps Overload Mitigation Project*. This project proposed to build a new Sycamore Canyon – Miramar 69 kV line. The ISO recommends using Miramar peakers to mitigate this issue. The peakers can provide sufficient mitigation even beyond 2020; hence the project is not needed.

Another project was submitted, *Los Coches Substation 230 kV Expansion Project*, which in addition to improving system reliability would solve this overload problem. This project seems to mitigate the overload on Sycamore – Scripps 69 kV line, but the ISO recommends using Miramar peakers for that purpose. Thus this project is not needed as a reliability project. In addition, this project claims to serve the cause of renewable integration by providing additional outlet for generation at Imperial Valley. These advantages were considered in developing the mitigation plan for the 33% renewable study which is part of this transmission plan. These factors are properly considered in the ISO's assessment of needed policy-driven transmission projects.

SDG&E also proposed the *TL633, Bernardo – Rancho Carmel 69 kV: Reconductor Project*. This line reaches its capacity in 2020, but does not show a severe overload. Area peakers are sufficient to mitigate this concern for the study horizon. The need for this upgrade will be further evaluated in a future planning cycle.

San Diego Area Reactive Support

SDG&E proposed the *Install Synchronous Condensers at Mission, Penasquitos and Talega 230 kV Substations Project* to address and anticipated need for reactive sources and sinks in the area. The reliability assessment performed by the ISO did not identify any issues that can be mitigated by these upgrades. These upgrades can solve an expected issue of reactive source-sink availability if and when Encina plant is retired. But there is a possibility of Encina re-powering and at this point of time the ISO has identified this project as a potential solution for voltage stability. The need will be evaluated in future planning cycles as the generation retirement issue becomes clearer.

Another reactive support project, *Add one 138 kV 43 MVAR Capacitor at Telegraph Canyon Substation Project* was submitted by SDG&E. A fast-track approval was requested for this project. Based on verification of SDG&E area load power factor and verification of reactive capability of Encina unit 5, the ISO concluded that the capacitor was not required at this point. The need for this reactive support will be evaluated in future planning cycles.

Emergency Conditions – Loss of a Two or More BES Elements (TPL 003)

In addition to the transmission facilities that would overload for Category B contingencies, there were additional transmission lines that may overload for Category C contingencies.

For these overloads that are listed in Appendix A, the NERC reliability standards allow for controlled load curtailment. The ISO recommends developing operating procedures or SPSs to drop load or generation for these contingencies.

The list of overloaded facilities and proposed mitigations is shown in Appendix A.

Mission-Old Town Area

SDG&E proposed the *Reconfigure TL23013 and TL23028 Project* for this area. The scope of this project includes converting TL23013 from a bundled line into two single conductor 230 kV lines and reconfiguration between Silvergate, Penasquitos, Old Town and Mission 230 kV substations. This project would eliminate the need to shed load under an extreme contingency which includes the loss of Otay Mesa power plant and TL50001 and TL23013 which is a (G-1/N-1 + N-1) contingency. After the *Sunrise Powerlink Project* comes into service, this scenario will be even more unlikely as it will have to be a (G-1/N-2 + N-1) contingency, hence this project is not needed.

Orange County Area

The southern Orange County area in SDG&E's service territory demonstrates multiple Category C-driven issues by 2020. More than 40 combinations of contingencies can result in load shed in the southern Orange County area. Some of these problems are existing ones and there are SPSs to address these issues. Detailed contingency analysis results are presented in Appendix A. There are more than 40 contingencies that result in overloads in 2020 and the number is more than 70 beyond 2025. The ISO standards do not recommend using SPS that looks at more than six contingencies causing more than four elements to get overloaded. This highlights the need for a reliability upgrade in the area. Southern Orange County is fed by a single 230 kV source at Talega. Failure of certain components in this area under maintenance conditions can result in loss of entire South Orange County load which is expected to be about 523 MW by 2020. There are 16 combinations of credible contingencies just at Talega substation which result in loss of partial or complete Orange County load under maintenance condition. Historical planned outage data reveals that 'load at risk' notifications have been part of several planned outages in recent past. These notifications are issued when more than 100 MW of load is at risk during planned outage conditions. In 2009-2010, 'load at risk' notifications were issued on 50 days. This indicates that any maintenance work at Talega substation or at several other 138kV facilities frequently results in an increased risk of loss of load on the southern Orange County system. Loss of this load is also an existing concern due to the topology in this area. The proposed solution and alternatives have proposed in-service date of June 2015.

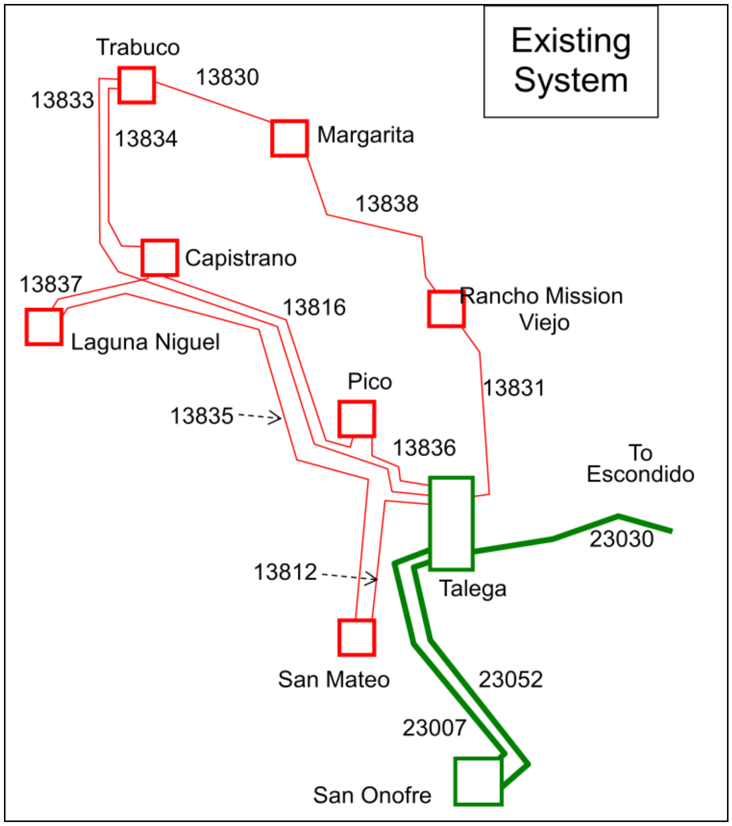


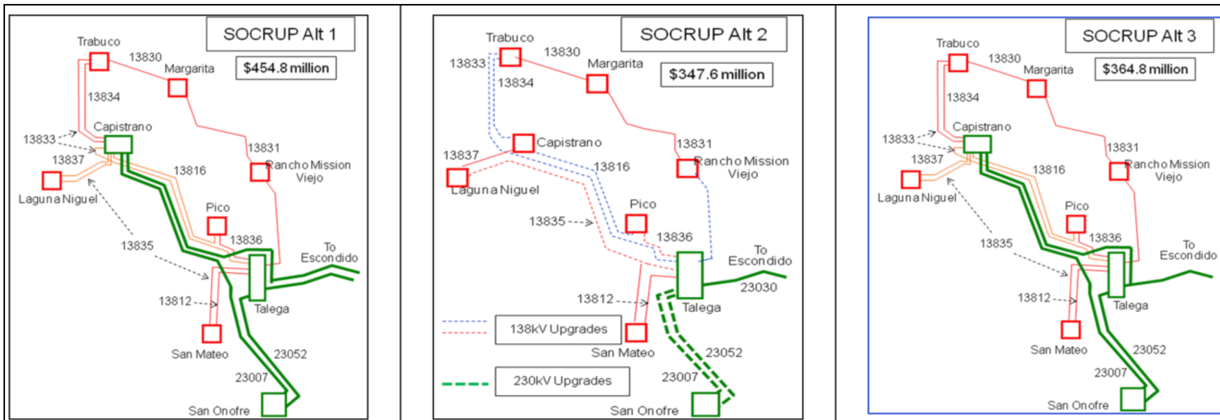
Figure 2.19-5: Existing Southern Orange County System

SDG&E submitted the *Modified – South Orange County Reliability Upgrade Project* to build new 230 kV lines and bring an additional source into southern Orange County in the 2008 request window and the ISO has been evaluating this project over several transmission planning cycles. The *Southern Orange County Reliability Upgrade Project (SOCRUP)* studies performed by SDG&E and the ISO provide substantial evidence that reliability need for upgrades exists in this area and the most effective method for achieving this is to add another source into this system. Most of the reliability concerns stem from the fact that only one 230 kV source feeds entire southern Orange County load. While it is important to develop a plan and ensure that the reliability concerns are addressed appropriately, it is also important to recognize that the upgrades should be optimal and cost effective. The southern Orange County area is susceptible to multiple Category C overloads by 2020, each requiring load shedding in this area. Under maintenance conditions, these load shed requirements are greater than 100 MW and can be as high as the entire southern Orange County load. Given these issues, the ISO performed an in-depth southern Orange County area transmission assessment to identify the necessary transmission upgrades in order to serve the area load reliably. After determining that alternative 2, the lowest cost alternative, required $347.6 million in investment, the ISO wanted to ensure that this investment would be a cost effective long-term plan. Therefore, all of the alternatives were designed to last beyond 2025 and compared on that basis. The purpose of this analysis was to identify the minimum upgrades needed during this timeframe to address NERC compliance and then to explore possibilities for alleviating concerns caused by a single source supplying the entire southern Orange County load. In addition to mitigating Category C issues, upgrades were identified to resolve issues faced under maintenance scenarios which can put significant load at risk. This effort led to creation of alternatives described below.

The project submitted by SDG&E was referred to as *SOCRUP Alternative 1.* The ISO worked with SDG&E to come up with two additional alternatives (*SOCRUP Alternative 2 and Alternative 3*). *SOCRUP Alternative 2* aims at upgrading 138kV system to solve potential overload issues, but it does not solve the problems created due to lack of a second source into this area. *SOCRUP Alternative 3* is a trimmed down version of alternative 1 (proposed by SDG&E) and provides similar reliability benefits as Alternative 1 while saving considerable amount of money.

Here is a brief summary of scope of each of these alternatives:

1. **SOCRUP Alternative 1:** Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and build a new Escondido to Capistrano 230 kV line using existing right-of-way. Estimated cost for this alternative is $454.8 million.
2. **SOCRUP Alternative 2:** Rebuild Capistrano 138kV substation (aging infrastructure maintenance project), reconductor 138kV lines – Talega – Pico, Talega – Laguna Niguel, Talega – Trabuco, Capistrano – Trabuco, Talega – Rancho Mission Viejo, and upgrade SONGS – Talega 230 kV lines. Upgrade two 230/138 kV transformer banks at Talega. Estimated cost for this alternative is $347.6 million.
3. **SOCRUP Alternative 3:** Rebuild Capistrano 230 kV substation, build a new SONGS – Capistrano 230 kV line using existing right-of-way, and tap off a 230 kV line to Capistrano from existing Escondido – Talega 230 kV line. Estimated cost for this alternative is $364.8 million.



-Reliable but most expensive
-Cheaper alternative provides similar reliability benefits

-No additional source into Orange County
-Only marginally cheaper than Alt 3 which brings another source into Orange County
- Mitigates cat-C overloads but Orange County load will still be at risk under planned outage conditions
-Does not mitigate issues with Talega substation configuration

-Provides similar reliability benefits as Alt-1, yet considerably cheaper
-Marginally more expensive than the cheapest alternative
-Additional source into Orange County
-Provides infrastructure for a possible future interconnection with SCE in Orange County.
-Flexibility to easily expand this into Alt-1 if required in future.

Figure 2.19-6: Southern Orange County Reliability Upgrade Project (Alternatives 1, 2 and 3)

Power flow study results of the peak load scenarios identified numerous facility loadings that exceeded their rated capabilities under Category C contingencies beyond 2015. All three alternatives considered here can mitigate the loading issues for Category C contingencies. In order to determine the most effective alternative, aspects beyond just the NERC compliance were taken into consideration. Historical data for bus outages at Talega and planned outages that put load at risk was accumulated and examined. It was quite evident that the lack of second source into southern Orange County puts more load at risk than the Category C issues noticed in the reliability assessment of the system. Hence, in order to improve the overall reliability of this system, it is important to bring another source into this area. The project submitted by SDG&E (Alternative 1) aims to achieve this, but Alternative 3 achieves similar reliability performance at a considerably lower cost. Alternative 2 mitigates the Category C issues through 2021, but fails to deliver another source into this area and hence fails to address the risk of load shedding due to contingencies at Talega. Alternative 3 provides another source into southern Orange County system at very little extra cost compared to Alternative 2. It also offers a potential for future upgrades in case of further load growth. After a comprehensive analysis, the ISO staff concluded that *SOCRUP Alternative 3* as the most effective, feasible solution to meet the reliability needs of southern Orange County area. Therefore, the ISO has found that the *SOCRUP Alternative 3* project is needed to address the reliability concerns in the southern Orange County area.

Other Projects

There were two projects submitted in the Imperial Valley region with a wide geographical scope:

The *North Gila - IV #2 Double Circuit Project* was submitted by Southwest Transmission Partners and on behalf of Energy Capital Partners II and its affiliates. The proposed project to build a second North Gila to Imperial Valley 500 kV double circuit line would increase the West of River transfer capability by up to 3000 MW. The project also claims to deliver significant amount of renewable resources bi-directional between Arizona and California. The reliability need for this project was not identified in the ISO's reliability assessment studies; hence the project is not needed as a reliability project.

The *IV Renewable Transmission Project (Reliability)* was submitted by Citizens Energy Corporation. This project aims at collecting and delivering renewable generation located in Imprial Valley to concentrated retail energy markets principally in southern California. Due to the interconnection to Arizona and Nevada, this project also claims to deliver renewable energy from and to those areas. The reliability need for this project was not identified in ISO's reliability assessment studies; hence the project is not needed as a reliability project.

2.19. 5 Key Conclusions

The ISO initially proposed a total of 10 upgrades (see Appendix A) to address identified reliability concerns.

In response to the ISO study results and proposed solutions:

- 28 reliability project submissions were received through the 2010 request window. Out of the 28 reliability projects, several projects were alternatives for solving the same problems.

The following nine projects are determined to be needed by the ISO:

- *TL644, South Bay-Sweetwater: Reconductor*: Proposed in-service date given by SDG&E is 2013;
- *New Sycamore – Bernardo 69 kV Line*: Proposed in-service date is June, 2015;
- *TL626 Santa Ysabel – Descanso mitigation*: Proposed in-service date is June, 2013;
- *Reconductor TL663, Mission-Kearny*: Proposed in-service date is June, 2015;
- *Reconductor TL670, Mission-Clairemont*: Proposed in-service date is June, 2015;
- *Reconductor TL676, Mission-Mesa Heights*: Proposed in-service date is June, 2015;
- *TL694A San Luis Rey-Morrow Hills Tap*: Reliability: Proposed in-service date for this project is June, 2012;
- *Upgrade Los Coches 138/69 kV Bank 50*: Proposed in-service date is June, 2013; and.

- *South Orange County Reliability Upgrade Project (SOCRUP) Alternative 3*[24]: Proposed in-service date is June, 2015.

The following 11 projects submitted in the request window are determined not to be needed:

- *TL648, Poway – Rancho Carmel*: 69 kV Reconductor: Proposed in-service date is June, 2015;.
- *TL6915 & TL6924 Sycamore-Pomerado #1 & #2*: Reconductors: Proposed in-service date is June, 2015;
- *TL682 Warner-Rincon*: Reconductor: Proposed in-service date is June, 2012;
- *TL693 San Luis Rey-Melrose: Reconductor*: Proposed in-service date is June, 2015;
- *TL694A San Luis Rey-Morrow Hills Tap*: Reliability: Proposed in-service date is June, 2012;
- *TL680B – Melrose-Melrose Tap Reconductor;* Proposed in-service date is June, 2013;
- *TL6916, Sycamore-Scripps Overload Mitigation (a new Sycamore – Miramar 69 kV Line)*: Proposed in-service date is June, 2015;
- *Reconfigure TL23013 and TL23028*: Proposed in-service date is June, 2011;
- *Barrett Interim Solution*: Proposed in-service date is October, 2012;
- *North Gila - IV #2 Double Circuit Project:.* Proposed in-service date is May, 2015; and
- *Imperial Valley Renewable Transmission Project (Reliability Project)*: Proposed in-service date is September, 2015.

The following eight projects will be evaluated in future planning cycles –

- *Reconductor TL631, El Cajon-Los Coches*: Proposed in-service date is June, 2013;
- *TL633, Bernardo – Rancho Carmel 69 kV*: Reconductor: Proposed in-service date is June, 2012;
- *Los Coches Substation 230 kV Expansion*: Proposed in-service date is June, 2015;
- *TL6912 - Reconductor San Luis Rey-Pendleton*: Proposed in-service date is June, 2020;
- *Upgrade Mission 138/69 kV Transformer Banks 51 and 52*: Proposed in-service date is June, 2015;
- *TL13835B Laguna Niguel - Talega Tap Mitigation*: Proposed in-service date is June, 2020;
- *Install synchronous condensers at Mission, Penasquitos and Talega 230 kV Substations*: Proposed in-service dates for these synchronous condensers are June 2013, June 2016 and June 2019; and
- *Add one 138 kV 43 MVAR Capacitor at Telegraph Canyon Substation*: Proposed in-service date is April, 2011.

During this year's reliability assessment, all the Category B problems observed were addressed by projects submitted through request window. After considering all the alternatives the ISO has determined 9 projects are needed. Out of the 11 projects found not to be needed during this planning cycle, several projects are alternatives to the approved ones. The remaining projects which are not deemed necessary at this point will

[24] 'South Orange County Reliability Upgrade Project (SOCRUP) Alternative 3' was formulated during evaluation of a project submitted by SDG&E – 'Modified - Southern Orange County Reliability Upgrade Project (M-SOCRUP)'. The ISO and SDG&E worked together to come up with SOCRUP Alternative 3 which has a reduced scope compared to M-SOCRUP. Refer to 'Orange County Area' write up under section 2.19.4 for further details.

be further evaluated during future planning cycles. The projects determined to be needed during this planning cycle will be included as planning assumptions for the next planning cycle.

Chapter 3 Study Results for Other Transmission Studies

3.1 Other Transmission Studies

Other transmission studies encompass studies of transmission projects identified in the ISO tariff that have not been addressed elsewhere in the transmission plan. These include projects that may be needed to maintain long-term congestion revenue rights (LT-CRR) feasibility, local capacity technical analysis (LCT) and location constrained resource interconnection facilities (LCRIFs).

Note that reliability requirements are addressed in chapters 1 and 2, policy driven projects are addressed in chapters 4 and 5, economic studies are addressed in chapter 6, and the evaluation of 2008/09 request window submittals is addressed in chapter 7.

3.2 Long-Term Congestion Revenue Rights Feasibility Studies

Consistent with sections 4.2.4 and 4.2.5 of the ISO's BPM for the transmission planning process, and the ISO's response to the FERC Order No. 681 and No. 681-A, the LT-CRR study included evaluation for feasibility of fixed LT-CRR with the addition of approved transmission projects in previous ISO transmission plans for on-peak and off-peak conditions. The fixed CRRs considered in the study are the long-term CRRs previously allocated, auctioned and executed during the 2009 and 2010 CRR annual allocation and auction processes in the ISO LT-CRR markets.

3.2.1 Objective

The primary objective of the LT-CRR simultaneous feasibility study (SFT) is to ensure that existing fixed LT-CRRs allocated and auctioned as part of the CRR Annual Allocation & Auction process remains feasible over the entire 10-year term when new and approved transmission infrastructure projects are added to the network model during the same time horizon.

3.2.2 Data Preparation and Assumptions

The 2010 LT-CRR study was performed using the base case network topology used for the July 2010 (DB 47) CRR allocation and auction process. All ISO newly approved transmission projects in the 2010 transmission plan were incorporated into the study case. A full AC power flow analysis was performed to validate acceptable system performance across the 10 year planning horizon. This modified base case was then used to perform the SFT-based market run, to check for fixed CRR feasibility.

In this SFT-based market run, all CRR sources and sinks from either CRR nominations or bids were applied to the full network model (FNM). Also all applicable transmission constraints were considered. This was performed to determine the resultant flows and identify any constraint violations. In the CRR market run setup, the network was limited to 60% of available transmission capacity, the transmission ownership rights were set to 60%, and the LT-CRR were set to 100%. At this point, the market in the CRR test system was set up and run. This provided a reliable and convenient user interface in data setup and results displays.

For the long-term CRR study, the CRR FNM DB47 was used. The following criteria were used to verify that the long-term planning study maintains the feasibility of fixed LT-CRRs:

- SFT is completed successfully with no limit expansion needed;
- The worst case base loading in each market run does not exceed 100% of enforced branch rating; and
- No new binding constraints are introduced.

3.2.3 Study Process

A brief outline of the current process is given below:

- Base case network model data preparation including a review of all newly approved projects applicable to the transmission planning cycle and incorporation into the network model for CRR allocation and auction process base case. The data preparation may involve the use of one or more of these applications: Siemens PSS/E, GE PSLF, MS Excel and appropriate text editor;
- The set up and performance of market runs in the CRR staging system environment;
- Review of results using user interfaces and displays; and
- Archival of the study data and results as save cases to a secured location.

3.2.4 Conclusions

The SFT study involved six market runs that reflected four seasonal (i.e., seasons 1, 2, 3 and 4) and two time-of-use (i.e., on-peak and off-peak) conditions. The results indicated that all existing fixed LT-CRRs remained feasible over their entire 10-year term as the new projects were added to the network topology. Furthermore, a marginal improvement to the worst base loading flows was observed.

3.3 Reliability Requirements for Resource Adequacy

The following sections 3.3.1 and 3.3.2 provide a summary of technical studies conducted by the ISO under the scope of the reliability requirements initiative in compliance with resource adequacy requirements in the ISO tariff. These studies include LCT analysis that addresses the minimum Local Capacity Requirements (LCR) on the ISO grid and RA Import Allocation.

3.3.1 Local Capacity Requirement Studies

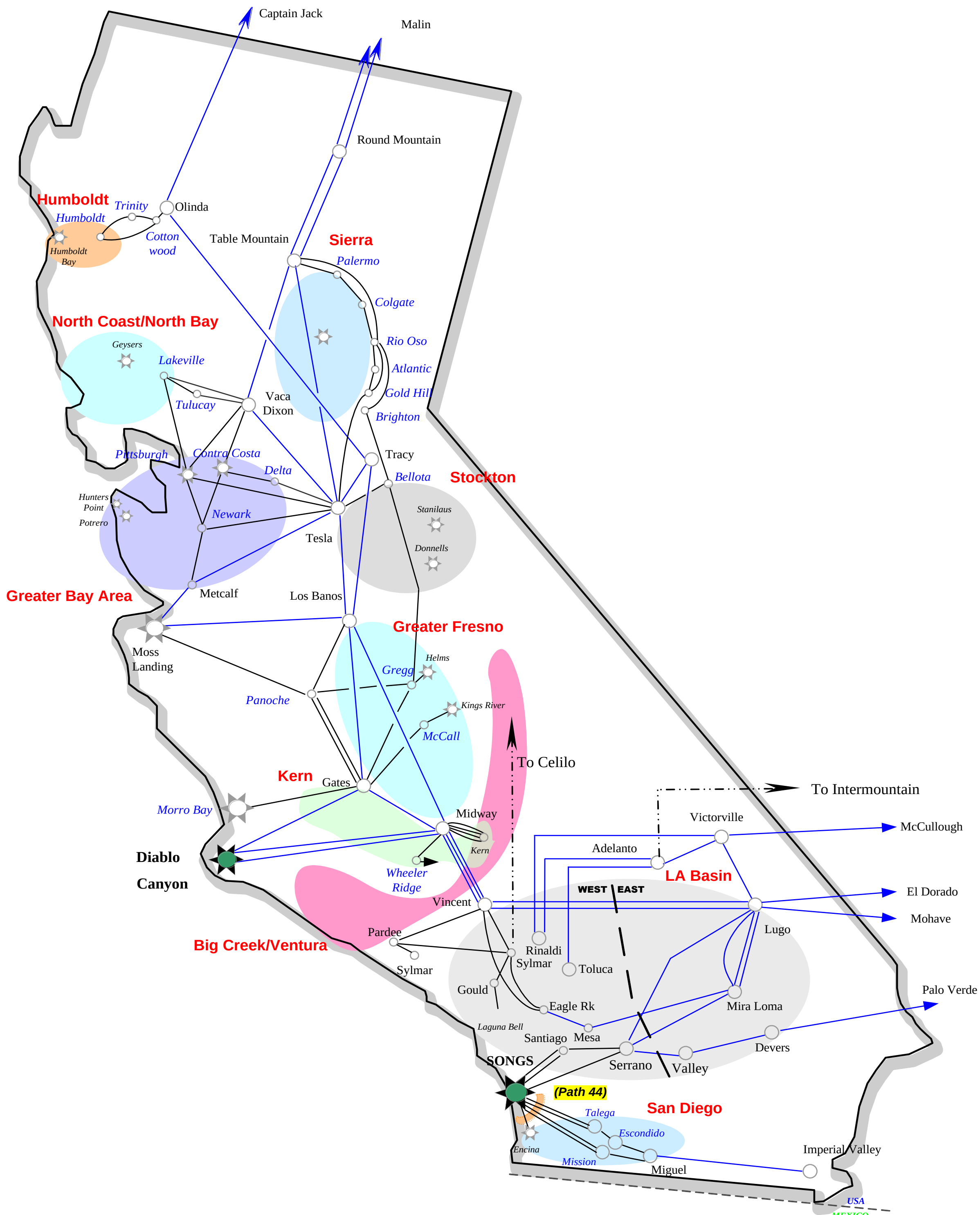
In 2010, the ISO conducted two types of LCT studies. A short-term LCT analysis was conducted for the 2011 system configuration to determine the minimum local capacity requirements for the 2011 resource procurement process in order to assess compliance in local capacity areas with the local capacity technical study criteria as required by tariff section 40.3. This study was conducted from January to April through a stakeholder process with a final report published on April 30, 2010. As part of the transmission planning process, a long-term LCT analysis was also performed to identify local capacity needs in the 2013 and 2015 periods and was published before the end of the year. The long-term analysis was performed to provide the transmission planning process participants with the trend of future LCR needs up to five-years in the future. This section summarizes study results from both the short-term and long-term LCR needs.

As appeared in the LCT Report and indicated in the LCT Manual, there are 10 load pockets throughout the ISO's controlled grid as shown in Table 3.3-1 below.

Table 3.3-1: List of LCR areas and the corresponding PTO service territories within the ISO BA area

No	LCR Area	PTO Service Territory
1	Humboldt	PG&E
2	North Coast and North Bay	
3	Sierra	
4	Greater Bay area	
5	Stockton	
6	Greater Fresno	
7	Kern	
8	Los Angeles (LA) basin	SCE
9	Big Creek/Ventura	
10	SDG&E area	SDG&E

Figure 3.3-1: Illustration for the approximate geographical locations of the LCR areas.



It should be noted that each load pocket is unique and differs in size of capacity requirements due to different system configuration. For example, the Humboldt area is a small pocket with total capacity requirements approximately 200 MW while the requirements in the Los Angeles Basin is approximately 10,000 MW. The short-term and long-term LCR needs from this year's studies are shown in Table 3.3-2.

Table 3.3-2: Local capacity areas and requirements for 2011, 2013 and 2015

LCR Area	Total LCR Need (MW)		
	2011	**2013**	**2015**
Humboldt	205	191	197
North Coast/North Coast	734	933	935
Sierra	2082	1768	1873
Stockton	682	469	491
Greater Bay Area	4878	3974	3951
Greater Fresno	2448	2102	2075
Kern	447	486	507
Los Angeles Basin*	10589	11304	5988*
Big Creek/Ventura	2786	2923	2872
San Diego**	3207	3347**	3478**
Total	**28058**	**27497**	**22367**

* Area is redefined as Western LA Basin in 2014; loads and qualifying capacity will decrease (see detailed description).
** Area changes configuration in 2012 and will be renamed into Greater San Diego/Imperial Valley Area.

For more information about the LCR criteria, methodology and assumptions please refer to the ISO website at: http://www.caiso.com/18a3/18a3d40d1d990.html .
For more information about the 2011 LCT study results, please refer to report posted on the ISO website at: http://www.caiso.com/2788/2788ab565da00.pdf .
For more information of the 2013-15 long-term LCT study, please refer to the report posted on the ISO website at: http://www.caiso.com/287c/287ca3cc28a80.pdf .

3.3.2 Resource Adequacy Import Allocation

In accordance with ISO tariff section 40.4.6.2.1 the ISO has established the maximum RA import capability to be used in the year 2011. This data can be found on the ISO website.[25] In addition, the ISO also posted information regarding the entire 2011 Import Allocation process on the website.[26]

3.4 LCRIF

The previous transmission planning process and the RTPP provide parties an opportunity to submit LCRIF project proposals through the request window. The ISO received one request window proposal in the

[25] http://www.caiso.com/27c6/27c675b81c230.pdf
[26] http://www.caiso.com/1c44/1c44b2dd750.html

2010/2011 request window (see description of the proposal in chapter 8). Due to the timing of the generation projects seeking to interconnect to the proposed LCRIF, the ISO was unable to complete its analysis in time for inclusion in this transmission plan. The LCRIF study results will be released upon completion of the analysis. If the ISO determines that the proposed LCRIF meets the all of the tariff criteria for conditional approval, the project will be presented to the Board of Governors.

Chapter 4 Study Methodology for Identifying Transmission Needed to Meet the 33% Renewables Portfolio Standard

4.1 Overview of the Planning Methodology to meet 33% RPS

4.1.1 Scenario Building and Least Regrets Methodology

In developing this transmission plan, the ISO sought to ensure that transmission facilities will be adequate to achieve the 33% RPS goals while minimizing the risk of over-building and imposing costs to ratepayers for facilities that are under-utilized or otherwise stranded. The plan for achieving the 33% goal is based on the best available information and recognizes that transmission need is dependent on a forecast of the types, locations and timing of new resources. To account for this uncertainty, the plan relies on several data sources to forecast needs and uses a "least regrets" approach captured in ISO tariff section 24.4.6.6 to determine whether to approve a facility in the current planning cycle, defer approval pending re-evaluation in the next cycle, or reject the facility as not being needed. A rigorous portfolio development process was undertaken by the ISO to identify four potential RPS development portfolios for analysis in this transmission plan. The development of these portfolios was in conformance with the criteria in section 24.4.6.6. This chapter describes in detail the approach that the ISO took to incorporate commercial interest in resources in geographic areas, to the full extent, in the portfolio development process. It also describes how the CPUC or local regulatory authorities' resource planning process information was incorporated to the fullest extent. In addition, the portfolio development work performed in CPUC resource planning process included a cost comparison of these resources and the base information from that work was incorporated into the ISO portfolios. The environmental evaluation data from the CPUC process for the zones that the transmission would be interconnecting was also extensively incorporated in the ISO portfolio development process. The approach the ISO has taken allowed the planning process to be flexible to adapt to new information.

Central to the least regrets concept is the RTPP's distinction between category 1 policy-driven facilities that the ISO recommends be built now, and category 2 facilities that should be re-evaluated in future planning cycles if conditions warrant such consideration. Any transmission upgrade or addition element that is included in the ISO base scenario and a significant percentage of the sensitivity scenarios may be classified as a category 1 element. Transmission upgrade or addition elements that are included in the base scenario but not in any of the sensitivity scenarios or in an insignificant number of the sensitivity scenarios generally will be category 2 elements unless the ISO finds that sufficient analytic justification exists to designate them as category 1. Each future transmission planning cycle will consider whether category 2 lines from the prior cycle merit promotion to category 1. It also will identify new category 1 and 2 lines based on updated forecasts, changes in state policy, updates to generator development plans and status, and other information available at that time.

Policy-driven facilities are identified through a scenario based study approach involving several steps.[27] These are summarized as follows:

1. Develop RPS portfolios as described in greater detail later in this chapter.
2. Verify the need under each scenario for transmission under development through the LGIP process but not permitted for construction yet.
3. Use production simulation, power flow and transient stability analysis to identify additional transmission facility needs in each of the scenarios.

4.1.2 Planning Paradigm

The lead times from transmission project inception to planning, permitting and construction can extend to as much as 10 years, which can potentially hinder an aggressive renewable energy development schedule. The planning period can be particularly long when the generation sources are located relatively far from load, as is the case with many renewable resources. One potential remedy is to make transmission planning less reactive and more anticipatory of future renewable generation needs. While this solution has the benefit of facilitating development and potentially reducing development costs, it also has the potential to lead to building more transmission than might be necessary.

The plan identifies the transmission needs for each of the four scenarios described in detail in the following section. Each scenario represents a generation development path toward meeting the 33% RPS goals. The process of developing plausible generation portfolios relies to a large degree on the following three main data sources: the CPUC list of discounted core projects, the ISO queue and interconnection processes, and environmental scoring provided by RETI. The likelihood of development in different regions will change as these scenarios are updated in future planning cycles. For example, detailed environmental studies for generation permitting applications will provide new data on regional development, which will be reflected in future transmission plans.

4.2 Base Input Assumptions for Comprehensive Transmission Planning to Meet 33% RPS

To meet the 33% RPS portfolio standard by 2020, the grid must have sufficient transmission capacity to interconnect renewable generation, as well as to transport the renewable energy to load. Some transmission upgrades have been identified or approved in earlier transmission planning processes prior to this comprehensive transmission planning study or as network upgrades in large generator interconnection agreements and LGIP studies. Table 4.2.1 summarizes these transmission projects.

[27] Section 24.4.6.6 of the approved tariff for the RTPP lists detailed criteria that the ISO uses in its analysis to identify need policy-driven transmission elements.

The additional transmission capacity provided by the upgrades listed in Table 4.2.1 were considered in the developing the 33% RPS portfolios.

Table 4.2.1 — Transmission projects considered in the 33% RPS portfolio development

Transmission Upgrade	Approval Status		Renewable Deliverability Potential with upgrade
	ISO	CPUC	MW
Carrizo - Midway	Transition Cluster	Pending PTC approval	900
Sunrise Powerlink	Approved	Approved	1700
Eldorado - Ivanpah	LGIA	Approved	1400
Pisgah - Lugo	LGIA	Need to file CPCN	1750
Valley - Colorado River	Approved	Approved	4700
West of Devers Upgrade	LGIA	Need to file CPCN	
Tehachapi	Approved	Approved	4500
Wind and Solar diversity in Tehachapi	Transition Cluster		1000
Coolwater - Lugo 230 kV line	LGIA	Need to file CPCN	600
South of Contra Costa reconductoring	Transition Cluster		300
Borden - Gregg 230 kV line reconductoring	Transition Cluster		800
Llano - Kramer 500 kV line, Kramer - Inyokern 230 kV, Bishop - Inyokern 230 kV lines	Transition Cluster		800

Some new substations are needed for the transmission projects listed in Table 4.2.1 and for interconnecting new generation projects. These substations are listed in Table 4.2.2.

Table 4.2.2 — New substations associated with the transmission projects considered in the 33% RPS portfolio development

Substation	Associated transmission lines	Served CREZs
New ECO 500 kV	Imperial Valley – Miguel 500 kV loop-in	San Diego South
New RedBluff 500 kV	Colorado River – Dever 500 kV lines loop-in	Riverside East
Conversion of Pisgah	Pisgah – Lugo 500 kV line; El	Pisgah, Mountain Pass

230 kV to 500 kV	Dorado – Lugo 500 kV loop-in	
New Jasper 230 kV	Coolwater – Lugo 230 kV loop-in	Kramer, San Bernardino Lucerne
Conversion of Ivanpah 115 kV to Ivanpah 230 kV	El Dorado – Ivanpah 230 kV	Mountain Pass
New Llano 500 kV	Vincent – Lugo 500 kV line loop-in; Kramer – Llano 500 kV line	Kramer, Owens Valley
New Carrizo 230 kV	Morro Bay – Midway 230 kV loop-in	Carrizo South and North, Santa Barbara

The new transmission facilities listed in Table 4.2.1 are shown on the map of California as in Fig. 4.2.1.

Fig. 4.2.1 — New transmission facilities allowing delivery of renewable generation

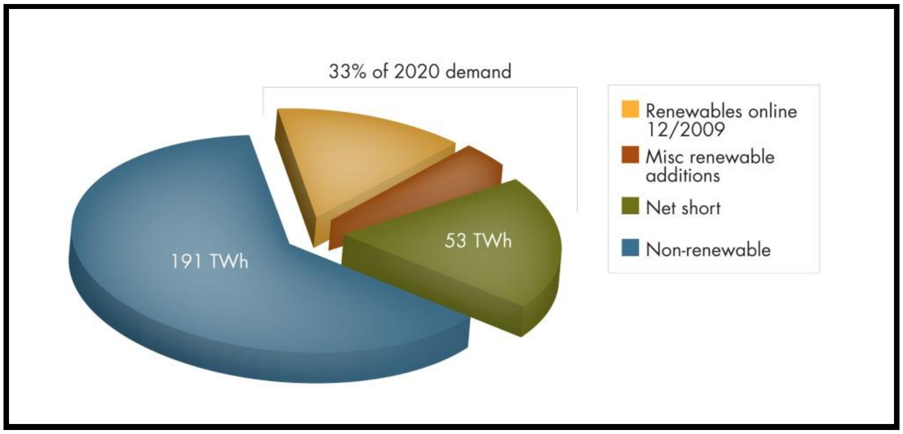
4.3 RPS Portfolio Development Methodology

4.3.1 Net Short Renewable Energy required for 33% RPS

The amount of incremental renewable energy resource additions that need to be added between 2010 and 2020 to meet the 33% RPS goal is referred to as "net short" energy. The forecasted retail sales in California in 2020 are approximately 286 TWh. Therefore, the 33% RPS portfolio requirement represents 94 TWh. However, there is already approximately 41 TWh of existing renewable production serving California load, so the net short is approximately 53 TWh. The ISO balancing authority portion of the net short is approximately 44 TWh. This transmission plan is designed to enable filling this gap. The net short energy used in this analysis was developed by RETI and CTPG.[28] The breakdown of the 33% energy requirement is shown in Fig. 4.3.1.

[28] CTPG Final Phase 2 Study Report, http://www.ctpg.us/public/images/stories/downloads/2010-05-07_final_phase_2_ctpg_study_report.pdf

Fig.4.3.1 — Net Short Renewable Energy in 2020 for 33% RPS



California requires a projected additional 52,764 GWh of energy from new renewable generation over the next decade to meet the 33% RPS goals. This represents roughly 19,000 MW of wind resources or 22,500 MW of solar if the entire gap were filled by a single resource type.[29]

4.3.2 Proxies for Likelihood of 33% RPS Portfolio Development

The four generation scenarios developed and studied by the ISO were based on different assumptions about the future mix of in-state, out-of-state and distributed generation resources. In creating each scenario, the ISO determined the in-state generation by assessing the aggregated likelihood of developing clusters of generation facilities. Individual generation projects were grouped into clusters on the basis of the local generation-related transmission projects required to support that cluster. Under each scenario, the ISO identified a set of generation-related transmission facilities that would serve the generation projects with the highest aggregated likelihood of development. In this way, the ISO developed plausible scenarios by assuming that the projects with the lowest barriers to development will be built first.

To develop an aggregated likelihood assessment for each cluster, the following four criteria were selected as proxies: two commercial interest proxies (interconnection queue and CPUC discounted core), and two likelihood of permitting success proxies (estimated environmental impact and actual construction permitting approval). Commercial interest, potential capacities, and costs of resources in renewable energy zones were considered by using renewable generation information in the interconnection request queue and the CPUC in their long-term procurement process. Using environmental impact information and permitting status information aligns with the ISO's need to perform an environmental evaluation as part of its selection criteria for policy driven elements. If a project has been approved for construction, then it must have successfully met the state's environmental requirements. This environmental information is also used in evaluating the likelihood of permitting success. This proxy addresses the ISO's need to evaluate the risk of stranding transmission investment because of the inability of generation identified in the portfolios to ever

[29] Assuming capacity factors for wind and solar of 0.32 and 0.27, respectively.

reach commercial operation. The four proxies are described in detail below. The ISO's consideration of other criteria is explained in chapters 4 and 5.

4.3.2.1 Interconnection Queue

The first and most direct way to demonstrate commercial interest is to participate in the ISO queue- based process. In all scenarios, projects from the ISO serial group, transition cluster and queue clusters 1 and 2 form the bulk of the projects with commercial interest. With very few exceptions, all projects in the serial group have executed interconnection agreements. All projects in the transition and queue clusters 1 and 2 have posted substantial financial security amounts that help assure their viability. Additional projects were identified from data provided by municipal power providers located in California, including the Imperial Irrigation District, Los Angeles Department of Water and Power, and the Transmission Agency of Northern California. Arizona Public Service and the Bonneville Power Administration queues provide the levels of out-of-state commercial interest. Queue presence, particularly generation in the ISO cluster study process, indicates that developers have made some investment in project siting and planning. The total energy available in the queue is shown in Fig. 4.3.2 and Fig. 4.3.3, representing northern and southern California, as well as the northern states. Energy is shown by CREZ or region, and by technology.

Fig. 4.3.2 — Total Potential Energy (GWh) from Northern California and Northern States

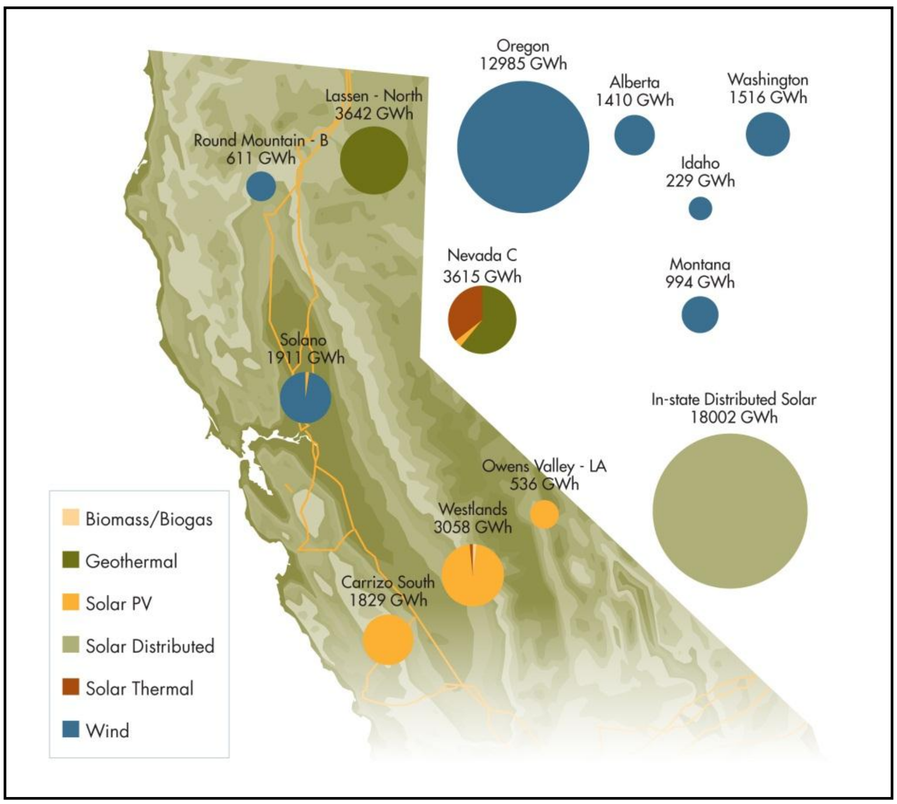
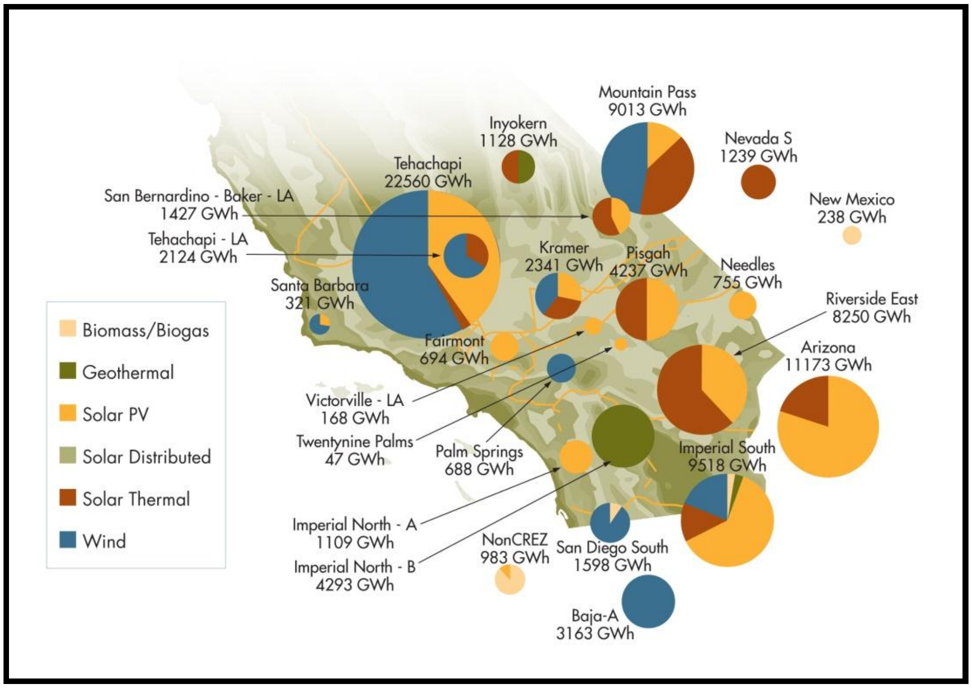


Fig. 4.3.3 — Total Potential Energy (GWh) from Southern California and Southwestern States



Based on these generation queue data, there are more than 135,000 GWh of potential in-state and out-of-state resources to meet the 53 TWh net short, including more than 90,000 GWh of in-state generation from the interconnection queue, and 18,000 GWh of in-state distributed resources. More than 26% is solar photovoltaic, 12% solar thermal and 30% wind. Also, more than 50% of the potential renewable resources are located in southern California.

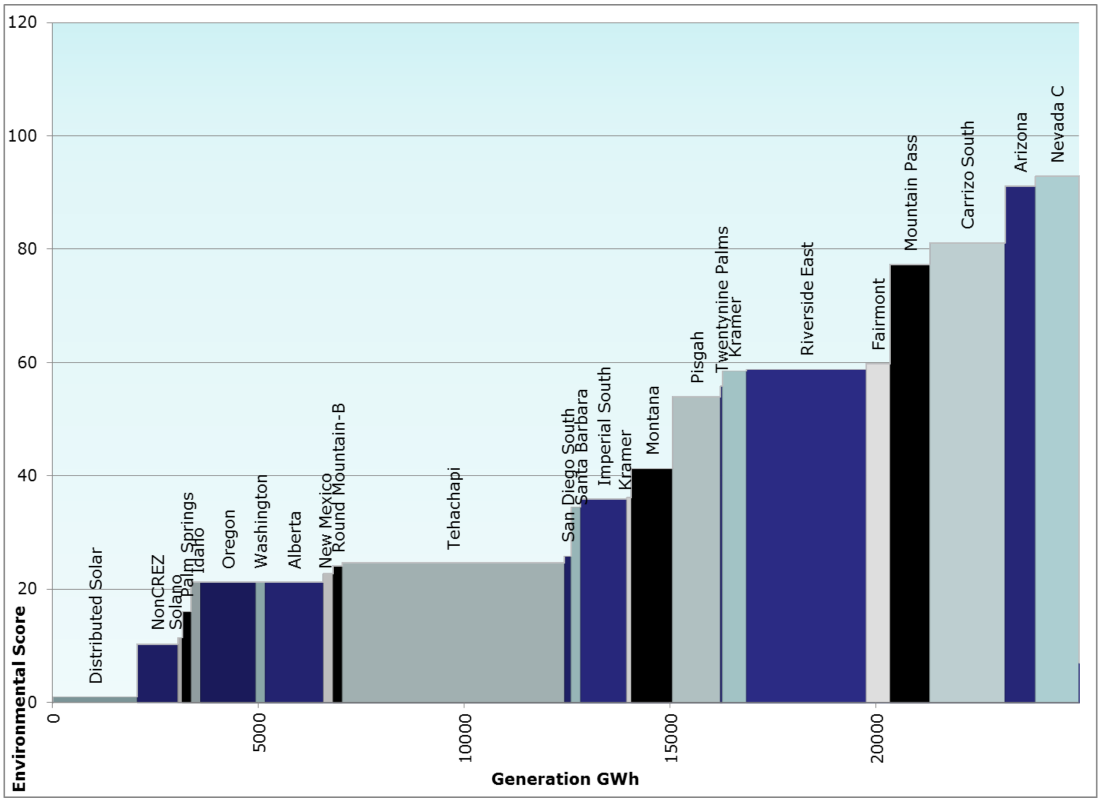
4.3.2.2 CPUC Discounted Core

The CPUC chose a set of projects that with a high degree of likelihood of being developed and included them as a foundation in its portfolio development process. The ISO used this same set of projects as a foundation for its portfolios as well. The CPUC chose the projects based on two publicly available criteria that also adequately demonstrated developer interests: projects must have a signed power purchase agreement, and a permitting application submitted to the responsible permitting entity (CEC, Bureau of Land Management). Like projects already in the queue, these projects were further along in the development process than generation projects without purchase agreements. However, permitting, financial and technology related barriers to development must be overcome by these projects as well.

The discounted core project list includes large in-state generators, out-of-state renewable energy credits (RECs) and distributed generation projects, as shown in Fig. 4.3.4 below and are aggregated by CREZ. The figure shows the amount of GWh expected to be produced from the projects and their average environmental score. Scores were normalized to a scale between 0 and 100, with a low score indicating a lower impact and a higher relative likelihood of obtaining environmental permitting.

Figure 4.3.4 shows that environmental barriers to development of distributed solar generation were predicted to be the lowest, whereas projects in Mountain Pass, Carrizo South, Arizona and Central Nevada are predicted to have higher environmental impacts and perhaps more difficulty in gaining permitting approval.[30]

Fig. 4.3.4 — Discounted Core Projects Sorted by Environmental Score



All large scale generation projects considered in this transmission plan demonstrated commercial interest through being in the CPUC's discounted core, the ISO queue or both. Most of the generation was also far enough along in the interconnection process to have executed generation interconnection agreements. However, as described below, environmental information was also used to identify generation considered in this transmission plan.

4.3.2.3 Estimated Environmental Impact of New Development

Estimated environmental impact scores for each CREZ were calculated by RETI and refined by Aspen Environmental Group. Aspen used eight criteria as proxies for assessing environmental impacts of development in each CREZ and aggregated these by technologies to provide a set of CREZ and

[30] See subsection below for description of environmental scoring.

technology specific scores.[31] Environmental scores for transmission corridors outside of the CREZs were estimated by RETI and refined by the CPUC.[32] The RETI environmental scoring and rankings are available in its series of phase 1 and 2 reports and updates.[33] With respect to the CREZ environmental scores, as noted in RETI's phase 2A final report, "CREZ identification includes high-level environmental screening that: 1) excludes certain areas from consideration as development sites, based on statutory or policy restrictions; and 2) indicates areas where energy development may create fewer environmental concerns, based on the best information available to the [RETI] Environmental Working Group (EWG)."[34]

4.3.2.4 CEC Permitting Approval

Renewable generation projects with permitting approval from the CEC have achieved a significant milestone toward development. These are considered to have a higher likelihood of development than projects that are merely in the interconnection queue and projects in the discounted core that have not been permitted. Thus, for purposes of the ISO's portfolio development analysis, these types of projects were accorded greater weight in the portfolios.

4.3.3 Common Steps in Portfolio Building

For each of the scenarios, the ISO took two initial common steps toward finding the transmission projects needed for supporting the generation projects with the highest aggregated likelihood of development. The following provides a description of those two steps.

Step 1— Selecting generation projects with existing and potential transmission

The effect of transmission additions or upgrades being considered for approval in the ISO planning processes is a criterion that the ISO must consider in determining the need for policy driven elements. Therefore, the effects of transmission already approved or well along in the approval process on the development of generation that those projects would serve was considered in the portfolio development process. Because transmission takes much longer to develop and construct than generation, the fact that some transmission is already approved or well along in the approval process is an enabler to generation development. The existence of previously approved transmission removes a layer of uncertainty for generators. In addition, all of the transmission ultimately included in this transmission plan is needed to serve generation in the discounted core or generation with LGIA's, so this transmission has well established commercial interest driving its need. Therefore generation projects under development were assigned to available existing transmission capability or to a transmission line under development. The

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31 Environmental scores are the same as those used in the CPUC LTPP. The methodology used by Aspen Environmental Group is given here: http://www.cpuc.ca.gov/NR/rdonlyres/431E5A0B-E226-4FF6-9BA9-4D8D5A86A28D/0/AspenEnvironmentalScoring.pdf , though they have been updated since then. Further details of the methodology will be released with the CPUC LTPP Report.

32 Transmission corridor scores are the same as those developed and used by the CPUC in LTPP. Details will be released with the CPUC report.

33 These are available at http://www.energy.ca.gov/.

34 RETI, Phase 2A Final Report, pg. 1-5; available at http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F-REV2.PDF.

transmission lines were filled with generation projects up to their deliverability capability. The generation projects were assigned to these transmission lines in the following order:

- Projects with approved CEC permitting
- CPUC discounted core projects
- Projects selected by environmental score — lowest to highest.

Transmission projects considered in the portfolio development that are already approved or well along in the approval process are referred to as LGIP lines because the need for them is driven by the development of renewable generation. All of the LGIP lines are either permitted for construction have executed or tendered LGIAs. (The ISO has also identified several major transmission projects approved through previous planning cycles as LGIP lines, as those projects were also driven largely by the development of renewable generation.) The LGIP lines and existing available transmission were linked to projects with the highest likelihood of development from the areas that these lines serve. The existing transmission and LGIP lines were determined to have sufficient capacity to accommodate all discounted core and CEC permitted projects. The remaining capacity on the LGIP lines was utilized by the projects with the most favorable environmental scores. This process resulted in each transmission line receiving an aggregate environmental score reflecting the projects it serves.

Step 2: Build Portfolios

In the second step, the core portfolio and transmission for each of the scenarios was formed by adding LGIP-driven transmission lines with their associated projects from step 1, in order of aggregated environmental score, until the net short energy was exceeded. After this was completed, it was determined that the LGIP lines turned out to be the same facilities that would be required to deliver energy from the discounted core projects.

Fig. 4.3.5 – Overview of Common Steps in Portfolio Building

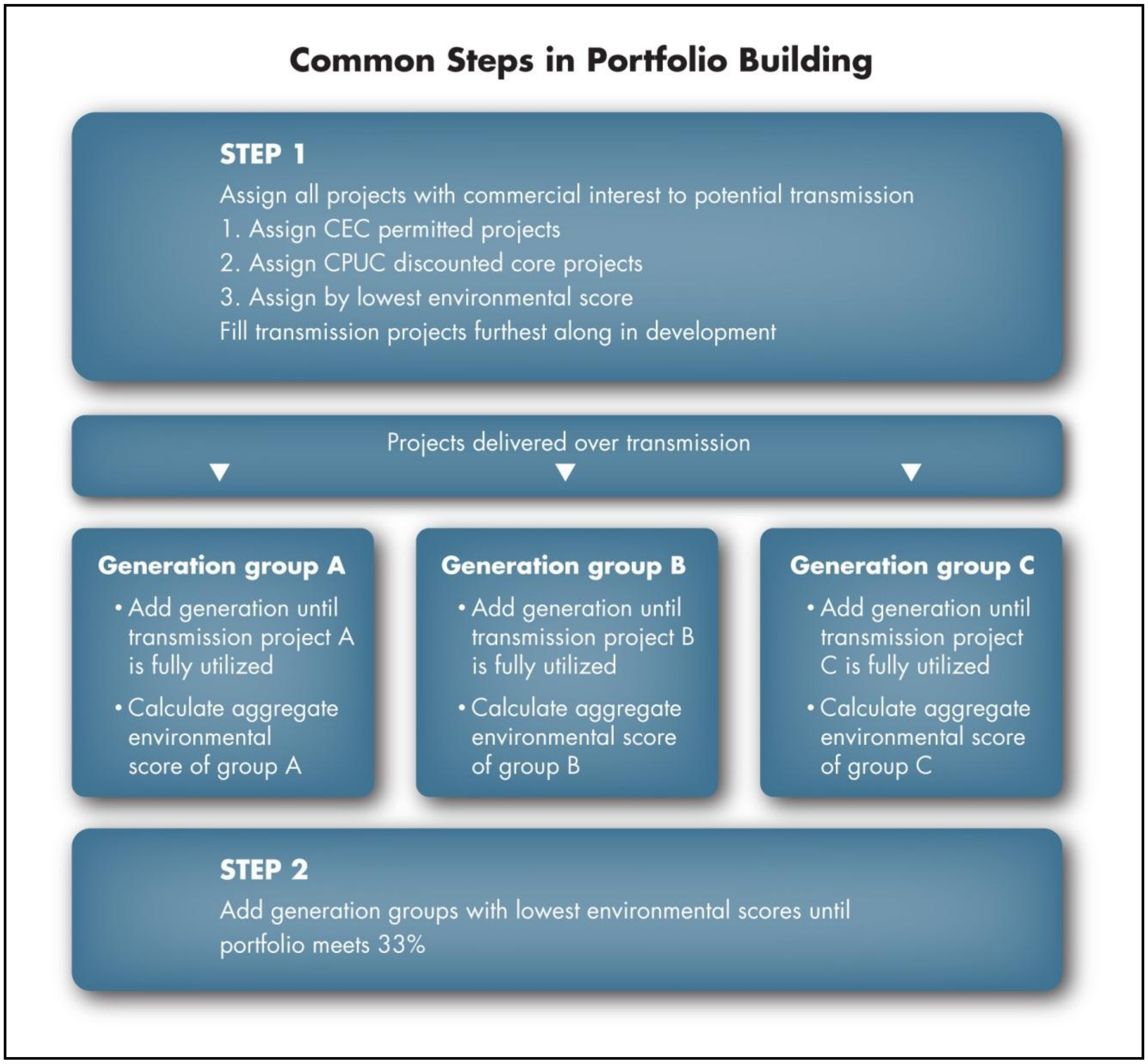
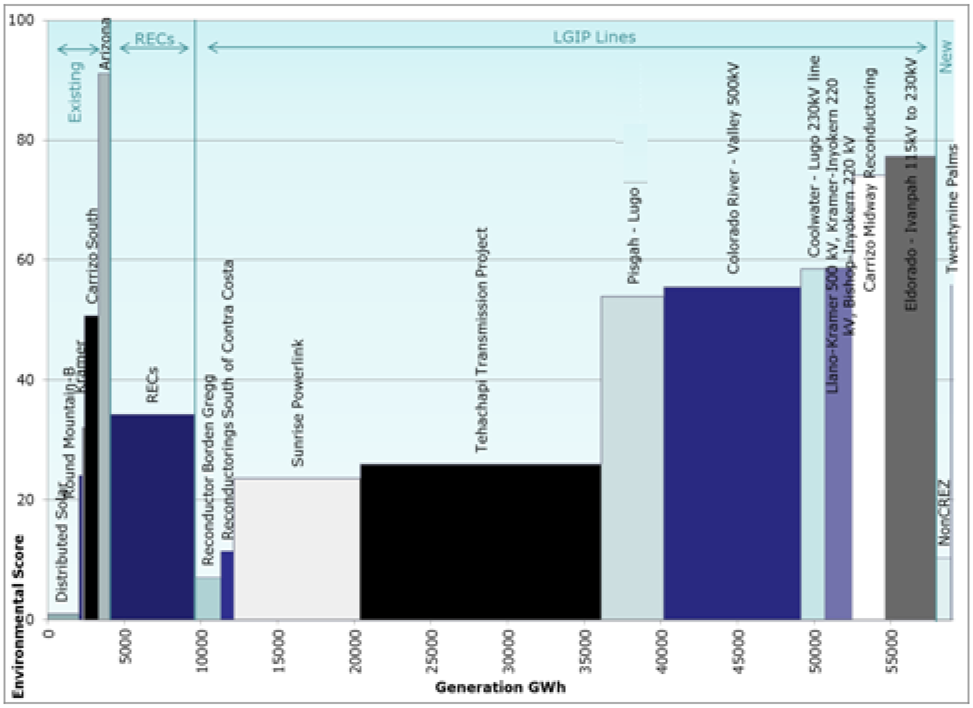


Figure 4.3.6 illustrates the results of this portfolio building step. It shows the generation portfolios and associated transmission projects needed to deliver renewable energy to load with the lowest total environmental score while including all discounted core projects. The existing transmission was determined to be utilized, including the assumptions of transmission availability for 2,050 GWh of distributed solar projects in the discounted core. The renewable energy credits were included as part of the discounted core and contributed to meeting the net short energy.

Fig. 4.3.6 - Step 2 – LGIP Lines and Aggregated Environmental Scores



This initial set of transmission facilities and related generation formed the basis for the 33% RPS portfolios built under each study scenario. The ISO also tested the need for the lines identified in these two initial steps for each portfolio. The following sections provide the description of the further development for each portfolio and how they were modeled in the studies.

4.3.4. ISO-Studied 33% RPS Portfolios

4.3.4.1 High Transmission Utilization Portfolio

In the high transmission utilization scenario, the ISO modeled the largest plausible expected energy from large in-state generating facilities. It was assumed that development would occur primarily in the CREZ areas within California.

This scenario has the following assumptions:

- 5.5 TWh of out-of-state RECs identified by the CPUC in the discounted core
- 2 TWh of distributed generation identified by the CPUC in the discounted core
- Remaining net short energy (45 TWh) would be met by large in-state generation.

This scenario represents a plausible upper bound on feasible in-state large renewable generation investment. The portfolio was built by drawing on the set of transmission and related generation projects as identified above in step 2.

Because of the discrete blocks of generation capacity added by each transmission project, the ISO exceeded the 33% RPS energy requirements. To adjust the portfolio to precisely meet the renewables goal, some generation had to be removed. This final action also allowed the ISO to eliminate the need for lower potential transmission projects initially included in the portfolio and verified the transmission needed for this scenario.

Generation projects were dropped from the portfolio based on their environmental score until the net short energy requirement was precisely reached. The result was that projects that were least likely to be developed based on environmental score proxy were removed from the portfolio, thereby reducing transmission line utilization.

After eliminating projects with the worst environmental score, the LGIP lines with lower than 10% utilization (i.e., in terms of capacity utilization) were dropped from the portfolio along with the associated generations projects. A major LGIP line with such low forecast utilization would experience a number of economic and regulatory challenges and therefore is less likely to proceed than projects with higher utilization. The remaining transmission in the portfolio connects the CREZs with the highest likelihood of development.

4.3.4.2 High Out-of-State Portfolio

The high out-of-state scenario included the same out-of-state energy imports as defined in the CPUC cost-constrained portfolio,[35] with approximately 20 TWh of energy, or 38% of the net short energy. The CPUC approach in developing the cost-constrained portfolio identified resources with the lowest total cost. This represents a plausible upper bound on out-of-state development if cost minimization is the primary driver of renewable energy project development to meet the state policy goals.

This high out-of-state scenario differs from the CPUC cost-constrained case because, while it assumed the same out-of-state energy imports, the in-state generation was selected based on the likelihood of development according to environmental score, rather than on economic criteria. In addition, rather than relying solely on relatively short-term contracts for energy credits, the ISO assumed some need to physically deliver energy from a portion of these projects that would drive the need for investment in the interconnection between California and the Pacific Northwest. The ISO determined that an additional 2,000 MW of transmission capacity was needed to deliver energy from the Pacific Northwest. The existing transmission to deliver energy from the Southwest, however, was expected to be sufficient for this analysis. Both of these determinations were based on the results of ISO production simulation studies. The ISO selected out-of-state renewable generation projects from the Arizona Public Service and the Bonneville Power Administration based on their interconnection queues.

To find the transmission portfolio for this scenario, the ISO added additional out-of-state resources to the "full utilization" transmission portfolio from Step 2 of section 4.3.3. The in-state generation projects then

[35] The CPUC cost constrained portfolio was developed as part of the Long-Term Procurement Planning process. It represents the lowest cost portfolio out of the collection of portfolios developed by the CPUC to guide procurement of CPUC jurisdictional load serving entities.

were backed down and associated transmission was determined if needed based on environmental score until the net short energy was met but not exceeded. The LGIP lines with less than 10% utilization were dropped in the final portfolio.

4.3.4.3. High Distributed Generation Portfolio

The high distributed generation portfolio includes the same quantity of energy supplied by distributed generation as defined in the CPUC environmentally constrained portfolio with 18,002 GWh, or 34% of the net short energy. This portfolio represents a relatively high distributed generation scenario compared to the other three developed in this cycle.

In similar fashion to the high out-of-state scenario, the additional distributed generation in this scenario was added to the "full utilization" transmission portfolio from step 2 of section 4.3.3 above. In-state resources were backed down based on environmental score until the portfolio met the net short energy. The LGIP lines with less than 10% utilization were also dropped from the final portfolio.

4.3.4.4. Hybrid Portfolio

In the above three portfolios, the ISO modeled reasonable bounds of plausible development for three types of generation that correspond to potential different objectives: in-state large scale projects; out-of-state and relatively low cost projects; and in-state, relatively low environmental impact forms of distributed generation. The ISO considered that the likely resource scenario will have moderate aspects of each of the first three scenarios, and therefore defined a combination of all three. Although the high out-of-state scenario represents the lowest cost scenario, it requires approximately 1,000 miles of new interstate transmission. The hybrid portfolio does not require any new interstate transmission, but it maximizes the use of existing interstate transmission. It also includes more distributed generation than the discounted core, but it is a moderate amount compared to the high distributed generation portfolio. It then makes up the balance of the net short with large in-state renewable generation, but relies on higher grade locations within the CREZs than the high transmission utilization portfolio. Under the hybrid scenario, 50% of the out-of-state resources from the high out-of-state scenario and approximately 33%[36] of the distributed generation resources from the high distributed generation scenario were developed. The portfolio, therefore, has 10,085 GWh of out-of-state generation and 6,080 GWh of distributed generation, representing 31% of the net short energy. The remaining net short was assumed to be supplied from large in-state resources.

To create the hybrid portfolio, the ISO added a moderate amount of additional out-of-state and distributed generation resources to the fully utilized portfolio of step 2 in section 4.3.3.

[36] Initially 50% of the distributed generation in the high distributed generation portfolio was contemplated to be added to the hybrid scenario. However, substantial progress in the Imperial Irrigation District interconnection queue process was achieved in the fall of 2010. This information led the ISO to include additional generation in the IID area in the hybrid portfolio and resulted in displacing some of the distributed generation, so that only 33% of the distributed generation in the high distributed generation portfolio was included in the hybrid scenario.

This methodology assumed that the need for each LGIP line was established during the development of the first three portfolios. The development of the hybrid portfolio took advantage of the transmission need results from the development of the first three portfolios, and does not include any LGIP lines not needed in any of the first three portfolios. The environmental scores used by the ISO for this portfolio development process were the same, for the same generation technology, across an entire CREZ. However, the ISO believes that some areas within a CREZ will be easier to permit than other areas because of site specific information. In addition, some areas within the same wind CREZ are more productive than others. Based on these observations, the ISO considered that every CREZ has high, medium and low grade areas for development, and that the high grade areas will be developed before the low grade areas. In other words, every transmission line identified as needed during the development of the first three portfolios would have at least some generation developed in the high grade sites. This reflects the assumption that developers would select the best sites within each CREZ, leaving each one partially utilized. Based on this, the ISO backed down loading on the lines proportionally so that all lines had similar percentage of capacity utilization. The generation projects loading each line were backed down in order based on the environmental score of each technology.

4.4. Assessment Methods

4.4.1 Power Flow and Stability Assessment

The NERC/WECC reliability and ISO planning standards were adhered to in the comprehensive transmission planning studies. The description of these standards and criteria was provided in chapter 2. All required assessments, including power flow contingency analysis, post-transient voltage stability analysis, and transient stability analysis, were performed. The contingencies that had been used in the ISO annual reliability assessment for NERC compliance were revised to reflect the network topology changes and were simulated in the transmission planning assessments.

Contingencies that could impact system-wide stability were simulated and investigated extensively. The existing special protection schemes were examined in the planning base cases to ensure they were still applicable. The assessments that were performed included conventional, post-transient power flows, voltage stability analyses, time-domain transient simulations and small signal stability analyses.

Similar assessments were performed for proposing mitigation plans for reliability concerns identified in the planning studies. Multiple alternatives were compared to identify the preferable mitigations. If the same reliability concerns had been identified in the ISO annual reliability assessment for NERC compliance and was not aggravated by the renewable interconnection, by default the preliminary reliability mitigation would be considered part of the comprehensive plan but would not be included in the policy-driven transmission mitigation requirements.

4.4.2 Deliverability assessment

Deliverability of the renewable generation in the studied 33% RPS portfolios was assessed by following the ISO generator deliverability assessment methodology. Transmission upgrades were identified that would be

necessary to make all in-state renewable generation in the portfolios maintain full capacity deliverability. Those that were identified in the baseline scenario were then identified as category 1 or category 2 projects.
The details of the deliverability assessment methodology can be found at http://www.caiso.com/23d7/23d7e41c14580.pdf

4.4.3 Production cost simulation

Production cost simulations were performed for all four renewables scenarios. The TEPPC 2020 economic assessment was used as the starting database. The 3 scenarios were modeled on top of this database. The ABB GridView software was used to perform the production cost simulations in the planning studies.
The simulation results were used to identify the generation dispatch and path flow patterns in the 2020 study year after the scenarios were modeled in the system. The selected patterns were used as reference in power flow and stability base case development. The results were also used to analyze the utilization of the transmission system, particularly the major import paths and transmission upgrades.

4.5 Power flow and Stability Data Development

4.5.1 Base Case Assumptions

4.5.1.1 Starting base cases

The peak and off-peak base cases for the year 2020 in the ISO annual reliability assessment for NERC compliance were used as the starting points of the base case development for the 33% RPS comprehensive transmission planning studies. In the ISO annual reliability assessment, different peak and off-peak base cases were developed for each PTO area, although they were developed from the same WECC seed base cases. For the transmission planning studies, the ISO developed the unified base cases for the entire ISO controlled grid by merging the base cases from different PTO areas. The unified planning base cases and the starting base cases that had been used to develop the unified base cases are listed in Table 4.5.1.

Table 4.5.1 - Starting base cases for the 33% RPS comprehensive transmission planning studies

Unified Planning Base case	**Starting Base cases**		
	PG&E	**SCE**	**SDGE**
2020 peak	2020 1-in-5 peak	2020 1-in-10 peak	2020 1-in-10 peak
2020 off-peak	2020 off-peak	2020 off-peak	2020 off-peak

4.5.1.2 Load conditions

As specified by the ISO's planning standards, the system-wide study used 1-in-5 coincident peak load. Also used was the CEC load forecast that was posted in December 2009.

A load level of 50% of the 1-in-5 peak load was selected as the reference of the off-peak load condition and the basic off-peak load profile. Additional load conditions were considered for assessing particular local area transmission needs based on historical load profiles. The details are provided along with the mitigation plans for the local areas in chapter 5.

Table 4.5.2 - Load condition by areas

Planning Area	**1-in-5 coincident peak load**	**Off-peak**
PG&E	31610.3	15805.15
LADWP	7074.76	3537.38
SCE	28140.86	14070.43
SDG&E	5533.22	2766.61
IID	1350.96	675.48

4.5.1.3 Conventional Resource Assumptions

The transmission planning studies utilized the ISO Grid Planning Guideline for the assumptions regarding future conventional resources if the resources met one of the following criteria:

1. Under construction, or
2. Having received regulatory approval.

A resource would not be modeled or would be dispatched in the base cases if its retirement has been officially announced. The OTC units were modeled in the base cases.

4.5.1.4 Transmission Assumptions

Similar to the ISO's annual reliability assessments for NERC compliance, all transmission projects approved by the ISO, including those approved by the ISO Board and management, were modeled in the base cases for the transmission planning studies.

In addition, the transmission facilities that are listed in Table 4.5.3 and various substations and transformer upgrades for generation interconnections are modeled in the base cases.

Table 4.5.3 – Transmission Projects Needed and Modeled in Portfolio Base Cases[37]

Transmission Upgrade
Carrizo – Midway
Sunrise Powerlink
Eldorado - Ivanpah 230 kV lines
Pisgah – Lugo
Valley - Colorado River
West of Devers Upgrade
Tehachapi
2nd and 3rd 500/230 kV transformers at Whirlwind substation
Coolwater - Lugo 230 kV line
South of Contra Costa reconductoring
Borden - Gregg 230 kV line reconductoring
Various substations for generation project interconnections

4.5.2 Modeling RPS Portfolios

4.5.2.1 Power Flow Model and Reactive Power Capability

As discussed in section 4.3, the renewable capacity and technology in each CREZ were determined based on environmental scores and commercial interest. The CPUC discounted core and generation interconnection queues of the ISO and utilities were used as the pool of renewable generators to fill up the determined capacity for each CREZ. Note that this process of selecting generation projects was only meaningful to meet the capacity for CREZs and should not be interpreted as favoring any particular generation project. All generation projects still need to go through the interconnection process for approval.

If a project in the ISO or PTO's generation interconnection queues was included in a portfolio, it was modeled in the base cases as in the generation interconnection study, including the reactive power capability, i.e., the minimum and the maximum reactive power output. If a project was selected from other sources, such as the discounted core or the out-of-state projects but not in the generation interconnection queues, the actual power flow model may not have been available; then an equivalent model was used that matched the capacity as listed in the portfolios. When an equivalent model was used, it was assumed that the generator could regulate bus voltage within a power factor range of 0.95 lagging to leading if it was a wind turbine generator or solar PV generator. For the renewable generation that used other technology such as solar thermal, geothermal, biomass and biogas, typical data were used in the equivalent model and may have a larger power factor range than the 0.95 lagging and leading.

Each of the studied portfolios included distributed generation. If a distributed generator in a portfolio had information on interconnection point and capacity, it was modeled as an equivalent generator at the point of

[37] Llano – Kramer 500 kV line, Kramer – Inyokern 230 kV, Bishop – Inyokern 230 kV lines were not needed in any of the four portfolios, and therefore were not modeled.

interconnection and had a power factor range of 0.95 lagging and leading. Some of the distributed generators did not have specific interconnection information, so they were modeled implicitly by scaling down the load.

4.5.2.2 Dynamic Modeling of Renewable Generators

Similar to the power flow model, the dynamic models from the generation interconnection study were used for the projects in the ISO or PTO generation interconnection queue if available. For all projects whose dynamic models were not available, generic models were used in the transmission planning study. For geothermal, biomass, biogas and solar thermal projects, the dynamic models of similar existing units in the system were used, including generator, exciter, power system stabilizers and governor models. For wind turbine generators and solar PV generators, the GE-PSLF program's generic models were used. The ISO further assumed in this study that the type 3 wind turbine, which is for a doubly fed induction generator, was used for wind generators. The type 4 inverter turbine, which has a full converter interface and variable speed capabilities, was used for solar PV generators. For types 3 and 4 dynamic models, the control parameters were set so that the generators have low voltage ride through, low frequency ride through and dynamic reactive power capabilities.

4.5.3 Generation Dispatch and Path Flow in Base Cases

The power flow and stability studies were based on the assumptions of generation dispatch that were based on historical data and engineering judgments. As the 33% RPS portfolios and the necessary transmission upgrades take place, the generation dispatch and power flow patterns could change. Therefore, the historical data of the generation dispatch and path flows could not be applied directly to predict the future system conditions.

Production cost simulation software uses unit commitment and economic dispatch on an hourly basis for the study year. Although it may not exactly match the real-time operation of the power market, the production cost simulation results can be used as a reference to predict future dispatch and flow patterns. Different portfolios for power flow and stability assessments can be developed based on the production cost simulations results.

In the transmission planning studies, the production cost simulations have been used to investigate the future generation dispatch and path flow patterns with renewable integration. The base cases for power flow and stability assessments were developed by using the production cost simulation results as references. Generally, certain hours that represented some typical stressed patterns of path flows in the 2020 study year were selected from the production cost simulation results. Three critical factors were considered in the selection of the stressed patterns:

- Renewable generation output,
- The power flow on the major importing paths into the California, and
- Load level.

For example, one set of hours selected for reference purposes was the near maximum renewable generation output and near maximum imports of California during peak hours and off-peak hours. Similarly, other hours were selected to study different renewable and path flow patterns stressing particular paths and local areas.

The renewable generation outputs for the selected hours in the power flow and stability assessment base cases were determined based on the hourly profiles that have been used in CTPG or the TEPPC profiles, depending on the data availability. Similarly, the existing renewable and hydro generation in California was dispatched at the selected hour based on the historical profiles that could be found in the WECC TEPPC database. Operation nomograms were considered in determination of hydro generation output.

It was recognized that the modeling of network constraints had significant impacts on the results of production simulation. The simplest constraints are the thermal ratings of branches under normal and contingency conditions. It is not feasible to model all contingencies and branches in the production cost simulation because of computational capability limits. Given this gap between the production cost simulation, which is based on DC power flow model, and the power flow and stability assessments, the dispatch of conventional thermal units in power flow and stability assessments followed the following principles:

- Maintain the selected path flow patterns for the given renewable and hydro generation outputs;
- Follow variable cost to determine the order of dispatch; and
- Out of order dispatch may be used to mitigate local constraints.

In the dispatch of conventional thermal generation, OTC units were not particularly dispatched off-line or had their outputs reduced before other units. The OTC units were, however, dispatched down first in the event of ties — where an OTC unit and a non-OTC unit had the same variable cost and could meet the same local reliability needs. Most OTC units could still be off-line before other units because of the relative high variable cost, but some might be dispatched on-line to mitigate local constraints. Approved and potential OTC re-powered units were considered in the modeling of the base cases.

Chapter 5 Planning Assessment for 33% RPS Transmission

Sections 5.1, 5.2 and 5.3 set out the generation portfolios, the base cases and scenarios, and a system overview which was employed in the 33% RPS analysis.

Sections 5.4, 5.5, and 5.6 set out the results of the technical analysis of the SDG&E, the SCE, and the PG&E systems, respectively. These sections identify system issues under each of the portfolios, and potential mitigations. It must be noted that an issue identified in a single scenario, however, is not sufficient to require mitigation. The review of the various portfolio and scenario results and the selection of projects to be determined as needed are set out in section 5.9

Sections 5.7 and 5.8 set out testing of broader power system implications and production simulation utilization analysis, respectively. In section 5.9, the results of the analysis are assimilated, and the projects are categorized as category 1 projects which are identified as needed in this planning cycle, and category 2 projects which could be needed and which will be carried forward into future planning cycles.

5.1. Renewable Portfolios

5.1.1 Portfolio 1 — High Transmission Utilization Scenario

The High Transmission Utilization scenario incorporated plausible but high levels of in-state resource development. The resulting portfolio is shown in Figure 5.1-1.

Figure 5.1-1 High Transmission Utilization Portfolio

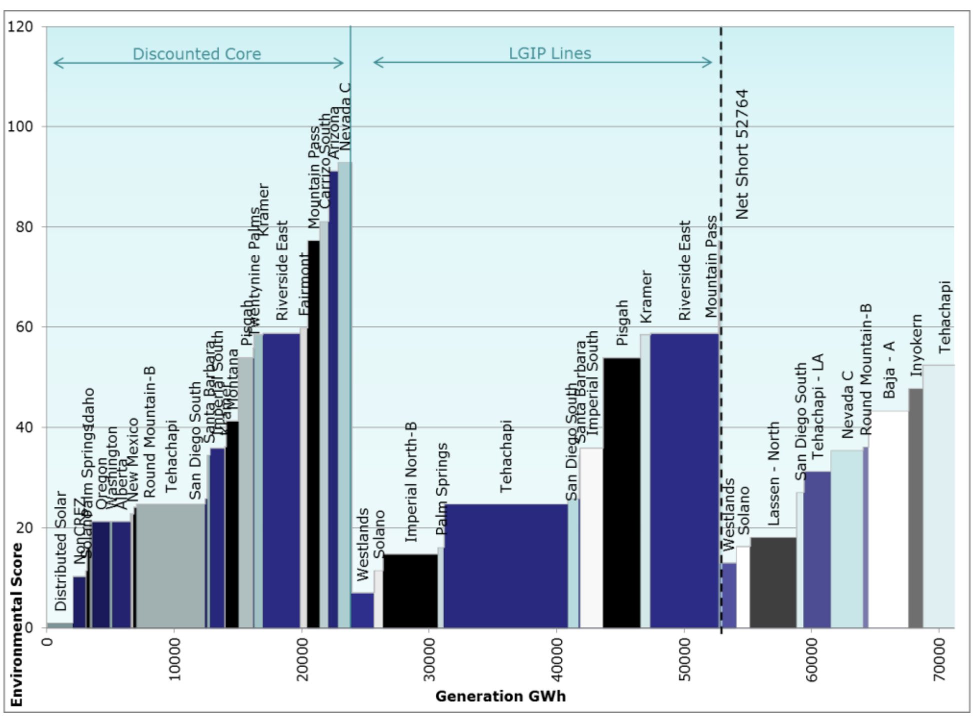


Table 5.1-1 High Transmission Utilization Portfolio — Resource distribution by CREZ and level of commercial interest

	Location	All Resources		Discounted Core		Interconnection Queue		CEC Approved	
		GWh	MW	GWh	MW	GWh	MW	GWh	MW
In-State	Carrizo South	697	299	697	299	0	0	0	0
	Distributed Solar	2864	1303	2058	1032	0	0	0	0
	Fairmont	1827	670	584	230	0	0	0	0
	Imperial North-B	4293	594	0	0	4293	594	0	0
	Imperial South	2927	974	1115	389	2927	974	701	300
	Kramer	810	330	703	292	810	330	584	250
	Mountain Pass	1018	434	958	410	1018	434	958	410
	NonCREZ	779	139	983	167	0	0	0	0
	Palm Springs	641	227	217	77	641	227	0	0
	Pisgah	4090	1750	1169	500	4090	1750	0	0
	Riverside East	8201	3427	2905	1192	8201	3427	2921	1250
	Round Mountain-B	221	78	221	78	221	78	0	0
	San Bernardino - Lucerne	119	42	0	0	119	42	0	0
	San Diego South	1030	331	156	21	1030	331	0	0
	Santa Barbara	321	123	233	83	321	123	0	0
	Solano	796	282	107	38	796	282	0	0
	Tehachapi	13740	5110	5399	1912	13740	5110	0	0
	Twentynine Palms	0	0	0	0	0	0	0	0
	Victorville	568	201	0	0	568	201	0	0
	Westlands	1582	720	0	0	1582	720	0	0
	In-State Total	46525	17034	17554	6740	28911	10269	5165	2210
Out-of-State	Alberta	1410	516	1410	516	0	0	0	0
	Arizona	737	290	737	290	0	0	737	290
	Idaho	229	90	229	90	0	0	0	0
	Montana	994	300	994	300	0	0	0	0
	Nevada C	1062	450	1062	450	0	0	0	0
	New Mexico	238	32	238	32	0	0	0	0
	Oregon	1341	524	1341	524	0	0	0	0
	Washington	230	90	230	90	0	0	0	0
	Out-of-State Total	6240	2292	6240	2292	0	0	737	290
Total		52764	19326	23794	9032	28911	10269	5902	2500

Table 5.1-2 High Transmission Utilization Portfolio — Resource distribution by CREZ and technology type

	Location	All Resources		Generation by Resource Type (GWh)					
		GWh	MW	Wind	Large Solar PV	Solar Thermal	Small Solar PV	Biogas/ Biomass	Geothermal
In-State	Carrizo South	697	299	0	697	0	0	0	0
	Distributed Solar	2864	1303	0	0	0	2864	0	0
	Fairmont	1827	670	0	1827	0	0	0	0
	Imperial North-B	4293	594	0	0	0	0	0	4293
	Imperial South	2927	974	1551	125	701	0	261	289
	Kramer	810	330	226	0	584	0	0	0
	Mountain Pass	1018	434	0	60	958	0	0	0
	NonCREZ	779	139	0	117	0	0	662	0
	Palm Springs	641	227	641	0	0	0	0	0
	Pisgah	4090	1750	0	0	4090	0	0	0
	Riverside East	8201	3427	0	3072	5129	0	0	0
	Round Mountain-B	221	78	221	0	0	0	0	0
	San Bernardino - Lucerne	119	42	119	0	0	0	0	0
	San Diego South	1030	331	874	0	0	0	156	0
	Santa Barbara	321	123	233	88	0	0	0	0
	Solano	796	282	796	0	0	0	0	0
	Tehachapi	13740	5110	12714	1026	0	0	0	0
	Twentynine Palms	0	0	0	0	0	0	0	0
	Victorville	568	201	0	568	0	0	0	0
	Westlands	1582	720	0	1582	0	0	0	0
	In-State Total	46525	17034	17375	9162	11463	2864	1079	4582
Out-of-State	Alberta	1410	516	1410	0	0	0	0	0
	Arizona	737	290	0	737	0	0	0	0
	Idaho	229	90	229	0	0	0	0	0
	Montana	994	300	994	0	0	0	0	0
	Nevada C	1062	450	0	127	935	0	0	0
	New Mexico	238	32	0	0	0	0	238	0
	Oregon	1341	524	1341	0	0	0	0	0
	Washington	230	90	230	0	0	0	0	0
	Out-of-State Total	6240	2292	4203	863	935	0	238	0
Total		52764	19326	21578	10025	12398	2864	1317	4582

Relying solely on in-state large renewable generation projects to meet the net short energy beyond the discounted core, the high utilization scenario represents a plausible upper bound on in-state transmission utilization. The generation in the CREZs serving projects that are least favorable environmentally was backed down. Those CREZs included Mountain Pass, Carrizo South, and Kramer.

5.1.2 High Out-of-State Scenario – Portfolio 2

Out-of-state resources include generation in Arizona and the Northwest, bringing total out-of-state generation to 19,281 GWh, or 37% of the net short energy. In addition, rather than relying solely on renewable energy credits (RECs), the ISO assumed some need to physically deliver energy from a portion of these projects, which could result in the need for additional investment in the interconnection California and the Pacific Northwest. In particular, the assessment of Portfolio 2 led to determining that 2000 additional MW of capacity was needed to deliver energy from the Pacific Northwest. However existing transmission from the Southwest was expected to be sufficient to accommodate additional renewable resource output from renewable resources in the Southwest.

Figure 5.1-2 High Out-of-State Portfolio

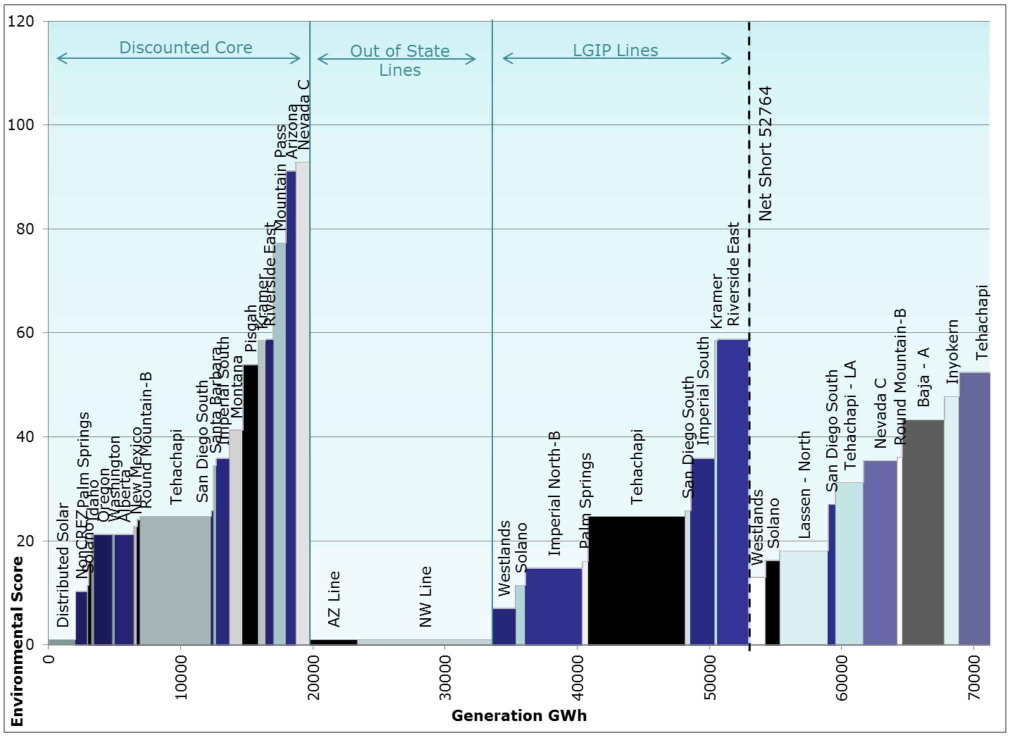


Table 5.1-3 High Out-of-State Portfolio –Resource distribution by CREZ and level of commercial interest

	Location	All Resources		Discounted Core		Interconnection Queue		CEC Approved	
		GWh	MW	GWh	MW	GWh	MW	GWh	MW
In-State	Carrizo South	0	0	0	0	0	0	0	0
	Distributed Solar	2671	1223	2058	1032	0	0	0	0
	Fairmont	1242	440	0	0	0	0	0	0
	Imperial North-B	4293	594	0	0	4293	594	0	0
	Imperial South	2802	925	990	340	2802	925	701	300
	Kramer	810	330	584	250	810	330	584	250
	Mountain Pass	966	413	966	413	0	0	966	413
	NonCREZ	663	89	866	117	0	0	0	0
	Palm Springs	641	227	217	77	641	227	0	0
	Pisgah	1169	500	1169	500	1169	500	0	0
	Riverside East	2921	1250	584	250	2921	1250	2921	1250
	Round Mountain-B	221	78	221	78	221	78	0	0
	San Bernardino - Lucerne	119	42	0	0	119	42	0	0
	San Diego South	1030	331	156	21	1030	331	0	0
	Santa Barbara	193	69	193	69	193	69	0	0
	Solano	836	296	107	38	836	296	0	0
	Tehachapi	11324	4010	5399	1912	11324	4010	0	0
	Twentynine Palms	0	0	0	0	0	0	0	0
	Westlands	1582	720	0	0	1582	720	0	0
	In-State Total	33483	11538	13544	5108	19361	6224	5165	2210
Out-of-State	Alberta	1410	516	1410	516	0	0	0	0
	Arizona	4317	1790	737	290	0	0	737	290
	Idaho	229	90	229	90	0	0	0	0
	Montana	994	300	994	300	0	0	0	0
	Nevada C	1062	450	1062	450	0	0	0	0
	New Mexico	238	32	238	32	0	0	0	0
	Oregon	10801	4190	1341	524	0	0	0	0
	Washington	230	90	230	90	0	0	0	0
	Out-of-State Total	19281	7458	6240	2292	0	0	737	290
Total		52764	18995	19783	7400	19361	6224	5902	2500

Table 5.1-4 High Out-of-State Portfolio –Resource distribution by CREZ and technology type

	Location	All Resources		Generation by Resource Type (GWh)					
		GWh	MW	Wind	Large Solar PV	Solar Thermal	Small Solar PV	Biogas/ Biomass	Geothermal
In-State	Carrizo South	0	0	0	0	0	0	0	0
	Distributed Solar	2671	1223	0	0	0	2671	0	0
	Fairmont	1242	440	0	1242	0	0	0	0
	Imperial North-B	4293	594	0	0	0	0	0	4293
	Imperial South	2802	925	1551	0	701	0	261	289
	Kramer	810	330	226	0	584	0	0	0
	Mountain Pass	966	413	0	0	966	0	0	0
	NonCREZ	663	89	0	0	0	0	663	0
	Palm Springs	641	227	641	0	0	0	0	0
	Pisgah	1169	500	0	0	1169	0	0	0
	Riverside East	2921	1250	0	0	2921	0	0	0
	Round Mountain-B	221	78	221	0	0	0	0	0
	San Bernardino-Lucerne	119	42	119	0	0	0	0	0
	San Diego South	1030	331	874	0	0	0	156	0
	Santa Barbara	193	69	193	0	0	0	0	0
	Solano	836	296	836	0	0	0	0	0
	Tehachapi	11324	4010	11324	0	0	0	0	0
	Twentynine Palms	0	0	0	0	0	0	0	0
	Westlands	1582	720	0	1582	0	0	0	0
	In-State Total	33483	11538	15984	2824	6342	2671	1080	4582
Out-of-State	Alberta	1410	516	1410	0	0	0	0	0
	Arizona	4317	1790	0	4317	0	0	0	0
	Idaho	229	90	229	0	0	0	0	0
	Montana	994	300	994	0	0	0	0	0
	Nevada C	1062	450	0	127	935	0	0	0
	New Mexico	238	32	0	0	0	0	238	0
	Oregon	10801	4190	10801	0	0	0	0	0
	Washington	230	90	230	0	0	0	0	0
	Out-of-State Total	19281	7458	13664	4444	935	0	238	0
Total		52764	18995	29648	7268	7277	2671	1318	4582

In backing down in-state resources as described in Chapter 4, the majority of projects displaced by the new out-of-state generation were located in Tehachapi, Riverside East and Pisgah. The additional out-of-state generation resulted in more headroom on the in-state transmission lines. Reaching the RPS goal in this case is unlikely to be transmission constrained. Less than full utilization does not mean that the lines are not needed, but only that additional resources could be delivered on them without additional upgrades.

5.1.3 High Distributed Generation Scenario – Portfolio 3

The high distributed generation scenario includes 18,615 GWh and 9,248 MW of distributed generation resources.

Figure 5.1-3 High Distributed Generation Portfolio

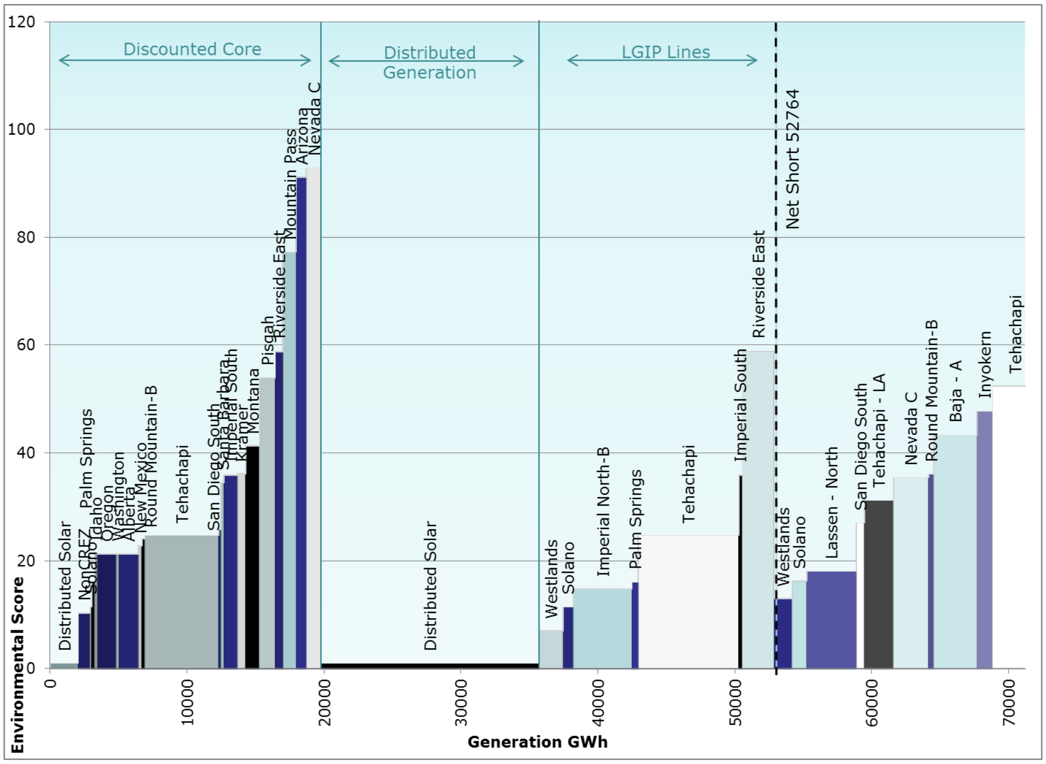


Table 5.1-5 High Distributed Generation Portfolio – Distribution by CREZ and commercial interest

	Location	All Resources		Discounted Core		Interconnection Queue		CEC Approved	
		GWh	MW	GWh	MW	GWh	MW	GWh	MW
In-State	Carrizo South	0	0	0	0	0	0	0	0
	Distributed Solar	18615	9248	2058	1032	0	0	0	0
	Fairmont	1242	440	0	0	0	0	0	0
	Imperial North-B	4293	594	0	0	4293	594	0	0
	Imperial South	1251	376	990	340	1251	376	701	300
	Kramer	584	250	584	250	584	250	584	250
	Mountain Pass	919	393	919	393	919	393	919	393
	NonCREZ	663	89	866	117	0	0	0	0
	Palm Springs	641	227	217	77	641	227	0	0
	Pisgah	1169	500	1169	500	1169	500	0	0
	Riverside East	2921	1250	584	250	2921	1250	2921	1250
	Round Mountain-B	221	78	221	78	221	78	0	0
	San Diego South	1030	331	156	21	1030	331	0	0
	Santa Barbara	193	69	193	69	193	69	0	0
	Solano	836	296	107	38	836	296	0	0
	Tehachapi	10364	3670	5399	1912	10364	3670	0	0
	Twentynine Palms	0	0	0	0	0	0	0	0
	Westlands	1582	720	0	0	1582	720	0	0
	In-State Total	46524	18578	13544	5108	17162	5445	5165	2210
Out-of-State	Alberta	1410	516	1410	516	0	0	0	0
	Arizona	737	290	737	290	0	0	737	290
	Idaho	229	90	229	90	0	0	0	0
	Montana	994	300	994	300	0	0	0	0
	Nevada C	1062	450	1062	450	0	0	0	0
	New Mexico	238	32	238	32	0	0	0	0
	Oregon	1341	524	1341	524	0	0	0	0
	Washington	230	90	230	90	0	0	0	0
	Out-of-State Total	6240	2292	6240	2292	0	0	737	290
Total		52746	20822	19783	7400	17162	5445	5902	2500

Table 5.1-6 High Distributed Generation Portfolio –Distribution by CREZ and technology type

	Location	All Resources		Generation by Resource Type (GWh)					
		GWh	MW	Wind	Large Solar PV	Solar Thermal	Small Solar PV	Biogas/ Biomass	Geothermal
In-State	Carrizo South	0	0	0	0	0	0	0	0
	Distributed Solar	18615	9248	0	0	0	18615	0	0
	Fairmont	1242	440	0	1242	0	0	0	0
	Imperial North-B	4293	594	0	0	0	0	0	4293
	Imperial South	1251	376	0	0	701	0	261	289
	Kramer	584	250	0	0	584	0	0	0
	Mountain Pass	919	393	0	0	919	0	0	0
	NonCREZ	663	89	0	0	0	0	663	0
	Palm Springs	641	227	641	0	0	0	0	0
	Pisgah	1169	500	0	0	1169	0	0	0
	Riverside East	2921	1250	0	0	2921	0	0	0
	Round Mountain-B	221	78	221	0	0	0	0	0
	San Diego South	1030	331	874	0	0	0	156	0
	Santa Barbara	193	69	193	0	0	0	0	0
	Solano	836	296	836	0	0	0	0	0
	Tehachapi	10364	3670	10364	0	0	0	0	0
	Twentynine Palms	0	0	0	0	0	0	0	0
	Westlands	1582	720	0	1582	0	0	0	0
	In-State Total	46524	18578	13129	2824	6295	18615	1080	4582
Out-of-State	Alberta	1410	516	1410	0	0	0	0	0
	Arizona	737	290	0	737	0	0	0	0
	Idaho	229	90	229	0	0	0	0	0
	Montana	994	300	994	0	0	0	0	0
	Nevada C	1062	450	0	127	935	0	0	0
	New Mexico	238	32	0	0	0	0	238	0
	Oregon	1341	524	1341	0	0	0	0	0
	Washington	230	90	230	0	0	0	0	0
	Out-of-State Total	6240	2292	4203	863	935	0	238	0
Total		52746	20822	17332	3687	7230	18615	1318	4582

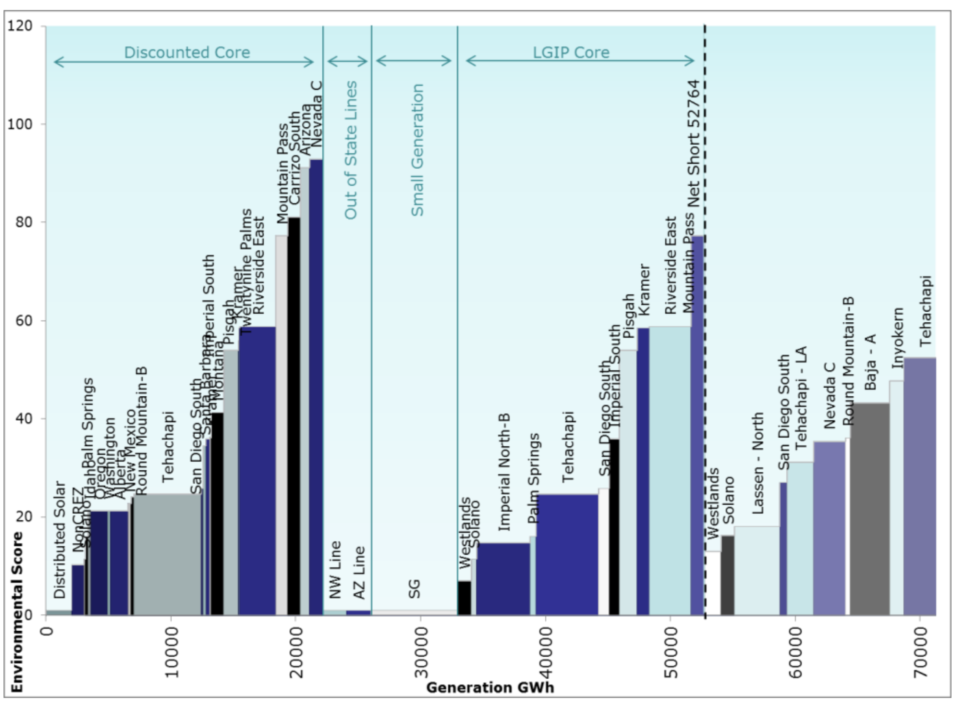
Adjusting in-state generation down from the high utilization portfolio to accommodate the increase in distributed generation, the amount of in-state generation was backed down further in the distributed generation portfolio than had been required in creating the out-of-state case. Generation resources were predominantly removed from Imperial South, San Diego South, Carrizo South, Pisgah, Riverside East and Kramer using the process described in chapter 4.

As in the out-of-state scenario, renewable generation development under this scenario was unlikely to be transmission constrained. The distributed generation case spread the resources equally around the grid in an effort to mitigate any need for additional transmission.[38] Again similar to the out-of-state case, renewable generation development is unlikely to be transmission constrained for some time, even after meeting the 2020 33% RPS goal.

5.1.4 Hybrid Portfolio – Portfolio 4

The hybrid portfolio is generated as described in chapter 4. The ISO considered that a more likely scenario would include moderate development of all three types of resources: large in-state, out-of-state and distributed generation. The hybrid scenario includes development of 50% of the out-of-state resources from the high out-of-state case, and approximately 33% of the distributed generation resources from the high distributed generation case. The resulting portfolio is shown in the figure below by CREZ.

Figure 5.1-4 Hybrid Portfolio



38 The distributed case assumed that those resources could be installed at the distribution level without having a major impact on transmission need or costs as long as the resources did not exceed 30 percent of the peak load within each distribution planning area.

Table 5.1-7 Hybrid Portfolio — Resource distribution by CREZ and level of commercial interest

	Location	All Resources		Discounted Core		Interconnection Queue		CEC Approved	
		GWh	MW	GWh	MW	GWh	MW	GWh	MW
In-State	Carrizo South	1007	489	1007	489	1007	489	0	0
	Distributed Solar	6080	2902	2058	1032	0	0	0	0
	Fairmont	1242	440	0	0	1242	440	0	0
	Imperial North-A	1766	725	0	0	1766	725		
	Imperial North-B	4293	594	0	0	4293	594	0	0
	Imperial South	2740	924	289	40	2740	924	0	0
	Kramer	478	188	179	68	478	188	60	26
	Mountain Pass	1985	849	958	410	1985	849	958	410
	NonCREZ	779	167	983	167	0	0	0	0
	Palm Springs	641	227	217	77	641	227	0	0
	Pisgah	2598	1112	1169	500	2598	1112	0	0
	Riverside East	6225	2595	2905	1192	6225	2595	2921	1250
	Round Mountain-B	221	78	221	78	221	78	0	0
	San Bernardino-Lucerne	119	42	0	0	119	42	0	0
	San Diego South	1030	331	156	21	1030	331	0	0
	Santa Barbara	233	83	233	83	233	83	0	0
	Solano	499	177	107	38	499	177	0	0
	Tehachapi	9059	3208	5399	1912	9059	3208	0	0
	Twentynine Palms	0	0	47	20	0	0	0	0
	Victorville	568	201	0	0	568	201	0	0
	Westlands	1116	508	0	0	1116	508	0	0
	In-State Total	42679	15838	15923	6124	19820	6576	3940	1686
Out-of-State	Alberta	1410	516	1410	516	0	0	0	0
	Arizona	2646	1090	737	290	0	0	737	290
	Idaho	229	90	229	90	0	0	0	0
	Montana	994	300	994	300	0	0	0	0
	Nevada C	1062	450	1062	450	0	0	0	0
	New Mexico	238	32	238	32	0	0	0	0
	Oregon	3276	1274	1341	524	0	0	0	0
	Washington	230	90	230	90	0	0	0	0
	Out-of-State Total	10085	3842	6240	2292	0	0	737	290
Total		52764	19680	22163	8416	19820	6576	4677	1976

Table 5.1-8 Hybrid Portfolio — Resource distribution by CREZ and technology type

	Location	All Resources		Generation by Resource Type (GWh)					
		GWh	MW	Wind	Large Solar PV	Solar Thermal	Small Solar PV	Biogas/ Biomass	Geothermal
In-State	Carrizo South	1007	489	0	1007	0	0	0	0
	Distributed Solar	6080	2902	0	0	0	6080	0	0
	Fairmont	1242	440	0	1242	0	0	0	0
	Imperial North-A	1766	725	0	1766	0	0	0	0
	Imperial North-B	4293	594	0	0	0	0	0	4293
	Imperial South	2740	924	541	939	710	0	261	289
	Kramer	478	188	231	0	247	0	0	0
	Mountain Pass	1985	849	0	0	1985	0	0	0
	NonCREZ	779	167	0	117	0	0	662	0
	Palm Springs	641	227	641	0	0	0	0	0
	Pisgah	2598	1112	0	0	2598	0	0	0
	Riverside East	6225	2595	0	2265	3960	0	0	0
	Round Mountain-B	221	78	221	0	0	0	0	0
	San Bernardino - Lucerne	119	42	119	0	0	0	0	0
	San Diego South	1030	331	874	0	0	0	156	0
	Santa Barbara	233	83	233	0	0	0	0	0
	Solano	499	177	499	0	0	0	0	0
	Tehachapi	9059	3208	9059	0	0	0	0	0
	Twentynine Palms	0	0	0	0	0	0	0	0
	Victorville	568	201	0	568	0	0	0	0
	Westlands	1116	508	0	1116	0	0	0	0
	In-State Total	42679	15838	12418	9020	9500	6080	1079	4582
Out-of-State	Alberta	1410	516	1410	0	0	0	0	0
	Arizona	2646	1090	0	2646	0	0	0	0
	Idaho	229	90	229	0	0	0	0	0
	Montana	994	300	994	0	0	0	0	0
	Nevada C	1062	450	0	127	935	0	0	0
	New Mexico	238	32	0	0	0	0	238	0
	Oregon	3276	1274	3276	0	0	0	0	0
	Washington	230	90	230	0	0	0	0	0
	Out-of-State Total	10085	3842	6139	2773	935	0	238	0
Total		52764	19680	18557	11793	10435	6080	1317	4582

The hybrid portfolio shows that the net short energy can be met with the LGIP lines and a moderate amount of out-of-state energy imports and distributed generation.

5.1.5 Summary

The total energy in each scenario is shown geographically and by technology type in the figures of northern and southern California shown below.

Fig. 5.1-5 Comparison of Energy Produced (GWh) from the Resources Selected in Each Scenario by Location and Technology in Northern California and Other Northern States

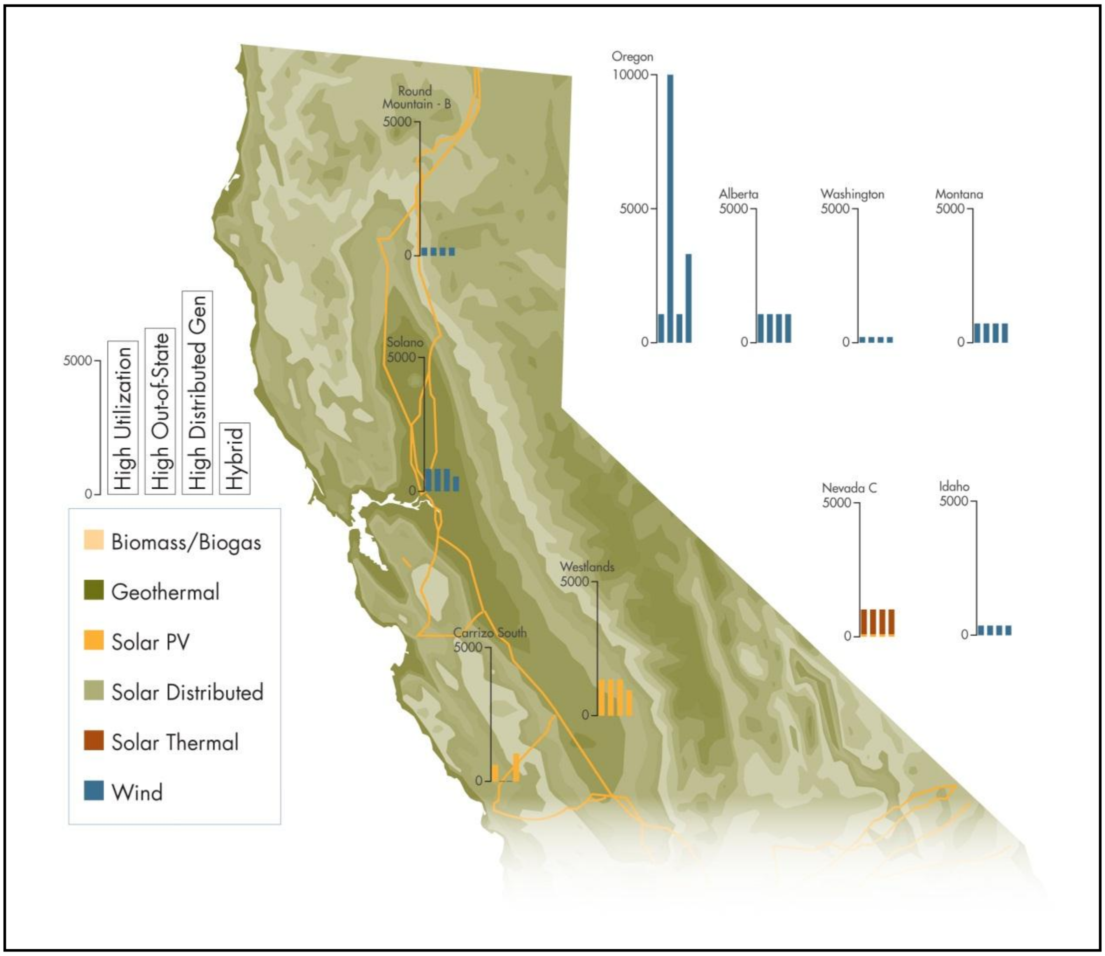
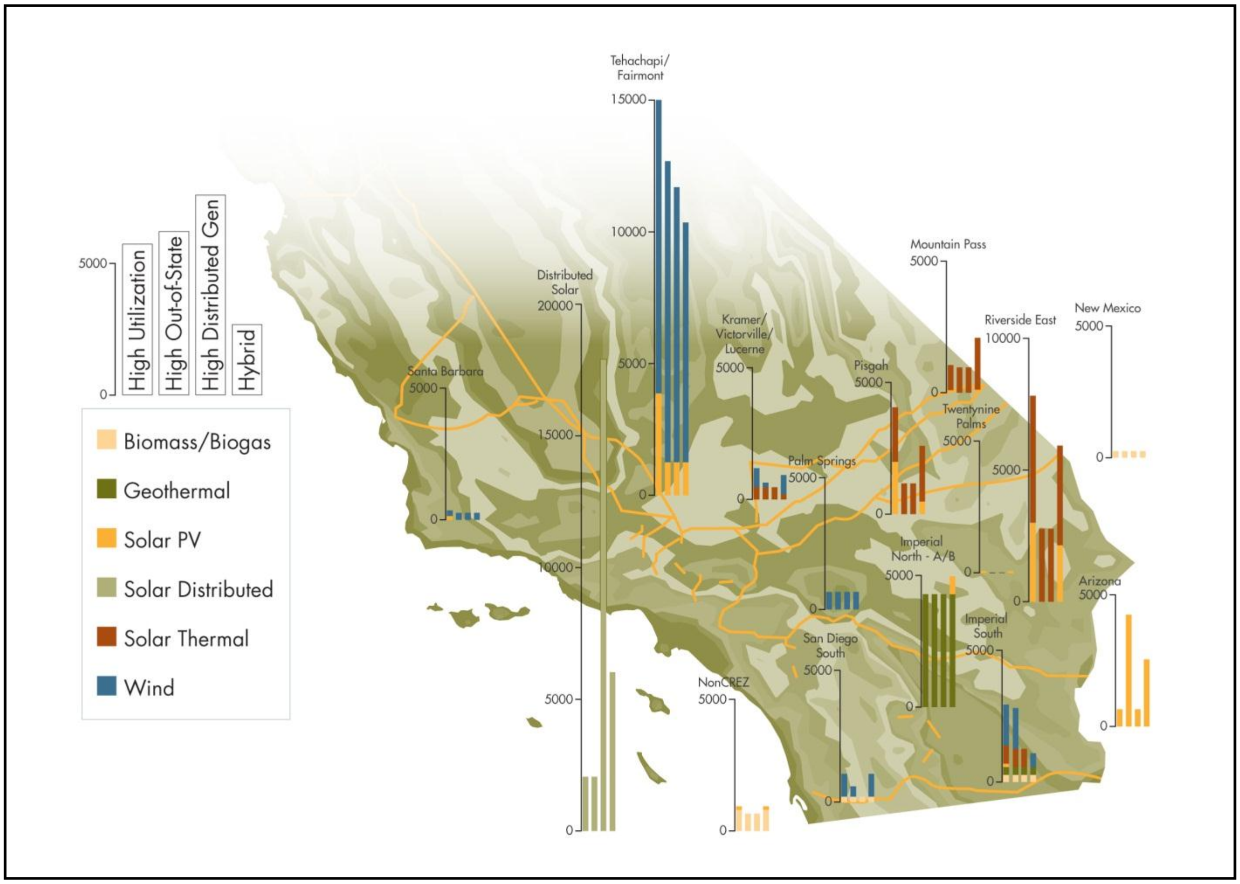


Fig. 5.1-6 Comparison of Energy Produced (GWh) from the Resources Selected in Each Scenario by Location and Technology in Southern California and the Other Southern States



There is a substantial range covered by these scenarios. The high utilization portfolio maintains plausible but relatively modest estimates of resources from out-of-state (6,240 GWh), and distributed generation (2,864 GWh) with relatively high estimates of in-state large solar (20,204 GWh) and wind (17,794 GWh). The high distributed generation case contains 18,615 GWh of distributed generation, which reduces the need for in-state resources. The high out-of-state case contains both physical imports of approximately 3,000 MW and 1,500 MW over the northern and southern interties respectively, with the remaining capacity provided through the use of renewable energy credits, the use of existing transmission capability made available by displacing other imports, or the use of arbitrage from one time period to another through trading mechanisms.

5.1.6 Renewable deliverability potential provided by LGIP lines

As discussed earlier in Sections 4.2 and 4.3, available transmission capacity from approved transmission upgrades and potential transmission capacity from LGIP lines were important factors in the development of 33% RPS portfolios. Once the renewable portfolios were developed, the need for the transmission upgrades was assessed. Transmission upgrades approved through prior planning cycles or projects advanced through the LGIP that have received CPUC approval included Tehachapi, Eldorado–Ivanpah, Colorado River–Valley, and Sunrise, as shown in Table 4.2-1 in section 4.2. The need for these approved transmission upgrades has been fully evaluated during their study and approval processes and will not be re-examined in this section. Instead, this section will focus on the need for the remaining LGIP lines.

A two-step examination was performed on the LGIP lines listed in Table 4.2-1 in section 4.2. It relies on the results of deliverability assessments for generation interconnections as an input to this examination. The first step was to examine, for each renewable portfolio, if a transmission deficiency would occur without modeling the LGIP lines. In this step, the renewable generation deliverability of the system without LGIP lines was taken from generation interconnection study results. Then the renewable generation in the CREZs that utilized the LGIP lines was identified from the same generation interconnection studies. The total renewable capacity in these identified CREZs in each portfolio was compared with the renewable generation deliverability of the system without the LGIP lines modeled. If the total renewable capacity was greater than the existing deliverability, then a transmission deficiency was identified. The test results are shown in Table 5.1-9. In this table, “P4”, “P1”, “P2”, “P3” are used to represent portfolios 4, 1, 2, and 3, respectively. Also provided in this table is the description of reliability concerns causing the transmission deficiency.

Table 5.1-9 Potential reliability concerns without the LGIP line upgrades in each of four portfolios

	Renewable Deliverability without upgrade	Renewable capacity in CREZs that need the upgrades to be deliverable for resource				Deliverability concerns in portfolios without upgrade				Description of deliverability concerns without upgrade
Transmission Upgrade	MW	P4	P1	P2	P3	P4	P1	P2	P3	
Carrizo–Midway reconductoring	300	572	422	69	69	Yes	Yes	No	No	Thermal overload on the Carrizo–Midway portion of the Morro Bay–Midway 230 kV line
Pisgah–Lugo 500 kV line	275	1112	1750	500	500	Yes	Yes	Yes	Yes	Thermal overload on the existing Pisgah–Lugo 230 kV #1 and #2 lines

	Renewable Deliverability without upgrade	Renewable capacity in CREZs that need the upgrades to be deliverable for resource				Deliverability concerns in portfolios without upgrade				Description of deliverability concerns without upgrade
Transmission Upgrade	MW	P4	P1	P2	P3	P4	P1	P2	P3	
West of Devers Upgrade	1600	2822	3654	1477	1477	Yes	Yes	No	No	Thermal overload on the West of Devers 230 kV lines
South of Contra Costa recondutoring	0	177	282	296	296	Yes	Yes	Yes	Yes	Thermal overload on the South of Contra Costa lines
Borden–Gregg 230 kV line reconductoring	220	508	720	720	720	Yes	Yes	Yes	Yes	Thermal overload on the Borden–Gregg 230 kV line
Coolwater–Lugo 230 kV line	323	431	573	372	250	Yes	Yes	Yes	No	Thermal overload on the Kramer–Lugo 230 kV #1 and #2 lines
Llano–Kramer 500 kV line, Kramer–Inyokern 230 kV, Bishop–Inyokern 230 kV lines (Note 1)	600	0	0	0	0	No	No	No	No	Thermal overload on Kramer–Lugo 230 kV lines, Bishop–Inyokern–Kramer 115 kV lines, Kramer 230/115 kV transformers

The second step of the test is to examine the utilization of facility upgrades or additions, which is calculated as below:

Utilization = (Renewable capacity–Renewable deliverability without upgrade)/(Renewable deliverability with upgrade–Renewable deliverability without upgrade)

Using the portfolio 4 and Carrizo–Midway reconductoring as example:

Utilization of Carrizo-Midway reconductoring = (572-300)/(900-300)=45%

Table 5.1-10 Renewable deliverability potential with LGIA line upgrades and the utilization of potential deliverability in each of four portfolios

Transmission Upgrade	Renewable Deliverability without upgrade	Renewable Deliverability with upgrade	Utilization of facility upgrades				Renewable capacity in CREZs that need the upgrades to be deliverable for resource adequacy				
	MW	MW	P4	P1	P2	P3	P4	P1	P2	P3	CREZs
Carrizo–Midway reconductoring	300	900	45%	20%	0%	0%	572	422	69	69	Carrizo South, Santa Barbara
Pisgah–Lugo 500 kV line	275	1750	57%	100%	15%	15%	1112	1750	500	500	Pisgah
West of Devers Upgrade	1600	4700	39%	66%	0%	0%	2822	3654	1477	1477	Riverside East, Palm Springs
South of Contra Costa reconductoring	0	300	59%	94%	99%	99%	177	282	296	296	Solano
Borden–Gregg 230 kV line reconductoring	220	800	50%	86%	86%	86%	508	720	720	720	Westlands
Coolwater–Lugo 230 kV line	323	600	39%	90%	18%	0%	431	573	372	250	Kramer, Victorville, San Bernardino–Lucerne
Llano–Kramer 500 kV line, Kramer–Inyokern 230 kV, Bishop–Inyokern 230 kV lines	600	1400	0%	0%	0%	0%	0	0	0	0	Kramer, Victorville, San Bernardino–Lucerne

5.2. Base cases and Scenarios for Power Flow and Stability Assessments

5.2.1 Base cases and scenarios overview

The 33% RPS transmission planning studies examined multiple scenarios for different RPS portfolios in order to investigate the transmission need under different conditions. Both peak and off-peak conditions were assessed in these studies. In addition, specific renewable output snapshots such as low solar and nighttime were assessed. These additional sensitivity studies were used to investigate particular transmission needs in certain local areas. The detailed information about the local area assessments can be found in section 5.4.
Table 5.2-1 shows the scenarios and base cases that were studied in the comprehensive transmission planning assessment.

Table 5.2-1 Scenarios and base cases in the comprehensive transmission planning assessment to meet 33% RPS

Portfolios	1-in-5 Peak	High N.CA Hydro, peak load	Off-peak (50% of peak)	Low or no solar, off-peak load	8760 hours Production cost simulation
Portfolio1 (high utilization)	Yes		Yes	Yes	Yes
Portfolio 2 (high import)	Yes				Yes
Portfolio 3 (high DG)					Yes
Portfolio 4 (hybrid)	Yes	Yes	Yes		Yes

Different RPS portfolios will cause different dispatch and path flow patterns in the system. Although historical data about system operations has been widely used as a reference in the base case development for many transmission planning studies, additional information was needed for the 33% RPS comprehensive transmission planning studies. Production cost simulations have been performed for all four renewable generation portfolios as discussed above. Snapshots (including generation dispatch and path flows) at different hours were used to develop the base cases for different scenarios in the portfolios.
The base cases were developed to represent the reasonably stressed scenarios according to the production cost simulation results for the 2020 study year with the corresponding renewable portfolios. In selecting the reasonably stressed scenarios, historical system operation data and knowledge from other transmission planning studies was also considered. If the production cost simulation showed that some path flows were much lower than the historical levels, path flows higher than the production cost simulation results were modeled in the base cases to preserve the existing transmission contracts on the paths. Sensitivity scenarios were also developed to investigate specific stressed patterns that are deemed credible based on historical data. The selection of the snapshots for portfolios is shown in Table 5.2-2.

Table 5.2-2 Renewable dispatch and path flow patterns by portfolios

Portfolio and scenario	Renewable output	East of River	Path 42	Path 26	Path15	COI	PDCI
Portfolio1 peak	High (13,300 MW)	5460 (E-W)	550 (IID-SCE)	240 (N-S)	2700 (S-N)	4000 (N-S)	1550 (N-S)
Portfolio 1 off-peak	High (12,200 MW)	2850 (E-W)	500 (IID-SCE)	1750 (S-N)	5100 (S-N)	900 (N-S)	900 (N-S)
Portfolio 1 low solar in PGE	Low (6300 MW)	4450 (E-W)	660 (IID-SCE)	2350 (S-N)	5200 (S-N)	1350 (N-S)	400 (N-S)
Portfolio 1 midnight	Low (4460 MW)	4350 (E-W)	720 (IID-SCE)	2050 (N-S)	950 (S-N)	1520 (N-S)	0
Portfolio 2 peak	Medium (8600 MW)	5230 (E-W)	500 (IID-SCE)	1830 (N-S)	990 (S-N)	6370 (N-S)	2400 (N-S)
Portfolio 4 peak	High (11850 MW)	5200 (E-W)	930 (IID-SCE)	850 (S-N)	2010 (S-N)	4790 (N-S)	2600 (N-S)
Portfolio 4 off-peak	High (11560)	4740 (E-S)	960 (IID-SCE)	2600 (S-N)	4320(S-N)	1980 (N-S)	900 (N-S)

In general, transmission stressed patterns and the potential needs for transmission upgrades were bounded by the assessed scenarios. It was not necessary to assess all patterns with each portfolio.

5.2.2 Assessments by portfolios

All reliability assessments required by NERC and WECC planning standards and ISO grid planning guidelines were performed on portfolio 1, portfolio 2 and portfolio 4, including, but not limited to, power flow contingency analysis, post-transient voltage stability analysis and transient stability analysis. The contingencies that have been used in the ISO annual reliability assessment were revised to reflect the network topology changes and were simulated in the 33% RPS comprehensive transmission planning studies.

In addition, production cost simulations were performed for all four 33% RPS portfolios. Deliverability assessments were performed for portfolios 1 and 4. The deliverability assessment was not conducted for portfolio 2, which includes higher percentage of out-of-state renewable resources in the portfolio and hence a lower percentage of in-state renewable resources than portfolio 1. Table 5.2-3 summarizes the assessments conducted by portfolio.

Table 5.2-3 Assessment methods in the comprehensive transmission planning assessment to meet 33% RPS

Portfolio	Power flow contingency analysis	Post-transient analysis	Transient stability analysis	Production cost simulation	Deliverability assessment
Portfolio1 (high utilization)	Yes	Yes	Yes	Yes	Yes
Portfolio 2 (high import)	Yes	Yes	Yes	Yes	

Portfolio 3 (high DG)				Yes	
Portfolio 4 (hybrid)	Yes	Yes	Yes	Yes	Yes

Power flow, stability and deliverability assessments were not performed for portfolio 3 because this portfolio, with high distributed generation, is expected to cause less reliability concerns and deliverability issues than the other portfolios. This is because the distributed generation in the power flow base cases are modeled by scaling load down proportionally.

5.3 System and Renewable Interconnection Overview

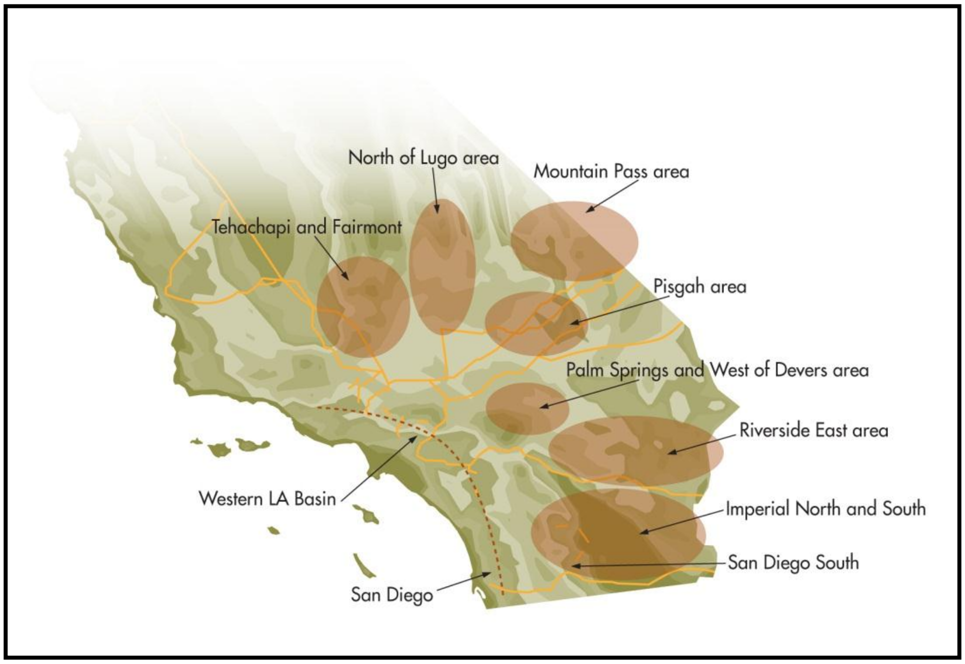
5.3.1 Southern California renewable interconnection and system overview

The southern California system of the ISO controlled grid consists of the SCE and SDGE systems. The southern California system connects with the northern California system through the 500 kV lines of Path 26. On the east, the southern California system connects with the remaining WECC system via Path 46 (West of River) and Path 49 (East of River). The ISO controlled grid in southern California also connects with LADWP, IID and other municipal systems. There is an interconnection between SDGE's system and CFE's system in the south.

The LA Basin and San Diego are two major load centers in the southern California system. They are tied together via Path 43 and Path 44 (North and South of San Onofre). Electrically, these two areas can be deemed as one load pocket, which has radial connections with the remaining system. The renewable-rich areas in southern California are located outside of this load pocket. The delivery of the renewable energy into the load pocket competes for the transmission capacity with the current energy import into the pocket.

The Western LA Basin is a sub-area inside the LA Basin that has been identified in LCR studies. Coincidentally, the Western LA Basin and San Diego areas are two areas that are subject to potential OTC retirements. As discussed in Section 4.4, most OTC units are off after generation re-dispatch based on economic dispatch due to their relatively high variable costs. This causes potentially high import levels into the Western LA Basin and San Diego areas, resulting in potential low voltage or voltage instability concerns. The geographic overview of the southern California system and renewable interconnection is illustrated in Fig. 5.3-1.

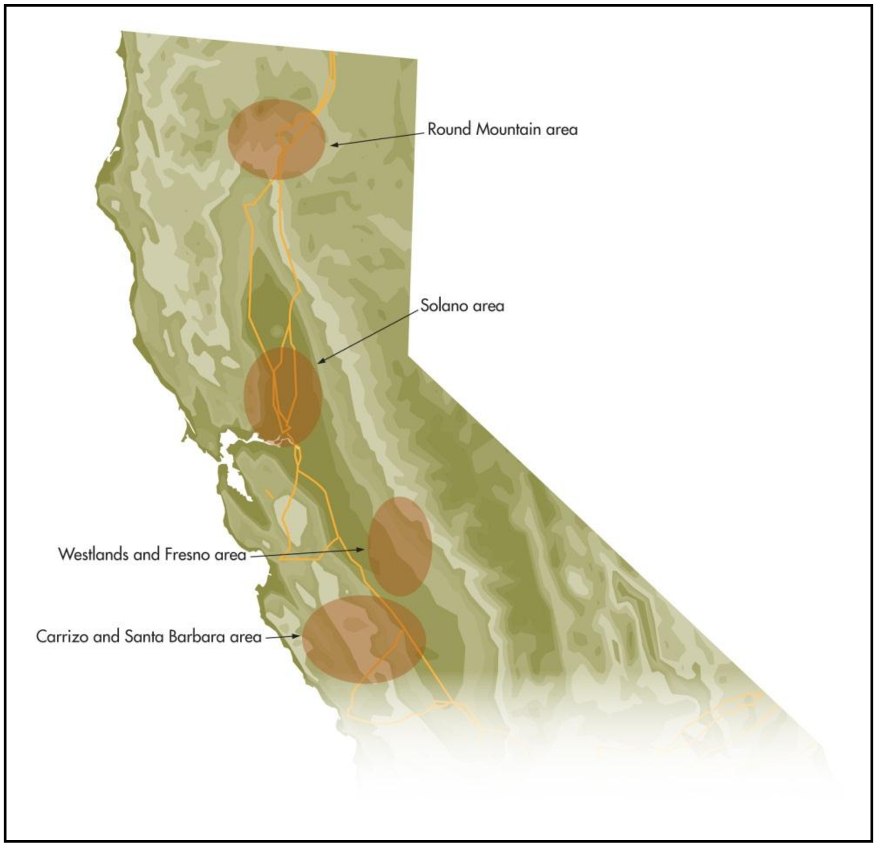
Figure 5.3-1 Renewable interconnection in Southern California – geographic overview



5.3.2 Northern California Renewable Interconnection and System Overview

The renewable generation rich areas in northern California mainly include the Round Mountain, Solano, Westlands and Carrizo areas. Most of these areas are located in or are in parallel to the corridor of the 500 kV lines running from the Pacific Northwest to the southern California. The renewable generation output from these areas will not only change the power flow magnitude on the 500 kV corridor, but will also affect the existing special protection schemes that are designed to protect the path ratings of COI, Path 15 and Path 26. On the other hand, some local systems of rich renewable generation areas may face more stressful situations than without the renewable generation when there are 500 kV facility outages. The geographic overview of the northern California system and renewable interconnection is illustrated in Figure 5.3-2.

Figure 5.3-2 Renewable interconnection in Northern California–geographic overview



5.3.3 Out-of-State Renewable Interconnection and California System Overview

Out-of-state renewable resources have been included in the 33% RPS portfolios. Similar to conventional out-of-state resources, renewable out-of-state resources in the future are likely to come from the northwest and southwest via COI, PDCI and East of River transmission lines, respectively. The out-of-state renewable resources and the major delivering paths in the portfolios are illustrated in Figure 5.3-3.

Figure 5.3-3 Out-of-state renewable interconnection–geographic overview

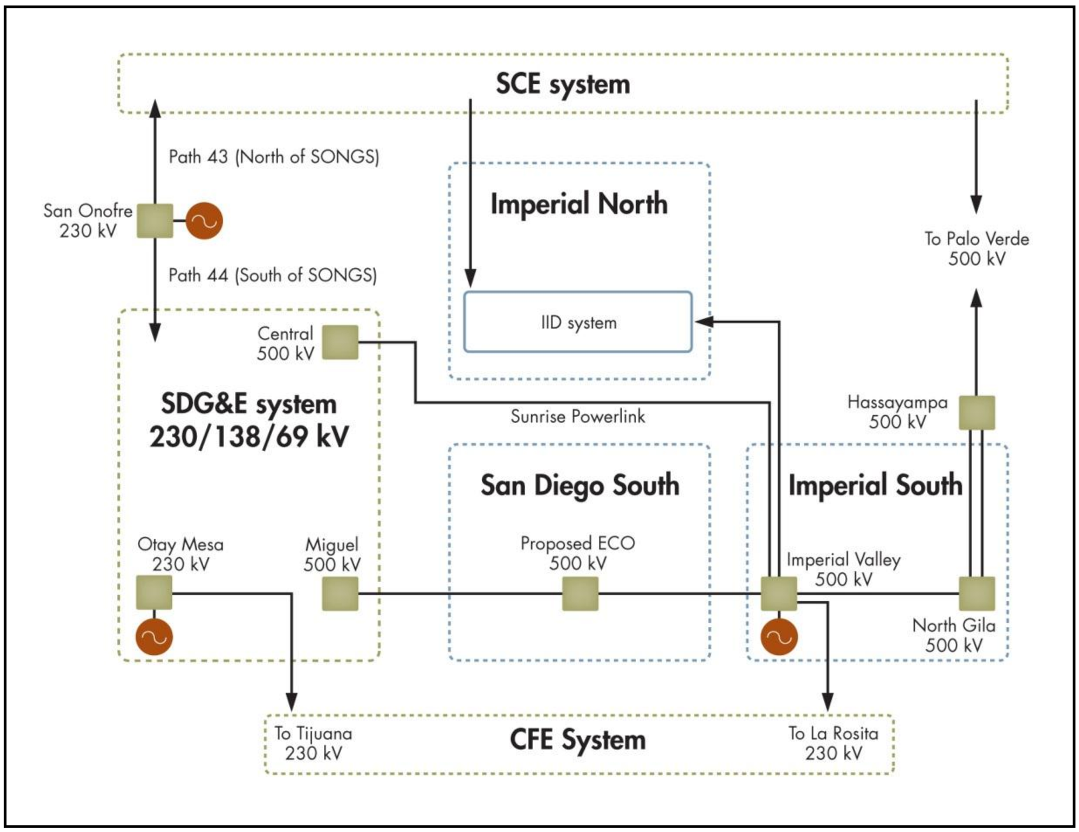
5.4 Assessment Results and Mitigations in SDG&E Area

5.4.1 SDG&E system overview

The SDG&E system configuration is shown in Figure 5.4-1. The major transmission upgrade in the SDG&E system modeled in the 33% RPS comprehensive transmission planning studies is the Sunrise Powerlink 500 kV transmission line and the associated plan of service. As discussed in section 4.1, the ECO 500 kV substation that the Imperial Valley–Miguel 500 kV line will loop into is also modeled in the base cases.

There are four CREZs in the east that have a direct impact on the SDG&E system. San Diego South and Imperial South CREZs are shown in Figure 5.3-1. Imperial North–A and Imperial North–B are located inside the IID's territory.

Figure 5.4-1 SDG&E system overview



5.4.2 Mitigations for San Diego internal overloads and voltage concerns

In this analysis, the ISO relied on San Diego internal generation capacity and new reactive support to mitigate San Diego internal overloads and other reliability concerns. As shown on Fig. 5.4-11, SCE generation can also help to mitigate some of San Diego overloads and voltage concerns. Thus, mitigation for the San Diego internal overloads and reliability concerns considered the generation dispatch in SCE, particularly in the LA Basin. Details about the Western LA Basin generation requirements can be found in section 5.5.

Summary of Analysis

The studies identified voltage instability following the double outage of Imperial Valley–ECO and Imperial Valley–Central 500kV lines. Some of the portfolios also identified voltage instability following single outages of Imperial Valley–ECO, ECO–Miguel, and IV–Central 500kV lines. These N-1 and N-2 outages require a special protection scheme that trips generation at Imperial Valley (existing and renewable). In addition, the SPS includes cross-tripping the Otay Mesa–Tijuana 230 kV line in the summer and Imperial Valley–La Rosita 230 kV line in the winter, if overloads occur on the CFE system. All of the above N-1 and N-2 outages require the cross trip. The studies also identified voltage instability following the N-2 outage of SONGS generators. Post-transient study results are summarized in Table 5.4-1.

Table 5.4-11 Post-transient Study Summary without Mitigation

Worst Contingency	Portfolio 1 Peak Case	Portfolio 2 Peak Case	Portfolio 4 Peak Case
IV–ECO 500kV (n-1)	Voltage collapse	Voltage collapse	Case solves
ECO–Miguel 500kV (n-1)	Voltage collapse	Voltage collapse	Voltage collapse
IV–Central 500kV (n-1)	Voltage collapse	Case solves	Case solves
IV–ECO 500kV & IV–Central 500kV Lines (n-2)	Voltage collapse	Voltage collapse	Voltage collapse
Otay Mesa–MiguelTap–South Bay 230 kV & Otay Mesa–Miguel Tap–Sycamore 230 kV (n-2)	Voltage collapse	Case solves	Case solves
SONGS–g2 (n-2)	Voltage collapse	Voltage collapse	Voltage collapse

In addition, the studies identified thermal overloads inside the San Diego system, which are summarized in Table 5.4-2.

Table 5.4-2 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Peak Case	Portfolio 2Peak Case	Portfolio 4 Peak Case
Miguel-Miguel 60 230/138 kV	TL13826 PRCTRVLY-MIGUEL ck 1	468	102%	<100%	<100%
Miguel-Miguel 60 230/138 kV	ML BK 61 230/138	468	102%	<100%	<100%
Miguel 500/230 kV #1	Miguel 500/230 kV #2 (no SPS)	1329	113%	107%	107%
Miguel 500/230 kV #2	Miguel 500/230 kV #1 (no SPS)	1344	112%	105%	106%
Pomerado-Sycamore 69 kV #1	Pomerado-Sycamore 69 kV #2	179	108%	103%	103%
Pomerado-Sycamore 69 kV #2	Pomerado-Sycamore 69 kV #1	179	108%	103%	103%
Poway-Pomerado 69 kV	Sycamore-Pen 230 kV	148	124%	114%	114%
Poway-Pomerado 69 kV	Artesian-Sycamore 69 kV	148	118%	111%	114%
Poway-Pomerado 69 kV	Sycamore-Scripps 69 kV	148	113%	107%	107%
Poway-Pomerado 69 kV	Otay Mesa-South Bay 230 kV	148	112%	105%	105%
Poway-Pomerado 69 kV	Escondido 230/69 kV #3	148	109%	104%	103%
Poway-Rancho Carmel 69 kV	Artesian-Sycamore 69 kV	114	106%	101%	100%
South Bay-Miguel Tap 230 kV	Base system	912	111%	105%	102%
South Bay-Montgomery Tap 69 kV	Silvergate-South Bay 230 kV	170	108%	103%	100%
South Bay 230/69 kV #1	Silvergate-South Bay 230 kV	285	106%	102%	100%

South Bay 230/69 kV #2	Silvergate-South Bay 230 kV	285	106%	102%	100%
Sycamore-Chicarita 138 kV	Encina 230/138 kV	204.1	109%	103%	103%
Sycamore-Scripps 69 kV	Otay Mesa-South Bay 230 kV	174	114%	108%	107%
Sweetwater-Sweetwater Tap 69 kV	Silvergate-South Bay 230 kV	215	129%	122%	116%

DESCRIPTION AND SCOPE OF PROPOSED MITIGATION SOLUTIONS

Portfolio 4 scenario

For portfolio 4, the hybrid portfolio and the baseline scenario, the re-powering of generation in the SCE and SDG&E areas was identified as the expected mitigation for the identified voltage instability and thermal overloads. This was the expected mitigation because the integration of intermittent renewable generation requires controllable generation to reliably operate the balancing authority area. However, other transmission alternatives were also assessed. The generation capacity in the internal San Diego area needed to be maintained at about 2,000 MW (520 MW of OTC repower and 1,480 MW of existing QF, peakers and other thermal units), assuming Western LA Basin available capacity was not less than 6,200 MW. Under this assumption, the SDG&E import was about 3,300 MW.

To mitigate voltage deviations greater than 5% on the SDG&E system following N-1 and G-1/N-1 outages, 400 MVAr of reactive power support was needed at Sycamore and Mission 230 kV substations. The cost of the reactive power support is estimated to be $160 million.

For the portfolio 4 scenario, maintaining the SDG&E import at no higher than 3,300 MW by dispatching internal generation as discussed above eliminated the identified thermal overloads in the Sycamore 69 kV area. The new Sycamore-Bernardo 69 line, that has been already been identified as a reliability upgrade in ISO annual NERC compliance reliability assessment and can be found in Chapter 2, mitigated the overloads identified as overloaded in the deliverability assessment . The cost of the line is estimated to be $30 million.

The deliverability assessment for this portfolio also identified the need for a third 500/230 kV transformer at Miguel. This was needed since the N-1 outage of either bank creates an overload on the remaining bank. Tripping 1,150 MW of generation was not sufficient to eliminate the overload.

The deliverability assessment also identified the need to revise the existing Border SPS to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line.

Table 5.4-3 shows the portfolio 4 deliverability assessment results for the San Diego area.

Table 5.4-3 Portfolio 4 Deliverability Assessment results

Overloaded Facility	Contingencies	Flow	Undeliverable Zone
Miguel 500/230 kV #1	Miguel 500/230 kV #2 (no SPS)	114%	San Diego South,

			Imperial South
Miguel 500/230 kV #2	Miguel 500/230 kV #1 (no SPS)	110%	San Diego South, Imperial South
Pomerado-Sycamore 69 kV #1	Pomerado-Sycamore 69 kV #2	101%	Imperial South
Pomerado-Sycamore 69 kV #2	Pomerado-Sycamore 69 kV #1	101%	Imperial South
Pomerado-Poway 69 kV	Artesian-Sycamore 69 kV	110%	Imperial South
Sweetwater-Sweetwater Tap 69 kV	Silvergate-South Bay 230 kV	132%	San Diego
Division-Sampson 69 kV	Silvergate-South Bay 230 kV	108%	San Diego

Portfolio 1 scenario

For portfolio 1, the expected mitigation for the identified voltage instability and thermal overloads inside San Diego was the re-powering of generation in the SCE and SDG&E areas. The generation capacity in the internal San Diego area needed to be maintained at about 2,550 MW (520 MW of OTC repower and 2,030 MW of existing QF, peakers and other thermal units), assuming Western LA Basin available capacity was not less than 6,700 MW. Under this assumption, the SDG&E import was about 2,800 MW.

Because the SDG&E import is only 2,800 MW in portfolio 1 after dispatching 2,550 MW internal generation in the base case, it did not require the Sycamore-Bernardo 69 kV line or the third 500/230 kV bank at Miguel. Tripping 1,150 MW of generation was sufficient to eliminate the N-1 overloads of the Miguel banks.

To mitigate voltage deviations greater than 5% on the SDG&E system following N-1 and G-1/N-1 outages, 400 MVAr reactive power support was needed at Sycamore and Mission 230 kV substations.

The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line.

Table 5.4-4 shows the Portfolio 1 Deliverability Assessment results for the San Diego area.

Table 5.4-4 Portfolio 1 Deliverability Assessment Results

Overloaded Facility	Contingencies	Flow	Undeliverable Zone
Miguel 500/230 kV #1	Miguel 500/230 kV #2 (no SPS)	107%	Tripping 1150 MW of generation sufficient to eliminate overload
Miguel 500/230 kV #2	Miguel 500/230 kV #1 (no SPS)	104%	Tripping 1150 MW of generation sufficient to eliminate overload

Pomerado-Sycamore 69 kV #1	Pomerado-Sycamore 69 kV #2	<100%	
Pomerado-Sycamore 69 kV #2	Pomerado-Sycamore 69 kV #1	<100%	
Pomerado-Poway 69 kV	Artesian-Sycamore 69 kV	<100%	
Sweetwater-Sweetwater Tap 69 kV	Silvergate-South Bay 230 kV	121%	San Diego
Division-Sampson 69 kV	Silvergate-South Bay 230 kV	<100%	

Portfolio 2 scenario

For portfolio 2, the SDGE system had the same reliability concerns as identified in portfolio 1 and portfolio 4. The concerns in portfolio 2, according to Table 5.4-2, were less severe than in portfolio 1, because this portfolio consists of higher out-of-state renewable resources, especially in the Northwest. They are more severe than in portfolio 4 mainly because there is less distributed generation in portfolio 2 than in portfolio 4. The mitigation solutions for these concerns are also similar to the mitigation solutions for the other two portfolios. The mitigations required about 2,350 MW San Diego internal generation, assuming Western LA Basin available capacity was not less than 6,550 MW. With these generation capacity assumptions, the system can sustain SONGS G-2 or Sunrise/SWPL N-2 contingencies.

To mitigate voltage deviations greater than 5% on the SDG&E system following N-1 and G-1/N-1 outages, 400 MVAr reactive power support is needed at Sycamore and Mission 230 kV substations.

This portfolio did not require the third transformer at Miguel since tripping 1,150 MW of generation for the N-1 outage of either bank was sufficient to eliminate the overloads. It also did not require the Sycamore-Bernardo 69 kV line since the import is only 3100 MW.

The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line.

BACKGROUND

Owing to the assumption that a large amount of internal San Diego generation would be unavailable due to retirement and the assumption that a large number of new generation resources in the Imperial Valley area will be developed, the loop flow through CFE in the transmission planning studies for 33% RPS can be as high as 700 MW for some studied scenarios. This high loop flow was not observed in annual reliability assessments. Generation interconnection studies, on the other hand, did not assume the retirement of internal generation, so there was enough internal generation dispatched to prevent such a high loop flow through CFE.

Given the assumptions of San Diego internal generation and the renewable generation modeled in the Imperial Valley area, the power flow and stability assessment identified multiple thermal overloads, as well as post-transient voltage collapse following several outages.

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1: San Diego internal generation, Imperial Valley (IV)-La Rosita (ROA) phase shifter, and reactive power support inside SDG&E

Portfolio 4 scenario (Alternative 1)

If internal SDG&E generation is about 1,500 MW, and assuming Western LA Basin available capacity is not less than 6,200 MW, an alternative was to install a phase shifter with maximum angles of +/-30 degree on the IV-ROA 230 kV line to limit the loop flow through the CFE system and mitigate the overloads in the Otay Mesa area. With this alternative, the angle of the phase shifter would be set at 30 degrees in order to minimize the loop flow. By doing so, the loop flow would be under 200 MW. In this scenario, the SDG&E import is about 3,850 MW. Approximately 700 MVAr of reactive support would be needed at Sycamore, Talega and Mission 230 kV substations to mitigate voltage deviations for N-1 and G-1/N-1 outages. This alternative also required the new Sycamore-Bernardo 69 kV line to mitigate overloads in the Sycamore 69 kV area.

This alternative required the third 500/230 kV transformer at Miguel. Tripping 1,150 MW of generation was not sufficient to eliminate the N-1 overloads on either transformer. The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line. A new SPS would be needed to open the Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer.

Portfolio 1 scenario (Alternative 1)

For this scenario, if internal SDG&E generation is about 1,700 MW, and assuming Western LA Basin minimum generation dispatch is not less than 6,700 MW, an alternative was to install a phase shifter with maximum angles of +/- 30 degree on the IV-ROA 230 kV line to limit the loop flow through the CFE system and mitigate the overloads in the Otay Mesa area. With this alternative, the angle of the phase shifter would be set at 30 degrees in order to minimize the loop flow. By doing so, the loop flow was under 200 MW. In this scenario, the SDG&E import is about 3,700 MW.

Approximately 700 MVAr of reactive support would be needed at Sycamore, Talega and Mission 230 kV substations to mitigate voltage deviations for N-1 and G-1/N-1 outages. This alternative also required the Sycamore-Bernardo 69 kV line to mitigate overloads in the Sycamore 69 kV area. This alternative required the third 500/230 kV transformer at Miguel. Tripping 1150 MW of generation was not sufficient to eliminate the N-1 overloads on either transformer. The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line. A new SPS would be needed to open the Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer.

Portfolio 2 scenario (Alternative 1)

For this scenario, if internal SDG&E generation is about 1600 MW, and assuming Western LA Basin available capacity is not less than 6,550 MW, an alternative was to install a phase shifter with maximum angles of +/- 30 degree on the IV-ROA 230 kV line to limit the loop flow through the CFE system and mitigate the overloads in the Otay Mesa area. With this alternative, the angle of the phase shifter would be set at 30 degrees in order to minimize the loop flow. By doing so, the loop flow is under 200 MW. In this scenario, the SDG&E import is about 3,800 MW.

Approximately 700 MVAr of reactive support would be needed at Sycamore, Talega and Mission 230 kV substations to mitigate voltage deviations following N-1 and G-1/N-1 outages. This alternative also required the Sycamore-Bernardo 69 kV line to mitigate overloads in the Sycamore 69 kV area. This alternative required the third 500/230 kV transformer at Miguel. Tripping 1,150 MW of generation was not sufficient to eliminate the N-1 overloads on either transformer. The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line. A new SPS would be needed to open the Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer.

Alternative 2: San Diego internal generation, IV-ROA phase shifter, reactive power support inside SDG&E, and IV-ROA reactor switched in for contingencies

Portfolio 4 scenario (Alternative 2)

If internal SDG&E generation is about 1,400 MW, and assuming Western LA Basin available capacity is not less than 5,200 MW, an alternative was to install a phase shifter, which is the same size and angle setting as in Alternative 1, on the IV-ROA 230 kV line to limit the loop flow through the CFE system and mitigate the overloads in the Otay Mesa area. In this scenario, the SDG&E import is about 3950 MW.

Also, to prevent voltage collapse with the N-1 and N-2 500 kV outages in the Imperial Valley area, a series reactor on the IV-ROA 230 kV line would be needed to be installed and would be switched post contingency. With the series reactor, the cross-tripping Otay Mesa-Tijuana 230 kV line following the outages would not be needed. The size of the reactor needed to be at least 20 ohms, otherwise Otay Mesa-Tijuana 230 kV line would overload. Approximately 1,100 MVAr of reactive support would be needed at Sycamore, Talega, Mission, and Otay Mesa 230 kV substations to mitigate voltage deviations following N-1, N-1/G-1 and N-2 contingencies.

This alternative also required the new Sycamore-Bernardo 69 kV line to mitigate overloads in the Sycamore 69 kV area. This alternative required the third 500/230 kV transformer at Miguel. Tripping 1,150 MW of generation is not sufficient to eliminate the N-1 overloads on either transformer. The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line. A new SPS would be needed to open the Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer.

Portfolio 1 scenario (Alternative 2)

For this scenario, if internal SDG&E generation is about 1,400 MW, and assuming Western LA Basin available capacity is not less than 5,200 MW, an alternative was to install a phase shifter, which is the same size and angle setting as in the Alternative 1, on the IV-ROA 230 kV line to limit the loop flow through the CFE system and mitigate the overloads in the Otay Mesa area. In this scenario, the SDG&E import is about 3,950 MW.

Also, to prevent voltage collapse with the N-1 and N-2 500 kV outages in the Imperial Valley area, a series reactor on the IV-ROA 230 kV line would be needed to be installed and would be switched post contingency. With the series reactor, the cross-tripping Otay Mesa-Tijuana 230 kV line following the outages would not be needed. The size of the reactor needed to be at least 30 ohms, otherwise Otay Mesa-Tijuana 230 kV line would overload.

Approximately 1,100 MVAr of reactive support would be needed at Sycamore, Talega, Mission, and Otay Mesa 230 kV substations to mitigate voltage deviations following N-1, N-1/G-1 and N-2 contingencies.

This alternative also required the new Sycamore-Bernardo 69 kV line to mitigate overloads in the Sycamore 69 kV area. This alternative required the third 500/230 kV transformer at Miguel. Tripping 1,150 MW of generation was not sufficient to eliminate the N-1 overloads on either transformer. The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line. A new SPS would be needed to open the Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer.

Portfolio 2 scenario (Alternative 2)

For this scenario, if internal SDG&E generation is about 1,400 MW, and assuming Western LA Basin available capacity is not less than 5,200 MW, an alternative was to install a phase shifter, which is the same size and angle setting as in Alternative 1, on the IV-ROA 230 kV line to limit the loop flow through the CFE system and mitigate the overloads in the Otay Mesa area. In this scenario, the SDG&E import is about 3,950 MW. To prevent voltage collapse with the N-1 and N-2 500 kV outages in the Imperial Valley area, a series reactor on the IV-ROA 230 kV line would need to be installed and would be switched post contingency. With the series reactor, the cross-tripping Otay Mesa-Tijuana 230 kV line following the outages would not be needed. The size of the reactor needed to be at least 20 ohms, otherwise the Otay Mesa-Tijuana 230 kV line would overload.

Approximately 1,100 MVAr of reactive support would be needed at Sycamore, Talega, Mission, and Otay Mesa 230 kV substations to mitigate voltage deviations following N-1, N-1/G-1 and N-2 contingencies. This alternative also required the new Sycamore-Bernardo 69 kV line to mitigate overloads in the Sycamore 69 kV area.

This alternative required the third 500/230 kV transformer at Miguel. Tripping 1,150 MW of generation was not sufficient to eliminate the N-1 overloads on either transformer. The existing SPS at Border would need to be revised to trip Border and Otay generation for the outage of South Bay-Silvergate 230 kV line. A new SPS would be needed to open the Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer.

SUMMARY OF MITIGATIONS FOR SDG&E AREA

Table 5.4-5 Summary of Mitigation for San Diego Internal Overloads and Voltage Concerns

Portfolio		Expected mitigation	Alternative 1	Alternative 2
P4	Generation requirements	6200 MW LA Basin	6200 MW LA Basin	5200 MW LA Basin
		2000 MW internal SDGE	1500 MW internal SDGE	1400 MW internal SDGE
	Associated mitigations	revise Border SPS	revise Border SPS	revise Border SPS
		new Sycamore-Bernardo 69 kV line*	new Sycamore-Bernardo 69 kV line *	new Sycamore-Bernardo 69 kV line *
			new Sycamore-Chicarita 138 kV SPS	new Sycamore-Chicarita 138 kV SPS
		Miguel 500/230 kV #3	Miguel 500/230 kV #3	Miguel 500/230 kV #3
		400 MVAr reactive support	700 MVAr reactive support	1100 MVAr reactive support
			IV- ROA phase shifter	IV- ROA phase shifter
				IV -ROA series reactor
P1	Generation requirements	6700 MW LA Basin	6700 MW LA Basin	5200 MW LA Basin
		2550 MW internal SDGE	1700 MW internal SDGE	1400 MW internal SDGE
	Associated mitigations	revise Border SPS	revise Border SPS	revise Border SPS
			new Sycamore-Chicarita 138 kV SPS	new Sycamore-Chicarita 138 kV SPS
		400 MVAr reactive support	700 MVAr reactive support	1100 MVAr reactive support
			IV- ROA phase shifter	IV- ROA phase shifter
			new Sycamore-Bernardo 69 kV line*	new Sycamore-Bernardo 69 kV line*
			Miguel 500/230 kV #3	Miguel 500/230 kV #3
				IV- ROA series reactor
P2	Generation requirements	6550 MW LA Basin	6550 MW LA Basin	5200 MW LA Basin
		2350 MW internal SDGE	1600 MW internal SDGE	1400 MW internal SDGE
	Associated mitigations	revise Border SPS	revise Border SPS	revise Border SPS
			new Sycamore-Chicarita 138 kV SPS	new Sycamore-Chicarita 138 kV SPS
		400 MVAr reactive support	700 MVAr reactive support	1100 MVAr reactive support
			IV- ROA phase shifter	IV- ROA phase shifter
			Miguel 500/230 kV #3	Miguel 500/230 kV #3

			new Sycamore-Bernardo 69 kV line*	new Sycamore-Bernardo 69 kV line*
				IV- ROA series reactor

* The new Sycamore-Bernardo 69 kV line has been identified as a needed reliability upgrade in the CAISO Annual NERC Compliance Reliability assessment.

5.4.3 Sunrise Path Rating Re-Rate

SUMMARY OF ANALYSIS

Table 5.4-6 Summary of flow on Sunrise Powerlink

	Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Peak Case	Portfolio 2 Peak Case	Portfolio 4 Peak Case
No mitigation case	IV-Central 500 kV line	Base system (N-0)	1000 MW	1018 MW	827 MW	820 MW
Expected mitigation	IV-Central 500 kV line	Base system (N-0)	1000 MW	848 MW	754 MW	722 MW
Alternative 1 mitigation	IV-Central 500 kV line	Base system (N-0)	1000 MW	1120 MW	1030 MW	950 MW
Alternative 2 mitigation	IV-Central 500 kV line	Base system (N-0)	1000 MW	1180 MW	1055 MW	983 MW

The studies identified a WECC Path Rating violation on Sunrise Powerlink (IV-Central 500kV line) under normal conditions. The proposed Path Rating is currently 1,000 MW. The addition of IID proposed upgrades (two 230 kV lines from Imperial Valley-IID IV Sub) also increases the flow on Sunrise.

The high flow on Sunrise is due to the fact that significant amount of internal San Diego generation was assumed to be retired, while at the same time a large amount of renewable generation in the Imperial Valley area was assumed to be on-line. Previous generation and transmission studies did not identify Sunrise flow exceeding the 1,000 MW path rating under normal conditions, however, the flow under contingencies has been identified as exceeding 1,000 MW. The mitigation for contingencies has been to readjust the system within 30 minutes following the contingency to bring the flow back down to 1,000 MW.

The identified generation solutions are effective in reducing the flow on Sunrise to under the 1,000 MW path rating. However, under the studied alternatives the flow on Sunrise exceeds 1,000 MW under normal conditions. The 33% RPS transmission planning studies for the different portfolios show that the Sunrise flow can exceed the 1,000 MW WECC path rating under both normal and contingency conditions without criteria concerns, when the alternative mitigations are implemented. Therefore, the ISO proposes to revise the Sunrise WECC path rating to allow the flow higher than 1,000 MW. Additional studies will be necessary to determine the new Sunrise rating.

5.4.4 SDGE-IID Upgrade

SUMMARY OF ANALYSIS

Thermal overloads were identified for normal and contingency conditions on the Imperial Valley-El Centro 230kV line in peak and off-peak cases.

Table 5.4-7 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Case	Portfolio 1 Off-peak case	Portfolio 2 Peak Case	Hybrid Peak Case	Hybrid Off-peak Case
Imperial Valley-El Centro 230kV ckt1	Base system (N-0)	239	108%	121%	86%	42%	200%

DESCRIPTION AND SCOPE OF PROPOSED MITIGATIONS

The proposed mitigation for the identified overloads on IV-El Centro 230kV is to use IID-proposed upgrades to add a new 230 kV switching station near the Imperial Valley Substation and upgrade the existing Imperial Valley-El Centro 230 kV single circuit line to double circuit. The new 230 kV double circuit line will loop in and out of the proposed new switching station. In addition, IID upgrades include an eight-mile-long 230 kV transmission line that will connect the Imperial Valley Substation to IID's Dixieland substation.

5.4.5 Series capacitor upgrade on north gila to imperial valley 500 kV line

The deliverability assessments for Portfolio 1 identified a need to upgrade the series capacitor on the North Gila to Imperial Valley 500 kV line to 3,000 A normal rating. Table 5.4-8 below shows the deliverability assessment results.

Table 5.4-8 Portfolio 1 Deliverability Assessment Results

Overloaded Facility	Contingencies	Flow	Undeliverable Zone
N. Gila–Imperial Valley 500kV No. 1	Base Case	109%	Pisgah
			Mountain Pass
	Devers–Red Bluff 500kV No. 1 & No. 2	118%	Riverside East
			Arizona

The estimated cost of the alternative is about $25 million.

5.5 Assessment results and mitigations in SCE areas

5.5.1 MITIGATIONS FOR WESTERN LA BASIN OVERLOADS AND VOLTAGE CONCERNS

The Western LA Basin is a load pocket in the SCE's system along the coast that is enclosed by sixteen 230 kV lines. Inside this load pocket there are four OTC power plants that total 4,770 MW capacity and the San Onofre nuclear power plant with 2,250 MW capacity. These OTC units, except for the nuclear plant, have relatively high variable operational costs. Therefore, when the economic dispatch to accommodate renewable generation is considered, these units will be shut down first. Although the 33% RPS transmission planning studies did not have particular assumptions about OTC retirements, the OTC units were assumed not to be dispatched because of their relatively high operational costs. However, as discussed above, it is expected that much of the OTC generation will be repowered because of the need for controllable generation. Without sufficient internal generation, this load pocket may have multiple reliability concerns according to previous studies, such as the LCR study. The 33% RPS transmission planning studies identified the same problems in this load pocket.

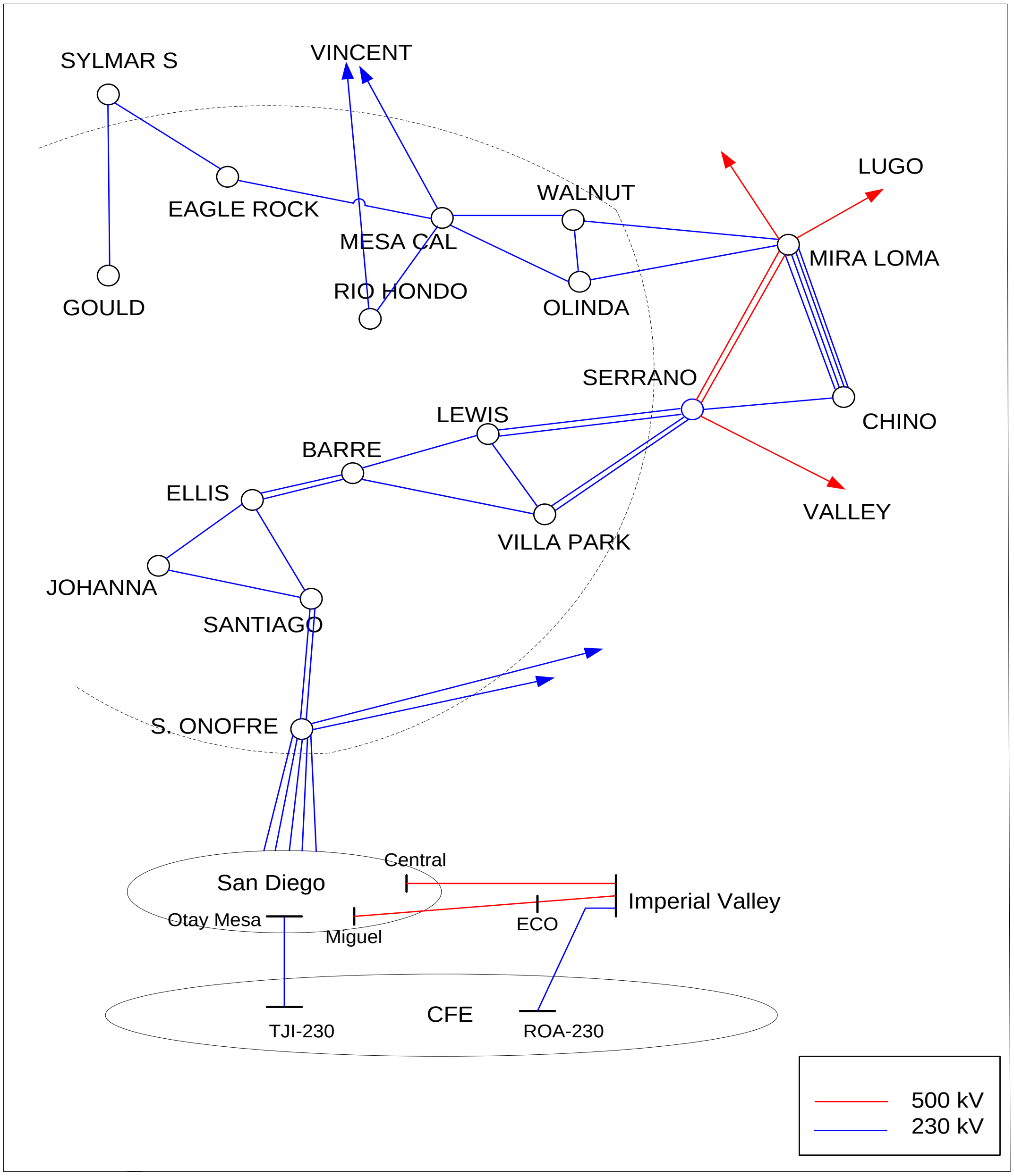
The boundary lines of the Western LA Basin are listed below:

- SERRANO to LEWIS 230 kV #1
- SERRANO to LEWIS 230 kV #1
- SERRANO to VILLA PK 230 kV #1
- SERRANO to VILLA PK 230 kV #2
- MIRALOMA to WALNUT 230 kV #1
- MIRALOMA to OLINDA 230 kV #1
- VINCENT to MESA 230 kV #1 and #2
- VINCENT to RIOHONDO 230 kV #1
- VINCENT to RIOHONDO 230 kV #2
- SYLMAR to EAGLROCK 230 kV #1

- SYLMAR to GOULD 230kV #1
- S.ONOFRE to TALEGA 230 kV #1
- S.ONOFRE to TALEGA 230 kV #2
- S.ONOFRE to SAN LUIS REY 230 kV #1
- S.ONOFRE to SAN LUIS REY 230 kV #2
- S.ONOFRE to SAN LUIS REY 230 kV #3

The Western LA Basin system configuration is shown in Figure 5.4-2.

Fig. 5.4-2 Western LA Basin overview



The ISO proposes to maintain the minimum generation dispatch inside the Western LA Basin to mitigate the 230 kV line overloads, as well as the voltage instability under the outage of two SONGS units. It should be noted that San Diego generation also helps to reduce east to west flows into the Western LA Basin and provides voltage support since the Western LA Basin and San Diego area are closely connected to each other electrically. Therefore, the mitigation for the Western LA Basin thermal loading and voltage performance considers the generation dispatch in San Diego. Details of San Diego generation requirements are provided in Section 5.4.

Summary of Analysis

The study identified multiple contingency overloads on the 230 kV lines inside the LA Basin in portfolios 1, 2 and 4, all in the peak load scenarios. The study also determined that a SONGS G-2 outage causes voltage collapse for the peak load scenarios in all the portfolios.

As discussed earlier in Section 5.2, the base cases for power flow and stability assessment were developed based on the production cost simulation results, which have relatively low dispatch of the conventional thermal generating units inside the load pockets. Such a dispatch caused concerns regarding reliability concerns in the load pockets. A minimum generation dispatch needs to be maintained under the heavy load conditions to mitigate reliability concerns. Alternatively, new transmission facilities would be needed to relax the minimum generation dispatch requirement. Transmission alternatives were considered and compared with the generation solution in the analysis.

Table 5.5-1 below lists all thermal overloads and voltage instability conditions when no mitigation measures are taken.

Table 5.5-1 Power Flow and Post Transient Summary without Mitigation

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case
	SONGS G-2		Voltage Collapse	Solved	Voltage Collapse	Solved	Voltage Collapse
LEWIS–VILLA PK 230kV line No. 1	SERRANO–LEWIS 230kV line No. 1 & No. 2	2540	116%	<100%	123%	<100%	111%
SERRANO–LEWIS 230kV line No. 2	SERRANO–VILLA PK 230kV line No. 1 & No. 2	3361	101%	<100%	106%	<100%	<100%
BARRE – LEWIS 230kV line No.1	BARRE–VILLA PK 230kV line No. 1	1494	105%	<100%	114%	<100%	<100%
BARRE – VILLA PK 230kV line No.1	BARRE–LEWIS 230kV line No. 1	1494	<100%	<100%	103%	<100%	<100%
SERRANO –VILLA PK 230kV line No.1	SERRANO –VILLA PK 230kV line No. 2	1518	<100%	<100%	103%	<100%	<100%
SERRANO 500/230kV bank No. 2	SERRANO 500/230kV bank No. 1	1344	<100%	<100%	101%	<100%	<100%

Description and Scope of Proposed Mitigations

Increasing generation in Western LA Basin could mitigate the thermal overloads and voltage instability. In all the portfolios, the peak scenario has low generation dispatched in Western LA Basin. Dispatching peakers and other small generators and potential repower generators of the OTC units in both Western LA Basin and San Diego areas could mitigate all concerns. There is no transmission capital cost for the proposed mitigation.

Table 5.5-2 Power Flow and Post Transient Summary with Recommended Mitigation

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case*	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case *	Portfolio 2 Peak Case
	SONGS G-2		Solved	Solved	Solved	Solved	Solved
LEWIS–VILLA PK 230kV line No. 1	SERRANO–LEWIS 230kV line No. 1 & No. 2	2540	<100%	<100%	<100%	<100%	<100%
BARRE – LEWIS 230kV line No.1	BARRE–VILLA PK 230kV line No. 1	1494	<100%	<100%	<100%	<100%	<100%
BARRE – VILLA PK 230kV line No.1	BARRE–LEWIS 230kV line No. 1	1494	<100%	<100%	<100%	<100%	<100%
SERRANO –VILLA PK 230kV line No.1	SERRANO – VILLA PK 230kV line No. 2	1518	<100%	<100%	<100%	<100%	<100%
SERRANO 500/230kV bank No. 2	SERRANO 500/230kV bank No. 3	1344	<100%	<100%	<100%	<100%	<100%
MIRALOME –OLINDA 230kV line No.1	Barre–Villa Park 230kV line No. 1 & Barre–Lewis 230kV line No. 1	988	<100%	<100%	<100%	<100%	<100%

* No generation re-dispatch is needed for the off-peak cases

The minimum generation requirements are different for each portfolio as shown in Table 5.5.3. Note that the minimum generation requirements for San Diego are also required and modeled to mitigate SCE's LA Basin overloads and voltage instability. The requirements on San Diego internal generation to mitigate San Diego's overloads and instability have been discussed in section 5.4. Also note that Section 5.4 discussed alternative mitigations with phase shifters and series reactors for SDG&E that would reduce the San Diego generation requirement. Table 5.513 only considers the expected solution with generation requirements for San Diego.

Table 5.5-3 Minimum generation dispatch for each portfolio

Portfolio	Western LA Basin (MW)	San Diego (MW)
4	6550	2000
1	6700	2550
2	6200	2350

The Western LA Basin minimum generation requirement is driven by the LA Basin overloads. The overloads are more severe when more generation is dispatched in the east and the East of River path flow is higher. Therefore, more generation inside the Western LA Basin is needed for portfolio 1.

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1: New Mira Loma–Lighthipe 500kV line and dynamic reactive support at Santiago, Eagle Rock, Encina and South Bay (500 MVAr at each location)

This alternative solution mitigated all the concerns of reliability concerns except one. Lewis–Villa Park 230kV line was still overloaded under the N-2 contingency of both Serrano–Lewis 230kV lines in Portfolio 1. An SPS would be needed to trip load at Lewis. The study results are shown in Table 5.5-5.

With the alternative mitigations in place and assuming that the proposed SPS trips 100MW load at Lewis, the minimum generation requirements for different portfolios are listed in Table 5.5-4. Under portfolio 2 peak scenario, there was relatively high north to south flow on Path 26. Therefore, the new Mira Loma–Lighthipe 500kV line provided the least relief on the west of Serrano flow. The minimum generation requirement is higher for portfolio 2 than the other two.

Table 5.5-4 Minimum generation dispatch for each portfolio (Alternative 1)

Portfolio	Western LA Basin (MW)	San Diego (MW)
4	4850	2000
1	5250	2550
2	5500	2350

The estimated cost of the alternative is about $500 million.

SUMMARY OF MITIGATIONS

The proposed mitigation, i.e., generation re-dispatch to maintain a minimum generation dispatch in Western LA Basin and SDG&E, is a less expensive solution than the alternative. However, it may result in higher operational cost than Alternative 1. Alternative 1 should be further evaluated in the next cycle of the comprehensive transmission planning study, especially after the OTC repower implementation plans become available.

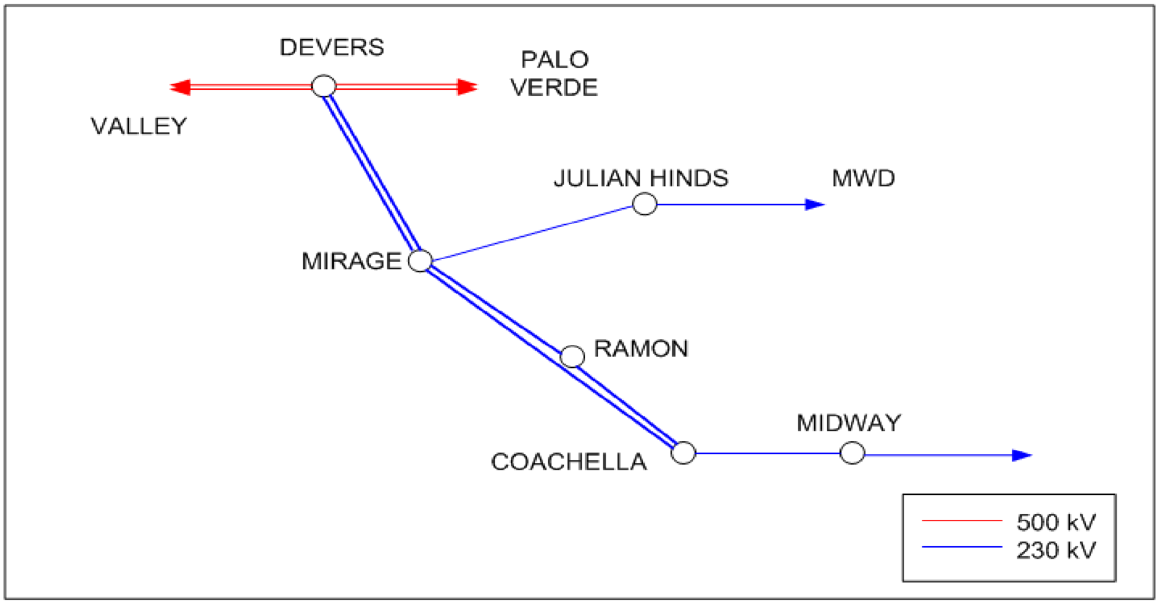
Table 5.5-5 Power Flow and Post Transient Summary with Alternative **1**

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case
	SONGS G-2		Solved	Solved	Solved	Solved	Solved
LEWIS–VILLA PK 230kV line No. 1	SERRANO–LEWIS 230kV line No. 1 & No. 2	2540	<100%	<100%	103%	<100%	<100%
BARRE – LEWIS 230kV line No.1	BARRE–VILLA PK 230kV line No. 1	1494	<100%	<100%	<100%	<100%	<100%
BARRE – VILLA PK 230kV line No.1	BARRE–LEWIS 230kV line No. 1	1494	<100%	<100%	<100%	<100%	<100%
SERRANO –VILLA PK 230kV line No.1	SERRANO – VILLA PK 230kV line No. 2	1518	<100%	<100%	<100%	<100%	<100%
SERRANO 500/230kV bank No. 2	SERRANO 500/230kV bank No. 3	1344	<100%	<100%	<100%	<100%	<100%
MIRALOME –OLINDA 230kV line No.1	Barre–Villa Park 230kV line No. 1 & Barre–Lewis 230kV line No. 1	988	<100%	<100%	<100%	<100%	<100%

5.5.2 Path 42 and Mirage-Devers Upgrades

Path 42 (the 230 kV lines between IID's Coachella and SCE's Mirage 230 kV substations) and Mirage–Devers 230 kV lines comprise the critical path to deliver renewable energy from IID to the ISO controlled grid. In the 33% RPS transmission planning studies, the solar, geothermal and biomass resources in Imperial North and South areas that are interconnected to IID's system have been included in all portfolios. The new potential renewable generation plus the existing IID geothermal generation makes the IID system an important renewable energy exporting area, especially during the hours when the IID load is low. Accordingly, the ISO proposes to reconductor Path 42 and Mirage–Devers 230 kV lines.

Figure 5.5-2 Path 42



Summary of Analysis

The Coachella-Mirage 230kV line, Coachella-Ramon 230kV line and Ramon-Mirage 230kV line were overloaded under category A normal conditions in both peak and off-peak scenarios of portfolio 4. The same three 230kV lines were overloaded under various category B and C outage conditions in both peak and off-peak scenarios in portfolios 1, 2 and 4.

An outage of one of the Devers-Mirage 230kV No. 1 and No. 2 line overloaded the remaining line in both peak and off-peak scenarios of portfolio 4.

Deliverability assessments for portfolio 1 and 4 both identified that the deliverability of Imperial North generation was limited by the contingency condition loading on the Coachella–Ramon 230kV line.

Path 42 flows in different portfolio scenarios are listed in Table 5.5-6. The study results are summarized in Tables 5.5-7 to Table 5.5-9.

Table 5.5-6 Path 42 Flows

	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 1 No Solar Case	Portfolio 2 Peak Case
Path 42 Flow (MW)	930	960	550	500	720	500

Table 5.5-7 Power Flow Summary without Mitigation

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 1 No Solar Case	Portfolio 2 Peak Case
COACHELV –MIRAGE 230kV line No.1	RAMON – MIRAGE 230kV line No.1	986	228%	216%	141%	111%	163%	132%
COACHELV –MIRAGE 230kV line No.1	DEVERS–REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	986	150%	155%	127%	<100%	105%	102%
COACHELV –MIRAGE 230kV line No.1	Base Case	986	132%	117%	<100%	<100%	<100%	<100%
COACHELV–RAMON 230kV line No. 1	COACHELV–MIRAGE 230kV line No. 1	986	252%	200%	140%	110%	150%	130%
COACHELV–RAMON 230kV line No. 1	DEVERS–REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	986	144%	151%	122%	<100%	101%	<100%
COACHELV–RAMON 230kV line No. 1	Base Case	986	127%	113%	<100%	<100%	<100%	<100%
RAMON – MIRAGE 230kV line No.1	COACHELV–MIRAGE 230kV line No. 1	986	243%	224%	135%	117%	169%	124%
RAMON – MIRAGE 230kV line No.1	DEVERS–REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	986	138%	174%	128%	<100%	119%	<100%
RAMON – MIRAGE 230kV line No.1	Base Case	986	106%	128%	<100%	<100%	<100%	<100%
DEVERS – MIRAGE 230kV line	DEVERS – MIRAGE 230kV line	1240	100%	112%	<100%	<100%	<100%	<100%

No.1	No.2							
DEVERS – MIRAGE 230kV line No.2	DEVERS – MIRAGE 230kV line No.1	1240	100%	112%	<100%	<100%	<100%	<100%

Table 5.5-8 Portfolio 4 Deliverability Assessment Result for Path 42 Lines

Overloaded Facility	Contingencies	Flow	Undeliverable Zone
Coachella–Ramon 230kV No. 1	Devers–Red Bluff 500kV No. 1 & No. 2	139%	Imperial North
	Red Bluff–Colorado River 500kVNo. 1 & No. 2	127%	
	Coachella–Mirage 230kV No. 1	114%	

Table 5.5-9 Portfolio 1 Deliverability Assessment Result for Path 42 Lines

Overloaded Facility	Contingencies	Flow	Undeliverable Zone
Coachella–Ramon 230kV No. 1	Devers–Red Bluff 500kV No. 1 & No. 2	105%	Imperial North

DESCRIPTION AND SCOPE OF PROPOSED MITIGATIONS

The proposed mitigation plan for this area includes reconductoring the Coachella-Ramon 230kV line, the Ramon-Mirage 230kV line, the Coachella-Mirage 230kV line, and the Devers-Mirage 230kV No.1 and No.2 lines. This reconductoring plan includes lines owned by IID and therefore will need to be coordinated with IID. The estimated cost is $80 million.

Table 5.5-10 Power Flow Summary with Recommended Mitigation

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	No Solar Case	Portfolio 2 Peak Case
COACHELV –MIRAGE 230kV line No.1	COACHELV– RAMON 230kV line No. 1	2850	<100%	<100%	<100%	<100%	<100%	<100%
COACHELV –MIRAGE 230kV line No.1	DEVERS– REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	2850	<100%	<100%	<100%	<100%	<100%	<100%
COACHELV– RAMON 230kV line No. 1	COACHELV– MIRAGE 230kV line No. 1	2850	<100%	<100%	<100%	<100%	<100%	<100%
COACHELV– RAMON 230kV line No. 1	DEVERS– REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	2850	<100%	<100%	<100%	<100%	<100%	<100%
RAMON – MIRAGE 230kV line No.1	COACHELV– MIRAGE 230kV line No. 1	2850	<100%	<100%	<100%	<100%	<100%	<100%
RAMON – MIRAGE 230kV line No.1	DEVERS– REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	2850	<100%	<100%	<100%	<100%	<100%	<100%
DEVERS – MIRAGE 230kV line No.1	DEVERS – MIRAGE 230kV line No.2	2850	<100%	<100%	<100%	<100%	<100%	<100%
DEVERS – MIRAGE 230kV line No.2	DEVERS – MIRAGE 230kV line No.1	2850	<100%	<100%	<100%	<100%	<100%	<100%

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1: Reconductoring the three Coachella to Mirage 230kV lines in the IID system and install SPS to trip IID generation under the N-1 outages of Devers-Mirage 230kV No. 1 or No. 2 line.

The estimated cost for this alternative is about $40 million.

SUMMARY OF MITIGATIONS

Upgrading Path 42 lines in the IID system has been identified by IID in its generation interconnection studies. Results in the 33% RPS transmission planning studies support the need for the upgrade. Furthermore, it is recommended that the down-stream Devers–Mirage 230kV lines in the SCE system be reconductored to mitigate the overloads identified in Portfolio 4 and to achieve full utilization of the IID upgrades.

Table 5.5-11 Power Flow Summary with Alternative 1

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 1 No Solar Case	Portfolio 2 Peak Case
COACHELV –MIRAGE 230kV line No.1	COACHELV–RAMON 230kV line No. 1	986	<100%	<100%	<100%	<100%	<100%	<100%
COACHELV –MIRAGE 230kV line No.1	DEVERS–REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	986	<100%	<100%	<100%	<100%	<100%	<100%
COACHELV–RAMON 230kV line No. 1	COACHELV–MIRAGE 230kV line No. 1	986	<100%	<100%	<100%	<100%	<100%	<100%
COACHELV–RAMON 230kV line No. 1	DEVERS–REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	986	<100%	<100%	<100%	<100%	<100%	<100%
RAMON – MIRAGE 230kV line No.1	COACHELV–MIRAGE 230kV line No. 1	986	<100%	<100%	<100%	<100%	<100%	<100%
RAMON – MIRAGE 230kV line No.1	DEVERS–REDBLUFF 500kV line No. 1 & No. 2 w/ SPS	986	<100%	<100%	<100%	<100%	<100%	<100%

5.5.3 ELDORADO–PISGAH 500KV LINE SERIES CAPACITOR UPGRADE

SUMMARY OF ANALYSIS

Overloading on the Eldorado–Pisgah 500kV line was identified under various category B and C outage conditions in the peak scenarios of Portfolio 1 and 4. The rating of the line is limited by the series capacitor. The loadings on the line exceeded the rating of the series capacitor, but were lower than the conductor emergency rating. The study results are summarized in Table 5.5-12.

Table 5.5-12 Power Flow Summary without Mitigation

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case
Eldorado–Pisgah 500kV line No. 1	McCullough–Victorville 500kV line No.1 & No.2	1600	105%	<100%	120%	<100%	<100%

DESCRIPTION AND SCOPE OF PROPOSED MITIGATIONS

The rating of Eldorado–Pisgah 500kV line is limited by the series capacitor. Upgrading the series capacitor to higher rating (2700 A) mitigated the overloads. The upgrade is estimated to cost $25 million.

Table 5.5-13 Power Flow Summary with Recommended Mitigation

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case
Eldorado–Pisgah 500kV line No. 1	McCullough–Victorville 500kV line No.1 & No.2	2700	<100%	<100%	<100%	<100%	<100%

DESCRIPTION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1: Install SPS to bypass the series capacitor when the loading on the series capacitor approaches its normal rating.

Bypassing the series capacitor on the Eldorado–Pisgah 500kV line mitigated the overloads. The upgrade is estimated to cost less than $1 million.

SUMMARY OF MITIGATIONS

Replacing the series capacitor is a relatively low-cost and more robust solution.

5.5.4 West of Devers Upgrades and Short-Term Solution

The West of Devers upgrades, consisting of reconductoring the four 230 kV lines of West of Devers, have been identified in the transition cluster Phase II study and included in the transition cluster project LGIAs. These upgrades were identified as needed in the portfolio development process for this 33% transmission planning study. The West of Devers upgrades, however, are estimated to take about 84 months following LGIA execution by the triggering transition cluster projects. In light of this long lead time, an interim solution for the West of Devers constraint was investigated in this planning study.

SUMMARY OF ANALYSIS OF INTERIM SOLUTIONS

Without the West of Devers upgrades, the four West of Devers 230kV lines would be overloaded under NERC category A, B and C conditions in all portfolios and scenarios. Table 5.5-14 summarizes the study results without the West of Devers upgrades.

Table 5.5-14 Power Flow Summary without West of Devers Upgrades

Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case
DEVERS – EL CASCO 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	1150	186%	138%	193%	105%	141%
DEVERS – EL CASCO 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	1150	162%	124%	166%	115%	117%
DEVERS – EL CASCO 230kV line No.1	Base Case	1150	104%	<100%	112%	<100%	<100%
DEVERS – VSTA 230kV line No.2	DEVERS–VALLEY 500kV No.1 & No. 2	1240	170%	132%	175%	108%	125%
DEVERS – VSTA 230kV line No.2	ALBERHIL – VALLEYSC 500kV line No. 1	1240	146%	118%	150%	118%	102%
SANBRDNO –DEVERS 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	796	221%	174%	228%	128%	159%
SANBRDNO –DEVERS 230kV line No.1	Base Case	796	111%	<100%	106%	<100%	<100%
SANBRDNO –DEVERS 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	796	188%	155%	193%	141%	128%
TOT185HS –DEVERS 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	1150	164%	125%	172%	103%	116%
TOT185HS –DEVERS 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	1150	139%	111%	146%	114%	<100%

TOT185HS –VSTA 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	1150	185%	125%	190%	117%	136%
TOT185HS –VSTA 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	1150	159%	129%	162%	128%	112%
EL CASCO–SANBRDNO 230kV line No. 1	DEVERS–VALLEY 500kV No.1 & No. 2	1150	124%	111%	127%	<100%	<100%

DESCRIPTION AND SCOPE OF INTERIM SOLUTIONS

Interim Solution: Reactors on Devers–San Bernardino 230kV line and Devers–Elcasco 230kV line and SPS to trip generation

Two 10 ohm series reactors were modeled on the Devers–San Bernardino 230kV line and Devers–El Casco 230kV line, respectively. As a result, the overloads on the West of Devers 230kV lines under the normal conditions were mitigated in all scenarios studied.

In addition, an SPS was installed to trip generation and load under the simultaneous outage of Devers–Valley 500kV No.1 and No. 2 lines, and generation under the various single contingencies.

The short-term solution is sufficient to mitigate all overloads identified in Portfolio 2, which has lower renewable generation in the Riverside East area. Although this study focused on the year 2020 and a full 33% RPS build out, it is expected that renewable generation development will occur in the Riverside and Imperial County CREZs, along with Arizona developments, starting immediately and that it will steadily increase between now and 2020. Therefore, it is also expected that this interim plan could accommodate roughly 75% of the generation in Portfolios 1 and 4, which is a reasonable estimate of the amount of renewable generation build out in these areas that would occur over the next 84 months. This will be explored with the affected generation through the LGIP.

The solution is expected to cost less than $50 million.

Table 5.5-15 Power Flow Summary with Alternative 1

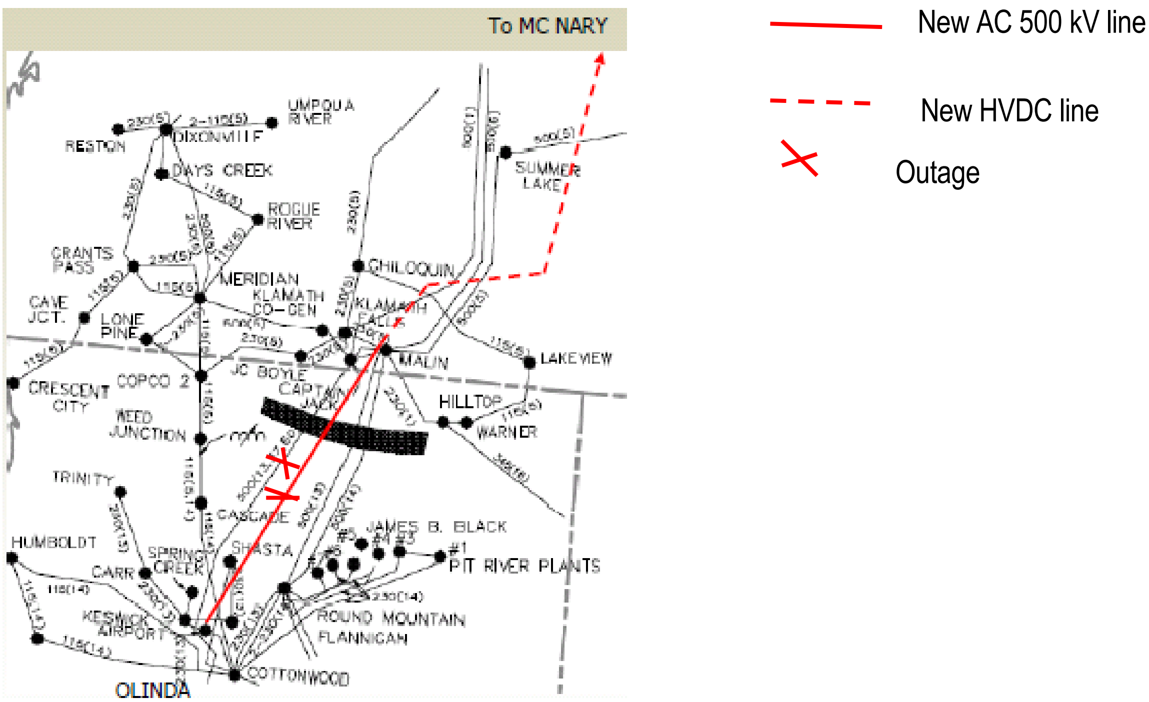
Overloaded Facility	Worst Contingency	Rating (A)	Portfolio 4 Peak Case	Portfolio 4 Off-Peak Case	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case
DEVERS – EL CASCO 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	1150	<100%	<100%	<100%	<100%	<100%
DEVERS – EL CASCO 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	1150	113%	<100%	117%	<100%	<100%
DEVERS – VSTA 230kV line No.2	DEVERS–VALLEY 500kV No.1 & No. 2	1240	110%	110%	116%	<100%	<100%
DEVERS – VSTA 230kV line No.2	ALBERHIL – VALLEYSC 500kV line No. 1	1240	129%	120%	134%	107%	<100%
SANBRDNO –DEVERS 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	796	114%	116%	121%	<100%	<100%
SANBRDNO –DEVERS 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	796	132%	126%	137%	101%	<100%
TOT185HS –DEVERS 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	1150	102%	103%	111%	<100%	<100%
TOT185HS –DEVERS 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	1150	122%	113%	129%	102%	<100%
TOT185HS –VSTA 230kV line No.1	DEVERS–VALLEY 500kV No.1 & No. 2	1150	121%	120%	127%	<100%	<100%
TOT185HS –VSTA 230kV line No.1	ALBERHIL – VALLEYSC 500kV line No. 1	1150	141%	131%	145%	116%	<100%

5.6 Assessment Results and Mitigations in PG&E area

5.6.1 Install SPS for Captain Jack–Olinda N-2 Contingency in Portfolio 2

Portfolio 2 case assumed that a new high voltage DC line between McNary and Captain Jack 500 kV substations would be constructed, as well as the second 500 kV AC transmission line between Captain Jack and Olinda substations. These transmission upgrades are needed to deliver out of state renewable generation assumed to be utilized in Portfolio 2. Double outages of both Captain Jack-Olinda 500 kV lines may cause overloads on the parallel 500 kV and 230 kV lines.

Fig 5.6.3 California-Oregon Border area



SUMMARY OF ANALYSIS

Table 5.6-5 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Summer Emergency Rating (MVA)	Portfolio 2 Peak Case
Malin-Round Mountain 500 kV # 2	Captain Jack-Olinda 500 kV # 1 and 2 SPS to trip 2400 MW NW	2449	101%
Malin-Round Mountain 500 kV # 1		2615	93%
Cottonwood-Round Mtn 230 kV # 3		297	97%

Cottonwood-Round Mtn 230 kV # 1	generation and Northern CA pumps. Open Captain Jack-McNary DC line	320	97%
Cottonwood-Olinda 230 kV # 1		369	107%
Cottonwood-Olinda 230 kV # 2		369	107%
Malin-Round Mountain 500 kV # 2	Captain Jack-Olinda 500 kV # 1 and 2 SPS to trip 2400 MW NW generation, Northern CA pumps and Pit River generation. Open Captain Jack-McNary DC line	2449	106%
Malin-Round Mountain 500 kV # 1		2615	98%
Cottonwood-Round Mtn 230 kV # 3		297	91%
Cottonwood-Round Mtn 230 kV # 1		320	88%
Cottonwood-Olinda 230 kV # 1		369	99%
Cottonwood-Olinda 230 kV # 2		369	99%

BACKGROUND

The Portfolio 2 peak case includes a second Captain Jack-Olinda 500 kV line in addition to other transmission upgrades needed to accommodate a high amount of out-of-state generation. Another upgrade modeled in the case was a high voltage DC line from McNary to Captain Jack capable of carrying 2,000 MW.

It was assumed that the series capacitors owned by PacifiCorp on the Malin end of the Malin–Round Mountain #2 500 kV transmission lines would be upgraded from 1800 to 4000 A. This project is in construction and planned to be completed by early 2011. Malin-Round Mountain #2 500 kV transmission line flow will then be limited by the line conductors.

It was also assumed that the California–Oregon Intertie (COI) Upgrade Project proposed by the Bonneville Power Administration (BPA) is in service. This project is needed to support 4,800 MW flow on COI under wide variety of system conditions. The plan of service includes:

- Install new series capacitors (25 ohm, 3000 A) at Bakeoven on John Day–Grizzly #1 and #2, along with required control, protection and communication equipment.
- Install two new 200 Mvar shunt capacitor groups at Captain Jack 500 kV, plus an additional 500 kV circuit breaker to fully develop a bay position.
- Install one new 300 Mvar shunt capacitor group at Slatt 500 kV, plus two additional 500 kV circuit breakers to fully develop a bay position.
- Reconductor approximately 1 mile of John Day–Grizzly #1 and #2 to a conductor capable of 3500 A at 30 degrees C ambient.
- Upgrade approximately 24.0 miles of John Day–Grizzly #2 from an MOT of 80 degrees C to 100 degrees C (3500 A).
- Add the new Captain Jack shunt caps to the FACRI remedial action scheme.
- Add the double line loss of Buckley – Grizzly #1 and either John Day–Grizzly #1 or #2 to High Gen Drop SPS.

This project is planned for completion in the spring of 2011.

With the addition of renewable resources in the northwest, the McNary–Captain Jack High Voltage DC line and a second Captain Jack–Olinda 500 kV AC line in Portfolio 2, the flow on the four 500 kV transmission lines between California and Oregon (COI) was modeled at 6,388 MW.

A double outage of the Captain Jack–Olinda 500 kV lines assumed tripping of 2,400 MW of northwest generation and 571 MW of CDWR pumps in addition to opening the new McNary–Captain Jack DC line. In addition, the studies also considered adding approximately 320 MW of Pit River tripping generation to the existing SPS to mitigate the overload on the 230 kV lines between Cottonwood and Olinda.

PROPOSED MITIGATIONS

The overloads caused by the double outage of both Captain Jack–Olinda 500 kV lines were only observed in the Portfolio 2 study. Two Captain Jack–Olinda 500 kV lines were modeled only in Portfolio 2, and this portfolio had the highest flow on COI compared with the other portfolios. No overloads were identified for a single outage of the Captain Jack–Olinda 500 kV line in any of the portfolios. The proposed mitigation would be to re-rate the Malin–Round Mountain 500 kV #2 line and to install an SPS for the double outage of the Captain Jack–Olinda 500 kV lines. The SPS would depend on whether rerating the Malin–Round Mountain 500 kV line is feasible. If the re-rate is not feasible, the SPS for the Captain Jack–Olinda double outage would be re-evaluated to trip more generation from the Northwest. To mitigate overloads on the Malin–Round Mountain 500 kV line #2, an additional 350 MW of generation would need to be tripped in Northwest. The SPS would also include tripping the Pit River generation, the pumping loads in northern California and opening the proposed Mc Nary–Captain Jack HVDC line with this outage.

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

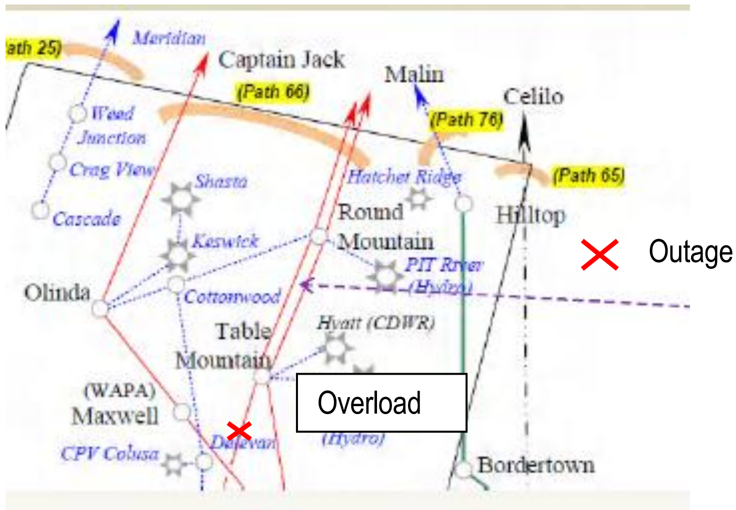
Alternative 1: Upgrade Cottonwood–Olinda 230 kV lines and Malin–Round Mountain 500 kV #2 line

This alternative was not recommended because it would cost more than the proposed Malin–Round Mountain 500 kV #2 line re-rate and SPS.

5.6.2 SPS for Round Mountain–Table Mountain 500 kV Outage

The area between Malin and Table Mountain is shown in the diagram below. High flow on COI with high levels of northern California hydro generation may cause overloads on each of the Round Mountain–Table Mountain 500 kV lines with an outage of the parallel circuit.

Figure 5.6-4 Round Mountain–Table Mountain area



Summary of Analysis

Table 5.6-6 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Summer Emergency Rating (MVA)	Portfolio 1 Peak Case	Portfolio 2 Peak Case	Portfolio 4 Peak Case 60 % NCH	Portfolio 4 Peak Case 80 % NCH
ROUND MTN-TABLE MTN 500 kV # 1	ROUND MTN-TABLE MTN 500 kV # 2	2841	84%	90%	95%	103%
ROUND MTN-TABLE MTN 500 kV # 2	ROUND MTN-TABLE MTN 500 kV # 1	2841	84%	90%	95%	103%

Proposed Mitigations

An SPS can be developed to bypass some of the series capacitors on the remaining Round Mountain–Table Mountain 500 kV line for an outage of the parallel 500 kV circuit in case of overloads.

Background

The Round Mountain–Table Mountain 500 kV transmission lines #1 or #2 may overload with an outage of a parallel circuit in the hybrid case with high levels of hydro generation in northern California and high COI flow. The COI flow in the hybrid peak case was modeled at 4,800 MW, and hydro generation in northern California was modeled at 80% of maximum output. High COI flow in addition to high levels of hydro generation caused these contingency overloads. No overloads on the Round Mountain–Table Mountain 500 kV transmission lines were observed under off-peak load conditions because of lower flow on COI.

Bypassing the series capacitors on the Round Mountain end of the line reduced flow from 103% to 82% of the line emergency rating. No other overloads are expected to occur if the series capacitors are bypassed.

Voltages are expected to be in the acceptable range, mainly because of a BPA transmission project that would eliminate Northwest constraints and allow maintaining a 4,800 MW COI rating. As discussed above, the BPA transmission upgrade project is expected to be completed in spring 2011.

Discussion of Other Considered Alternatives

Alternative 1— SPS to trip Northwest generation

The overload would be mitigated if approximately 200 MW of generation is tripped in the Northwest for an outage of one of the Round Mountain–Table Mountain 500 kV lines. This alternative is not recommended since bypassing series capacitors mitigates the overload without losing any generation.

Alternative 2 – Upgrade the Round Mountain-Table Mountain 500 kV lines.

This alternative is not recommended because it would cost more than the SPS to bypass the series capacitors.

5.6.3 SPS for Table Mountain South 500 kV Outage

The transmission system of northern California between Malin and Tesla is shown in the diagram below. A double outage of the two 500 kV transmission lines south of Table Mountain (Table Mountain–Tesla and Table Mountain–Vaca Dixon) may cause overload of the Table Mountain 500/230 kV transformer.

Figure 5.6-5 Table Mountain area transmission system

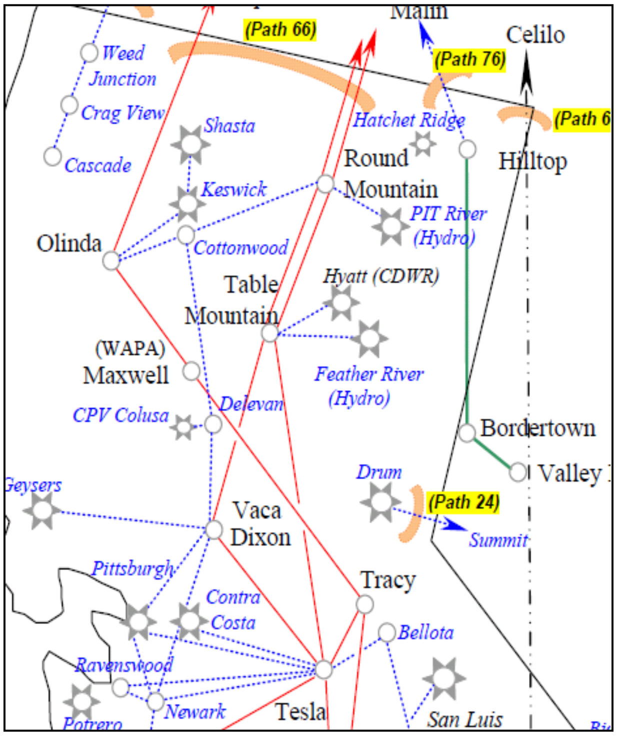


Table 5.6-7 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Summer Emergency Rating (MVA)	Portfolio 1 Peak Case	Portfolio 2 Peak Case	Portfolio 4 Peak case 60% NCH	Portfolio 4 Peak case 80% NCH
TABLE MT 500/230 kV bank #1	Table Mtn South double 500 kV outage, 2400 MW gen SPS	1122	99%	<95%	109%	111%

Currently the 500 kV double line outage south of Table Mountain triggers an SPS that trips generation at Hyatt and Thermalito hydro power plants in northern California, hydro generation in the Northwest and CDWR pumps. For the peak load cases, it was assumed that 2,400 MW of generation is tripped in the Northwest, which is consistent with the COI flow modeled in the cases. The amount of generation and pump tripping was the same for all peak cases.

There were no overloads for the double outage of 500 kV lines south of Table Mountain in the off-peak cases and no SPS was needed because of the low flow.

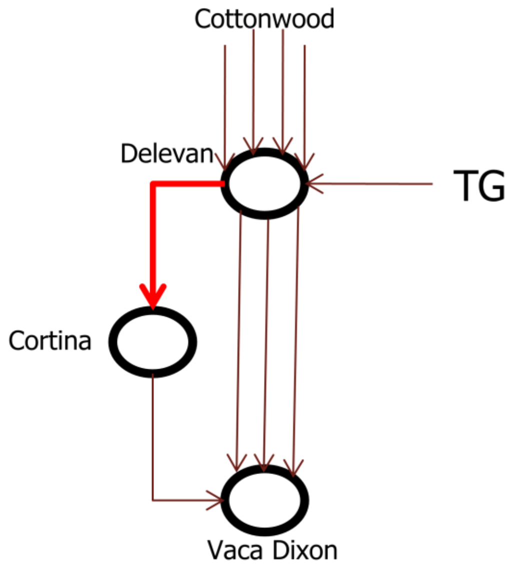
The overload depends on the amount of SPS and which generation it trips. Even without changing the amount of generation tripped by the SPS, replacing tripping generation at Hyatt with tripping one generation unit at Colusa would eliminate the overload on the Table Mountain 500/230 kV transformer.

Another alternative to mitigate the overload on the Table Mountain 500/230 kV transformer is to re-rate it to obtain an emergency rating.

5.6.4 Mitigation of overload on Delevan–Cortina 230 kV transmission line

Delevan–Cortina 230 kV transmission line may overload under several contingency conditions. The transmission system diagram of this area is shown in the figure below.

Figure 5.6-6 Delevan–Cortina area



Summary of Analysis

Table 5.6-8 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case	Portfolio 4 Peak Case (60% NCH)	Portfolio 4 Peak Case (80% NCH)
Delevan-Cortina 230 kV	RoundMt-TableMt-dlo-ns-2400	SE Rating 380	<100%	<100%	<100%	<100%	106%
	TableMtSouth-dlo-ns-2400		<100%	<100%	<100%	<100%	104%
	Olinda-Tracy-slo-ns		<100%	<100%	<100%	<100%	100%
	Delevan-Vaca Dixon Nos. 2 & 3 230 kV lines		<100%	<100%	<100%	<100%	102%

Description and Scope of Proposed Mitigations

The preferred mitigation is to install an SPS to reduce output from the Colusa generation for the following contingencies:

1. Olinda–Tracy–500 kV line

2. Delevan–Vaca Dixon Nos. 2 & 3 230 kV lines

For the double outage of 500 kV lines south of Table Mountain and the double outage of Round Mountain–Table Mountain 500 kV lines #1 and #2, it is recommended the existing SPS be modified to include Colusa generation.
This project is expected to cost $1 million to $2 million.

Table 5.6-9 Power Flow Summary with recommended mitigation

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case	Portfolio 4 Peak Case (60% NCH)	Portfolio 4 Peak Case (80% NCH)
Delevan-Cortina 230 kV	Round Mt,-Table Mt. 500 kV # 1 and #2	SE Rating 380	<100%	<100%	<100%	<100%	<100%
	500 kV double outage south of Table Mt.		<100%	<100%	<100%	<100%	<100%
	Olinda-Tracy 500 kV #1		<100%	<100%	<100%	<100%	<100%
	Delevan-Vaca Dixon # 2 & #3 230 kV lines		<100%	<100%	<100%	<100%	<100%

BACKGROUND

The thermal overload on the Delevan–Cortina 230 kV line has been identified in the hybrid scenario (Portfolio 4) with 80% northern California hydro and 4,800 MW COI flow. This is a scenario case developed with the hydro and COI flow at a point outside of the existing ACDC nomogram.
This overload is due to the high hydro dispatch along with the maximum import from the COI. Hence, this overload was not seen in any other 33% RPS portfolios or in the ISO annual assessment for NERC compliance.

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1: Congestion management

This alternative is not recommended because of the large number of contingencies that could possibly overload the Delevan–Cortina 230 kV line and the potential impact on renewable and hydro generation dispatch.

Alternative 2: Reconductor the Delevan–Cortina 230 kV line

This alternative would require 20 miles of 230 kV double circuit tower line reconductoring between Delevan and Cortina substations with a higher capacity conductor. In addition, this project scope would also include the upgrade of associated line terminal equipment to accommodate the higher conductor ratings.
This alternative is expected to cost $20 million to $30 million.

Alternative 3: Loop the Delevan–Vaca Dixon 230 kV line into Cortina

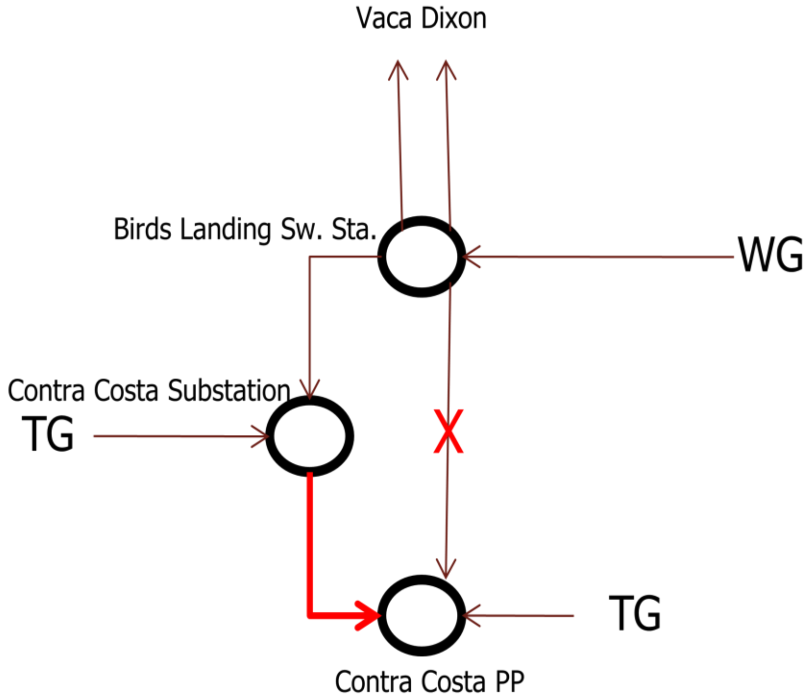
This alternative would require converting the existing Cortina 230 kV bus to a 6-element breaker-and-a-half bus and looping-in one of the Delevan–Vaca Dixon 230 kV lines into the Cortina 230 kV Substation. In addition, this project scope would also include upgrading the associated protection and automation equipment at the Cortina substation.

This alternative is expected to cost $15 million to $20 million.

5.6.5 Mitigation in Contra Costa area

The Contra Costa Substation–Contra Costa 230 kV line SPS is proposed to mitigate the identified reliability concerns in this area.

Figure 5.6-7 System configuration in the Contra Costa area



SUMMARY OF ANALYSIS

Table 5.6-10 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 4 Off-Peak Case
Contra Costa Substation-Contra Costa 230 kV line	Birds Landing Sw. St.-Contra Costa 230 kV Line	SE Rating 754	115%

No overloads were observed in the other portfolio cases.

Description and Scope of Proposed Mitigations

The preferred mitigation is to install an SPS to drop the Contra Costa area generation following an outage of the Birds Landing Sw. St.–Contra Costa 230 kV Line.

This project is expected to cost approximately $1 million.

Table 5.6-11 Power Flow Summary with proposed mitigation

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 4 Off-Peak Case
Contra Costa Substation-Contra Costa 230 kV line	Birds Landing Sw. St.-Contra Costa 230 kV Line	SE Rating 754	94%

Background

The portfolio 4 off-peak case has about 470 MW of wind generation dispatched in the Solano area connecting to the Birds Landing Switching Station. Under normal conditions, about 90% of the power injected at the Birds Landing Substation goes to the Bay Area via the two 230 kV lines to Contra Costa and the remaining 10% goes to Vaca Dixon via another two 230 kV lines. The comprehensive plan study for the portfolio 4 off-peak case identified that for an outage of the Birds Landing Sw. St.–Contra Costa 230 kV Line could overload the Contra Costa Substation–Contra Costa 230kV line by 15% over its emergency rating.

This is a generation interconnection driven overload exacerbated by the higher level of dispatch in the Solano area in the Portfolio 4 off-peak case.

Discussion of Other Considered Alternatives

Alternative 1: Reconductor the Contra Costa Substation–Contra Costa 230 kV line

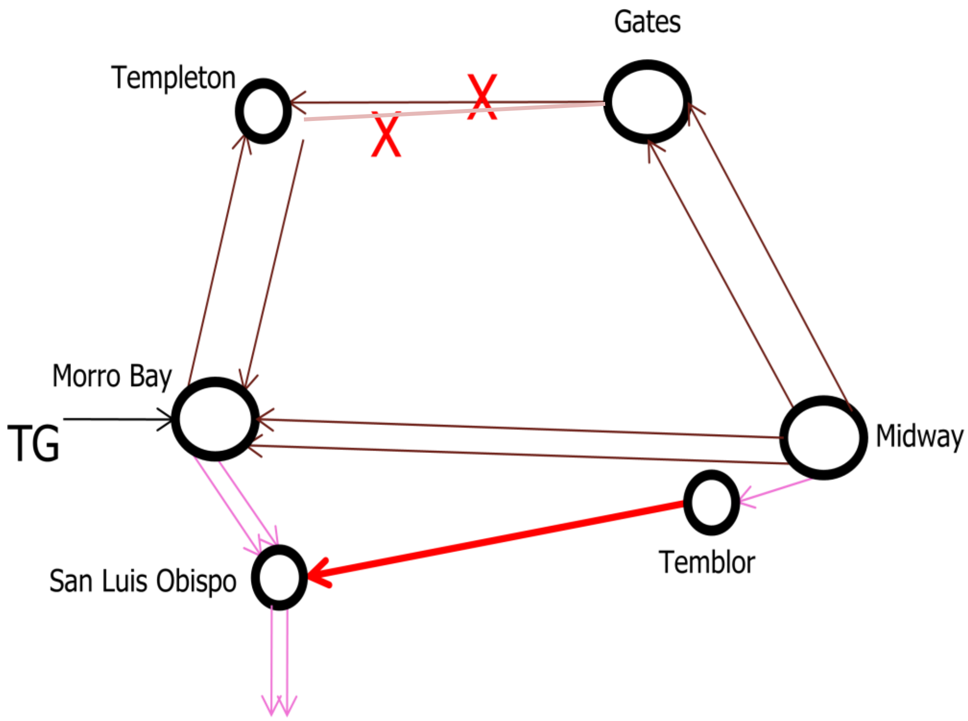
This alternative would require two miles of 230 kV line reconductoring between Contra Costa Power Plant and Contra Costa substations with a bundled 1113 ACSS conductor. In addition, this project scope would also include the upgrade of associated line terminal equipment to accommodate the higher conductor ratings.

This alternative is expected to cost $2 million to $3 million.

5.6.6 Mitigations in San Luis Obispo area

These mitigations include Temblor–San Luis Obispo #1 115 kV line reconductoring and voltage support. The area diagram is shown in the figure below.

Figure 5.6-8 San Luis Obispo area



SUMMARY OF ANALYSIS

Table 5.6-12 Power Flow Summary without mitigation

Reliability Concern	Worst Contingency	Rating	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case	Portfolio 4 Peak Cases
Temblor–San Luis Obispo 115 kV Line (all sections)	Morro Bay–Gates #1 and Templeton–Gates #1 230 kV Lines	436 (Amp)	<100%	<100%	128%	92%
Low voltage in San Luis Obispo 115 kV system	Morro Bay–Gates #1 and Templeton–Gates #1 230 kV Lines	0.9 pu (voltage)	>0.9 pu	>0.9 pu	0.81 pu	>0.9 pu

DESCRIPTION AND SCOPE OF POTENTIAL MITIGATIONS

The project scope would be to reconductor approximately 57 miles of the Temblor–San Luis Obispo #1 115 kV line from Temblor to San Luis Obispo substations with conductors capable of carrying a minimum load of 565 A. In addition, this project scope would also include the upgrade of associated line terminal equipment to accommodate the higher conductor ratings.

The installation of a 50 MVAr reactive power support within the San Luis Obispo 115 kV system would also be required to improve voltage performance following the contingency.

This project is estimated to cost $65 million to $75 million.

Table 5.6-13 Power Flow Summary with potential mitigation

Overloaded Facility or Low Voltage	Worst Contingency	Rating	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 2 Peak Case	Portfolio 4 Cases
Temblor–San Luis Obispo 115 kV Line (all sections)	Morro Bay–Gates #1 and Templeton–Gates #1 230 kV Lines	565 (Amp)	<100%	<100%	<100%	<100%
Low voltage in San Luis Obispo 115 kV system	Morro Bay–Gates #1 and Templeton–Gates #1 230 kV Lines	1.0 pu (voltage)	>0.9 pu	>0.9 pu	>0.9 pu	>0.9 pu

BACKGROUND

This overload is due to the assumption of zero generation at the existing Morro Bay Power Plant in addition to zero new renewable generation in the Carrizo area.

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1: Maintain local generation

Maintaining about 100 MW of local generation in the Morro Bay area would mitigate the potential thermal overload and low voltage concerns in the San Luis Obispo 115 kV system under the Category C contingency condition. This alternative would become viable if at least one unit at the existing Morro Bay Power Plant gets repowered.

Alternative 2: Add a new 115 kV line between Temblor and San Luis Obispo Substations

This alternative would be to construct a new 115 kV line between Temblor and San Luis Obispo substations in addition to the existing 115 kV line to help support the full delivery of power to the grid.

Currently, this alternative may not be the most cost effective alternative in providing the full delivery of power in the area.

Alternative 3: Load dropping SPS for Category C contingency

This alternative will be assessed further in the 2011/2012 comprehensive transmission planning cycle.

5.6.7 Mitigation of overloads in the Morro Bay area

An SPS that trips generation at Morro Bay area would be needed to mitigate Morro Bay–Templeton 230 kV #1 and #2 lines overload in the deliverability assessments for portfolio 1. The alternative is reconductoring the Morro Bay–Templeton 230 kV lines, which would not recommended since it will cost more than the SPS.

5.6.8 Mitigation of the Los Banos–Westley 230 kV line overload

The Los Banos–Westley 230 kV line may overload during contingency conditions. The area diagram is shown in the figure below.

Figure 5.6-9 Tesla-Los Banos transmission system

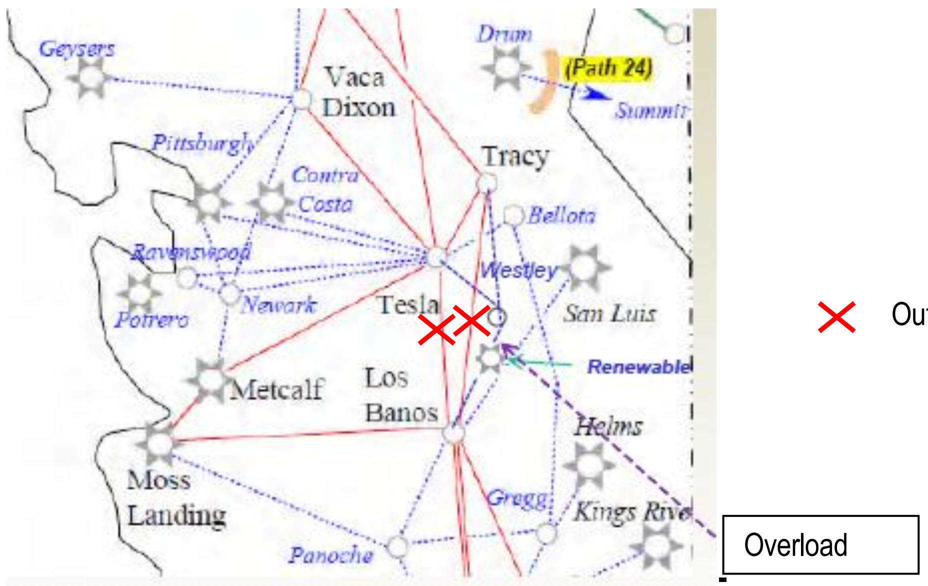


Table 5.6-14 Power Flow Summary without mitigation, with existing SPS

Overloaded Facility	Worst Contingency	Summer Emergency Rating (MVA)	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 1 Off-Peak Low solar	Portfolio 2 Peak Case	Portfolio 4 cases
WESTLEY – LOS BANOS 230 kV #1	Los Banos North double 500 kV line outage, S-N SPS	678	<95%	99%	<95%	<95%	<95%
	Malin-RndMt-dlo-ns- SPS		99%	<95%	<95%	<95%	<95%
	RoundMt-TableMt-dlo-ns-SPS		99%	<95%	<95%	<95%	<95%
	TableMtSouth-dlo-ns- SPS		104%	<95%	<95%	<95%	<95%
	TeslaNorth-dlo-ns- SPS		95%	<95%	<95%	<95%	<95%

DESCRIPTION AND SCOPE OF PROPOSED MITIGATIONS

Reconductoring the Los Banos to Westley 230 kV line would be proposed to mitigate the overloads and relieve the potential congestion. The cost is estimated to be $40 million.

BACKGROUND

Significant congestion on the Los Banos–Westley 230 kV line was observed in the production cost simulations. Renewable interconnection in the Fresno area and relative high flow from south to north on Path 15 because of renewable integration in southern California aggravate the flow on the Los Banos–Westley 230 kV line. In the 33% RPS planning studies, high flows on this 230 kV line have been observed in all portfolios although overload was identified only in the peak case of Portfolio 1.

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1: Develop an SPS for emergency overloading of the Los Banos–Westley 230 kV line. This SPS will trip generation south of Los Banos.

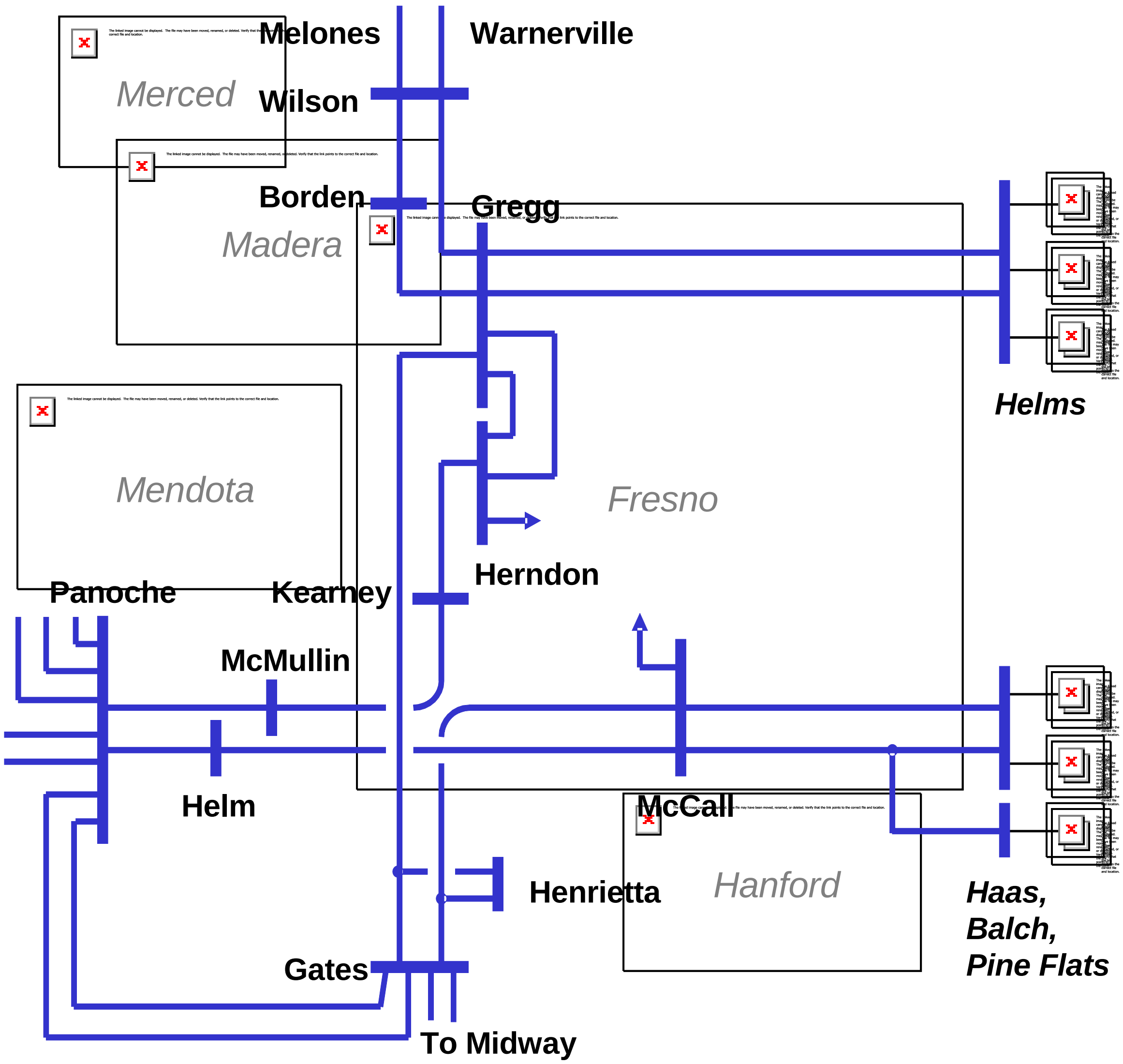
The renewable generation directly connecting to the Los Banos–Westley 230 kV line has the highest contribution to the overload. Tripping this generation could effectively mitigate the overload on the Los Banos–Westley 230 kV line in the Portfolio 1 peak case. However, the high flow from south to north is also a contributing factor in the overload or high flow levels on the line. The high flows are still expected even without direct generation interconnection to this line. Therefore, the SPS solution would not be recommended or would only be recommended as a potential interim solution if the renewable interconnection to the Los Banos–Westley 230 kV line occurs.

5.6.9 Mitigation of Fresno area overloads

FRESNO AREA OVERVIEW

The transmission diagram of the Fresno area is shown in the following figure.

Fig. 5.6-10 Fresno area transmisson system diagram



SUMMARY OF ANALYSIS

Table 5.6-15 Power Flow Summary without mitigation

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 1 Off-peak low solar case	Portfolio 2 Peak Case	Portfolio 4 Peak Case	Portfolio 4 Off peak Case
500 kV								
GATES 500/230 kV bank		SN Rating 1122						
	LosBanosSouth-dlo-sn		<95%	<95%	99%	<95%	<95%	<95%
	LosBanosNorth-dlo-sn		<95%	<95%	99%	<95%	<95%	<95%
	LosBanos-Gates#1-slo		<95%	<95%	102%	<95%	<95%	98%
230 kV								
HENTAP1 230 to GATES 230 kV line (GATES-GREGG)	Panoche-Kearney 230 (no SPS/SPS)	732 SN	<95%	105%/<95 %	119%/100 %	<95%	<95%	116%/97%
	DCTL: Helm–McCall & Gates–McCall 230 kV (no SPS/SPS)		<95%	118%/<95 %	133%/94%	<95%	<95%	128%/<95 %
	LosBanos south 500 -DLO		<95%	<95%	103%	<95%	<95%	95%
	LosBanos-Gates#1-slo		<95%	<95%	106%	<95%	<95%	100%
	Panoche-Kearney and Panoche-Helm 230 (no SPS/SPS)		<95%	114%/<95 %	120%/<95 %	<95%	<95%	127%/<95 %
GATES-MIDWAY 230 kV #1 line	Gates 500/230 kV bank	375 SE	<95%	103%	98%	<95%	<95%	<95%
	Gates-Midway 500 kV		<95%	99%	<95%	<95%	<95%	<95%
	Midway North double outage		<95%	108%	108%	<95%	<95%	<95%
GATES-MIDWAY 230 kV #2 line	Gates 500/230 kV bank	375 SE	<95%	103%	108%	<95%	<95%	<95%
	Gates-Midway 500 kV		<95%	99%	96%	<95%	<95%	<95%
	Midway North 500 kV double		<95%	108%	97%	<95%	<95%	<95%

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 1 Off-peak low solar case	Portfolio 2 Peak Case	Portfolio 4 Peak Case	Portfolio 4 Off peak Case
	outage							
KEARNEY–HERNDON 230 kV line	Base system (n-0)	328 SN	<95%	113%	112%	<95%	<95%	112%
	LosBanosNorth-dlo-sn	388 SE	<95%	101%	100%	<95%	<95%	100%
	Gates 500/230 kV (no SPS)		<95%	100%	102%	<95%	<95%	101%
	Warneville-Wilson 230 kV (no SPS)		<95%	109%	109%	<95%	<95%	110%
PANOCHE-GATES 230 KV # 1 and 2		339 SE						
	LosBanosSouth-dlo-sn		<95%	95%	<95%	<95%	<95%	<95%
	Gates-Gregg 230kV & Gates-McCall 230kV lines (w/SPS tripping 2 Helms)		<95%	110%	113%	<95%	<95%	101%
WARNEVILLE-WILSON 230 kV Line	Base system (n-0)	269 SN	<95%	<95%	<95%	<95%	<95%	100%
	Gates 500/230 kV bank	316 SE	<95%	<95%	102%	<95%	<95%	108%
	Panoche-Kearney 230 (no SPS/SPS)		<95%	101%/<95 %	106%/<95 %	<95%	<95%	113%/<95 %
	Panoche-Kearney and Panoche-Helm 230 (no SPS/SPS)		<95%	114%/<95 %	120%/<95 %	<95%	<95%	127%/<95 %
115 kV								
BARTON-HERNDON 115 kV Line	DCTL: Helm–McCall & Gates–McCall 230 kV	194 SE	<95%	<95%	<95%	111%	<95%	<95%
MANCHESTER-HERNDON 115 kV Line	DCTL: Helm–McCall & Gates–McCall 230 kV	194 SE	94%	<95%	<95%	112%	<95%	<95%
MC CALL-SANGER	McCall-Sanger # 1 115	194 SE	<95%	102%	98%	<95%	<95%	96%

Overloaded Facility	Worst Contingency	Rating (MVA)	Portfolio 1 Peak Case	Portfolio 1 Off-Peak Case	Portfolio 1 Off-peak low solar case	Portfolio 2 Peak Case	Portfolio 4 Peak Case	Portfolio 4 Off peak Case
115 KV # 3 LINE	McCall-Sanger # 1 & #2 115		<95%	139%	134%	<95%	<95%	131%
70 kV								
ORO LOMA-MENDOTA 70 kV line	Panoche-Mendota 115 kV	34 SE	105%	106%	<95%	<95%	<95%	<95%

Note 1: The SPS for the 500 kV double outage south of Los Banos (Los Banos–Gates and Los Banos–Midway) includes tripping two Helms pumps in addition to tripping Midway generation and northern California load for off-peak conditions.

Note 2: The SPS for 230 kV outages included tripping one or two Helms pumps for off-peak conditions.

DESCRIPTION AND SCOPE OF POTENTIAL MITIGATIONS—500KV

This alternative mitigation consists of the following upgrades. The total cost of the mitigation plan is expected to be approximately $1.030 billion to $1.15 billion.

1. Construct Midway-Gregg 500 kV Project, including:

1) Upgrade Gregg 230 kV Substation to 500/230 kV, install two 500/230 kV transformers
2) Construct a double circuit 500 kV transmission line between Midway and Gregg substations with 50% series compensation
3) Install two 91 MVAr shunt reactors at the Gregg end of each line

This portion of the mitigation plan is expected to cost $1.00 billion to $1.10 billion.

The addition of the Midway–Gregg 500 kV project would mitigate many overloads that may occur under summer off-peak load conditions when the Helms pump-storage power plant operates in the pumping mode with all three units. Helms pumping load is critical in accommodating high levels of renewable generation considered in this study. Having the Midway–Gregg 500 kV line would allow Helms to operate in the pumping mode with all three pumps operating under most expected off-peak load levels and, thus, over a flexible window of hours in the 2020 time frame and beyond.

The Midway–Gregg 500 kV project would mitigate overloads of the Gates 500/230 kV transformer, Gates–Gregg, Gates–Midway #1 and #2, Kearney–Herndon, Panoche–Gates #1 and 2 and Warneville–Wilson 230 kV lines, McCall–Sanger 115 kV line and Oro Loma–Mendota 70 kV line. However, it would create overload on the Gregg–Herndon #1 and #2 230 kV lines that would require mitigation. These lines are 1.5 miles long. In addition, it would exacerbate overloads of the Barton–Herndon 115 kV line, and Manchester–Herndon 115 kV line.

2. Upgrade both circuits of the Gregg–Herndon 230 kV double circuit transmission line. If reconductoring of this transmission line is not possible, construct a new 230 kV circuit between Herndon and Gregg substations (approximately 1.5 miles long).

This portion of the mitigation plan is expected to cost $1.5 million to $2 million for reconductoring and between $6.5 million to $7 million for the new line.

This upgrade would mitigate overload on the Gregg–Herndon #1 and #2 230 kV circuits caused by addition of the Midway–Gregg 500 kV Project.

3. **Reconductor 12.5 miles of the Barton–Herndon 115 kV line with conductors capable of carrying a minimum of 1200 A. In addition, this project scope would also include the upgrade of associated line terminal equipment to accommodate the higher conductor ratings.**

This portion of the mitigation plan is expected to cost $15 million to $22 million.
Reconductoring the Barton–Herndon 115 kV line would mitigate its overload under contingency conditions.

4. **Reconductor 9.3 miles of the Manchester–Herndon 115 kV line with conductors capable of carrying a minimum of 1200 A. In addition, the project scope would also include an upgrade of associated line terminal equipment to accommodate the higher conductor ratings.**

This portion of the mitigation plan is expected to cost $12 million to $15 million.
Reconductoring the Manchester–Herndon 115 kV line would mitigate its overload under contingency conditions

BACKGROUND

It is anticipated that ISO renewable integration studies currently in progress may identify the need for pumping with three Helms pumps during a high percentage of off-peak load hours. Therefore, the off-peak cases modeled new renewable generation projects, the Helms pump-storage power plant operating in pumping mode with three pumps at a total of approximately 960 MW, and most existing Fresno thermal units off-line. In addition, the sensitivity case modeled low PV solar generation production because of low insolation levels. The south-to-north flow on Path15 was at stressed levels in the off-peak cases because of high renewable generation development in southern California and the desert Southwest and low load levels during the off-peak conditions. Path 15 flow varied from about 4,000 MW to 5,200 MW in south to north direction in the off-peak scenarios studied.

All the above reasons contribute to high loading of the Midway–Gates, Gates–Gregg, Panoche–Gates, Kearney–Herndon and Warneville–Wilson 230 kV lines and the McCall–Sanger 115 kV line, and drive the need for the upgrades. In addition, in the low solar PV scenario, Gates 500/230 kV transformer may overload under contingency conditions.

Based on the results shown in Table 5.4.35, the need for the upgrades in the Fresno area is mainly identified in the low solar sensitivity case for Portfolio 1, which has the highest Path 15 flow among all studied scenarios (5,200 MW). Although the low solar sensitivity case is only studied for Portfolio 1, a similar low solar scenario is applicable to all portfolios. Table 5.4.35 shows that there are overloads on the same facilities for both Portfolio 1 and Portfolio 4 off-peak cases even with higher solar generation. Some overloads in the Portfolio 4 off-peak scenario are more severe than in the Portfolio 1 off-peak scenario, although less severe than in the Portfolio 1 low solar off-peak scenario. Overloads identified in the off-peak studies mainly depend on the Path 15 south to north flow, which will be higher if the solar generation in Fresno is lower. Therefore, it is expected that with low solar generation, the same overloads as in the low solar sensitivity case for Portfolio 1 will occur in the Portfolio 4 scenario under off-peak conditions with low solar. Thus, the need for upgrades identified in the studies of the low solar case in Portfolio 1 is also applicable to other scenarios, such as Portfolio 4; and the upgrades proposed based on the low solar Portfolio 1 scenario will be also needed for Portfolio 4.

The Manchester–Herndon and Barton–Herndon 115 kV lines overload under contingency peak load conditions in the Portfolio 2 power flow and stability assessment. Manchester–Herndon and Barton–Herndon 115 kV lines were identified as limiting elements after 2012 in the long term local capacity requirement study of the Herndon area.

Compared with Portfolio 1, Portfolio 2 has high north to south flow on the Fresno 230kV import lines, which causes high loading on the parallel 115kV path in case of a 230 kV outage. In addition, there was 80MW less generation modeled from the Kings River hydro group in the Herndon area. Manchester–Herndon and Barton–Herndon are two 115kV import lines in Herndon area. Thus the high north to south flow and low level of internal generation cause the import lines overload under contingency conditions.

Overloading on the Oro Loma–Mendota 70 kV line was also identified in the ISO 2010/2011 annual reliability assessment for NERC compliance. The assumed renewable generation in the local area in the studied portfolios exacerbate overload on the Oro Loma–Mendota 70 kV line.

The proposed mitigation plan mitigates all observed overloads in all scenarios studied. Regarding the route of the new Midway–Gregg 500kV line, there are two options: east route or west route. The east route option can establish an interconnection with the adjacent SCE's Big Creek system. A separate long-term reliability assessment of Big Creek area has identified that thermal overloads, voltage collapse and transient voltage dip, and frequency dip problems that could happen under the load conditions beyond the 2024 time frame. The long-term reliability needs in this area interact with the proposed plans to increase transfer capability from southern California to the north to deliver the renewable energy. The plan interconnecting the Fresno and Big Creek areas through this Midway – Gregg 500kV line will be assessed further and included in the next annual ISO comprehensive plan. These studies will also incorporate the results of the ISO renewable integration studies.

DISCUSSION OF OTHER CONSIDERED ALTERNATIVES

Alternative 1—New 230 kV Line Alternative

This 230 kV alternative consists of eight segments and is to cost approximately $230 million to $265 million.

1) Construct a new 230 kV line between Gregg and McCall Substations. The length of this line is approximately 45 miles.

This portion of the mitigation plan is expected to cost $55 million to $65 million.

This new transmission line would mitigate the overload of the Kearney–Herndon 230 kV line and significantly reduce loading on the Warneville–Wilson 230 kV line, as well as reduce loading on the Gates–Gregg 230 kV line. It would mitigate overloads on the Barton–Herndon and Manchester–Herndon 115 kV lines. However, the Kearney–Herndon and Gates–Gregg 230 kV lines may still overload if the load in the Fresno area is slightly higher. Therefore, these lines would need to be upgraded in approximately 2021 or earlier based on the current load forecast which depends on the load level at which the Helms pump storage plant would be operating in pumping mode with three pumps.

2) **Reconductor both circuits of the Midway–Gates 230 kV # 1 and # 2 transmission lines.**

This alternative involves reconductoring 64 miles of the Midway – Gates 230 kV lines #1 & #2 with conductors capable of carrying a minimum of 1,300 A. In addition, the project scope would include the upgrade of associated line terminal equipment to accommodate the higher conductor ratings.

This portion of the mitigation plan is expected to cost about $130 million.

Reconductoring the Midway–Gates 230 kV lines would mitigate the overload on these lines that was observed under contingency conditions in the Portfolio 1 off–peak scenarios. In addition to a renewable project looped into the Midway–Gates 230kV lines #1 and #2, these scenarios had stressed south-to-north flow on Path 15. In other renewable portfolio cases, Path 15 flow under off-peak conditions was not stressed (4,320 MW in the hybrid case versus 5,100-5,200 MW in the Portfolio 1 base case and sensitivity case, respectively).Therefore, there were no overloads for category B contingencies and the existing SPS was sufficient to mitigate the overload for category C.

Without reconductoring the Midway-Gates 230 kV lines, tripping one or two Helms pump or tripping some (up to 230 MW) generation at Midway mitigated the overload for category B contingencies. However, for a double outage of 500 kV lines North of Midway (Midway–Gates and Midway–Los Banos), no amount of generation or load tripping appeared to be sufficient to eliminate the overload. No additional generation was available for tripping. Also, loading on the Midway–Gates 230 kV lines was not sufficiently sensitive to the load tripping.

3) **Rerate Gates 500/230 kV to obtain emergency rating of at least 1270 MVA.**

The Gates 500/230 kV transformer presently is rated at 1122 MVA with no emergency rating. Its rerate would mitigate the overload of the Gates 500/230 kV transformer that was observed under off-peak conditions in the low solar output case described above.

If the transformer rerate appears not to be possible, then modification of the SPS for the South of Los Banos 500 kV double outage (Los Banos–Gates and Los Banos–Midway) and an additional SPS for the Los Banos–Gates 500 kV #1 line outage would need to be implemented.

This portion of the mitigation plan (additional SPS, transformer re-rate or both) is expected to cost $1 million to $5 million.

The mitigation plan would modify the SPS for a 500 kV double outage south of Los Banos because the existing SPS may not be sufficient with construction of a new 230 kV line from McCall to Gregg. In this case, additional generation tripping at Midway, including new renewable projects would be required. A new SPS to trip some generation at Midway, or to trip one Helms pump would be needed to mitigate the Gates 500/230 kV transformer overload with a single line outage of the Los Banos-Gates #1 500 kV transmission line.

Another alternative is adding a second 500/230 kV transformer at Gates to help support Helms pump storage plant operating in pumping mode with three pumps in case of low solar generation. This alternative would not be recommended because it is not cost effective compared to the proposed transformer upgrade.

4) **Upgrade terminal equipment of the Henrietta tap 1- Gates section of the Gates-Gregg # 1 230 kV line.**

Terminal equipment at the Henrietta tap 1– Gates section of the Gates–Gregg # 1 230 kV line is currently a limiting element that caused the line overload under contingency off-peak conditions in the scenario with low solar PV output described above. With this upgrade, the line rating would be limited by the conductor, which is 1113 ACSS capable of carrying 754 MVA. Even if this upgrade would not be sufficient to eliminate all overloads, it would be sufficient if the new Gregg–McCall 230 kV line proposed as a part of this mitigation plan is constructed. Without the terminal equipment upgrade, the new Gregg– McCall line will eliminate all the overloads except in case of the Los Banos – Gates #1 500 kV or Los Banos–Midway 500 kV single line outages that is expected to be about 1% and will be mitigated if the terminal equipment is upgraded.

This portion of the mitigation plan is expected to cost around or below $1 million.

However, the Henrietta Tap 1– Gates section of the Gates–Gregg # 1 230 kV line may still overload if the load in the Fresno area is slightly higher. Therefore, additional mitigation would be needed by approximately 2021 or earlier based on the current load forecast which depends on the load level at which the Helms pump storage plant will be operating in pumping mode with three pumps.

5) **Modify existing SPS to mitigate Panoche–Gates #1 and #2 230 kV line overload.**

A double outage of the Gates–Gregg and Gates–McCall 230 kV lines under off-peak conditions assumes tripping two Helms pumps. However, this measure was not sufficient to mitigate the Panoche–Gates 230 kV lines overload. Tripping up to 1,100 MW of generation at Midway brought loading on the Panoche–Gates 230 kV lines under the long-term emergency rating.

The Panoche–Gates 230 kV lines have 30-minute emergency ratings of 418 MVA, and the observed loading was under this value for all the contingencies.

The proposed mitigation of the Panoche–Gates 230 kV lines overload in this alternative plan was to apply their 30-minutes emergency rating. If the overload persists after 30 minutes, the proposal would be to trip generation at Midway for the Gates–Gregg and Gates–McCall 230 kV double line outage.

The proposed modification of the SPS is expected to cost $0.1 million and 0.3 million.

6) **Reconductor 20 miles of the Warnerville–Wilson 230 kV line with conductors capable of carrying a minimum of 1000 A.**

In addition to the proposed reconductoring, this project scope would include upgrading associated line terminal equipment to accommodate the higher conductor ratings.

This project is expected to cost between $38 million and $44 million.

The Warnerville–Wilson 230 kV line may overload under off-peak normal and contingency conditions in the hybrid case scenario and under contingency conditions in the Portfolio 1 off peak case with low solar PV generation. Addition of the McCall–Gregg 230 kV line significantly reduced loading on this line, but still did not eliminate its overload for the Gates 500/230 kV transformer outage in the hybrid case scenario. This line may also overload for the same contingency in other scenarios if the Helms pump storage power plant is pumping with three pumps with higher load in the Fresno area. Therefore, if the Warnerville–Wilson 230 kV line is not upgraded, it would limit the time when Helms pump-storage can pump at full load.

7) **Reconductor 9.2 miles of the Sanger–McCall 115 kV line with conductors capable of carrying a minimum of 1,400 A.**

In addition to the proposed reconductoring, the project scope would include an upgrade of associated line terminal equipment to accommodate the higher conductor ratings.

This portion of the mitigation plan is expected to cost $12 million to $15 million.

The reconductoring would mitigate the contingency overload on the Sanger–McCall #3 115 kV line under off-peak load conditions. Helms pump-storage power plant operating in pumping mode with three pumps in the off peak case aggravated the loading on this line.

Overload of the Sanger-McCall 115 kV line was also observed in the reliability assessment described in Chapter 2 and the recommendation was to use an interim temperature adjusted rating. However, this solution would not work with the assumptions in the 33% RPS scenarios because the overload percentage in the reliability analysis (4%) was significantly lower than in the 33% RPS study (up to 39%), due to the higher level of Helms pumping assumed.

8) **Convert the Oro Loma - Mendota 70 kV line to 115 kV operation.**

   The PG&E *Oro Loma - Mendota 70 to 115 kV Conversion Project* was proposed through the 2010 request window and was determined to be needed to mitigate identified reliability concerns.

Sensitivity Study for Alternative 1: New Double Circuit Gregg-McCall 230 kV Line

Alternative 1 includes a single circuit new 230 kV line between Gregg and McCall. This sensitivity study examined a new double circuit 230 kV line consisting of five segments instead of the eight proposed in the previous alternative. The total cost of the alternative mitigation plan is expected to be between $200 million and $230 million.

1) Construct a new double circuit 230 kV line (circuits #1 and #2) between Gregg and McCall substations. The length of this line is approximately 45 miles for each circuit.

This portion of the mitigation plan is expected to cost $75 million to $85million.

This new double-circuit transmission line would mitigate overload of the Kearney–Herndon 230 kV line, the Warneville–Wilson 230 kV line, as well as the Gates–Gregg 230 kV line. It would mitigate overloads on the Barton–Herndon 115kV line, Manchester–Herndon 115 kV line, and McCall–Sanger 115kV line. However, the Warneville–Wilson 230 kV line, Kearney–Herndon 230kV line, Gates–Gregg 230 kV line, and McCall–Sanger 115kV line may still overload if the load in the Fresno area is slightly higher. Therefore, these lines would need an upgrade in approximately 2021 or earlier based on the current load forecast, depending on the load level at which the Helms pump storage plant would be operating in pumping mode with three pumps.

2) Reconductoring both circuits of the Midway–Gates 230 kV #1 and #2 transmission lines (same as in the 230 kV alternative with a single-circuit 230 kV Gregg–McCall line).
3) Rerate Gates 500/230 kV to obtain emergency rating of at least 1270 MVA (same as in the 230 kV alternative with a single-circuit 230 kV Gregg–McCall line).
4) Modify the existing SPS to mitigate the Panoche–Gates #1 and #2 230 kV line overload (same as in the 230 kV Alternative with a single-circuit 230 kV Gregg–McCall line).
5) Use the solution that has been proposed in the ISO's annual reliability assessment for NERC compliance to mitigate the Oro Loma–Mendota 70 kV line overload. Please refer to Chapter 2 for the details regarding this project (same as in the 230 kV alternative with a single-circuit 230 kV Gregg–McCall line).

Alternative 2—Reconductoring Alternative

Total cost of the alternative reconductoring mitigation plan is expected to be approximately between $235 million and $260 million.

If the 230 kV McCall–Gregg line and 500 kV Midway–Gregg line cannot be built, the third alternative would be to use reconductoring as main mitigation for thermal overloads. However, if these lines are not built, the Henrietta tap– Gates section of the Gates–Gregg 230 kV line would overload under contingency conditions. Reconductoring of this line is not possible because it already has the heaviest conductor for this voltage level. Upgrading the terminal equipment of the Gates–Gregg 230 kV line is not adequate to mitigate the overloads. There is no operational procedure that can mitigate this overload because the studies showed that Gates–Gregg 230 kV line may still overload even if all available generation and load is tripped. Therefore, at least a new line from Henrietta to Gates would be needed in this alternative.

SUMMARY OF ALL MITIGATION PLANS

All the alternatives are summarized in the table below. The new 230 kV line alternative and reconductoring alternative mitigation plans have significantly lower cost than the 500 kV mitigation plan, however, they will have the following disadvantages that should be considered:

1) These plans would provide mitigation of all the observed overloads up to the year of 2020 based on the current load forecast, but not beyond.

2) The alternative mitigation plan would allow Helms pump-storage power plant to operate in the pumping mode with all three units. However, there would be more contingencies that require Helms units to be tripped in the 230 kV alternatives than in the 500 kV alternative.

3) The 230 kV mitigation plans will include new SPS and modifications to an existing SPS that will make operation of the system more complicated and less reliable.

4) The 230 kV mitigation plan would include a higher amount of generation and load tripping by the SPS compared with the 500 kV plan.

Table 5.6.16 Summary of mitigations for the Fresno area

Number	Overloaded Facility	Mitigation: new 500kV line Solution (alternative 0)	Mitigation: new 230kV line Solution (alternative 1)	Mitigation: Reconductoring Solution (alternative 2)
1	GATES 500/230 kV bank	new Midway–Gregg 500 kV line	Rerate Gates 500/230 kV to obtain emergency rating of at least 1270 MVA	Rerate Gates 500/230 kV to obtain emergency rating of at least 1270 MVA
2	HENTAP1 230 to GATES 230 kV line (GATES–GREGG)		Upgrade terminal equipment	Build new line
5	PANOCHE–GATES 230 KV # 1 and 2 lines		Modify existing SPS or using 30min emergency rating	Modify existing SPS or using 30min emergency rating
3	GATES–MIDWAY 230 kV #1 line		Reconductor	Reconductor
4	GATES–MIDWAY 230 kV #2 line		Reconductor	Reconductor
7	WARNEVILLE–WILSON 230 kV Line		Reconductor	Reconductor
9	ORO LOMA–MENDOTA 70 kV line		Oro Loma 70 kV Area Reinforcement proposed in annual NERC compliance reliability assessment	Oro Loma 70 kV Area Reinforcement proposed in annual NERC compliance reliability assessment
8	MC CALL–SANGER 115 KV # 3 line		Reconductor	Reconductor
6	KEARNEY– HERNDON 230 kV line		new Gregg–McCall 230kV line	Reconductor
10	BARTON–HERNDON 115 kV Line	Reconductor		Reconductor
11	MANCHESTER–HERNDON 115 kV Line	Reconductor		Reconductor
13	GREGG – HERNDON 230KV line # 1 and 2	Reconductor or build a new line	NA	NA
	Total cost estimation	**$1,030M-$1,150M**	**$230M-$265M**	**$235-$260M**

5.7 System-Wide Stability Assessments

5.7.1 Objective and overview

In the studies to meet the 33% RPS goals, extensive stability assessments have been performed to examine if the system would withstand the extreme disturbances under various scenarios in different portfolios. Outages that potentially impact system-wide stability were simulated and investigated. This study was not a path rating study, so the path flows were not stressed beyond the conditions set out in the RPS scenarios.

The assessments that have been performed included, but were not limited to, post-transient voltage stability and reactive margin analyses, time-domain transient simulations, and eigenanalyses. In general, with appropriate mitigations that have been proposed in earlier sections, the system withstood extreme disturbances.

First, stability assessments were performed testing the WECC NE/SE separation. Then, eigenanalysis was applied to the base cases of different scenarios to determine whether the renewable interconnections introduced any new oscillation modes into the WECC system under both normal and contingency conditions. The modes that potentially interact with renewable interconnections were analyzed.

A critical contingency for the Southern California system, Sunrise/SWPL N-2 outage, was investigated from different aspects, including angle and voltage stability. The causes of system instability and effectiveness of mitigation plans proposed in Section 5.4 are discussed below.

Bulk system outages in the northern California system are not discussed in detail in this section because they have been discussed in Section 5.4.

5.7.2 WECC NE/SE Separation Scheme

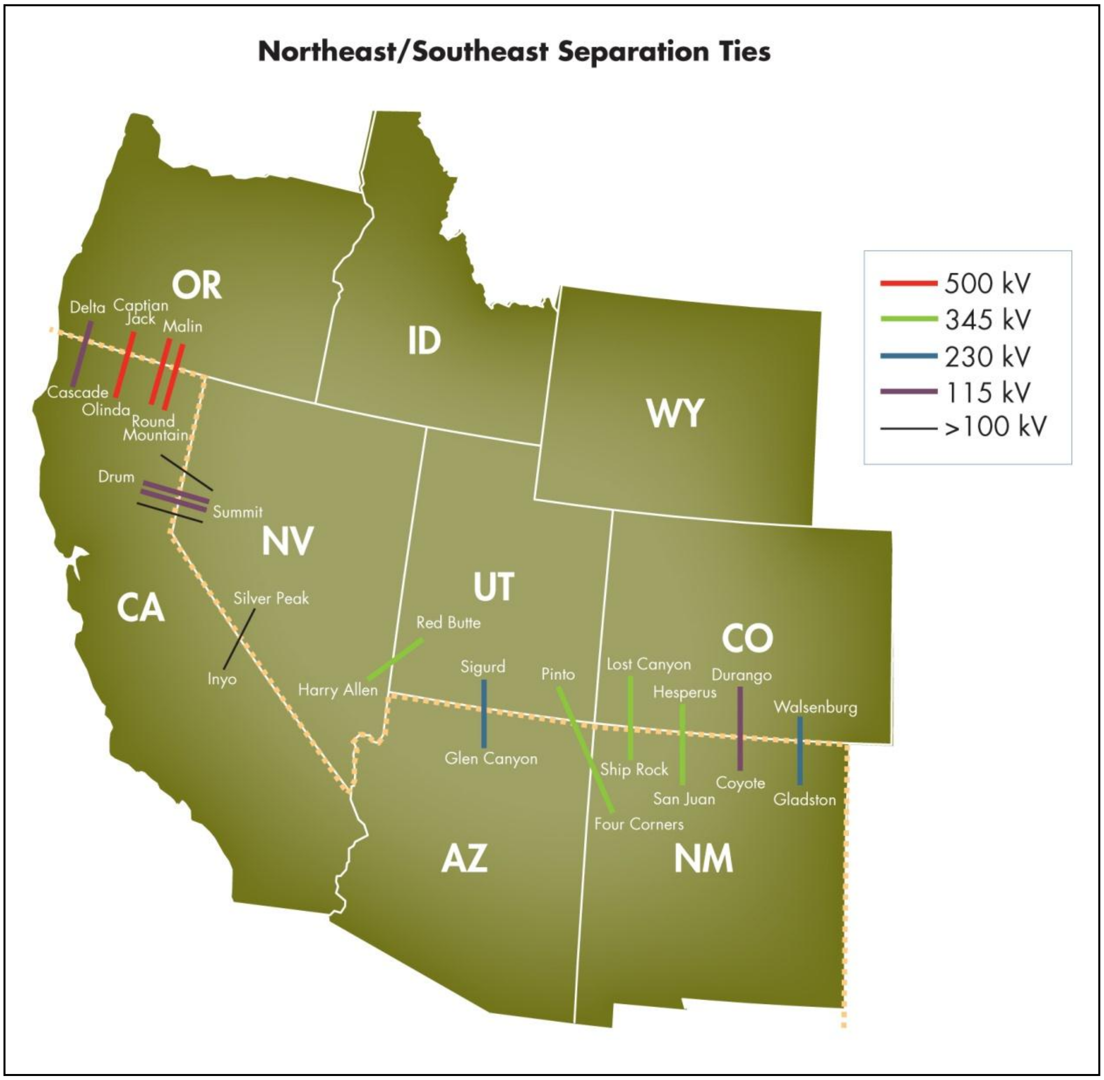
5.7.2.1 Background of WECC NE/SE separation scheme[39]

The CASI (California Simultaneous Import) nomograms were developed after the December 22, 1982 WSCC (WECC) disturbance. This disturbance occurred after the loss of the Pacific AC Intertie (PACI) within the PG&E service territory resulting in the WECC-1 RAS initiation (otherwise known as the Northeast/Southeast, or NE/SE, Separation Scheme).

The NE/SE separation scheme provides controlled separation within the WECC system for the loss of the three 500 kV lines south of the California Oregon border or the four 500 kV lines north of the California Oregon border of the California Oregon Intertie (COI). Both of these contingencies are NERC category D events. The resulting electrical islands are formed by controlled tripping of transmission lines as shown in Figure 5.5.1 below.

[39] "2009 Summer Operations Revisted CASI Study" by California Operating Studies Subcommittee and Southwest Area Study Group

Fig. 5.7.1 WECC NE/SE separation scheme



The separations occur along the following branch groups:

California–Oregon

Malin–Round Mtn. 500 kV #1

Malin–Round Mtn. 500 kV #2

Captain Jack–Olinda 500 kV

Sierra Pacific–PG&E

Summit–Drum 115 kV #1

Summit–Drum 115 kV #2

Summit–Drum 60 kV #3

Marble–Sierraville 69 kV

Oregon–PG&E

Delta–Cascade 115 kV

New Mexico–Colorado

San Juan–Hesperus 345 kV

Lost Canyon–Ship rock 345 kV

Coyote–Durango 115 kV

Walsenburg–Gladston 230 kV

Utah–New Mexico

Pinto–Four Corners 345 kV

Nevada–Utah

Harry Allen–Red Butte 345 kV

Utah–Arizona

Sigurd–Glen Canyon 230 kV

California–Nevada

Silver Peak–Control 60 kV

5.7.2.2 Assessed scenarios of WECC NE/SE separation

A preliminary study was performed to evaluate the impact on the system transient stability following the operation of the NE/SE separation scheme with a large amount of renewable generation being added to the system to meet the 33% RPS target in 2020. The study assumed the capacity margins and reserve margins represented in the WECC case for other balancing authority areas was representative of reasonable operating conditions for the purposes of this screening analysis, and at this time, testing has not been conducted on a wider range of various system-wide capacity margin conditions. The ISO is aware of research into system operation concerns under lower levels of capacity margin stemming from more generation potentially operating at its maximum output. While that research could result in additional operational requirements that will need to be reflected in future studies, those considerations will be reflected in future planning studies as the issues are better defined. Select scenarios for portfolio 1 and portfolio 4 were simulated with the WECC NE/SE separation scheme. These scenarios were selected among all scenarios in the 33% RPS planning study, because they represent the more stressed patterns on the critical paths related to the WECC NE/SE separation scheme. The critical paths that were monitored are COI, Path 26, EOR and TOT2. These paths were not particularly stressed further since the objective of the system-wide stability assessment in the planning study was to examine if the identified scenarios can withstand the extreme disturbances.

The critical path flows are summarized in Table 5.7-1.

Table 5.7-1 Path flows in the scenarios assessed for WECC NE/SE separation

Base Case Description	COI	Path 26 (N-S)	EOR	TOT 2 (N-S)
Portfolio 1 peak load	4000	240	5460	-518
Portfolio 4 peak load	4780	840	5210	-271
Portfolio 4 off-peak	1970	-2610	4740	-730

5.7.2.3 Simulation results

In general, the system is stable after the separation. The results and observations are summarized in Table 5.7-2.

Table 5.7-2 WECC NE/SE separation simulation results

Base Case Description	Result	Notes
Portfolio 1 peak load	Stable	Oscillations in the southern island are damped out 10 seconds after the initial fault. Large swings of frequency and bus voltages were observed. While the transient frequency dip is observed in the entire southern island, transient voltage dips are most significant in PG&E area. New wind and solar generators rode through the fault.
Portfolio 4 peak load	Stable	
Portfolio 4 off-peak	Stable	

The voltages of the following buses are plotted in Table 5.7-3.

Table 5.7-3 Selected buses for plotting voltage in WECC NE/SE separation study

Bus Name	Bus Voltage	Area
FOURCORN	500	14
GATES	500	30
LUGO	500	24
VINCENT	500	24
MIDWAY	500	30

The frequency of the following generators is plotted in Table 5.7-4.

Table 5.7-4 Selected buses for plotting frequency in WECC NE/SE separation study

Bus Name	Unit ID	Area
DIABLO	1	30
NAVAJO	1	14
PALOVERDE	3	14
SONGS	3	24

The voltage and frequency plots from time-domain simulations are shown in the following Figures 5.7-2 – 5.7-7.

Figure 5.7-2 Bus voltages after NE/SE separation- portfolio 1 peak load

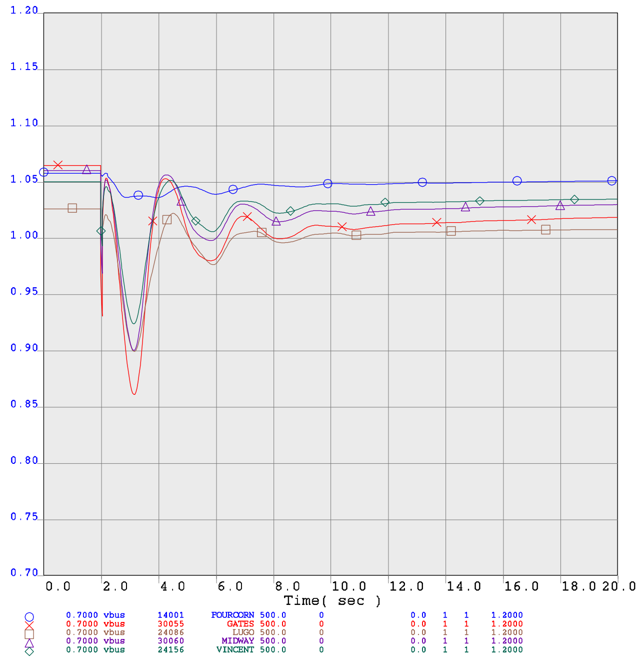


Figure 5.7-3 Frequency after NE/SE separation- portfolio 1 peak load

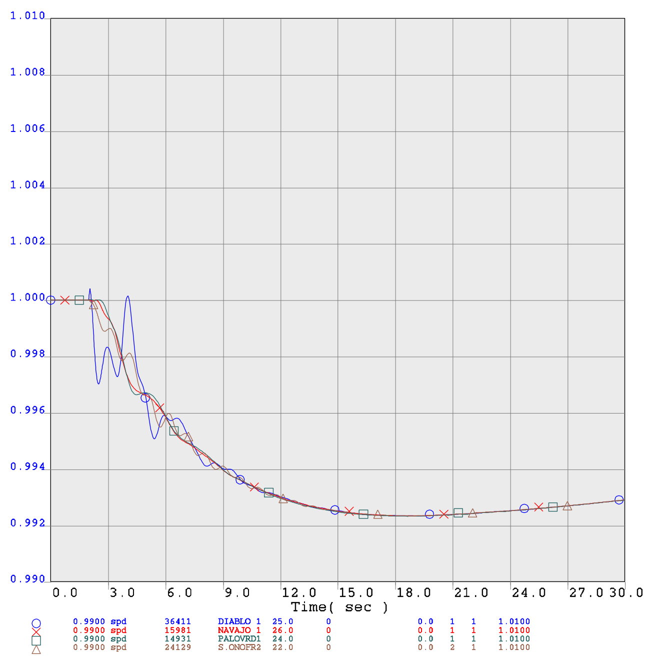


Figure 5.7-4 Bus voltages after NE/SE separation- portfolio 4 peak load

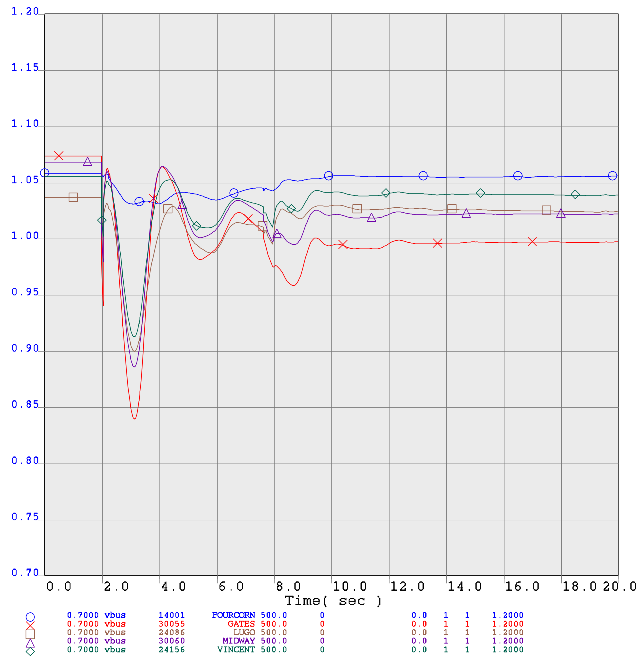


Figure 5.7-5 Frequency after NE/SE separation- portfolio 4 peak load

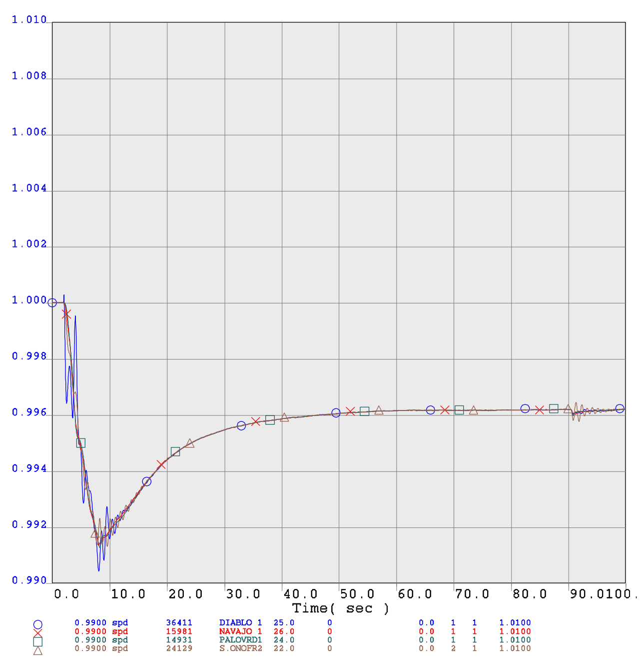


Figure 5.7-6 Bus voltages after NE/SE separation- portfolio 4 off-peak load

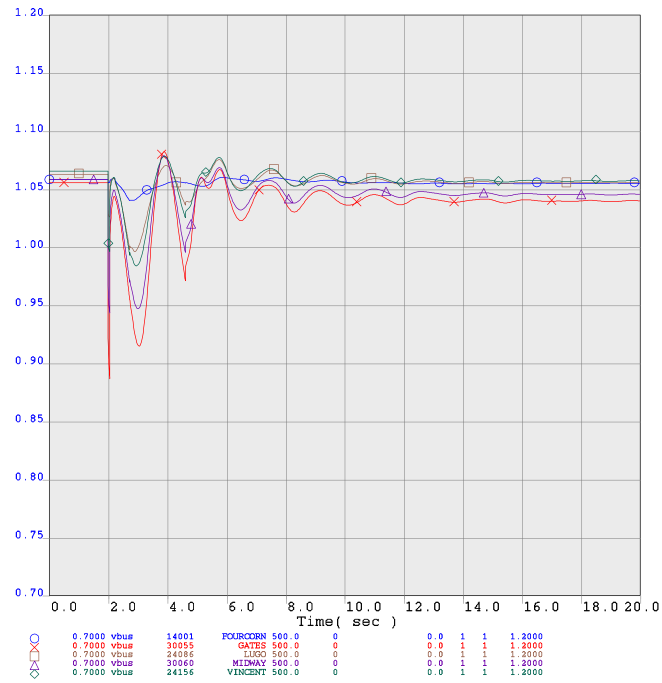
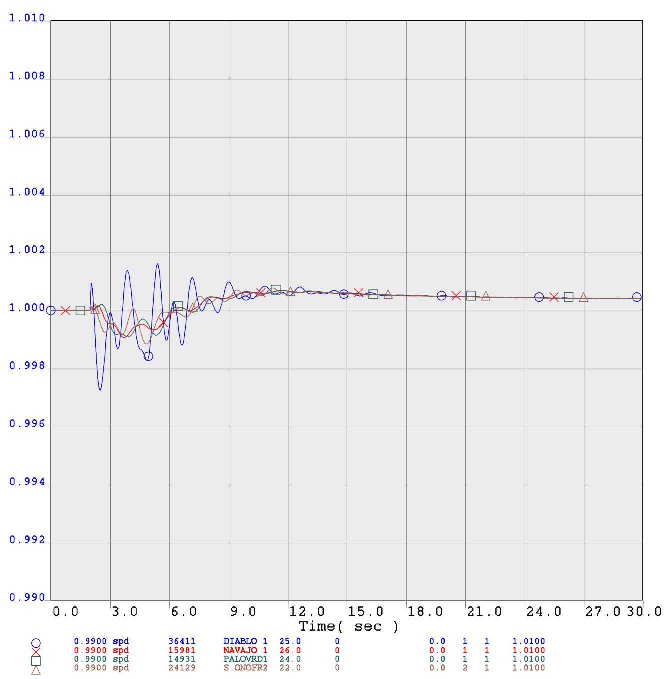


Figure 5.7-7 Frequency after NE/SE separation- portfolio 4 off-peak load



5.7.3 Small Signal Stability Assessment

The WECC system has suffered small signal instability events in its history, such as during the disturbance on August 10, 1996. Several inter-area oscillation modes are well known in the WECC system and many mitigation measures have been deployed to improve their damping. The purpose of this study was to assess small signal stability of the ISO controlled grid with addition of renewable resources to meet the 33% RPS target in 2020.

First, the SSAT tool for eigenanalysis developed by PowerTech Inc. was used to screen the oscillation modes. Then potentially impacted modes were investigated in detail.

The small signal stability analysis was performed on portfolio 4 and portfolio 1. Peak and off-peak scenarios were analyzed for each portfolio. Oscillation modes of interest, i.e., those with a frequency lower than 1.0 Hz and damping ratio lower than 20%, were identified and investigated. The results were compared to those for the same system conditions without the additional renewable resources to meet the 33% RPS target to better understand the impact of renewable generation.

The analysis was performed under normal conditions and contingency conditions. For the purpose of illustrating the impact of the renewable generation, this discussion focuses on the results for the normal conditions and the comparison among non-renewable scenarios and renewable scenarios. Similar impacts were observed under the contingency conditions.

The screening results show that the inter-area mode between the northwest and southwest areas of the WECC system was still observable in the base cases with renewable generation modeled. Similarly, the oscillation mode with about 0.5 Hz frequency between the Arizona system and the Northern California system was observed in both renewable and non-renewable base cases. The transmission reinforcement and protection schemes, however, have been designed over the years to protect the system from such inter-area oscillations. The damping ratios of the inter-area modes have been observed greater than 10% and are deemed to be well-damped and sufficiently stable. This observation from the eigenanalysis was also consistent with the time-domain simulation results that have been discussed in sections 5.4 –5.6 and section 5.7.2.

In addition to the two inter-area modes above, inter-area modes that involve several local areas and have a frequency in the range of 0.6 to 1.0 Hz have been identified. Some of these local areas are, coincidently, potential renewable-rich areas. Disturbances that are close or within these local systems may trigger oscillations or transient instability originating from the generators in these areas. The eigenanalyses identified the contributing oscillation or instability factors and helped to design the most effective mitigation plans.

Two of inter-area modes, IID and CFE/SDGE have been further investigated because they overlap with or are adjacent to the areas with large amounts of renewable generation resources.

A local mode that involves the generators north of Kramer was observed in all the scenarios.

The results are summarized in Tables 5.7-5 and 5.7-6 below.

Table 5.7-5 Selected inter-area modes observed in the study

Participating areas	Scenario	Mode (Frequency / Damping)		
		Portfolio 4	Portfolio 1	No Renewable
Northwest–Southwest	Peak load	0.221 / 16.92%	0.223 / 16.68%	0.223 / 14.66%
	Off-peak	0.256 / 13.34%	0.258 / 12.99%	0.258 / 14.26%
Arizona–PG&E	Peak load	0.507 / 11.92%	0.506 / 12.05%	0.496 / 12.38%
	Off-peak	0.521 / 11.30%	0.521 / 11.26%	0.521 / 11.23%
IID	Peak load	0.712 / 7.43%	0.713 / 8.74%	0.730 / 8.03%
	Off-peak	0.816 / 6.59%	0.795 / 9.56%	0.825 / 13.76%
CFE/SDGE	Peak load	0.747 / 12.00%	0.757 / 10.03%	0.745 / 10.67%
	Off-peak	0.872 / 10.13%	0.881 / 10.95%	0.825 / 13.76%

Table 5.7-6: Selected local modes observed in the study

Participating areas	Scenario	Mode (Frequency / Damping)		
		Portfolio 4	Portfolio 1	No Renewable
North of Kramer	Peak load	0.979 / 6.53%	0.963 / 5.88%	0.847 / 6.32%
	Off-peak	0.865 / 2.22%	0.858 / 2.07%	0.813 / 6.07%

The mode scatter plots of the four inter-area modes are shown below. The mode shape scatter plot is intended to show what parts of the power system are exhibiting the selected mode's behavior. Both the real and imaginary parts are plotted on a coordinate plane and each point on the scatter plot is associated with a generator. The points are color-coded according to control area. The distance between a point and the origin on the horizontal axis indicates the participation of the generator into the mode, i.e., the potential oscillation with certain frequency and damping ratio. The position of a point on the plot also reflects the phase in the oscillation of the generator.

Figure 5.7-8: Mode Shape Scatter of Northwest–Southwest Mode (portfolio 4 peak)

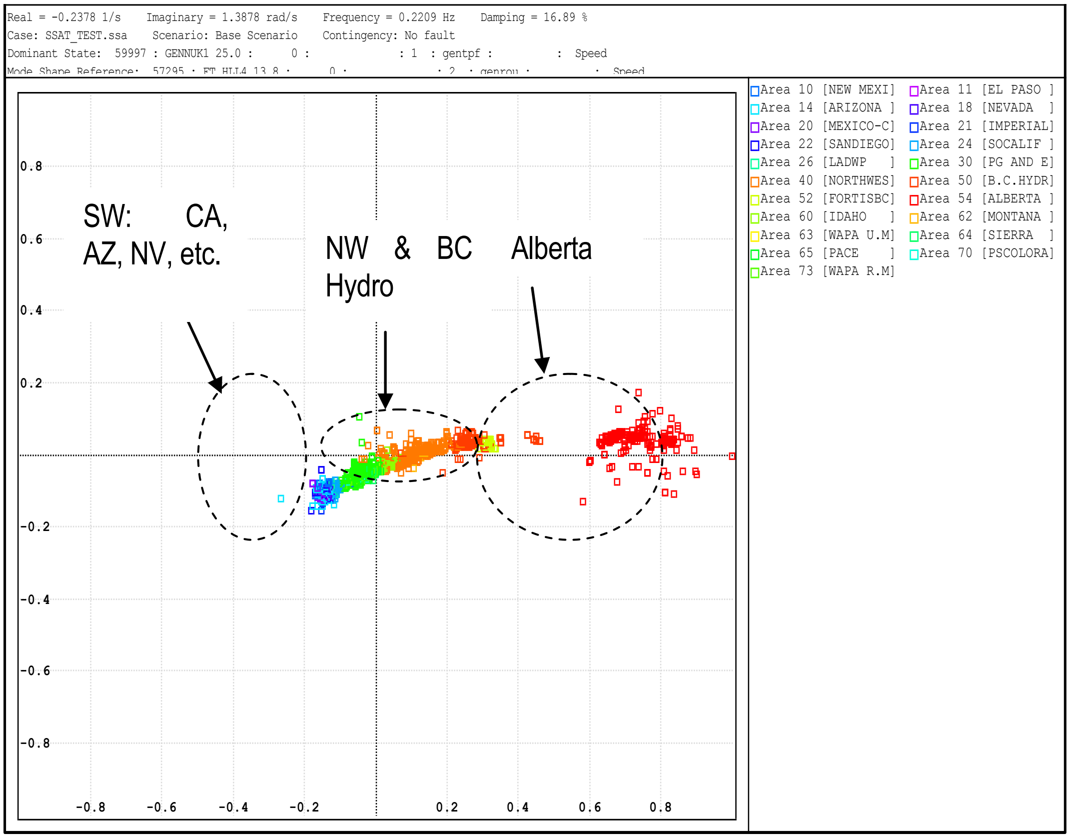


Figure 5.5-9: Mode Shape Scatter of Arizona–PG&E Mode (portfolio 4 peak)

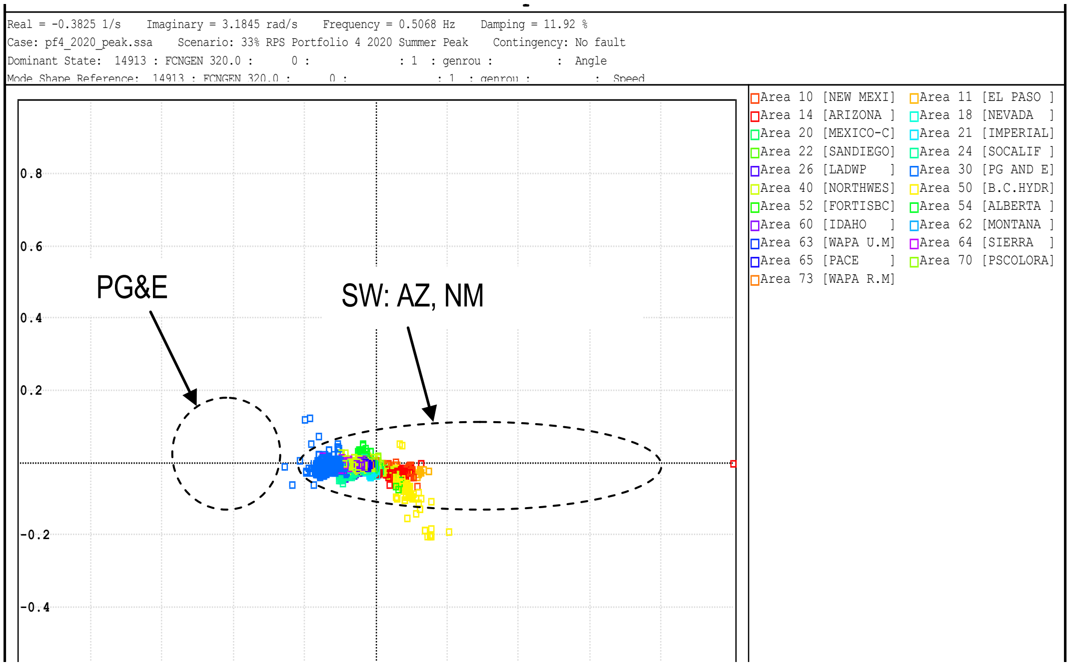


Figure 5.7-10 Mode Shape Scatter of IID–Remaining system Mode (portfolio 4 peak)

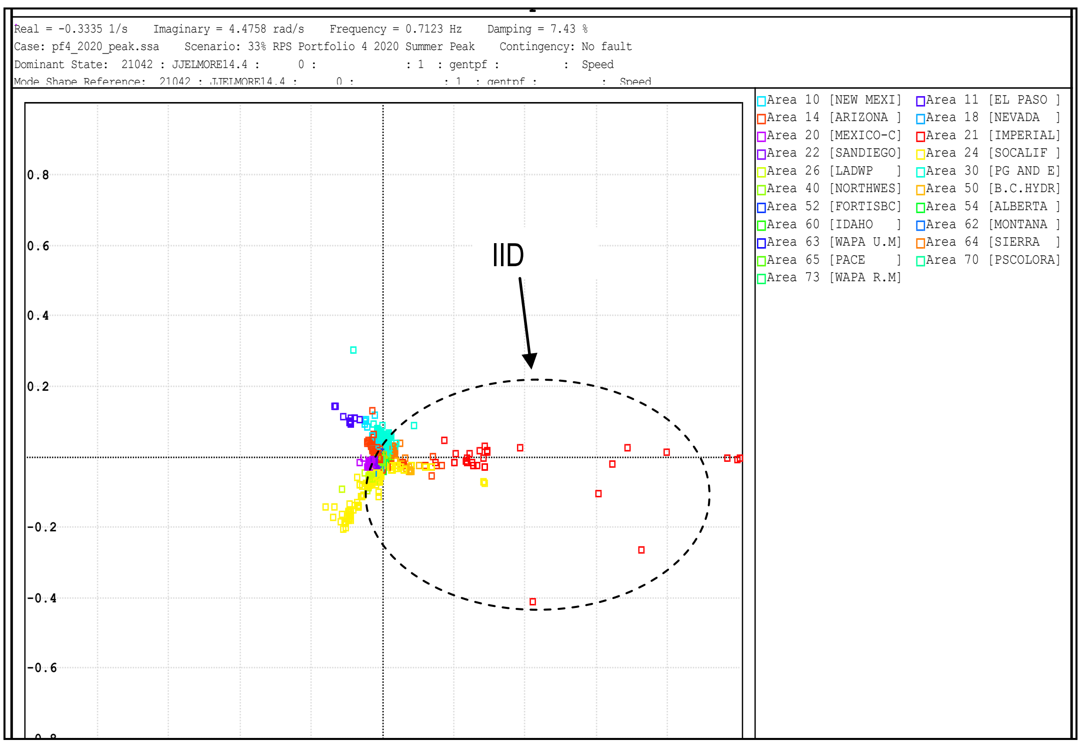
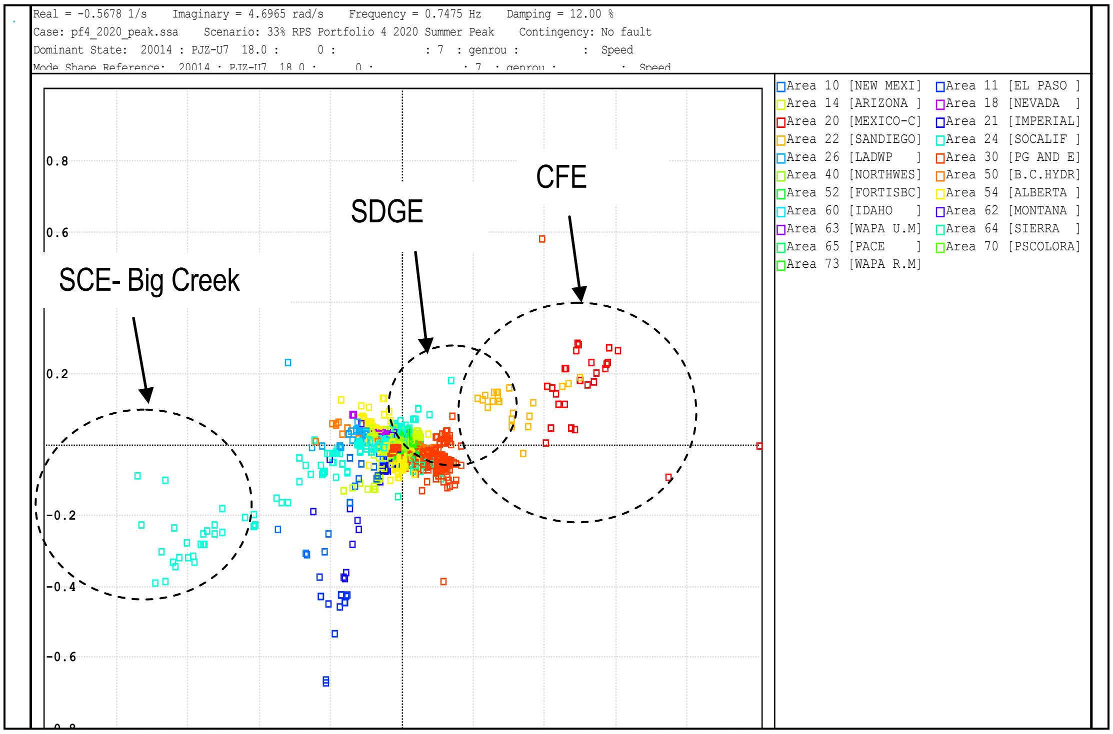


Figure 5.7.11 Mode Shape Scatter of CFE/SDGE and Big Creek (portfolio 4 peak)



It has been observed that the renewable resources do not introduce any new inter-area oscillation modes of interest. The same inter-area modes are identified in both renewable and non-renewable scenarios. The frequencies and damping ratios are only slightly different between renewable and non-renewable scenarios. The small changes in the frequencies and damping ratios are mainly because of the re-dispatch of conventional synchronous generators in the system with the addition of the renewable resources. As the majority of the renewable resources use the inverter-based technologies, they do not directly participate in the inter-area oscillation modes.

The addition of the renewable resources has a more noticeable impact on the local modes, especially under the off-peak conditions. For example, it has been observed that the damping of the North of Kramer local mode is significantly lower in the 33% RPS cases under off-peak condition. In all the peak cases and non-renewable off-peak case, the North of Kramer mode involves the generators located north to the Control substation oscillating against the generators near Kramer substation. Lack of PSS and the relatively long electric distance between Control and Kramer are the main reasons of the relatively low damping of this local mode. In the renewable off-peak cases, the thermal units near Kramer are turned off. As a result, the North of Kramer mode evolves into generators north of Control acting against the main system south of Kramer. The electric distance between the two areas increases, thus the damping ratio deteriorates significantly.

It has been identified in the transient time-domain simulations that generators in the IID system oscillate against the remaining system following disturbances on Path 42. The eigenanalyses confirmed the time-domain simulation results. In addition, Table 5.7-5 shows that the IID mode has less damping ratio in portfolio 4 than in other portfolios. Meanwhile, the time-domain simulations showed that the system experiences transient instability following disturbances on Path 42 in portfolio 4 studies without tripping generation in the

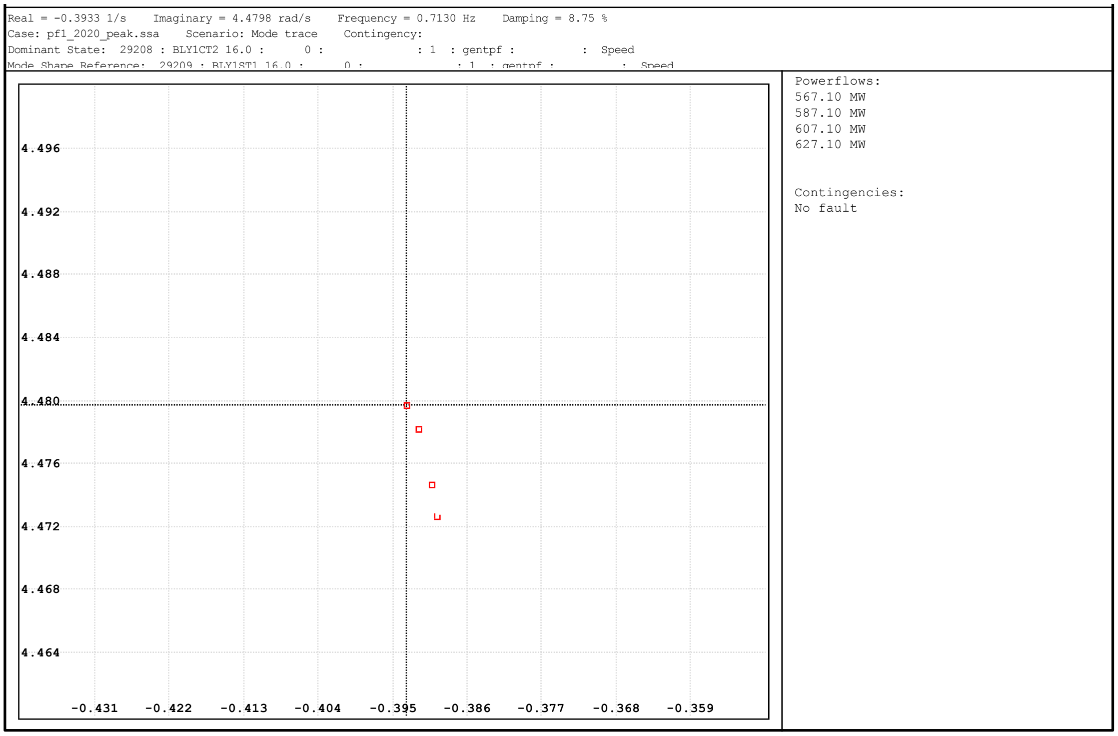
IID area. This is mainly because much more new renewable generators have been modeled in the IID area in portfolio 4 compared to portfolio 1, so the IID system and the inter-tie with the remaining system are more stressed than in portfolio 1. Table 5.7-7 shows the frequency and damping ratio changes when the renewable generation increases in IID system. Portfolio 1 peak case is used as the base point.

Table 5.7-7 Mode trace for the IID mode as renewable increases in IID

Renewable in IID (MW)	Frequency	Damping
567	0.7130	8.7457
587	0.7127	8.7163
607	0.7122	8.6902
627	0.7199	8.6780

The corresponding scatter plot is shown in Figure 5.7-8 to 5.7-12. The point at the origin in the scatter plot corresponds to the 567 MW of IID renewable generation case (portfolio 1 peak case). As more renewable generation is dispatched in the IID system, the eigenvalue moves to the left on the complex plane. The damping ratio decreases as the renewable generation increases.

Figure 5.7-12 Mode trace scatters of CFE/SDGE mode as IID renewable increases



Generators in the CFE and SDGE systems may participate in oscillations as shown in Fig. 5.7-12, which is also consistent with the time-domain simulation results. The worst contingency related to these two systems is the Sunrise/SWPL 500 kV N-2 that may be associated with controlled generation and load tripping, and cross-tripping of 230 kV lines between CFE and SDGE systems. This contingency may also trigger voltage instability in the system. This issue will be further analyzed in the following section in more detail.

There are several local modes associated with converter controls for doubly fed asynchronous generators (DFAG). Such local oscillation modes originate from the reactive and voltage control of the converters. The frequencies are between 0.2 Hz and 0.5 Hz. These modes can be observed in the time-domain simulation results under disturbances occurring close to the generators**.**

5.7.4 Sunrise/SWPL N-2 assessment

5.7.4.1 Background

In the comprehensive transmission planning study it was observed that voltage collapse may occur following the N-2 outage of Sunrise and SWPL during peak load conditions for Portfolios 1, 2, and 4. Turning on internal SDG&E generation or SCE's LA Basin generation makes it possible to mitigate the voltage instability. The results have been summarized in section 5.4. In addition, it was also observed that the system may have oscillation with poor damping after the N-2 contingency.

A Q-V curve and reactive power margin analysis, transient time-domain simulation and eigenanalysis are applied to assess the Sunrise/SWPL N-2 contingency to identify the reasons of poor system performances and identify the appropriate mitigation, which have been proposed in section 5.4 and not repeated here. The detailed results of these analyses are described below.

5.7.4.2 Reactive power margin analysis

The table below shows a summary of the SDG&E total import and individual flows in the portfolio 4 peak case and whether the N-2 outage of Sunrise and SWPL results in voltage collapse. The table shows that even though the total SDG&E import can be the same, the distribution of the flows between South of San Onofre (Path 44) and the two 500 kV lines west of Imperial Valley is the deciding factor on whether the system may experience voltage collapse following the N-2 outage.

Table 5.7-8 Stressed flow patterns for Sunrise/SWPL N-2 assessments

	Not solved with load tripping	Solved with load tripping	Marginally solved with load tripping
SDG&E Total Import	3938	3933	3935
Path 44 Flow	722	838	803
IV-ECO Flow	1496	1441	1457
IV-Central Flow	817	781	792
IV 500 kV Westward Flow	2313	2222	2249

A Q-V analysis was performed on the 3,933 MW import case shown in the previous table to identify the reactive power margin at various buses. It is observed that many buses across the SDG&E system have small or zero reactive power margins. The table below summarizes the reactive power margin at various buses throughout the system.

Table 5.7-9: Reactive power margins at various buses in the base case with 3,933 MW SDGE import

Bus	MVAr margin (3933 MW SDG&E import, N-2 outage with load tripping)
South Bay 69 kV bus	1.3 MVAr
Otay Mesa 230 kV bus	0 MVAr
Encina 230 kV bus	0 MVAr
Borrego 69 kV bus	2.6 MVAr
Miguel 230 kV bus	0 MVAr
Bus	**MVAr margin (3933 MW SDG&E import, N-2 outage with load tripping)**
San Luis Rey 230 kV bus	0 MVAr
Talega 230 kV bus	0 MVAr
Rincon 69 kV bus	8.7 MVAr
Escondido 69 kV bus	5 MVAr

Sampson 69 kV bus	0 MVAr
Crestwood 69 kV bus	7.4 MVAr
San Luis Rey 69 kV bus	0 MVAr

The graphs below show the MVAr margin at various buses following the N-2 outage of Sunrise and SWPL using the Portfolio 4 peak load base case with the generation mitigation and alternative solutions modeled. The mitigations have been described in detail in Section 5.4 and include reactive power support at various locations in the San Diego system. The graphs demonstrate that there are enough reactive power margins in the SDG&E system following the N-2 outage with the generation mitigation and alternative solutions. One major difference between the various proposed mitigations is that the phase shifter and reactor solution models additional reactive power support at Otay Mesa, which is reflected in the plots. The mitigations were tested with 2.5% load increase in the SDG&E system and were shown to provide sufficient reactive power margin.

Figure 5.7-13 Q-V curves following Sunrise/SWPL N-2 contingency (portfolio 4 peak generation mitigation solution)

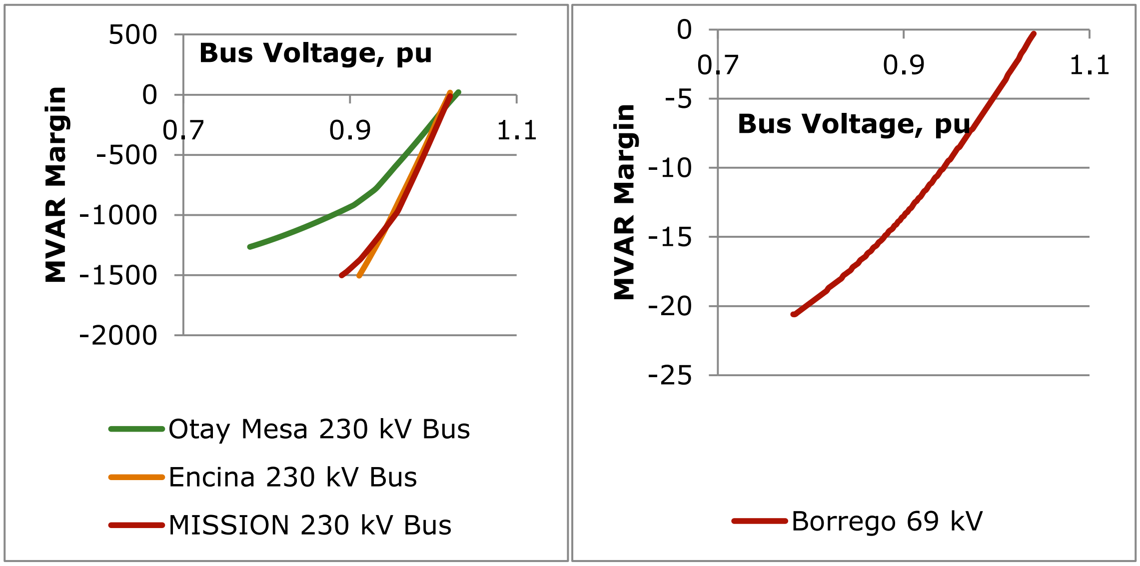


Figure 5.7-14 Q-V curves following Sunrise/SWPL N-2 contingency (portfolio 4 peak phase shifter mitigation solution)

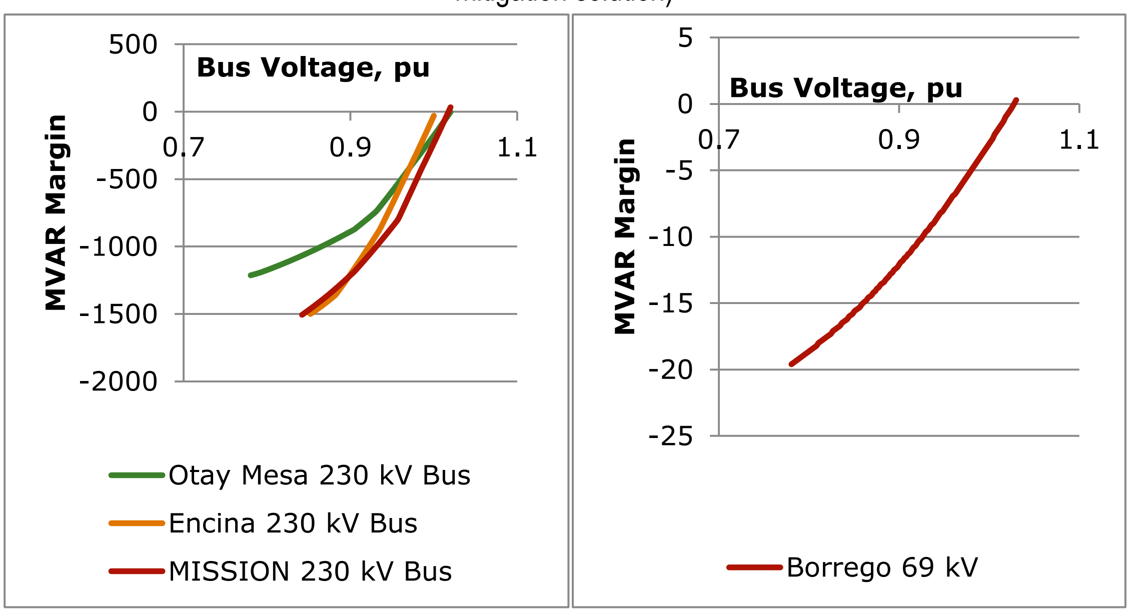
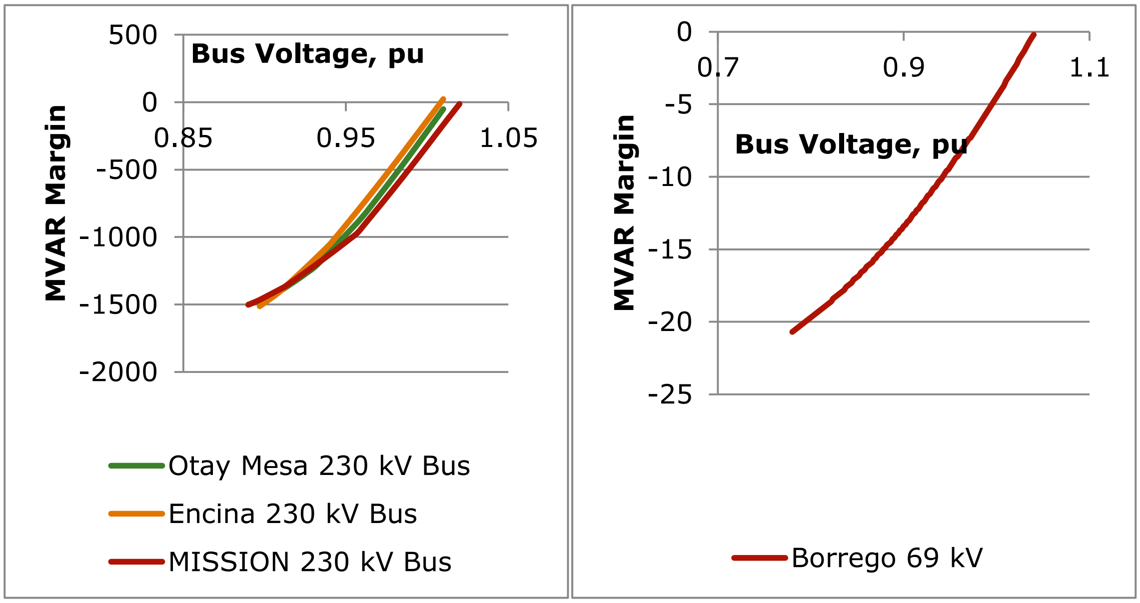


Figure 5.7-15 Q-V curves following Sunrise/SWPL N-2 contingency (portfolio 4 peak phase shifter and reactor mitigation solution)



5.7.4.3 Time-domain transient simulations

The Sunrise/SWPL N-2 contingency with CFE cross-tripping SPS triggered oscillations in the system with poor damping under peak load conditions for Portfolios 4, 2, and 1. The generation outputs of Otay Mesa unit in the San Diego area and PJZ-Unit 5 in the CFE area were plotted to illustrate the oscillation and the effect of mitigation plans. From the transient simulation plots in Figure 5.7-16 and Fig. 5.7-17, it is observed that the CEF generators did not oscillate much compared to the Otay Mesa units. This is because the disturbance caused by the cross-tripping has more impact on SDGE units than on CFE units. Another observation from the transient simulation results is that the oscillations eventually become damped out without causing any criterion concerns. Still, eigenanalyses have been performed to investigate the reason for the oscillation and reported in the following section.

Figure 5.7-16 Otay Mesa generation output with Sunrise/SWPL N-2 and proposed mitigations

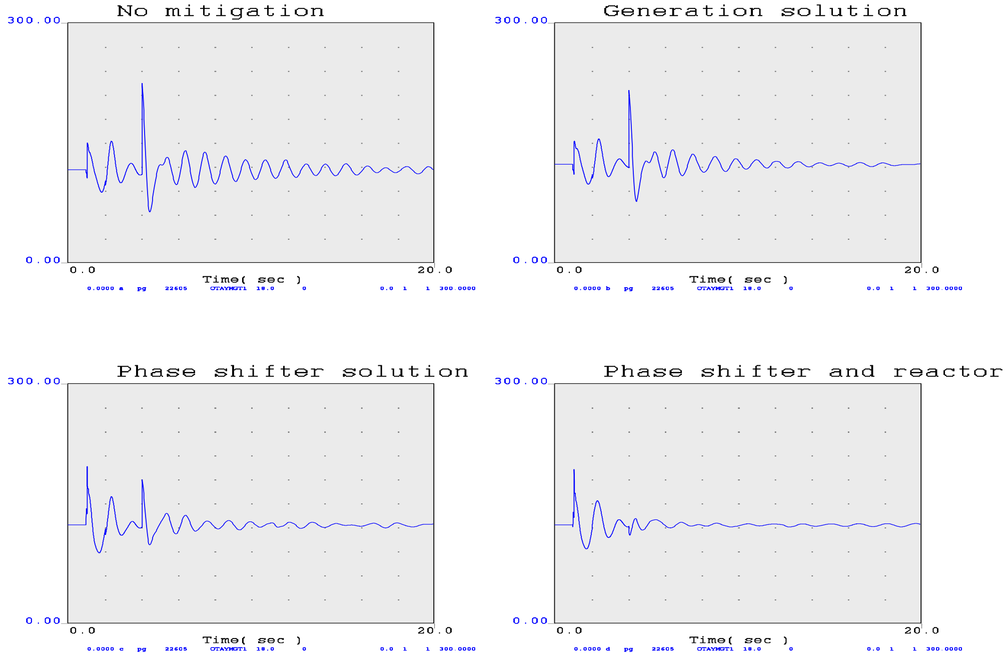
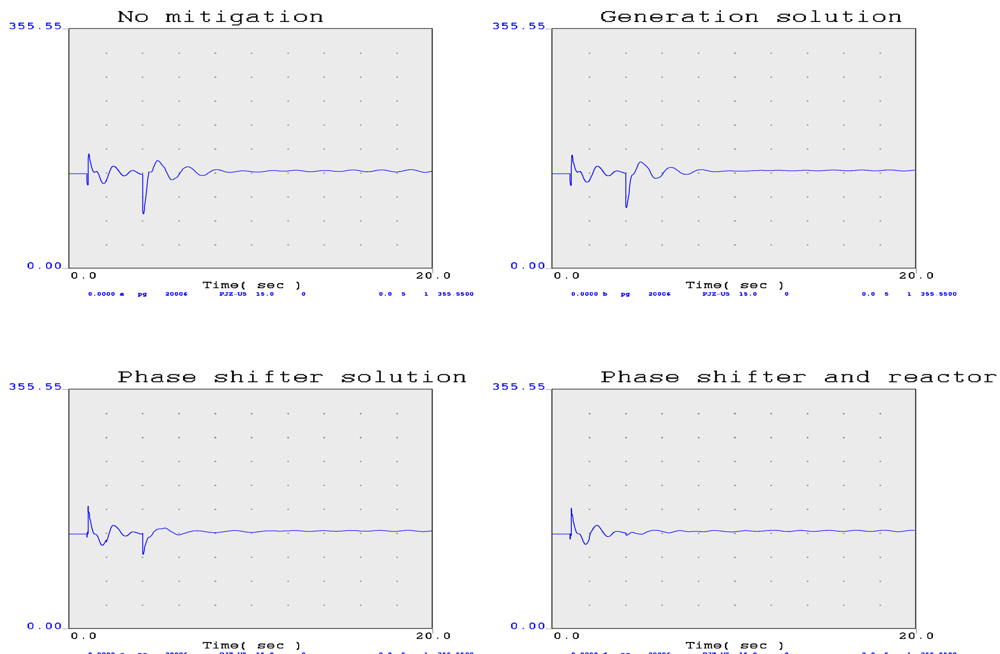


Figure 5.7-17 PJZ Unit 5 generation output with Sunrise/SWPL N-2 and proposed mitigations



5.7.4.4 Eigenvalue Analyses

Eigenvalue analyses were performed for the Portfolio 4 peak case to analyze the oscillations observed in the transient analysis. The following figures show the mode shape scatters with and without the proposed mitigations. Because the generation and phase shifter solutions require cross-tripping the Otay Mesa-Tijuana 230 kV line, which leaves the CFE system radially connected to the Imperial Valley substation, the CFE generators and SDGE generators are far apart on the scatter plot as shown in Figures 5.7-18, 5.7-19, 5.7-20, and 5.7-21, when compared to Figure 5.7-11. The damping of the CFE mode in each of these scenarios is between 11.96% and 13.81%. However, damping the SDG&E mode in the generation mitigation and phase shifter solution scenarios is between 5.27 % and 6.19%. The reactor solution allows the CFE system to have a similar configuration as the no fault case with two 230 kV lines connecting CFE and SDG&E, thus, the scatter plot, as in Figure 5.7-22, is similar to Figure 5.7-11.

Figure 5.7-18 Mode Shape Scatter of CFE Mode (0.641 Hz) following Sunrise/SWPL N-2 contingency (portfolio 4 peak generation mitigation solution)

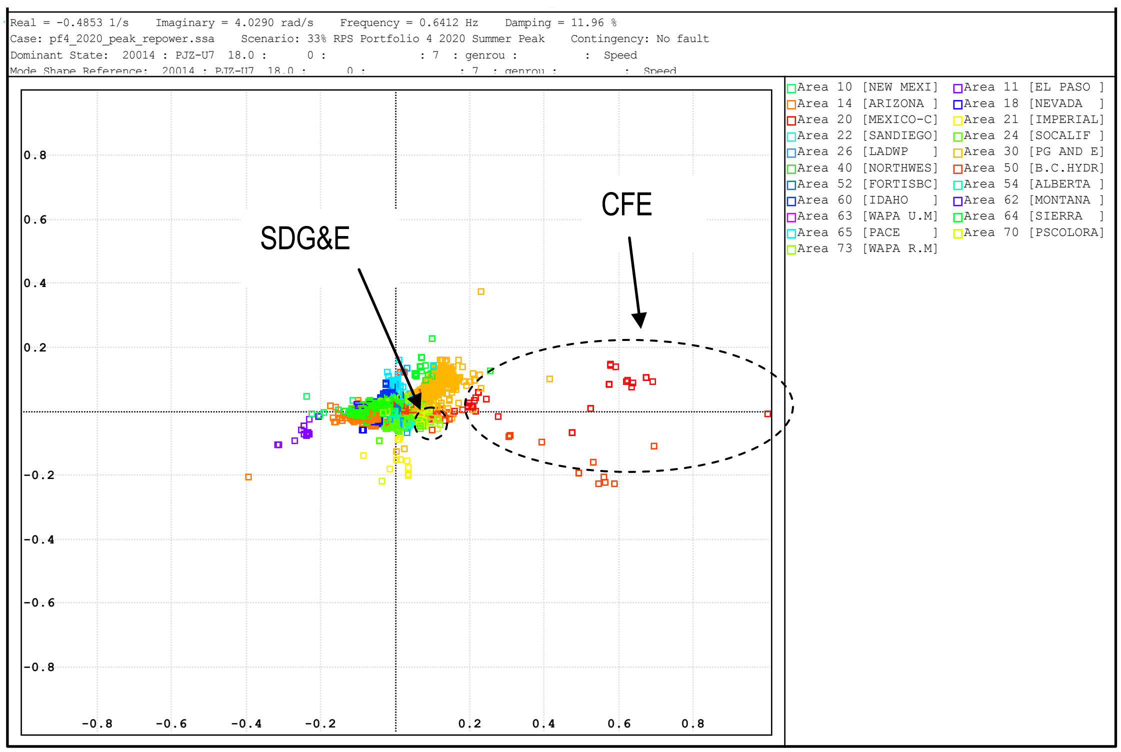


Figure 5.7-19 Mode Shape Scatter of SDG&E Mode (0.786 Hz) following Sunrise/SWPL N-2 contingency (portfolio 4 peak generation mitigation solution)

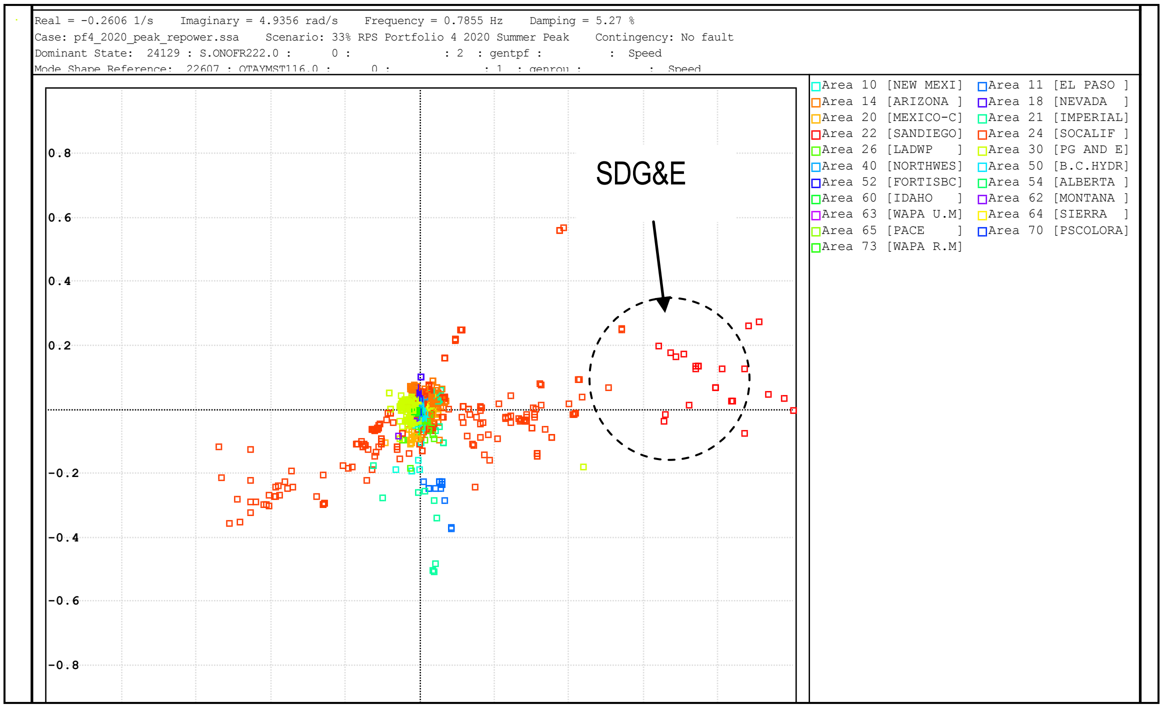


Figure 5.7-20 Mode Shape Scatter of CFE Mode (0.567 Hz) following Sunrise/SWPL N-2 contingency (portfolio 4 peak phase shifter mitigation solution)

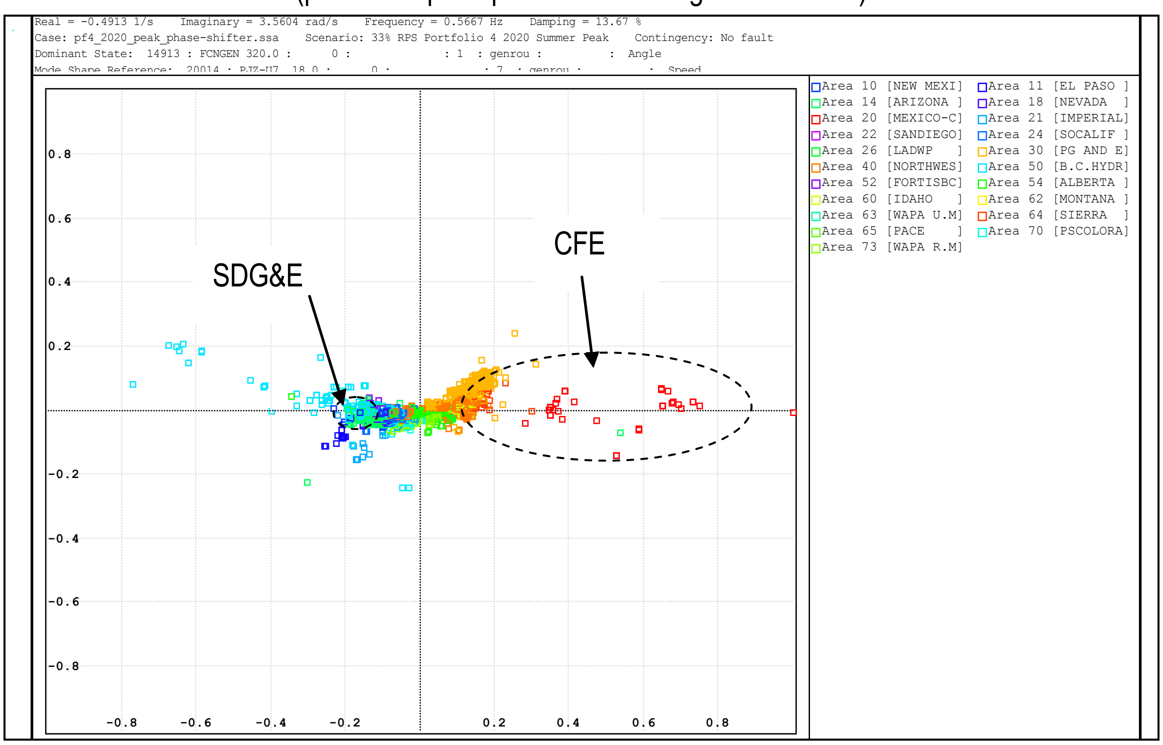


Figure 5.7-21 Mode Shape Scatter of SDG&E Mode (0.832 Hz) following Sunrise/SWPL N-2 contingency (portfolio 4 peak phase shifter mitigation solution)

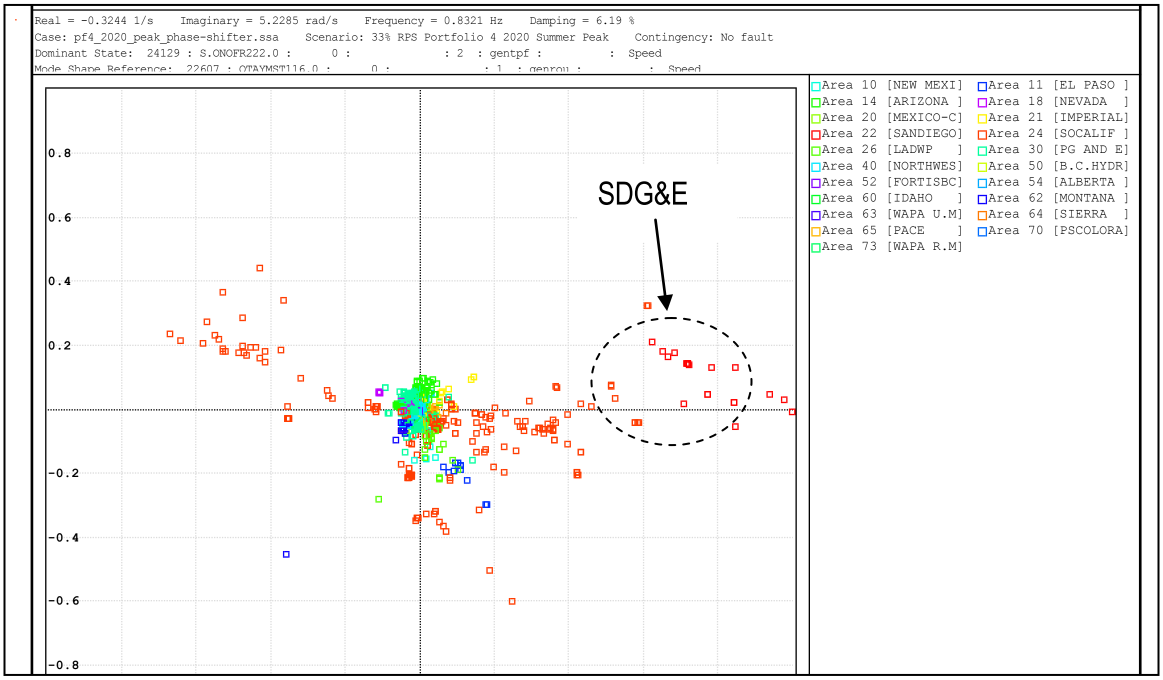
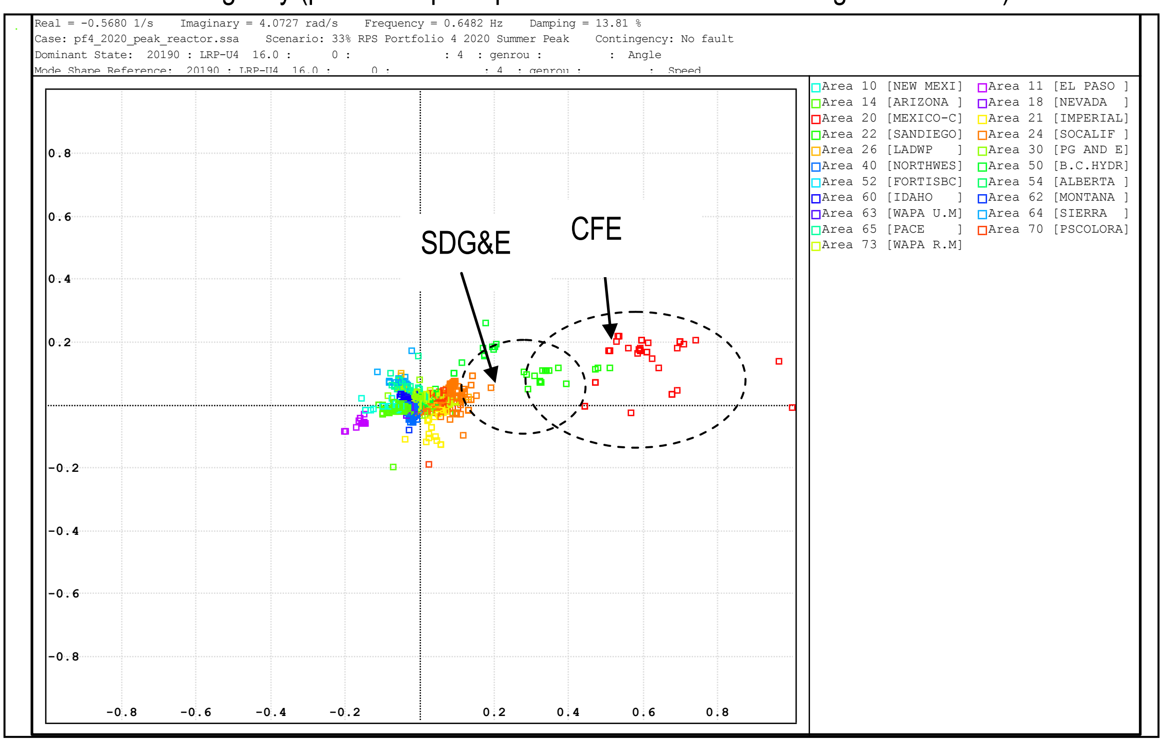


Figure 5.7-22 Mode Shape Scatter of CFE and SDG&E (0.648 Hz) Mode following Sunrise/SWPL N-2 contingency (portfolio 4 peak phase shifter and reactor mitigation solution)



5.7.5 Northern California Bulk System Assessment

Transient stability time-domain simulations were performed for all 500 kV single and double contingencies in Northern California, including three-phase faults on 500 kV buses as well as double outages of nuclear generation units (Palo Verde, San Onofre and Diablo). The scenarios studied were Portfolio 1 peak and off-peak, Portfolio 2 peak and Portfolio 4 peak and off-peak cases.

No criteria concerns were identified in the transient stability studies for all the cases and all contingencies studied if the appropriate SPS was used for each contingency.

Several outages showed sustained oscillations on the Ice Harbor and Dexter generators in the Northwest. These oscillations may be caused by a modeling error in the governor models. The dashpot time constants for these governors were unusually small, and with larger time constants there were no oscillations. This issue is not related to the renewable generation.

In addition, the peak case for Portfolio 1 had high voltages in the Midway area; therefore, one PV generation unit was tripped for overvoltage for several contingencies single and double-line contingencies in the Midway-Gates–Los Banos area. To avoid this tripping, either adjust the relay settings, or adjust reactive support in the area to lower the voltage in the base case.

5.8 Production Cost Simulation and Utilization analysis

Production cost simulations have been performed for all portfolios to evaluate the utilization of the transmission system for 8,760 hours of the 2020 study year. Most transmission lines have been monitored in the production cost simulations, but instead of analyzing all transmission lines, two sets of transmission lines or branch groups are specifically analyzed. They are the import branch group of the Western LA Basin and San Diego load pocket, and transmission upgrades in the ISO's 33% renewable transmission plan.

It is expected that the utilization of these transmission lines will vary in different portfolios because the renewable generation distribution and technology are different from one portfolio to another.

5.8.1 Import branch group to Western LA Basin and San Diego

The Western LA Basin is a load pocket in the SCE's system along the coast that is enclosed by sixteen 230 kV transmission lines. Inside this load pocket there are four OTC power plants that have total 4,770 MW capacity and the San Onofre nuclear power plant with 2,250 MW capacity. Similarly, San Diego is a load pocket that has OTC units with 950 MW capacity. Although there were no particular assumptions of OTC retirement in the 33% RPS planning studies, because of their relatively high variable production cost, these OTC units (except for the nuclear plants) are among those shut down first to accommodate renewable generation based on the economic dispatch. Without sufficient internal generation inside these load pockets, there will be various reliability concerns as noted in previous studies, such as the LCR study. The 33% planning studies have identified similar problems in these load pockets, as discussed in Sections 5.4 and 5.5.

These two load pockets are connected to each other via WECC Path 43 (North of SONGS) and Path 44 (South of SONGS) and forming a larger load pocket where the generation capacity on both sides of Path 43 and Path 44 is needed to maintain system reliability.

The boundary lines of the Western LA and San Diego load pocket are listed as below. The system configuration is shown in Fig. 5.8-1.

- IMPERIAL VALLEY to CENTRALS 500 kV #1
- ECO to MIGUEL 500 kV #1
- Tijuana to OTAY MESA 230 kV #1
- SERRANO to LEWIS 230 kV #1
- SERRANO to LEWIS 230 kV #2
- SERRANO to VILLA PK 230 kV #1
- SERRANO to VILLA PK 230 kV #2
- MIRA LOMA to WALNUT 230 kV #1
- MIRA LOMA to OLINDA 230 kV #1
- VINCENT to MESA 230 kV #1 and #2
- VINCENT to RIOHONDO 230 kV #1 and #2
- SYLMAR S to EAGLROCK 230 kV #1
- SYLMAR to GOULD 230kV #1

The above sixteen lines form the import branch group into Western LA and San Diego. The duration curves of this import branch group from the market simulations of four portfolios are shown in Fig. 5.6.2.

Fig. 5.8-1 Boundary of Western LA and San Diego load pocket

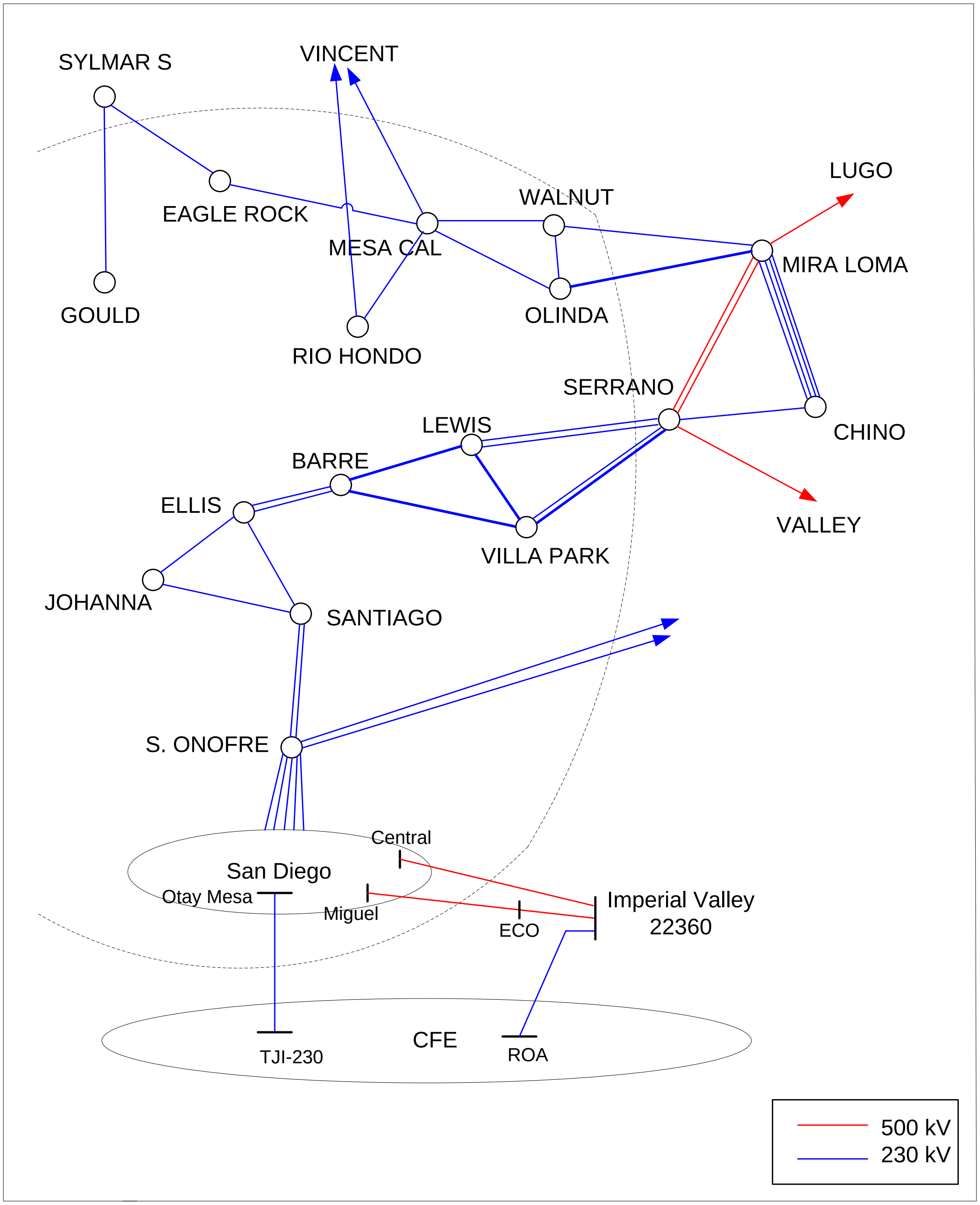
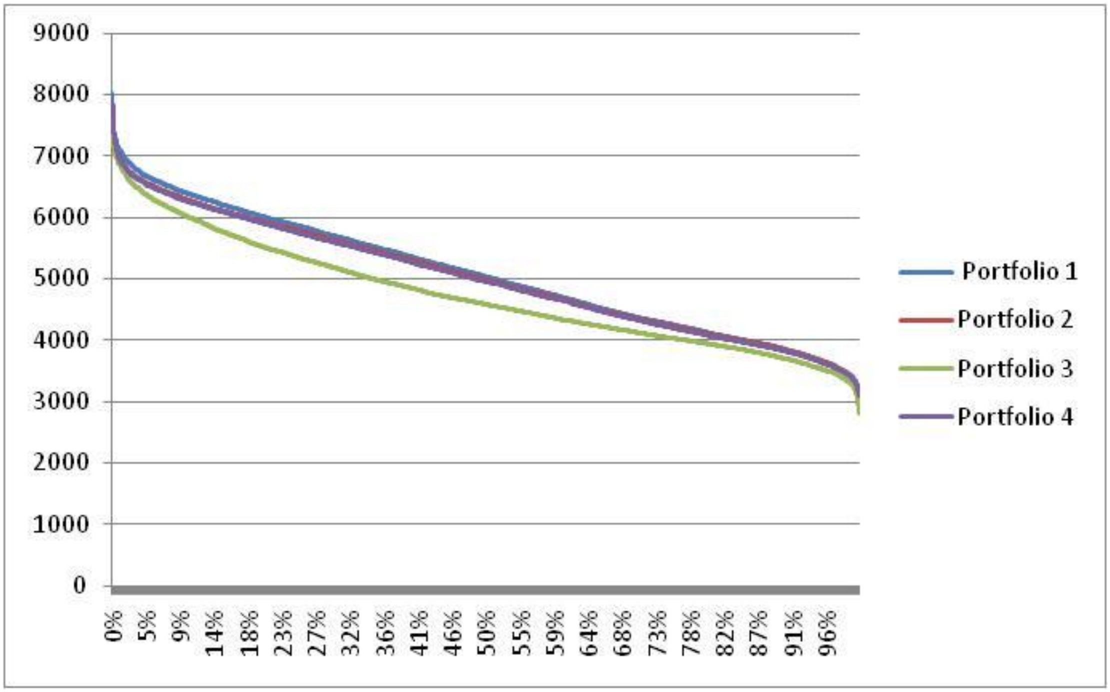


Fig. 5.8-2 Duration of power flow on the Western LA and San Diego import branch group



It can be seen from Fig. 5.8-2 that the utilization of the import branch group to the Western LA and San Diego load pocket is lower in Portfolio 3 compared to other portfolios. This is because higher penetration of distributed generation is modeled in Portfolio 3 and distributed generation is close to the load centers reducing the need for import.

5.8.2 High Potential and LGIA lines

The power flow duration curves are plotted for the following transmission lines and upgrades that have been listed in Table 4.1-1 and modeled in the base cases.

- Reconductoring of the Borden–Gregg 230 kV line
- Tehachapi renewable transmission project
- New Coolwater–Lugo 230 kV line
- Eldorado–Ivanpah 115 kV to 230 kV conversion project
- Pisgah–Lugo 230 kV to 500 kV line conversion
- New Colorado River–Devers 500 kV line
- Path 42 reconductoring
- West of Devers Reconductoring
- Sunrise Powerlink 500 kV Project

Borden–Gregg 230 kV line

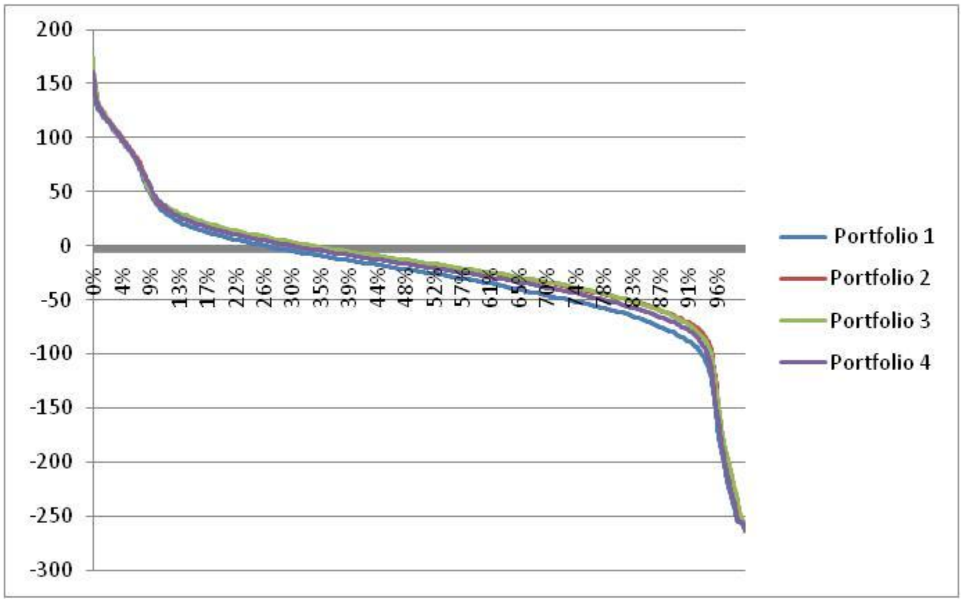
The Borden–Gregg 230 kV line is in parallel with Path 15. The power flow on this 230 kV line is highly impacted by generation in the Fresno area and the flow on the parallel 500 kV lines. The power flow can be from north to south or the other way around depending on the Fresno generation and 500 kV flow pattern.

When the flow on the 500 kV bulk system is high from north to south, which is the case in Portfolio 2, the utilization of Borden–Gregg 230 kV line from south to north is reduced. Renewable generation in Westlands CREZ, which is mainly in the Fresno area, has direct impact on the flow on this 230 kV line.

Table 5.8-1 CREZs mainly served by Borden–Gregg 230 kV line

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Westlands	720	720	720	508
Total	720	720	720	508

Figure 5.8-3 Power flow duration curves of Borden– Gregg



Tehachapi Renewable Transmission Project (TRTP)

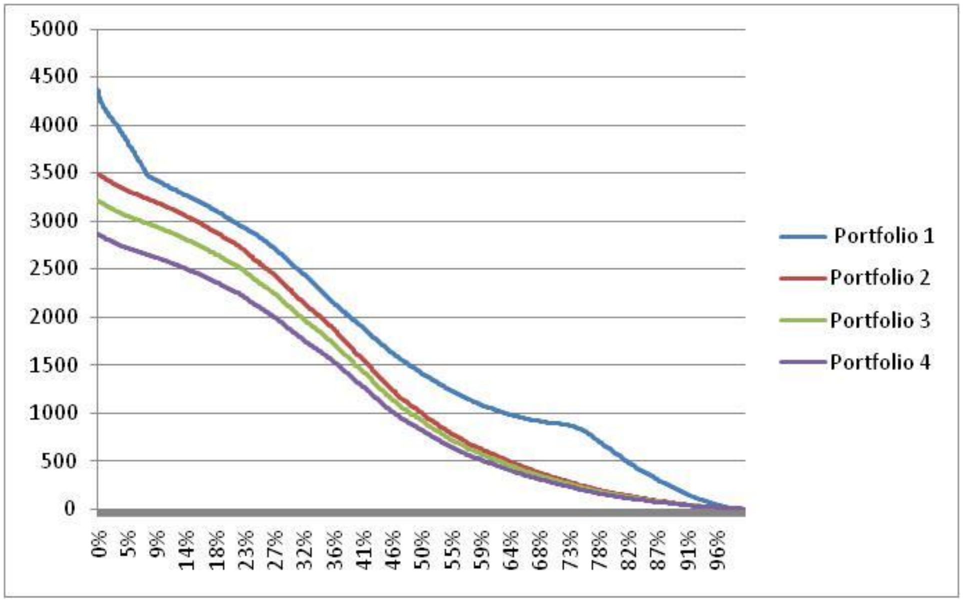
This project has been designed to accommodate 4,500 MW of renewable generation. The original study for the project assumed that all renewable generators in the Tehachapi area would be wind. Considering the diversity of wind and solar generation interconnection in this area, the total capacity that can be interconnected via Tehachapi lines is expected to be greater than 4,500 MW.

The CREZs served by the Tehachapi lines, consisting of 11 segments of high voltage transmission facilities, are Tehachapi and Fairmont. The duration curves shown in Fig. 5.8-4 are only for the flows on the 500 kV transmission lines and transformers that come out from the CREZs. Flows on the 230 kV transmission lines out of the CREZs are not reflected in the figure.

Table 5.8-2 CREZs mainly served by TRTP

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Tehachapi	5110	4010	3670	3208
Fairmont	670	440	440	440
Total	5780	4450	4110	3648

Figure 5.8-4 Power flow duration curves of TRTP



Cool Water–Lugo 230 kV line

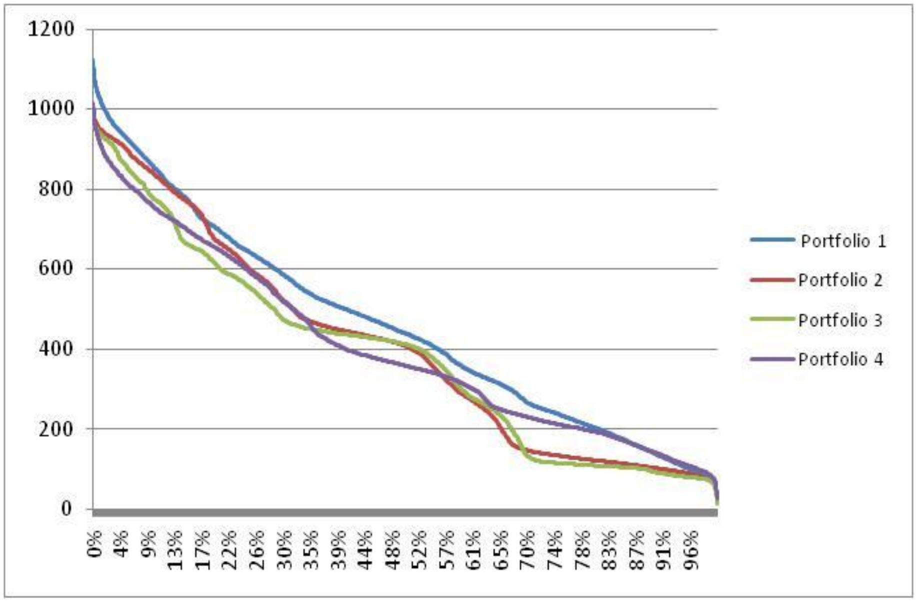
The Cool Water–Lugo 230 kV line mainly serves the renewable generation in the North of Lugo area that includes several CREZs, such as Kramer, Inyokern and Owens Valley. The existing generation in North of Lugo, including conventional thermal, solar thermal, geothermal and hydro generation, also contribute to the flow on the Cool Water–Lugo 230 kV line.

In the 33% RPS planning study, only the Kramer CREZ was selected to be included in the renewable portfolios based on the portfolio development methodology described in chapter 4.

Table 5.8-3 CREZs mainly served by Cool Water–Lugo 230kV line

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Kramer	330	330	250	188

Fig. 5.8-5 Power flow duration curves of Cool Water–Lugo



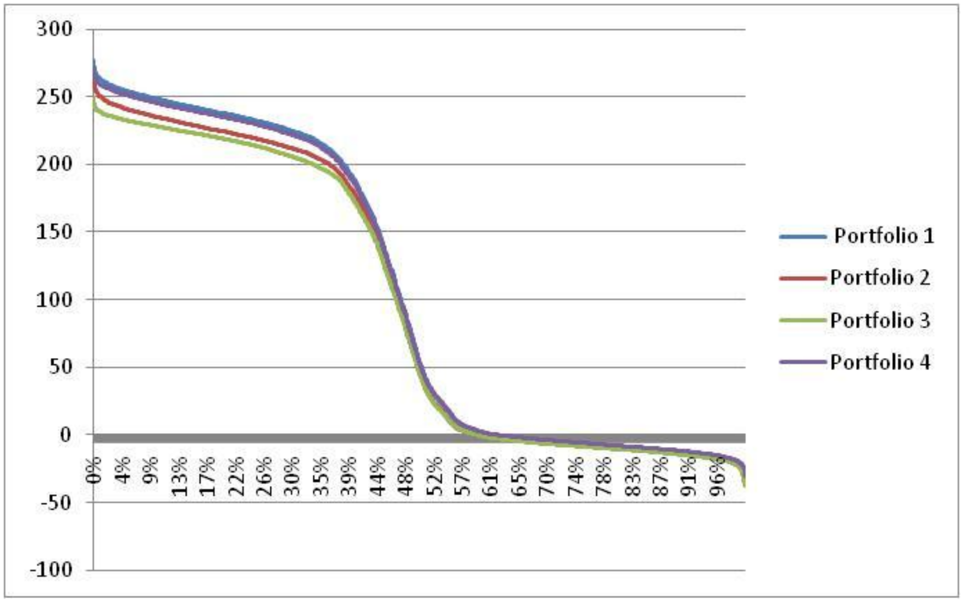
Eldorado–Ivanpah 230 kV Transmission Project (EITP)

This project is designed to interconnect and deliver renewable generation in the Mountain Pass CREZ. The renewable generation in this CREZ is in the area between Mountain Pass and the Eldorado subsation. Besides the Ivanpah and Eldorado substations, the Primm substation that loops into the Ivanpah–Eldorado 230kV lines is modeled to interconnect some of the renewable generation. The duration curves shown in Figure 5.8-6 are for the flow on the EITP lines measured at the Eldorado end, but they do not account for the generation output from the renewable generators that may directly connect to Eldorado. Importing flow into Eldorado from the East of River provides counterflow on Eldorado–Ivanpah 230 kV line that may reduce its utilization, which is the case in Portfolio 2.

Table 5.8-4 CREZs mainly served by Eldorado–Ivanpah 230 kV lines

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Mountain Pass	434	413	393	849

Fig. 5.8-6 Power flow duration curves of El Dorado–Ivanpah 230 kV lines



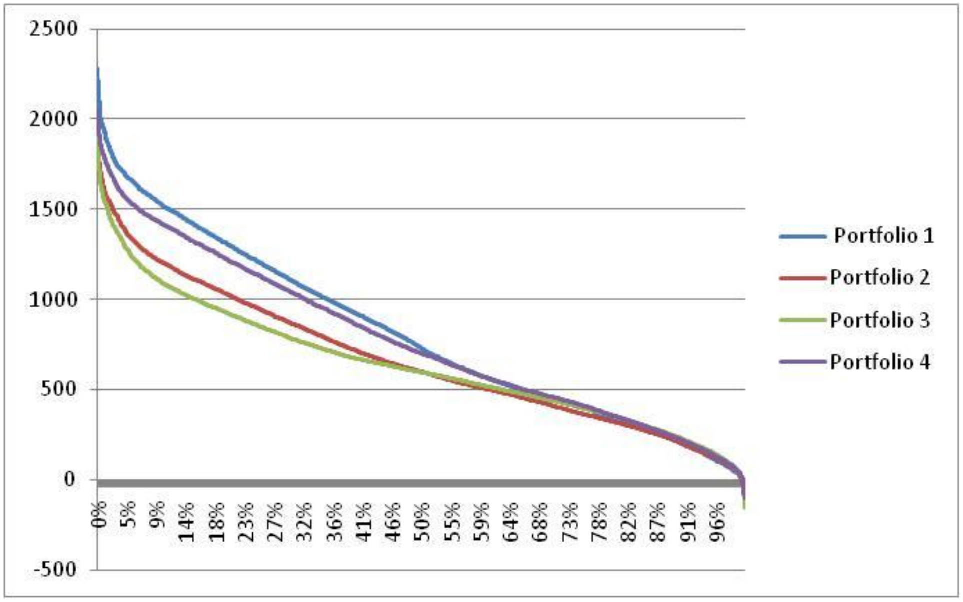
Pisgah–Lugo 500 kV lines

The loop-in of the existing Eldorado–Lugo 500 kV line into the new Pisgah 500 kV substation and conversion of one of the existing Pisgah–Lugo 230 kV lines to 500 kV create two Pisgah–Lugo 500 kV lines. This upgrade serves renewable interconnections in the Mountain Pass, Pisgah and NV West areas. The East of River flow also has direct impact on the flow on the Pisgah–Lugo 500 kV lines.

Table 5.8-5 CREZs mainly served by Pisgah–Lugo 500 kV lines

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Mountain Pass	434	413	393	849
Pisgah	1750	500	500	1112
NV West	450	450	450	450
Total	2634	1363	1343	2411

Fig. 5.8-7 Power flow duration curves of Pisgah–Lugo 500 kV lines



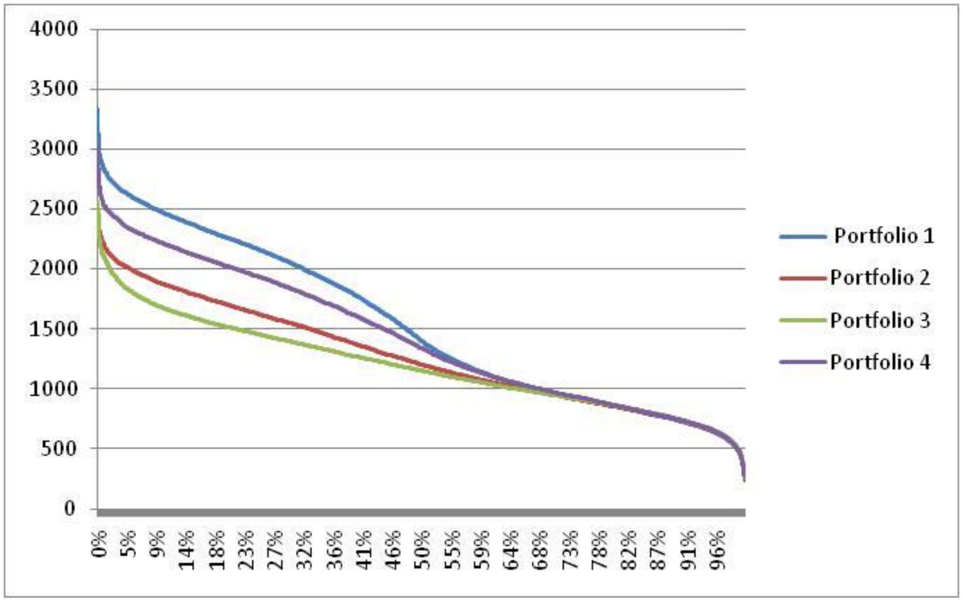
Colorado River–Devers 500 kV lines

The Colorado River 500 kV substation and the loop-in of the existing Palo Verde–Devers 500 kV line into this substation create the line number 1 of the Colorado River–Devers 500 kV lines. The #2 line is part of the Colorado River–Valley 500 kV transmission project. The Colorado River–Devers 500 kV lines are used to interconnect and deliver renewable generation mainly in Riverside East and Arizona. The Devers–Valley 500 kV lines also serves the renewable generation in Palm Spring and Imperial areas, similar to the West of Devers 230 kV lines.

Table 5.8-6 CREZs mainly served by Colorado River–Valley 500 kV lines

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Riverside East	3427	1250	1250	2595
Arizona	290	1790	290	1090
Total	3717	3040	1540	3685

Fig. 5.8-8 Power flow duration curves of Colorado River–Devers 500 kV lines



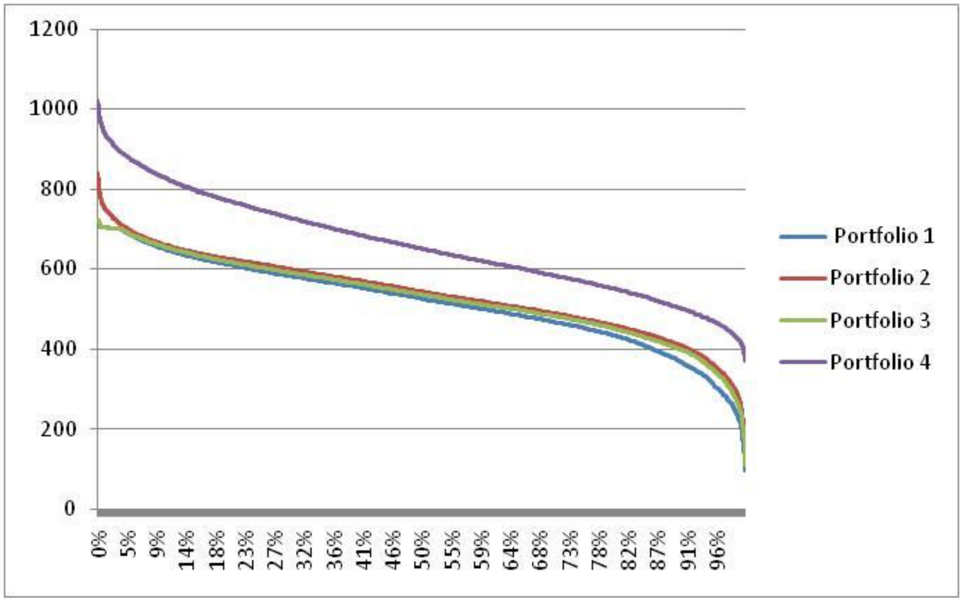
Path 42

Path 42 is the tie between the IID and SCE systems. The renewable generation in the IID system and the Imperial Valley area of the SDGE system contributes to the flow on Path 42. The utilization of Path 42 in portfolio 4 is much higher than in other portfolios because Portfolio 4 includes much more new generation in Imperial North CREZs that are in the IID territory, than other portfolios, based on the latest information of environmental impact.

Table 5.8-7 CREZs mainly served by Path 42

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Imperial North	594	594	594	1319
Imperial South	974	925	376	924
San Diego South	331	331	331	331
Total	1899	1850	1301	2574

Fig. 5.8-9 Power flow duration curves of Path 42



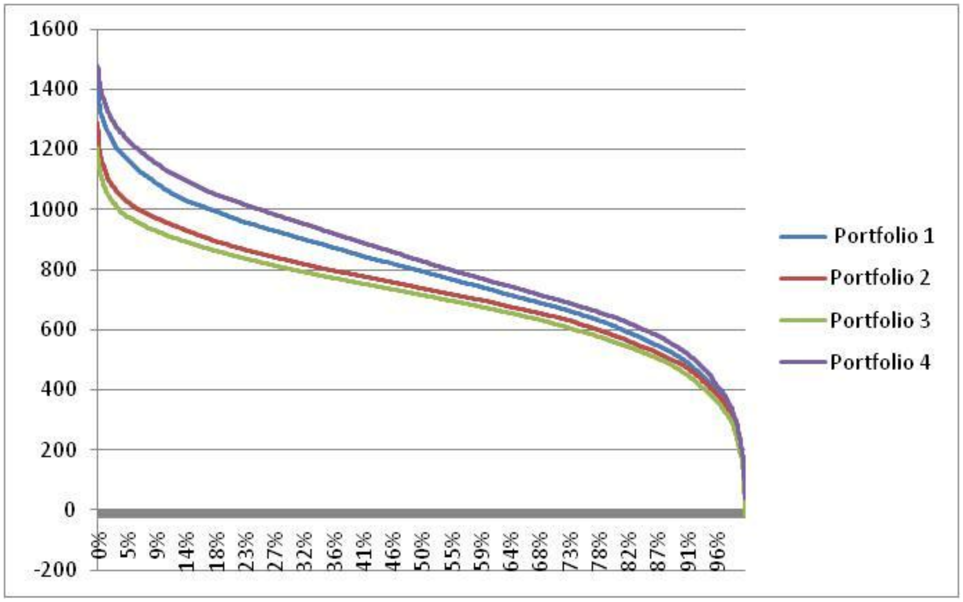
West of Devers 230kV lines

The West of Devers (WOD) branch group, consisting of four 230kV lines going west from Devers substation, is downstream of the Path 42 and Colorado River–Devers 500 kV lines. Renewable generation output from Imperial North and Riverside East, as well as imports from EOR, flows through the WOD branch group. The high utilization of WOD branch group in Portfolio 4 and Portfolio 1 is caused mainly by the high renewable penetration in the IID system and the Riverside East area, respectively.

Table 5.8-8 CREZs mainly served by WOD 230kV lines

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Riverside East	3447	1250	1250	2615
Palm Springs	244	244	244	244
Imperial North	594	594	594	1319
Total	4285	2088	2088	4178

Fig. 5.8-10 West of Devers Power Flow Duration Curves



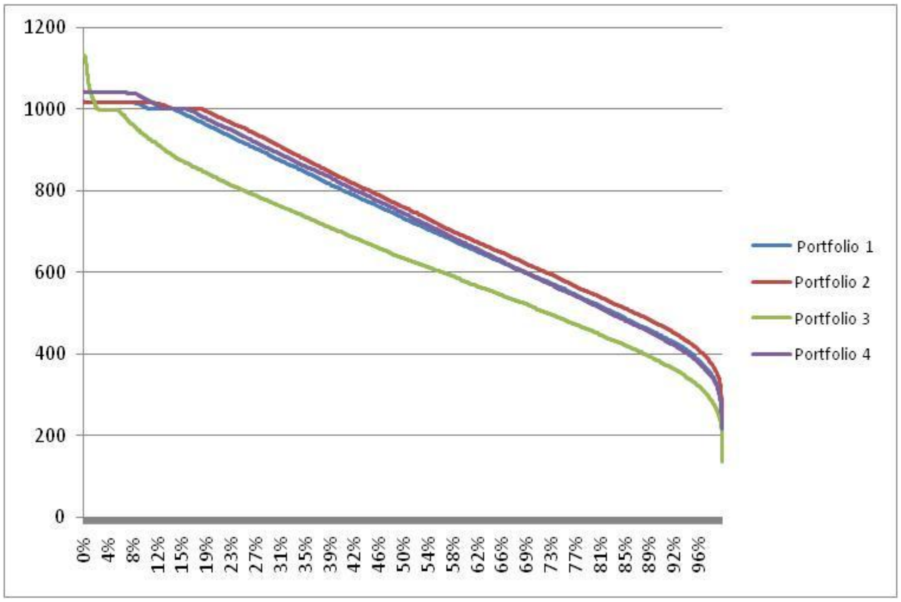
Imperial Valley–Central 500 kV line (Sunrise Powerlink)

The Sunrise Powerlink 500 kV line runs in parallel with the existing Imperial Valley–Miguel 500 kV line and delivers generation, including renewable generation from the Imperial North and South, San Diego South, and Arizona areas into the San Diego area. East of River flow also impacts the flow on Sunrise Powerlink.

Table 5.8-9 CREZs mainly served by Path 42

CREZ	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Imperial North	594	594	594	1319
Imperial South	974	925	376	924
San Diego South	331	331	331	331
Arizona	290	1790	290	1090
Total	2289	3640	1591	3664

Fig. 5.8-11 Sunrise Power Link Flow Duration Curves



5.9 Conclusions from Comprehensive Planning Assessment to Meet 33% RPS

Comprehensive assessments have been performed on all four 33% renewable portfolios, including power flow and stability assessments, a deliverability assessment and a production cost simulation.
On top of the transmission upgrades that are listed in Table 4.1.1, which have been modeled in the starting power flow base cases and the production model, both generation and transmission needs to accommodate 33% renewable portfolios have been identified in the 33% RPS comprehensive transmission
Section 5.9.1 summarizes the study results.
Section 5.9.2 identifies the projects that have been selected as category 1 projects which are identified as needed in this planning cycle.
Section 5.9.2 identifies the projects that have been selected as category 2 projects which could be needed and which will be carried forward into future planning cycles.

5.9.1 Summary of 33% RPS comprehensive transmission planning assessment

Comprehensive assessments have been performed on all four 33% renewable portfolios, including power flow and stability assessments, a deliverability assessment and a production cost simulation.
On top of the transmission upgrades that are listed in Table 4.1-1, which have been modeled in the starting power flow base cases and the production model, both generation and transmission needs to accommodate 33% renewable portfolios have been identified in the 33% RPS comprehensive transmission planning studies. The study results are summarized in Table 5.9-1.

Table 5.9-1 Summary of 33% RPS Planning Study Results

	Mitigation for Portfolio 4	Mitigations for other portfolios	Alternative
1	1) Maintain 2000 MW generation inside San Diego, meanwhile assuming Western LA Basin available capacity is not less than 6200 MW (see SCE-1) 2) The third Miguel 500 kV transformer 3) Revise the existing Border SPS to trip Border and Otay generation for outage of Silvergate-South Bay 230 kV N-1 4) 400 MVAr reactive power support at Sycamore and Mission230 kV substations	Portfolio 1: 1) Maintain 2550 MW generation inside San Diego and 6700 MW in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer Portfolio 2: 1) Maintain 2350 MW generation inside San Diego and 6550 MW generation in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer	Portfolios 1, 2 and 4: 1) 1400 MW SDGE generation 2) IV ROA phase shifter to limit CFE loop flow to no higher than 550 MW under N-0 condition 3) Revise Border SPS to trip Border and Otay gens (N-1 South Bay-Silvergate 230 kV to relieve overload on Sweetwater-Sweetwater Tap 69 kV and Division-Sampson 69 kV). 4) 1100 MVAr reactive support at Sycamore, Mission, Talega, and Otay Mesa 230kV (need 700 MVAr reactive support if Western LA Basin is assumed repowered, see SCE-1) 5) Third Miguel 500 kV transformer 6)IV ROA series reactor (20 ohms) for N-1 and N-2 contingencies, reactor less than 20 ohms overloads Otay Mesa-Tij following N-2 (need 30 ohms for Portfolio 1) (the need of the series reactor can be eliminated if SDGE internal generation is 1500 MW, 1600 MW and 1700 MW for Portfolio 4, 2 and 1, respectively, and Western LA Basin is assumed repowered, see SCE-1)
2	IID proposed upgrades in the IV 230 kV area	Portfolio 1: same as Portfolio 4.	N/A
3	N/A	Portfolio 1: N.Gila - Imperial Valley 500 kV Series Cap upgrade and install SPS to bypass the series cap once the flow exceeds the emergency rating.	N/A
4	1) Maintain generation capacity in Western LA Basin at about 6200 MW level for the 1-in-5 load assumption 2) San Diego available capacity not less than 2000 MW, otherwise, 400 MVar reactive Var support at SDGE is needed (See SDGE-1)	Portfolio 1: 1) Maintain generation capacity in Western LA Basin at about 6700 MW level for the 1-in-5 load assumption, 2) San Diego available capacity not less than 2550 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1) Portfolio 2: 1) Maintain generation capacity in Western LA Basin at about 6550 MW level for the 1-in-5 load assumption 2) San Diego available capacity not less than 2350 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1)	1)Build the new Mira Loma - Lighthipe 500 kV line and upgrade the existing Lighthipe 230 kV substation to 500 kV. 2) Install dynamic reactive power support at Santiago, Eagle Rock, Encina and South Bay (500 MVAr at each) 3) SPS of load tripping at Lewis following Serrano-Lewis 230 kV N-2. This alternative may minimize the requirement of OTC repower
5	Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)	Portfolio 1: same as Portfolio 4	Bypass the series cap following the contingency overload

6	Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) and Devers-Mirage 230 kV lines Assume IID internal upgrades to accommodate IID's new generation	All portfolios: Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42).	
7	WOD interim solution prior to WOD 230kV upgrades: Install serial reactors on Devers – San Bernardino 230 kV line and Devers – Elcasco 230kV line; Install SPS to trip generation and load under contingency conditions	All portfolios: same as Portfolio 4	N/A
8	1) Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line	Portfolio 1: same as Portfolio 4 Portfolio 2: 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line	1) Build the new McCall - Gregg 230 kV line 2) Reconductor Borden - Gregg 230 kV line 3) ReconductorMidway - Gates 230 kV #1 and #2 lines 4) Replace terminal equipment on Gates - Henrietta Tap 230 kV line 5) Develop the emergency rating for the Gates 500/230 kV transformer 6) Revise the existing SPS for Los Banos South N-2 contingency to increase generation tripping in South of Los Banos 7)Reconductor 20 miles of the Warnerville – Wilson 230 kV line;upgrade terminal equipment 8) Reconductor 9.2 miles of the Sanger – Mc Call 115 kV line; upgrade terminal equipment. 9) Oro Loma 70 kV Area Reinforcement proposed in annual NERC compliance reliability assessment
9	N/A	Portfolio 2: Re-rate Malin – Round Mt. 500 kV #2 line	Revise the existing SPS with additional generation tripping in NW for CapJack - Olinda 500 kV lines N-2, or reduce the NW HVDC schedule that modeled in Portfolio 2
10	N/A	Portfolio 1: Reconductor Los Banos - Westley 230 kV line	Revise LosBanos North SPS to increase generation tripping
11	N/A	Portfolio 2: Reconductor Temblor - San Luis Obispo 115 kV line and 50 MVAr reactive power support at San Luis Obispo 115 kV bus	Add a new 115 kV line between Temblor - San Luis Obispo
12	N/A	Portfolio 1: SPS to trip generation at Morro Bay area	Reconductorithe Morro Bay - Templeton 230 kV #1 and #2 lines
13	SPS to trip generation at Contra Coasta area	Portfolio 1 & 2: N/A	Reconductoring the Contra Coasta Sub - Contra Coast 230 kV line
14	SPS to trip generation at Colusa and revise the existing SPS for Round Mountain - Table Mountain N-2 and Table Mountain South N-2	Portfolio 1&2: N/A	Reconductoring Deleven - Cortina
15	SPS to bypass series cap on the remaining Round Mt. - Table Mt. 500 kV line p after the Round Mt. - Table Mt. 500 kV line N-1	Portfolio 1&2: N/A	SPS to trip more NW generation

Table 5.9.2 Summary of Estimated Costs and Schedules for 33% RPS Comprehensive Transmission Planning Upgrades

	Mitigation for portfolio 4	Cost	Schedule of upgrades for portfolio 4	Mitigations for other portfolios	Cost	Schedule of upgrades for portfolios 1 & 2	Alternative	Cost	Schedule of alternative upgrades
1	1) Maintain 2000 MW inside San Diego, meanwhile assuming Western LA Basin available capacity is not less than 6200 MW (see SCE-1) 2) The third Miguel 500 kV transformer 3) Revise the existing Border SPS to trip Border and Otay generation for outage of Silvergate-South Bay 230 kV N-1 4) 400 MVAr reactive power support at Sycamore and Mission230 kV substations	1) Depends on generation development 2) $75M 3) $0.1 4) $164M ($82M at each substation)	1) Depends on generation development 2) 60 months 3) 12 months 4) 36 months at each substation	Portfolio 1: 1) Maintain 2550 MW generation inside San Diego and 6700 MW in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer Portfolio 2: 1) Maintain 2350 MW generation inside San Diego and 6550 MW generation in Western LA Basin (see SCE-1) 2) Total 700 MVAr reactive power support at Sycamore, Mission and Talega 230 kV substations 3) New SPS to open Sycamore-Chicarita 138 kV line for the outage of Encina 230/138 kV transformer	1) Depends on generation development 2) additional $82M 3) $100,000 1) depends on generation development 2) additional %82M 3) $100,000	1) Depends on generation development 2) 36 months 3) 12 months 1) depends on generation development 2) 36 months 3) 12 months	1) 1400 MW SDGE generation 2) IV ROA phase shifter to limit CFE loop flow to no higher than 550 MW under N-0 condition 3) revise Border SPS to trip Border and Otay gens (N-1 South Bay-Silvergate 230 kV to relieve overload on Sweetwater-Sweetwater Tap 69 kV and Division-Sampson 69 kV). 4) 1100 MVAr reactive support at Sycamore, Mission, Talega, and Otay Mesa 230kV (need 700 MVAr reactive support if Western LA Basin is assumed repowered, see SCE-1) 5) Third Miguel 500 kV transformer 6)IV ROA series reactor (20 ohms) for N-1 and N-2 contingencies, reactor less than 20 ohms overloads Otay Mesa-Tij following N-2 (need 30 ohms for Portfolio 1) (the need of the series reactor can be eliminated if SDGE internal generation is 1500 MW, 1600 MW and 1700 MW for Portfolio 4, 2 and 1, respectively,	1) N/A 2) $100M 3) $100,000 4) $328M ($82M at each substation) 5) $75M 6) $10M	1) N/A 2) 36 months 3) 12 months 4) 36 months each substation 5) 60 months 6)36 months

							and Western LA Basin is assumed repowered, see SCE-1)		
2	IID proposed upgrades in the IV 230 kV area	N/A	36 months		N/A	N/A	N/A		
3	N/A	N/A	N/A	N.Gila - Imperial Valley 500 kV Series Cap upgrade and install SPS to bypass the series cap once the flow exceeds the emergency rating.	$25M	24 months	N/A		
4	1) Maintain generation capacity in Western LA Basin at about 6200 MW level for the 1-in-5 load assumption, 2) San Diego available capacity not less than 2000 MW, otherwise, 400 MVar reactive Var support at SDGE is needed (See SDGE-1)	N/A	N/A	Portfolio 1: 1) Maintain generation capacity in Western LA Basin at about 6700 MW level for the 1-in-5 load assumption. 2) San Diego available capacity not less than 2550 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1) Portfolio 2: 1) Maintain generation capacity in Western LA Basin at about 6550 MW level for the 1-in-5 load assumption. 2) San Diego available capacity not less than 2350 MW, otherwise, 700 MVar reactive Var support at SDGE is needed (See SDGE-1)	N/A	N/A	1)Build the new Mira Loma - Lighthipe 500 kV line and upgrade the existing Lighthipe 230 kV substation to 500 kV. 2) Install dynamic reactive power support at Santiago, Eagle Rock, Encina and South Bay (500 MVAr at each) 3) SPS of load tripping at Lewis following Serrano-Lewis 230 kV N-2. This alternative may minimize the requirement of OTC repower	$500M	84 months
5	Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)	$25M	24 months	Same as Portfolio 4	$25M	24 months	Bypass the series cap following the contingency overload	$1M	24 months

6	Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) and Devers – Mirage No. 1 and No. 2 230 kV lines. Assume IID internal upgrades to accommodate IID's new generation	$80M	36 months	All portfolios: Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42). Assume IID internal upgrades to accommodate IID's new generation	$40M	36 months	Reconductor Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) and SPS to trip IID generation under outage of one Devers – Mirage 230kV line.	$40M	36 months
7	WOD interim solution prior to WOD 230kV upgrades: Install serial reactors on Devers – San Bernardino 230 kV line and Devers – Elcasco 230kV line; Install SPS to trip generation and load under contingency conditions	$20M	24 months	Same as Portfolio 4	$20M	24 months	N/A	N/A	N/A
8	1)Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line	1) $1,000M-$1,100M 2) $1.5M-$2M 3) $38M-$44M 4) $15M-$22M 5) $12M-$15M	1)72 Months 2)24 Months 3)36 Months 4)36 Months 5)36 Months	Portfolio 1: Same as Portfolio 4 Portfolio 2: needs item 4) and 5)	Portfolio 1: Same as Portfolio 4 Portfolio 2: needs itiem 4) and 5)	Portfolio 1: Same as Portfolio 4 Portfolio 2: needs itiem 4) and 5)	1) Build the new McCall - Gregg 230 kV line 2) Reconductor Midway - Gates 230 kV #1 and #2 lines 3) Replace terminal equipment on Gates - Henrietta Tap 230 kV line 4) Develop the emergency rating for the Gates 500/230 kV transformer 5) Revise the existing SPS for Los Banos South N-2 contingency to increase generation tripping in South of Los Banos 6)Reconductor 20 miles of the Warnerville – Wilson 230 kV line; upgrade terminal equipment 7) Reconductor 9.2 miles of the Sanger – Mc Call 115 kV line; upgrade terminal equipment. 8) Oro Loma 70 kV Area Reinforcement proposed in annual NERC compliance reliability assessment	1) $55M-$65M 2) $120 M- $130 M 3) $1M 4) $1M-$5M 5) $1M - $2M 6)$38M-$44M 7) $12M - $15M 8)$0.2M - $0.5 M	1) 60 Months 2) 48 Months 3) 12 Months 4) 6 Months 5) 12 Months 6) 36 Months 7) 36 Months 8) 12 Months

9	N/A			Portfolio 2: Re-rate Malin – Round Mt. 500 kV #2 line	<$1M	6 Months	Revise the existing SPS with additional generation tripping in NW for CapJack -Olinda 500 kV lines N-2, or reduce the NW HVDC schedule that modeled in Portfolio 2	$1M- $2M	12 Months
10	N/A			Portfolio 1: Reconductor Los Banos - Westley 230 kV line	$12M-$15M	24 Months	Revise LosBanos North SPS to increase generation tripping	$1M- $2M	12 Months
11	N/A			Portfolio 2: Reconductor Temblor - San Luis Obispo 115 kV line and 50 MVAr reactive power support at San Luis Obispo 115 kV bus	$65M - $75M	36 Months	Add a new 115 kV line between Temblor - San Luis Obispo	$70M - $100M	60 Months
12	N/A			Portfolio 1: SPS to trip generation at Morro Bay area	$1M- $2M	12 Months	Reconductor the Morro Bay - Templeton 230 kV #1 and #2 lines	$25M-$30M	24 Months
13	SPS to trip generation at Contra Coasta area	$1M- $2M	12 Months	Portfolio 1&2: N/A			Reconductor the Contra Coasta Sub - Contra Coast 230 kV line	$2M- $3M	24 Months
14	SPS to trip generation at Colusa and revise the existing SPS for Round Mountain - Table Mountain N-2 and Table Mountain South N-2	$1M- $2M	12 Months	Portfolio 1&2: N/A	N/A	N/A	Reconductor Deleven - Cortina	$6M-$10M	24 Months
15	SPS to bypass series cap on the remaining Round Mt. - Table Mt. 500 kV line p after the Round Mt. - Table Mt. 500 kV line N-1	$1M-$2M	12 Months	Portfolio 1&2: N/A	N/A	N/A	SPS to trip more NW generation	$1M-$2M	12 Months

5.9.2 List of Category 1 Upgrades

Table 5.9.3 Category 1 upgrades

Category 1 Transmission projects for Portfolio 4	Lead Time for Implementation	Note
Path 42 and Mirage-Devers upgrades	36 months for Path 42/Mirage-Devers upgrades.	1) Need West of Devers (WOD) interim solution that will use SPS of generation and load tripping and series reactors to mitigate the potential reliability concerns prior to the in-service date of the permanent WOD upgrade of reconductoring the 230 kV lines. It is estimated that the implementation of the WOD interim solution needs 36 months.

In the 2010/2011 cycle of the Comprehensive Transmission Plan, the Coachella - Mirage and Coachella-Ramon-Mirage 230 kV lines (Path 42) owned by IID and Devers-Mirage 230 kV lines owned by SCE were identified as constraints on the delivery of renewable generation in the base line scenario (Hybrid, Portfolio 4). Through CTPG the ISO has worked with IID on the coordination of these two upgrades. IID has over 1000 MW of renewable generation in their interconnection and transmission service queues that are in the late stages of negotiation contractual agreements to construct the Path 42 upgrades along with other upgrades required on the IID system.
The Mirage – Devers 230 kV line reconductoring upgrades have been categorized as category 1 upgrade for the following reasons:

- Mirage – Devers 230 kV line reconductoring upgrade has been identified as needed for Portfolio 4 (the most likely portfolio).
- Path 42 upgrade has been identified as needed in the generation interconnection process by IID to deliver renewable generation in the IID system into the CAISO balancing authority area. The generation developers of the renewable generation in the IID system have publicy communicated their plans to fund the necessary upgrades identified as needed by IID, including Path 42 upgrade.
- Mirage – Devers 230 kV line reconductoring and the Path 42 (Coachella – Mirage and Ramon – Mirage) upgrades are both needed in order to allow delivery of renewable generation in the baseline portfolio. A commitment to fund the Path 42 upgrades provides assurance that the Mirage-Devers upgrades will not become stranded assets.
- The difference on the Mirage – Devers flow among Portfolio 4 and other portfolios is mainly because the renewable generation modeled in Portfolios 1 and 2 is less than Portfolio 4 (detail can be found in Section 5.1). The development of Portfolio 1 and Portfolio 2 was prior to Portfolio 4. During the development of Portfolio 4 the ISO learned about the substantial progress that had been made in the interconnection of generation in the IID and the related Path 42 upgrades through discussions with CTPG and incorporated that information. Had the ISO revisited the already-completed Portfolios 1 and 2 with the same information, it is expected that the Mirage – Devers upgrades would also have been determined to be needed in Portfolio 1 and Portfolio 2.
- Mirage – Devers 230 kV double circuit tower line is only about 20 miles long and the cost of the upgrade is estimated to be only about $40 million.

In summary, Mirage – Devers upgrades has been recommended as category 1 upgrade that in conjunction with IID's planned Path 42 upgrades will deliver the renewable generation in the Imperial County area to meet the State's 33% RPS. Although the Mirage-Devers upgrades have been identified as category 1 elements, these elements consist of reconductoring existing 230 kV lines owned by SCE. According to ISO tariff Section 24.5.2, if the selected elements involve upgrades on an existing PTO facility, the PTO will construct and own such facilities. Thus, SCE is the project sponsor for the Mirage-Devers upgrade and there will be no competitive solicitation.

5.9.3. List of Category 2 Upgrades

Table 5.9.4 Category 2 Upgrades

Category 2 Transmission Upgrades	Lead Time for Implementation
400 MVAr reactive power support at Sycamore, Mission, and Talega 230 kV substations	36 months for reactive power support
Category 2 Transmission Upgrades	**Lead Time for Implementation**
The third Miguel 500 kV transformer	60 months for the third Miguel 500 kV transformer
Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)	24 months for El Dorado – Pisgah 500 kV series cap upgrade
Fresno area: 1) Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line	72 months for Midway – Gregg 500 kV line 36 months to Reconductor multiple 230 kV lines
8	

In the 2010/2011 cycle of the Comprehensive Transmission Plan, a need for reactive power support in San Diego was identified and categorized as category 2. Although reactive power support is needed in all portfolios, the amount and location of the need is highly dependent on the status of OTC repowering in San Diego. However, because OTC policies and transmission studies for implementation of those policies are still in progress, the ISO plans to take advantage of OTC compliance plans expected soon and then perform further analysis of all transmission needs related to OTC compliance. Meanwhile, the relative short lead time of installing the reactive power support in San Diego (36 months) allows deferring the decision for this upgrade without impacted the achievement of 33% RPS goal by 2020.

The third Miguel 500/230 kV transformer is identified as needed for Portfolio 4 but not for other portfolios hence it is categorized as category 2 upgrade according to tariff section 24.4.6.6.

The El Dorado – Pisgah series capacitor upgrade is identified as needed for Portfolio 4 and other portfolios, however, but it is still recommended as category 2 upgrade. The lead time of this upgrade is estimated at 24 months which is relatively short considering the need of this upgrade is for 2020. Given this short lead time, it is reasonable to categorize this upgrade as category 2, so it can be re-evaluated in the following planning cycle using updated information without impacting the achievement of 33% RPS goal by 2020.

The Midway – Gregg 500 kV line and the associated upgrades in Fresno area have been identified as needed for both Portfolio 4 and Portfolio 1. The need for these upgrades is mainly driven by the assumption that three Helms units are pumping at the same time in the off-peak load condition. This assumption is based on the anticipation of a renewable integration requirement for pumped energy storage during the off-peak load condition. The need of these upgrades will be re-evaluated in the following planning cycle using updated results from ISO renewable integration studies that are currently in progress. Therefore, these upgrades are recommended as category 2 upgrades.

Chapter 6 Economic Planning Studies

The primary focus of the ISO economic planning studies is to identify potential transmission congestion in the ISO controlled grid and study if it is cost effective to mitigate the congestion. In the studies, the transmission system was based on conceptual transmission elements identified in the ISO's 2010/2011 Conceptual Statewide Transmission Plan and network additions specified in the ISO's comprehensive transmission plan. The ISO utilized this method to assess potential economic network upgrades by focusing on the areas of significant and reoccurring transmission congestion. The economic planning studies provide the basis for assessing and identifying additional cost-effective transmission elements, beyond those identified for other categories of transmission projects.

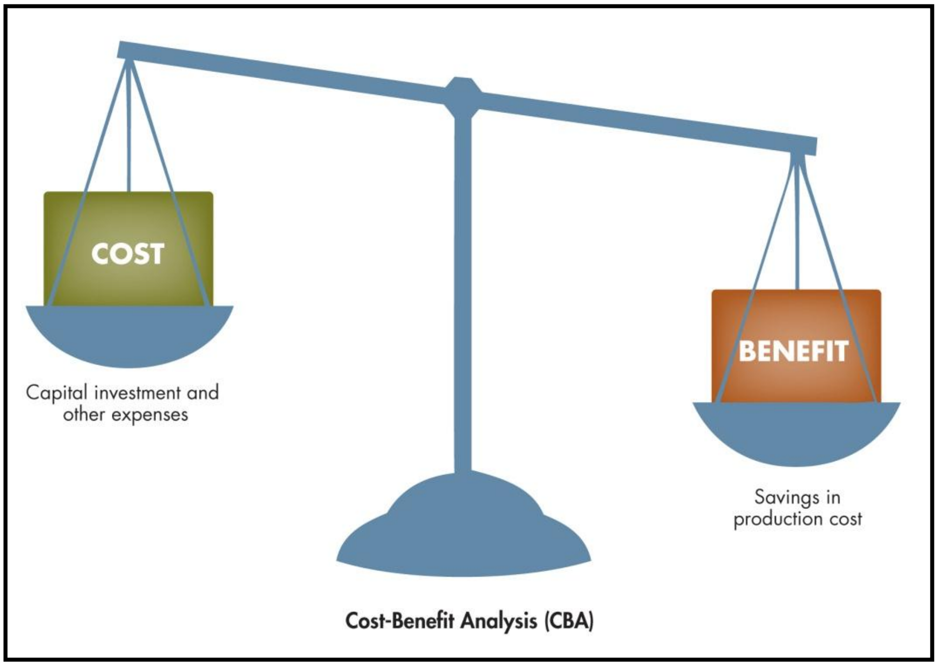
The studies were accomplished by simulating future system conditions consistent with the unified planning assumptions, as well as other data submitted through the request window. The studies utilized production cost simulation tool using Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) approaches to provide a viable framework for system conditions. The quantification of potential benefits is measured against the ISO's Transmission Economic Analysis Methodology (TEAM) approach.

The congestion study approach utilized in the 2010/2011 transmission planning cycle is consistent with ISO tariff section 24.4.6.7 which provides that the ISO will conduct an analysis to determine whether additional transmission elements are needed to address grid congestion and related issues. Under RTPP, the economic planning study is performed after evaluations of policy-driven transmission (i.e., meeting RPS goals) and reliability-driven transmission are completed. Network upgrades determined by reliability and renewable studies are modeled as inputs in the economic planning database. This is to ensure that the economically-driven transmission needs are not redundant and are beyond the reliability- and policy-driven transmission needs.

6.1 Technical Approach

As shown in Figure 6.1-1, the economic planning study weighs the costs and benefits of a proposed project. In order for a proposed network upgrade to qualify for an economic project, it has to demonstrate a positive net benefit to ratepayers in terms of a reduction in production costs, congestion costs, transmission losses, capacity or other electric supply costs resulting from improved access to cost-efficient resources. In comparing different alternatives, the mitigation plan that has the largest net benefit is generally considered as the most economic solution.

Fig. 6.1-1: Economic Planning Study – Weighing Costs and Benefits



In the ISO economic planning study, the required criteria is that the ISO-ratepayer benefit needs to be greater than the project cost in order to justify an economic project. Typically, the economic benefit includes three components: consumer payment decrease, generation revenue increase and transmission congestion revenue increase for the ratepayers, consistent with the requirements of tariff section 24.4.6.7 and the principles of the ISO's TEAM[40].

6.1.1 Engineering Analysis

Economic benefits of transmission network upgrades can be calculated by engineering analysis using production simulation and traditional power flow studies.

Production simulation is an important foundation for economic planning study. Based on algorithms of SCUC and SCED, production simulation computes unit commitment, generator dispatch, locational marginal prices (LMP) and transmission line flows over 8760 hours in a study year. With the objective of minimizing production costs, the computation balances supply and demand by dispatching economic generation while observing transmission constraints. Production simulation identifies transmission congestion over the study period that spans 8760 hours in a year. By comparing the "pre-project" and "post-project" study results, economic benefits can be calculated from savings of production costs or ratepayer payments.

In addition to the economic benefits computed by production simulation, any other benefits — where applicable and quantifiable — can be included. For example, some transmission upgrades may lead to a

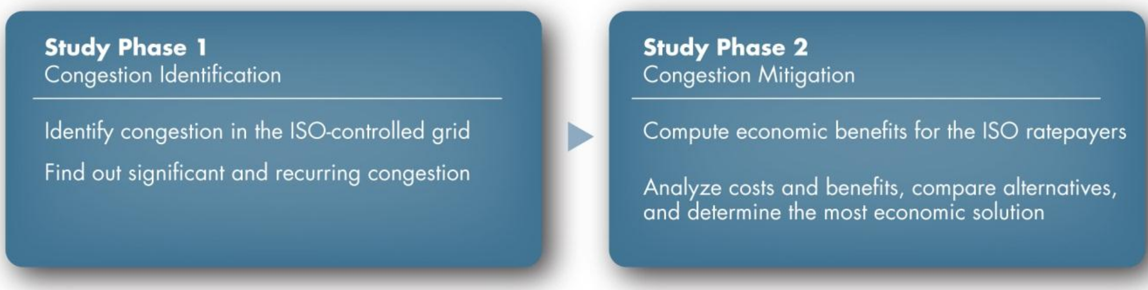
[40] http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf

reduction of Local Capacity Requirement (LCR) in an area. In such a case, LCR reduction yields capacity benefits.

6.1.2 Study Phases

The economic planning study is divided into two phases: congestion identification and congestion mitigation. The two study phases are shown in Figure 6.1-2.

Fig. 6.1-2: Economic Planning Study – Two Phases



In the first study phase (congestion identification), production simulation was conducted to simulate 8760 hours for each study year. In the simulation results, grid congestion was tabulated and ranked by congestion costs (in millions of dollars) and congestion duration (in hours). The top-five most severe congestion issues were identified as high-priority studies that were to be analyzed in the second study phase. The ISO selected the 2008-2009 request window project submittals that could address the identified top-five congestion as possible mitigation solutions. The selected projects were then evaluated under high-priority studies in the second study phase to see if economic benefits outweigh project costs.

In the second study phase (congestion mitigation), the top-five congestions were analyzed and mitigation plans were evaluated. Using production simulation and other means, the ISO determined the economic benefits for proposed mitigation plans. Finally, cost-benefit analysis was performed to determine if the proposed mitigation plans are economic. Among all the mitigation plans that would address identified congestions, the plan that had the largest net benefit was determined to be the most economic solution.

6.1.3 Software Tool

For this study, the ISO used ABB GridView™ software to conduct production simulation. The GridView program used is version 7.0, released on June 8, 2010. The computation engine has a service pack dated January 15, 2011.

6.1.4 Database

The WECC production cost model was used in the study. The database model is often referred to as the Transmission Expansion Planning Policy Committee (TEPPC) database. In this study, the TEPPC base case used was the 2017 PC4A case that was released by TEPPC on November 10, 2008.

To perform the studies, the ISO provided updates and additions to the original TEPPC database, with attention to modeling the California power system and various resource portfolios in more detail. Using the TEPPC database as a reference, the ISO developed the 2015 and 2020 base cases for this economic planning study.

6.2 Study Assumptions

This section summarizes major study assumptions in the economic planning study.

6.2.1 Study Assumptions for Generation Modeling

Table 6.2-1 lists the four alternative RPS net short scenarios models discussed in detail in Chapter 4. In the 33% RPS scenarios, some resources are located within California, others are outside the state.

Table 6.2-1: 33% RPS Portfolio Assumptions for ISO Economic Planning Studies

ID	Acronym	33% RPS Portfolios	Study Case
P1	High UTL	High in-state transmission utilization	Sensitivity 1
P2	High OOS	High out-of-state generation	Sensitivity 2
P3	High DG	High distributed generation	Sensitivity 3
P4	Hybrid	Blending elements of the above three portfolios	Reference case

Figure 6.2-1 illustrates the percentage of out-of-state and distributed generation for the four RPS net short scenarios. Figure 6.2-2 shows the technology compositions for these portfolios.

Other than the California 33% RPS goals, renewable energy targets were represented at about 15% of load consumption in other states throughout the WECC. The non-California renewable resources were modeled in the original TEPPC database and were not altered by the ISO.

Figure 6.2-1: RPS Net-Short Portfolios Modeled in the Study Cases

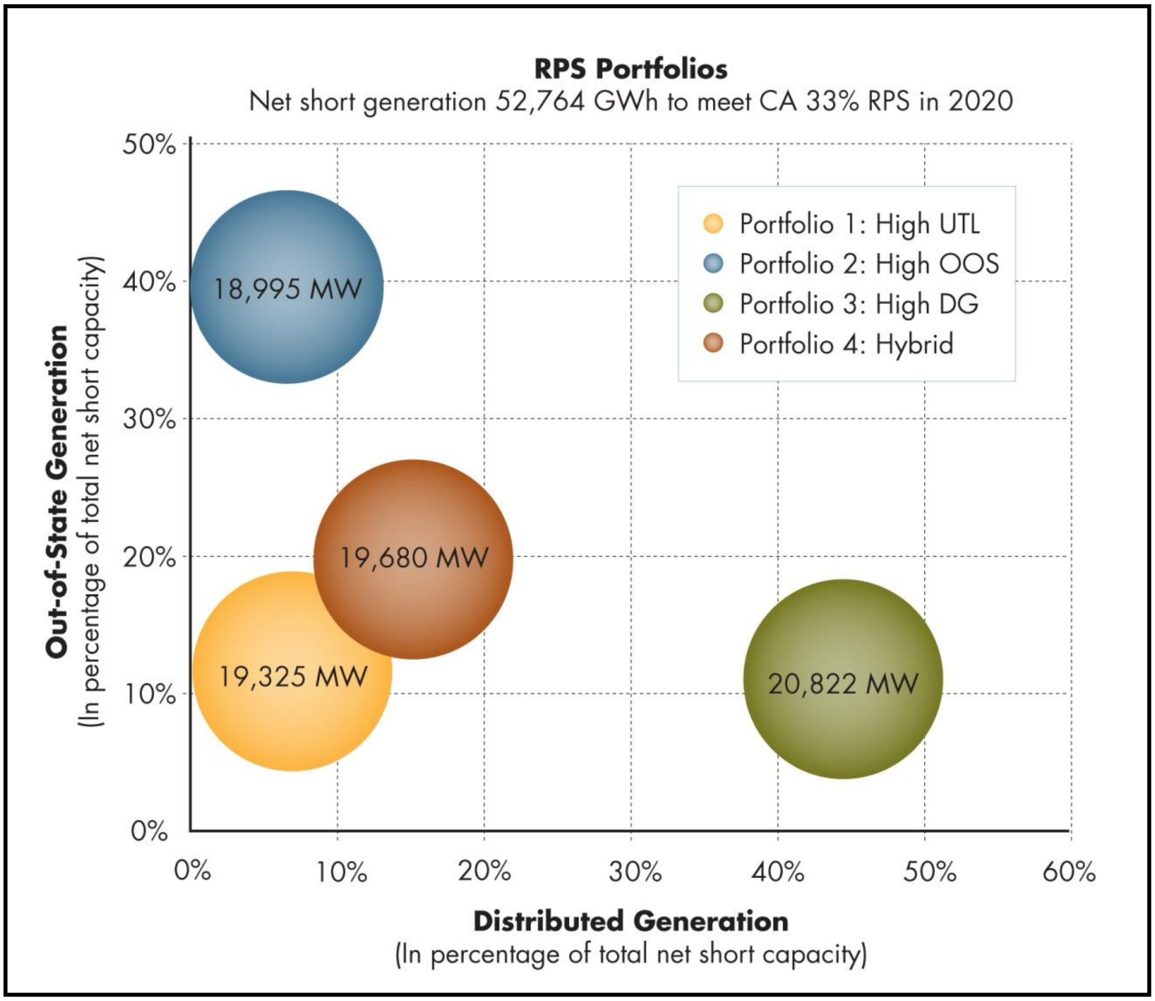
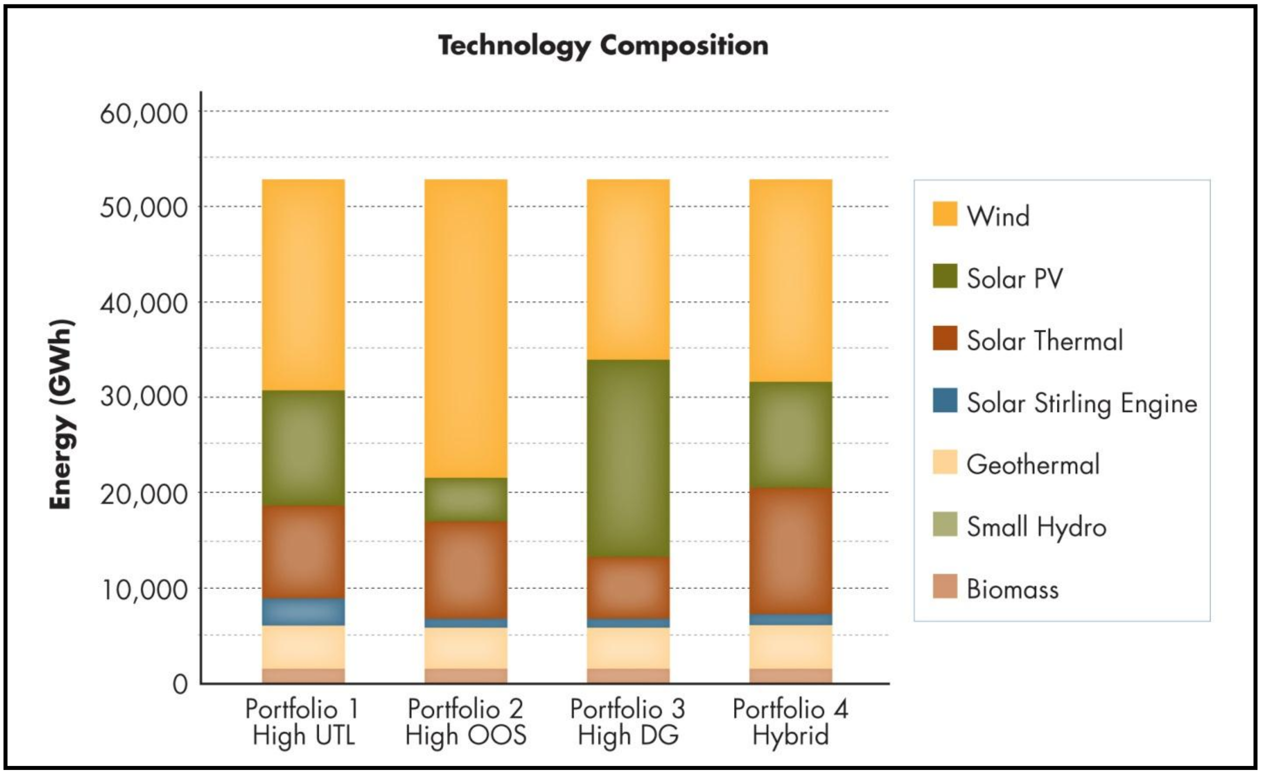


Figure 6.2-2: Technology Composition in the RPS Net-Short Portfolios



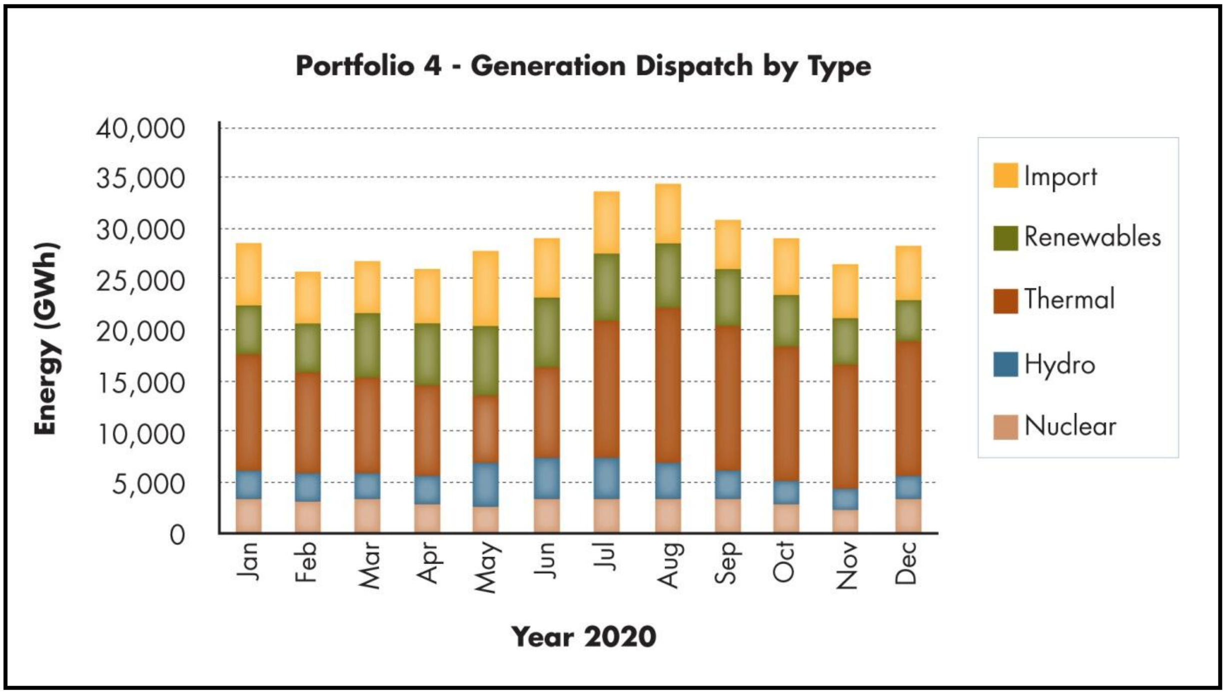
For the California OTC power plants, Table 6.2-2 lists the changes in the assumptions based on recent development for these plants. Other OTC plants were modeled in the study cases as existing units.

Table 6.2-2: Assumptions on OTC

#	Power Plant	Utility Area	Status	Year
1	Humboldt Power Plant	PG&E	Re-powered	2009
2	Potrero	PG&E	Retired	2010
3	Contra Costa #6 and #7 (to retire) Marsh Landing (to build)	PG&E	To repower	2013
4	South Bay	SDG&E	To retire	2012

Figure 6.2-3 is an overview of monthly generation supply to meet the load demand in California. The generation is categorized in nuclear, hydro, thermal, renewables and imports.

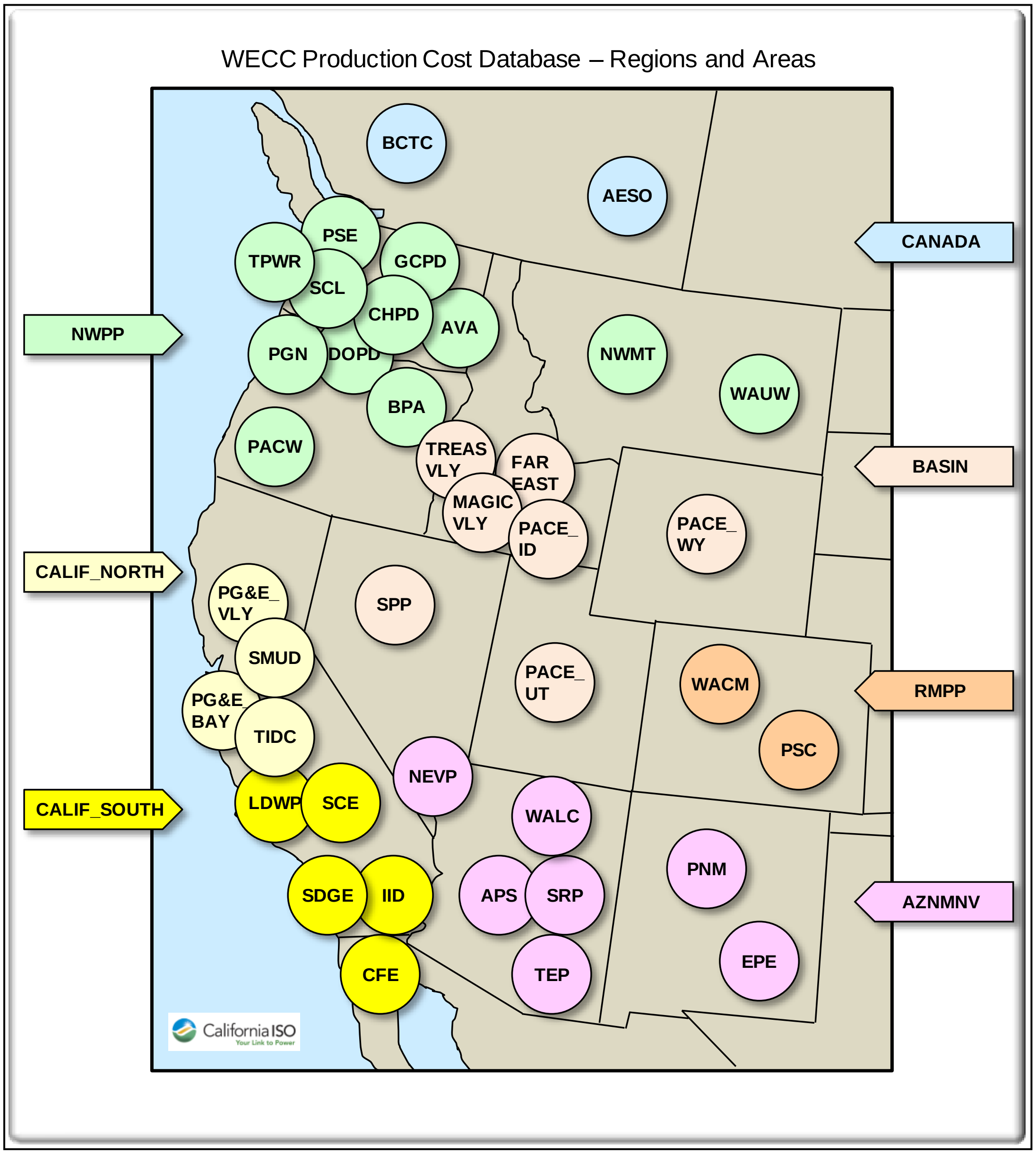
Figure 6.2-3: Types of Generation Supply to the California Region



6.2.2 Study Assumptions in Load Modeling

Figure 6.2-4 shows various regions and areas are defined in the WECC production simulation model. The regions and areas are mainly used for reporting purposes. The underlying power system is represented in a full network model.

Figure 6.2-4: Regions and Load Areas Defined in the TEPPC Database



In the database, area load was modeled according to the forecast data gathered by the Loads and Resources Subcommittee (LRS) in the WECC. In the database, a 1-in-2 heat wave load was represented. In the California region, the ISO updated the load model, based on the official CEC demand forecast which was published in December 2009.

The load distribution pattern throughout the system was enhanced. In the original TEPPC database, only one load distribution pattern was modeled. The ISO added an additional load distribution pattern to reflect different distribution patterns during different seasons. In the final database, both summer and winter load distribution patterns were modeled.

6.2.3 Study Assumptions in Transmission Network Modeling

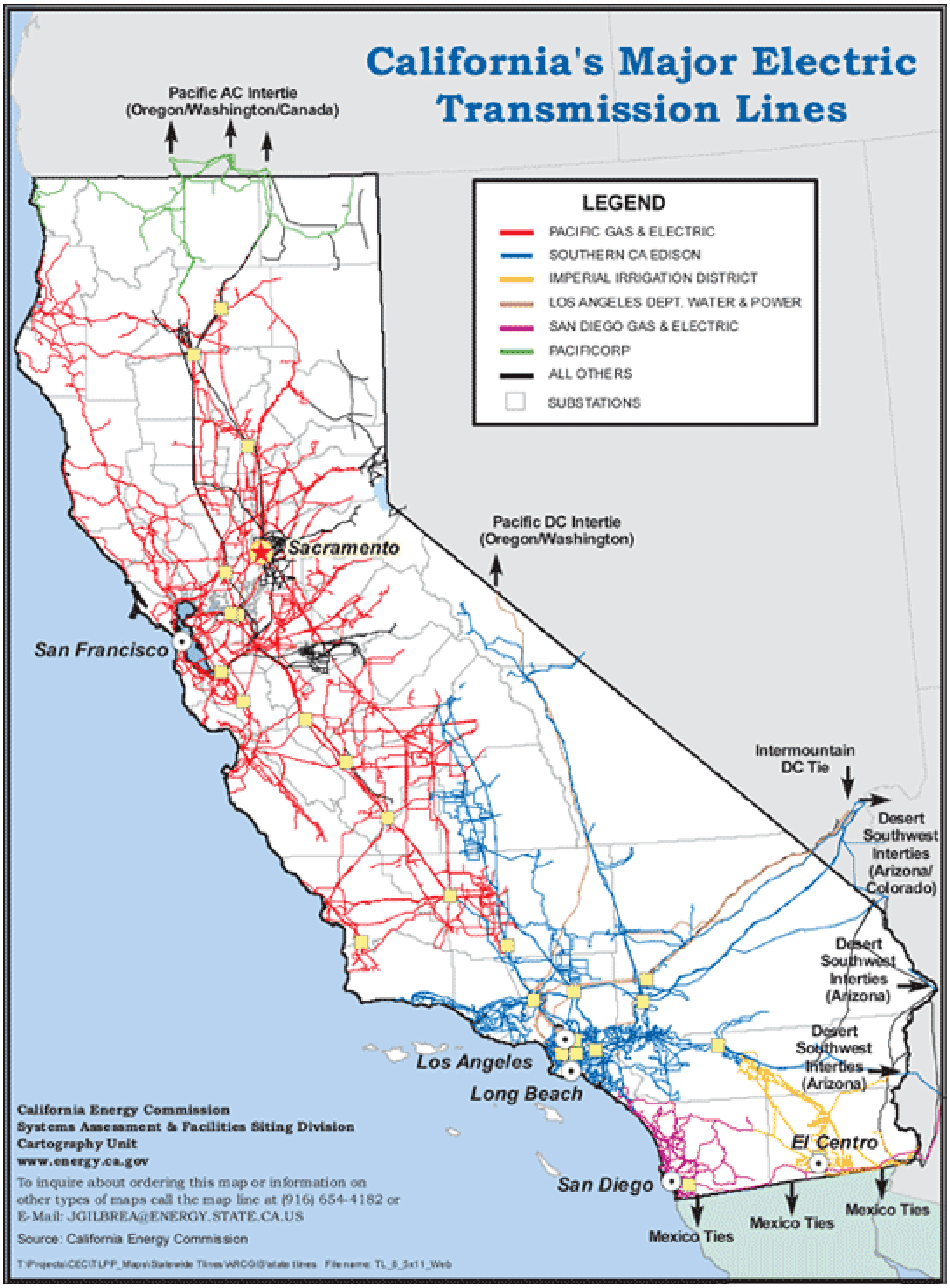
In the production simulation database, the entire WECC system was represented in a nodal network, where enforced transmission limits include individual transmission lines, paths (flowgates) and nomograms. Figure 6.2-5 is a high-level overview of the WECC system with some major transmission paths shown on the map.

Figure 6.2-5: Overview of the WECC System and Major Transmission Paths

Source: SSG-WI / PacifiCorp

Figure 6.2-6 is a map that provides an overview of the California transmission system.

Figure 6.2-6: Overview of California Transmission System



In the original TEPPC database, not all transmission lines were enforced with their limits. For this study, the ISO made modifications to the database to make sure all 500 kV and 230 kV line flows in the ISO-controlled grid stayed within their rated limits.

Another important enhancement by the ISO is the addition of contingency constraints in the transmission model. In the original TEPPC database, no contingencies were modeled. In the updated database, the ISO modeled contingencies that could cause constraints in the California transmission grid. Thus, the production simulation software adhered to limits necessary to avoid overloads in anticipation of those contingencies.

The study models transmission projects that have received ISO approvals in prior transmission cycles or have been identified for inclusion in LGIAs, as well as policy-driven projects that were evaluated and considered in this 2010/2011 planning cycle. These transmission projects include renewable transmission and reliability upgrades.

Table 6.2-3 lists renewable transmission projects developed from the renewable transmission studies conducted in the previous and this planning cycle.

Table 6.2-3: Renewable Transmission Projects Modeled in the Database

#	Project	Utility Area	Status	Operation Year
1	Tehachapi Renewable Transmission Project	SCE	Under construction	2015
2	Sunrise Power Link	SDG&E	Under construction	2012
3	Valley - Colorado River 500 kV line	SCE	Approved	2013
4	Eldorado – Ivanpah Transmission Project (EITP)	SCE	Approved	2013
5	Pisgah – Lugo 500 kV line	SCE	LGIA	2016
6	Coolwater – Lugo 500 kV line	SCE	LGIA	2018
7	West of Devers 230 kV reconductoring	SCE	LGIA	2017
8	Path 42 (IID – SCE) Upgrade	SCE – IID	ISO Proposed	2013

Table 6.2-4 lists some reliability projects proposed in this planning cycle. These reliability upgrades were modeled in the production simulation database as these were determined to be needed to mitigate reliability concerns.

Table 6.2-4: Newly Proposed Reliability Projects Modeled in the Database

#	Project	Utility Area	Operation Year
1	Moraga – Castro Valley 230 kV line capacity increase	PG&E	2013
2	Midway – Kern PP 230 kV lines #1, #3 and #4 capacity increase	PG&E	2013
3	Fulton 230/115 kV transformer	PG&E	2014

4	Rio Oso – Atlantic 230 kV line project	PG&E	2015
5	Red Bluff area 230/60 kV station	PG&E	2016
6	Morro Bay – Mesa 230 kV line	PG&E	2017
7	Borden – Gregg 230 kV line re-conductor	PG&E	2017

6.2.4 Economic Parameters Used in Cost-Benefit Analysis

In the cost-benefit analysis, the total costs and benefits of a project or mitigation proposal were compared. In this chapter, the terms "total cost" and "total benefit" mean the following:

- Total cost (or project cost) is the present value in 2010 US dollars of the annual revenue requirement or annual carrying charges. In other words, the cost consists of all expenses including capital investments, taxes, maintenance costs, and any other payments; and
- Total benefit means the accumulated yearly benefits over the project's economic life. The total benefit is also in the present value of 2010 US dollars.

In calculation of the total benefit, the following economic parameters were used:

- Economic life of new transmission facilities: 60 years;
- Economic life of upgraded transmission facilities: 40 years;
- Inflation rate: 2%;
- Benefits discount rate: 7.1% nominal or 7% real;
- Rate of system RA benefit: $5/kW-year; and
- Rate of LCR benefit: $20/kW-year.

6.3 Study Results – Congestion Identification

Congestion identification is the first phase in the economic planning study. In this study phase, grid congestions were identified by production simulation over 8760 hours in each study year. Simulation was performed for study cases of 2015 (the 5th planning year) and 2020 (the 10th planning year).

6.3.1 Identified Congestion with the Reference Case (ISO hybrid portfolio)

Table 6.3-1 lists the results of identified potential congestion for the reference case ("P4: Hybrid").

Table 6.3-1: Congestion in the ISO Controlled Grid – Base Case (P4: Hybrid)

#	Description	Utility	Year 2015		Year 2020		Average Congestion Cost ($M)
			Duration (hours)	Costs ($M)	Duration (hours)	Costs ($M)	
1	North Valley Area (NVA)	PG&E	29	0.511	68	1.662	1.086
2	Path 26 (Midway – Vincent)	PG&E-SCE	171	0.495	151	0.712	0.604
3	Los Banos North (LBN)	PG&E-TID	-	-	50	1.112	0.556
4	Path 45 (SDG&E – CFE)	SDG&E-CFE	8	0.302	9	0.167	0.234
5	Greater Fresno Area (GFA)	PG&E	54	0.126	77	0.263	0.194
6	Big Creek Area	SCE	4	0.108	10	0.243	0.175
7	Vincent 500 kV transformer	SCE	-	-	21	0.320	0.160
8	Path 66 (COI) and Path 25 (the 115 kV tie)	PacifiCorp – PG&E	17	0.016	29	0.137	0.077
9	Path 60 (Inyo – Control 115 kV tie)	SCE – LADWP	11	0.008	36	0.027	0.018
10	Path 61 (Victorville – Lugo)	SCE – LADWP	-	-	2	0.014	0.007
11	Path 24 (PG&E – Sierra)	PG&E – SPP	1	0.003	-	-	0.001
12	Path 15 (Midway – Los Banos)	PG&E and WAPA	-	-	3	0.000	0.000

In the above table, severity of congestion was ranked by average congestion costs in the last column; and congestion issues were grouped into twelve congestion areas.

Compared to the congestion study in the 2010 planning cycle, the identified congestion issues in the 2010/2011 are relatively mild. This is attributed to a lower load forecast, which has been adjusted downward by about 5% and lowers the renewable net short energy to meet the 33% RPS goals in 2020. As a result, the identified congestion was less than previous planning cycle's evaluations. Some congestion, (i.e., the Greater Bay Area congestion), was no longer identified in this planning cycle.

The identified congestion for the reference case became the foundation for congestion mitigation analysis in the second phase of the economic planning study. Given the milder congestion situation, there was less justification for economic upgrades to mitigate identified congestion.

6.3.2 Identified Congestion with Sensitivity Cases

In addition to the reference case scenario, congestion identification was also performed for three sensitivity cases that were based on alternative RPS scenarios: (1) P1: High Utilization, (2) P2: High Out-of-State, and (3) P3: High Distributed Generation. Study results for potential congestion for the three sensitivity cases are listed in Tables 6.3-2, 6.3-3 and 6.3-4, respectively.

Table 6.3-2: Identified Congestion for Sensitivity Case # 1 (P1: High Utilization)

#	Description	Utility	Year 2015		Year 2020		Average Congestion Cost ($M)
			Duration (hours)	Costs ($M)	Duration (hours)	Costs ($M)	
1	Los Banos North (LBN)	PG&E-TID	-	-	130	3.241	1.711
2	North Valley Area (NVA)	PG&E	33	0.513	65	1.724	1.118
3	Vincent 500 kV transformer	SCE	1	0.002	57	1.242	0.622
4	Path 26 (Midway – Vincent)	PG&E-SCE	141	0.357	124	0.624	0.491
5	Path 45 (SDG&E – CFE)	SDG&E-CFE	8	0.304	9	0.320	0.312
6	Big Creek Area	SCE	5	0.122	11	0.445	0.283
7	Greater Fresno Area (GFA)	PG&E	39	0.097	79	0.301	0.199
8	Path 66 (COI) and Path 25 (the 115 kV tie)	PacifiCorp – PG&E	20	0.019	28	0.109	0.064
9	Path 60 (Inyo – Control 115 kV tie)	SCE – LADWP	21	0.014	67	0.045	0.030
10	LA Basin Metro area	SCE	-	-	2	0.021	0.010
11	Path 24 (PG&E – Sierra)	PG&E – SPP	2	0.004	-	-	0.002

Table 6.3-3: Identified Congestion for Sensitivity Case # 2 (P2: High Out-of-State)

#	Description	Utility	Year 2015		Year 2020		Average Congestion Cost ($M)
			Duration (hours)	Costs ($M)	Duration (hours)	Costs ($M)	
1	Path 26 (Midway – Vincent)	PG&E-SCE	239	1.081	294	1.701	1.391
2	Vincent 500 kV transformer	SCE	1	0.002	41	0.869	0.436
3	Path 45 (SDG&E – CFE)	SDG&E-CFE	8	0.302	9	0.332	0.317
4	Big Creek Area	SCE	1	0.104	10	0.416	0.260
5	Greater Fresno Area (GFA)	PG&E	52	0.118	87	0.339	0.229
6	Los Banos North (LBN)	PG&E-TID	-	-	11	0.081	0.040
7	Greater Bay Area (GBA)	PG&E	2	0.001	40	0.084	0.043
8	North Valley Area (NVA)	PG&E	4	0.065	-	-	0.033
9	Path 61 (Victorville – Lugo)	SCE – LADWP	1	0.017	24	0.034	0.025
10	Path 66 (COI) and Path 25 (the 115 kV tie)	PacifiCorp – PG&E	18	0.015	19	0.034	0.025
11	Path 60 (Inyo – Control 115 kV tie)	SCE – LADWP	15	0.012	20	0.013	0.012

Table 6.3-4: Identified Congestion for Sensitivity Case #3 (P3 - High Distributed Generation)

#	Description	Utility	Year 2015		Year 2020		Average Congestion Cost ($M)
			Duration (hours)	Costs ($M)	Duration (hours)	Costs ($M)	
1	Path 26 (Midway – Vincent)	PG&E-SCE	188	0.633	225	1.375	1.004
2	North Valley Area (NVA)	PG&E	20	0.320	39	0.928	0.624
3	Los Banos North (LBN)	PG&E-TID	-	-	23	0.769	0.385
4	Path 45 (SDG&E – CFE)	SDG&E-CFE	8	0.303	8	0.295	0.299
5	Greater Fresno Area (GFA)	PG&E	33	0.088	81	0.316	0.202
6	Vincent 500 kV transformer	SCE	1	0.004	17	0.396	0.200
7	Big Creek Area	SCE	1	0.001	6	0.227	0.114
8	Path 66 (COI) and Path 25 (the 115 kV tie)	PacifiCorp – PG&E	21	0.021	28	0.065	0.043

9	Path 60 (Inyo – Control 115 kV tie)	SCE – LADWP	26	0.016	31	0.019	0.017
10	Path 61 (Victorville – Lugo)	SCE – LADWP	3	0.033	-	-	0.016
11	Path 24 (PG&E – Sierra)	PG&E – SPP	2	0.005	-	-	0.003
12	Path 15 (Midway – Los Banos)	PG&E and WAPA	-	-	1	0.000	0.000

6.4 Study Results – Congestion Mitigation

Congestion mitigation is the second phase in the economic planning study. For this study, the economic benefits of congestion mitigation measures were calculated and cost-benefit analysis was performed for each congestion mitigation alternatives.

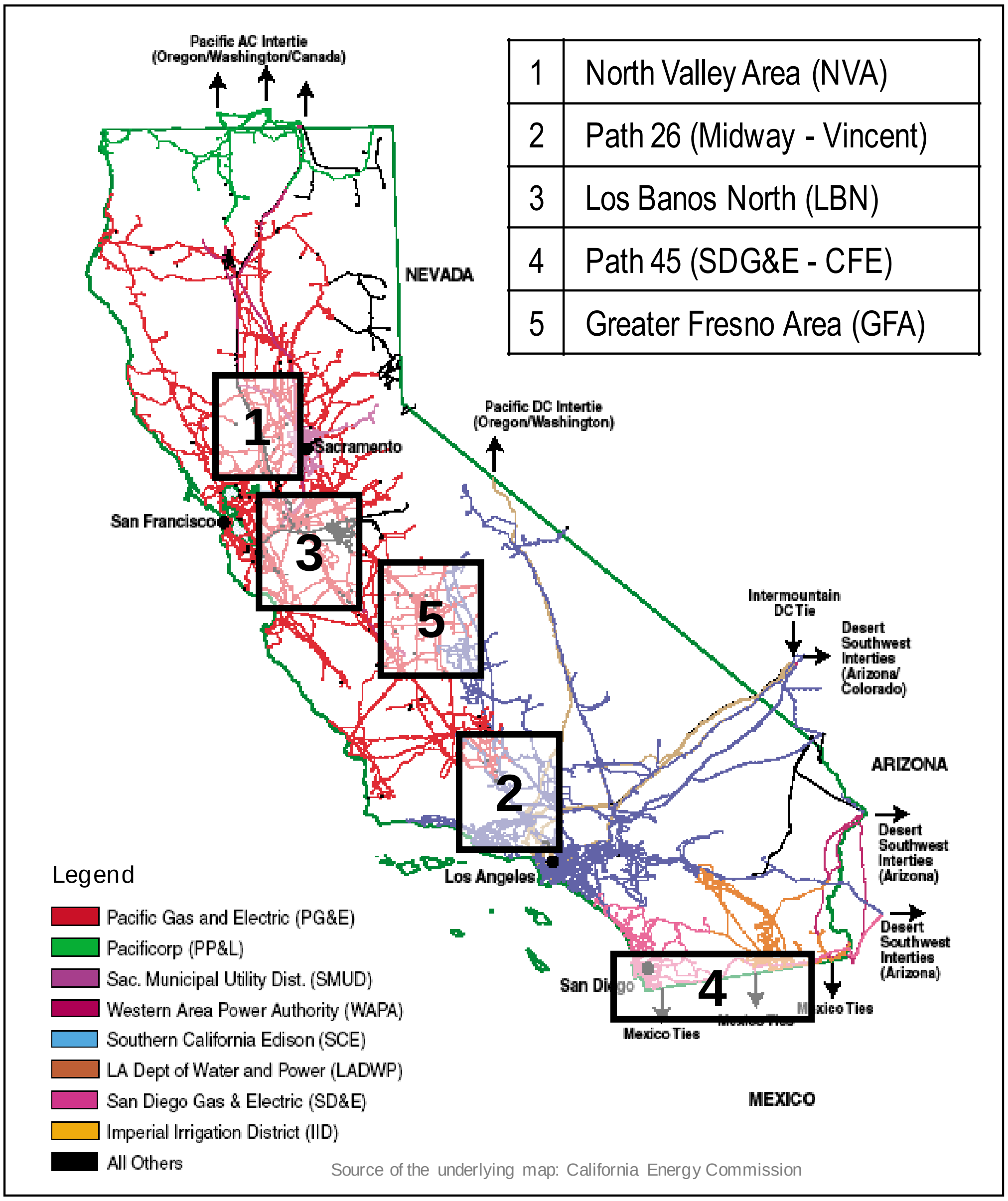
The ISO selected the economic studies in which to perform more detailed mitigation analysis by focusing on the top five congestion issues. According to Table 6.3-1 (identified congestion in the reference case), the top five congestion issues are listed in Table 6.4-1 below.

Table 6.4-1: Top-Five Congestion in the ISO-Controlled Grid

#	Description	Utility	Congestion Duration (Hours)	
			Year 2015	Year 2020
1	North Valley Area (NVA)	PG&E	29	67
2	Path 26 (Midway – Vincent)	PG&E-SCE	171	151
3	Los Banos North (LBN)	PG&E-TID	0	50
4	Path 45 (SDG&E – CFE)	SDG&E-CFE	8	9
5	Greater Fresno Area (GFA)	PG&E	54	77

Figure 6.4-1 is an overview of the top five congestion areas in a transmission map.

Figure 6.4-1: Overview of Top Five Congestion Areas in the ISO-Controlled Grid



For the congestion identified by the ISO economic studies, the stakeholders have proposed a number of network upgrade projects. The ISO correlated the request window submissions with the congested paths that would be studied. In addition to the stakeholder proposals, the ISO also put forward some mitigation plans. Table 6.4--2 lists congestion mitigation proposals that could address the top five congestion issues.

Table 6.4-2: Proposed Mitigation Measures That Address Top-Five Congestion

#	Congestion Mitigation Proposals	Proposed by	Source	Addressed Congestion
1	Loop Delevan – Vaca Dixon 230 kV line #1 into Cortina substation	ISO	-	North Valley Area (NVA)
2	Midway – Antelope 500 kV line	LS Power	RW2008	Path 26 (Midway – Vincent)
3	Midway – Antelope 500 kV line	PG&E	RW2009	
4	Central Valley Transmission Line Project (Midway – Whirlwind 500 kV #2)	Pattern Energy	RW2009	
5	Midway – Kramer 500 kV lines #1 and #2	PG&E	RW2008	
6	Los Banos to Tesla Transmission Line (500 kV)	Pattern Energy	RW2008	Los Banos North (LBN)
7	Los Banos – Westley #2 Transmission Project (230 kV)	Green Energy Express, LLC	RW2008	
8	North of Los Banos (230 kV reconductoring)	PG&E	RW2009	
9	Los Banos – Metcalf 500 kV line	ISO	-	
10	Reconductor Warnerville – Wilson 230 kV line	ISO	-	Greater Fresno Area (GFA)

Among the 10 proposed projects listed above, seven projects were submitted through the 2008-2009 request windows by stakeholders, and three projects were proposed by the ISO. In the following sub-sections, evaluations for each of the proposed congestion mitigation plans are provided.

6.4.1 North Valley Area (NVA)

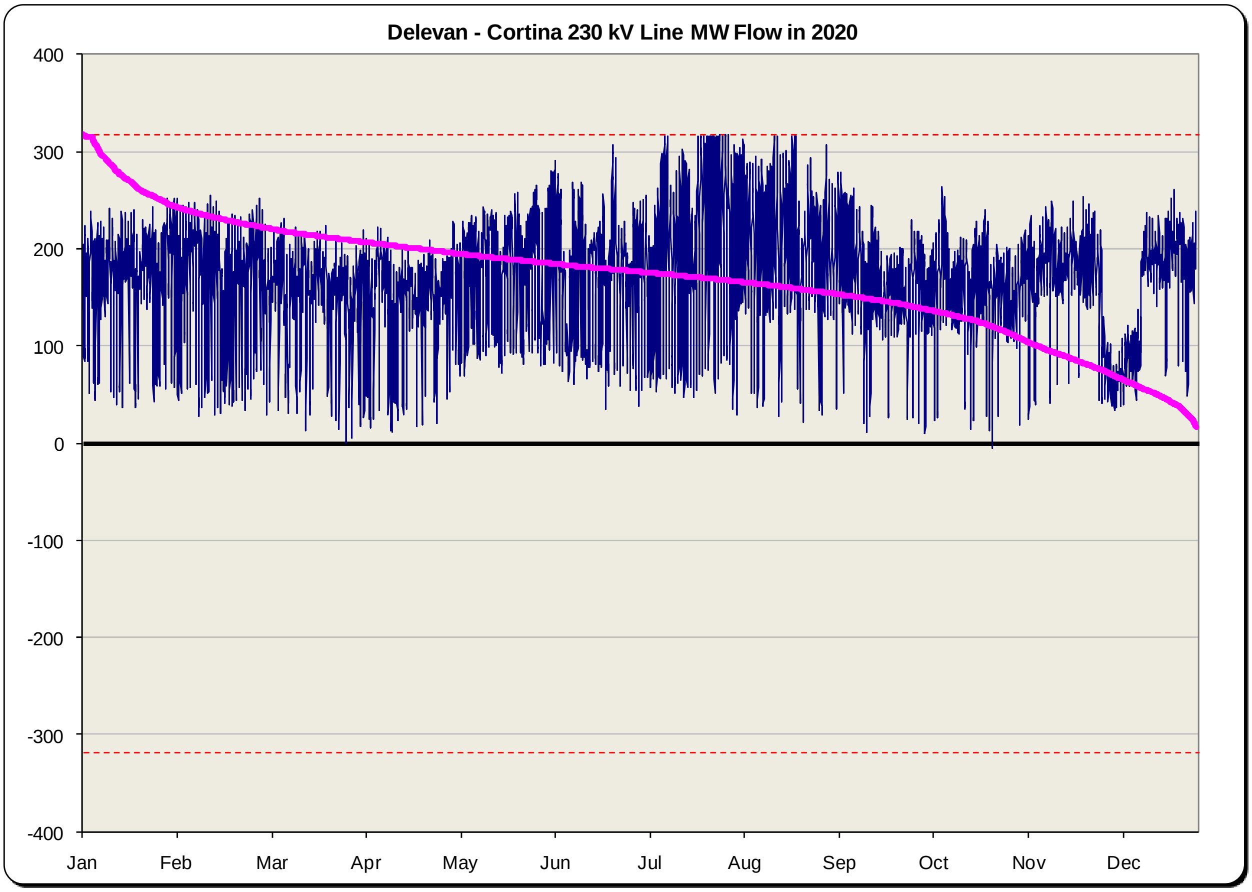
Table 6.4-3 lists simulation results regarding identified congestion in the North Valley Area (NVA).

Table 6.4-3: Congested Facilities in the North Valley Area (NVA)

#	Transmission Facilities	Year 2015		Year 2020	
		Congestion Duration (Hours)	Congestion Costs ($M)	Congestion Duration (Hours)	Congestion Costs ($M)
1	Delevan – Cortina 230 kV line	29	0.551	67	1.661
2	Table Mountain – Vaca Dixon 500 kV line	-	-	1	0.001

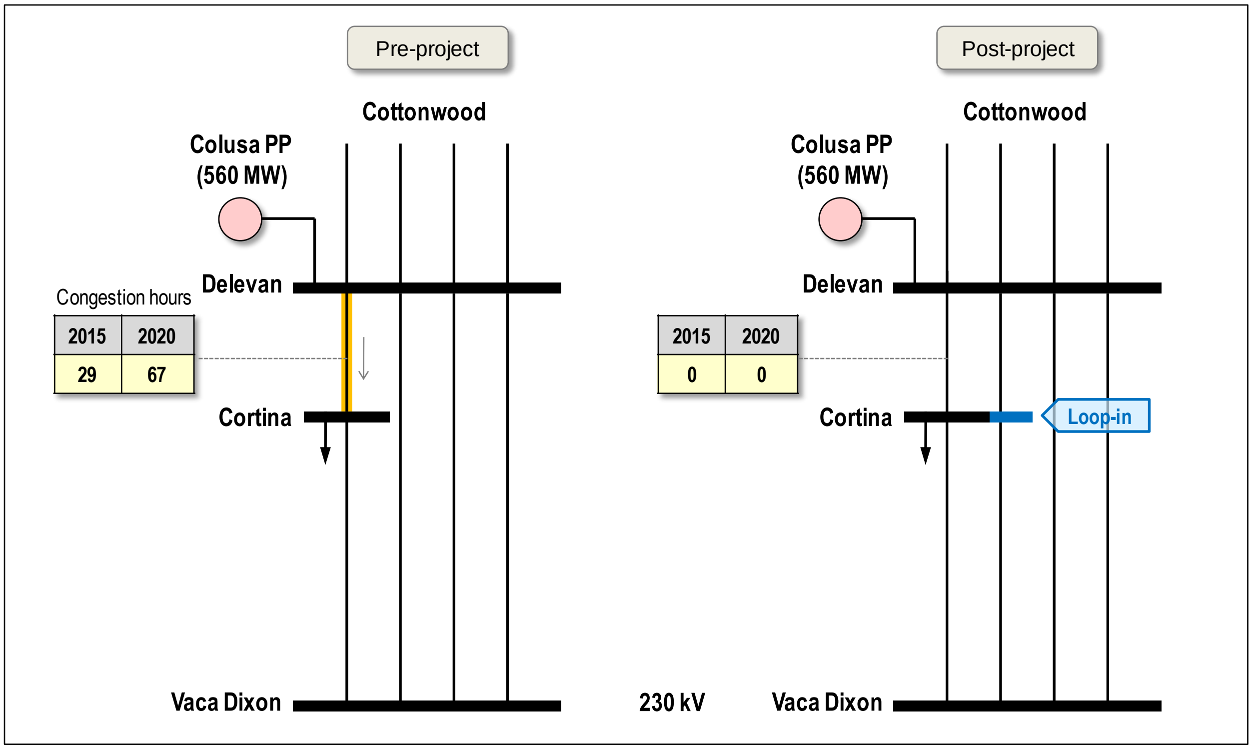
Figure 6.4-2 shows the simulated flow on the Delevan – Cortina 230 kV line in year 2020 from the studies. It is noted that congestion for this area typically occurs in the summer time when there is heavy flow from north to south direction.

Figure 6.4-2: Simulated MW Flow on the Delevan – Cortina 230 kV Line in Year 2020



To mitigate the congestion on the Delevan – Cortina 230 kV line, the ISO proposed to loop the Delevan – Vaca Dixon 230 kV line #1 into the Cortina substation. Figure 6.4-3 provides illustrations for these "pre-project" and "post-project" configurations.

Figure 6.4-3: Proposed Project for Congestion Mitigation of NVA –
Alternative 1 of 1 - Loop Delevan – Vaca Dixon 230 kV line #1 into Cortina Substation



As seen from the above diagram, from Delevan to Vaca Dixon, there are four parallel 230 kV transmission lines running north to south. The Colusa Power Plant, a 560 MW combined cycle plant owned by PG&E, is connected to the Delevan substation. In the existing configuration, one of the four 230 kV lines is looped into the Cortina substation. Due to load at the Cortina substation, the Delevan – Cortina 230 kV line carries more power than the parallel Delevan – Vaca Dixon 230 kV lines. When the north-to-south power transfer is heavy, congestion would occur on the Delevan – Cortina line; and the Colusa Power Plant would have to back down its output to avoid overloading the congested line. By looping the Delevan – Vaca Dixon #1 line into Cortina, the heavy loading on the Delevan – Cortina 230 kV line can be relieved by the parallel lines. As a result, the congestion would be mitigated. Table 6.4-3 lists study results of the cost-benefit analysis for the congestion mitigation measure.

Table 6.4-3 – Economic Benefits Due to Congestion Mitigation in the North Valley Area (NVA)

#	Description	Year 2015 Benefits ($M)	Year 2020 Benefits ($M)	Total Benefits ($M)	Total Cost ($M)	Net Benefits ($M)
1	Loop Delevan – Vaca Dixon 230 kV line #1 into Cortina substation (proposed by the ISO)	1.568	0.371	8	18	-10

As seen from the above table, the benefits of the mitigation plan were calculated to be $1.568 million and $0.371 million in 2015 and 2020, respectively. The annual benefits translated to a total benefit of $8 million.

The total benefit would be less than the estimated total project cost of $18 million. Therefore, given such results, it would not be cost-effective to mitigate identified congestion with the proposed project.

6.4.2 Path 26 (Midway – Vincent)

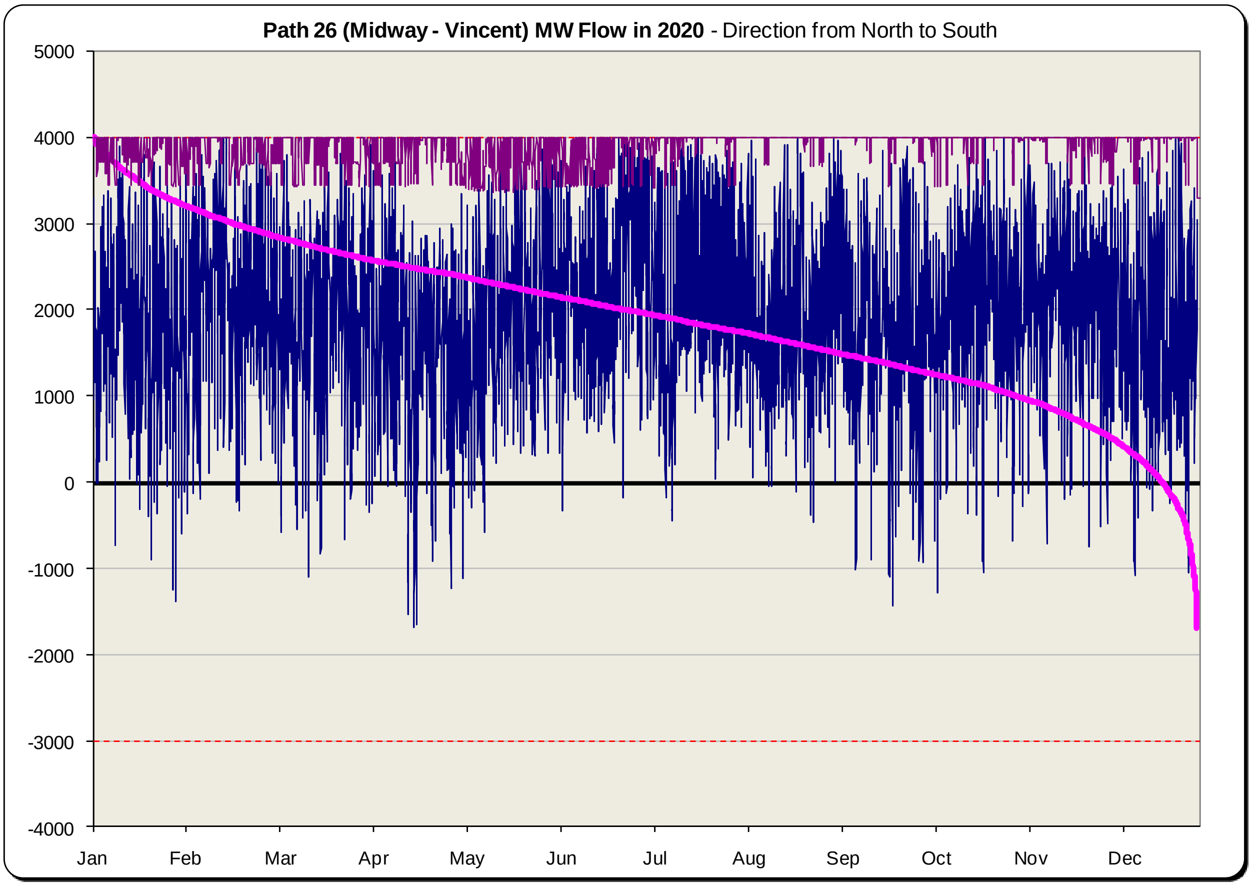
Table 6.4-4 lists study results regarding identified congestion on Path 26.

Table 6.4-4: Congested Facilities on Path 26 (Midway - Vincent)

#	Transmission Facilities	Year 2015		Year 2020	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Midway – Vincent 500 kV line #1, subject to loss of #2 line	100	0.334	117	0.549
2	Midway – Vincent 500 kV line #1, subject to loss of Midway – Whirlwind line	33	0.070	11	0.041
3	Midway – Vincent 500 kV line #2, subject to loss of Midway – Whirlwind line -south	20	0.065	5	0.004
4	Path 26 (Midway – Vincent) N2S rating	14	0.025	13	0.097
6	Path 26 (Midway – Vincent) N2S operating transfer capability	4	0.001	5	0.020
	Total:	171	0.495	151	0.712

Figure 6.4-4 shows the potential flows on Path 26 in the year 2020 from ISO studies for the reference case. In the figure, the curve beneath the 4000 MW line represents dynamic limits (i.e. operating transfer limits or nomogram limits) of the Path 26.

Figure 6.4-4: Simulated Path 26 Flows (2020)



As seen from the simulation results above, Path 26 congestion occurs mainly on the Midway – Vincent 500 kV lines #1 or #2, subject to loss of the parallel transmission lines. The congestion direction is from north to south. In addition to the L-1 congestion, the simulation results also showed some limit bindings on the north-to-south path rating and operating transfer capability.

To mitigate the congestion on Path 26, stakeholders submitted a number of proposals through the 2008-2009 request windows. Figure 6.4-5 and Figure 6.4-6 show the pre-project and post-project conditions regarding congestion relief by different alternatives.

Figure 6.4-5: Congestion Mitigation for Path 26 –
Alternative 1A or 1B: Build a New Midway – Antelope 500 kV Line (proposed by various proponents)

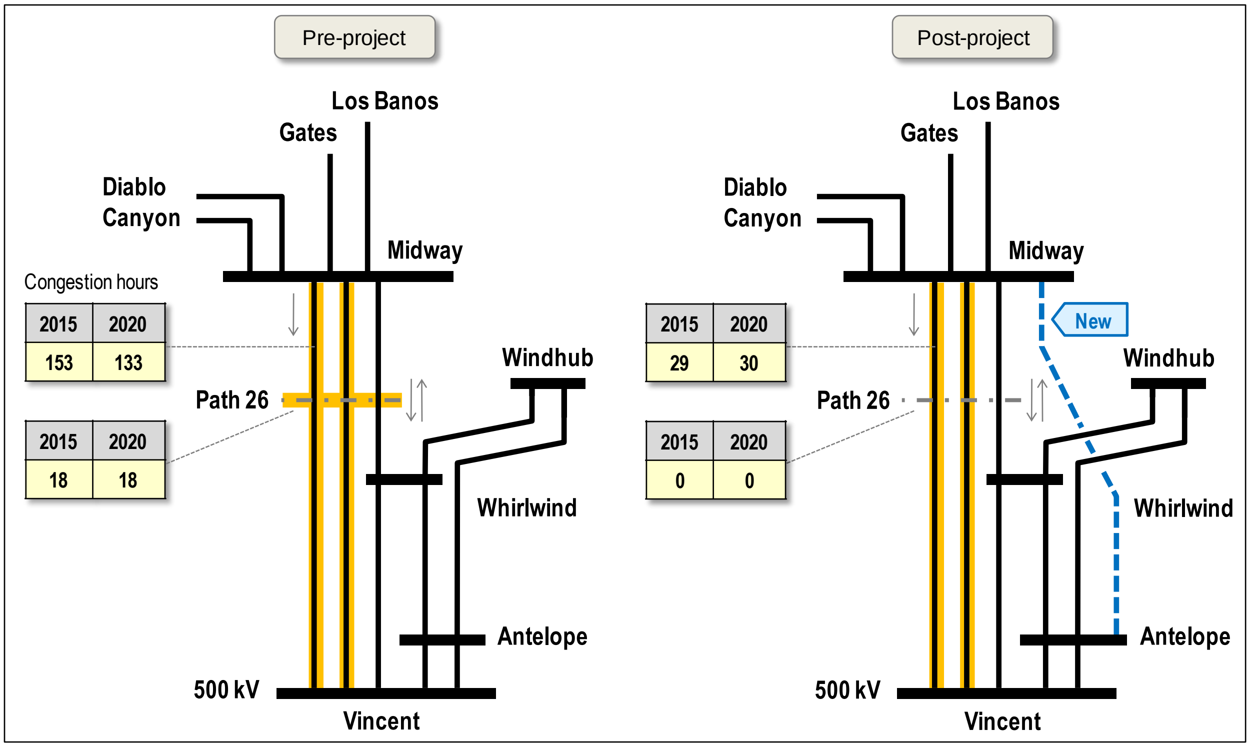


Figure 6.4-6: Congestion Mitigation for Path 26 –
Alternative 2: Build a New Midway – Whirlwind 500 kV Line #2

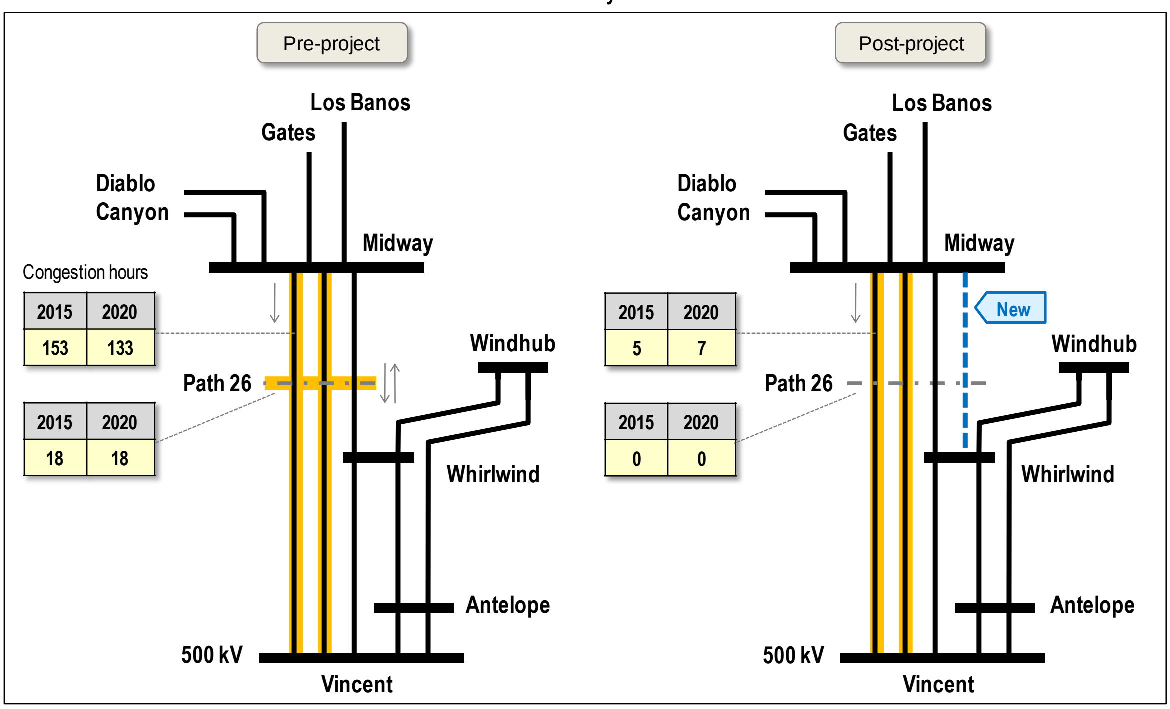


Table 6.4-5 lists study results of cost-benefit analysis for the congestion mitigation measures on Path 26.

Table 6.4-5: Congestion Mitigation on Path 26 (Midway – Vincent): Economic Benefits (in 2010 Dollars) for Different Alternatives

Alt.	Description	Year 2015 Benefit ($M)	Year 2020 Benefit ($M)	Total Benefit ($M)	Total Cost ($M)	Net Benefit ($M)
1A	Midway – Antelope 500 kV line (Proposed by California Transmission Development, LLC in RW2008)	1	0	2	524	-522
1B*	Midway – Antelope 500 kV SCTL (Proposed by PG&E in RW2009)	1	0	2	524	-522
2	Midway – Whirlwind 500 kV SCTL (Proposed by Central Valley Transmission Line, LLC in RW2008)	2	0	5	400	-395
3**	Midway – Kramer 500 kV lines #1 and #2 (Proposed by PG&E in RW2009)	-	-	-	-	-

As seen from the above table, the amount of benefits is not considered to be material. In comparison to the costs of the mitigation plans, it is not economic to mitigate the congestion. There are not enough economic justifications for proposed network upgrades on Path 26.

Notes:

* With Alternative 1B (Midway – Antelope 500 kV line), the project proponent did not provide technical data and cost estimates. In this situation, the ISO assumes that Alternative 1B has the same technical and economic data as Alternative 1A.

** With Alternative 3 (Midway – Kramer 500 kV lines #1 and #2), the project proponent submitted the proposal as “for information only”. Also, the project proponent did not include technical data and cost estimates. In absence of those data, economic evaluation of this alternative is not performed.

6.4.3 Los Banos North (LBN)

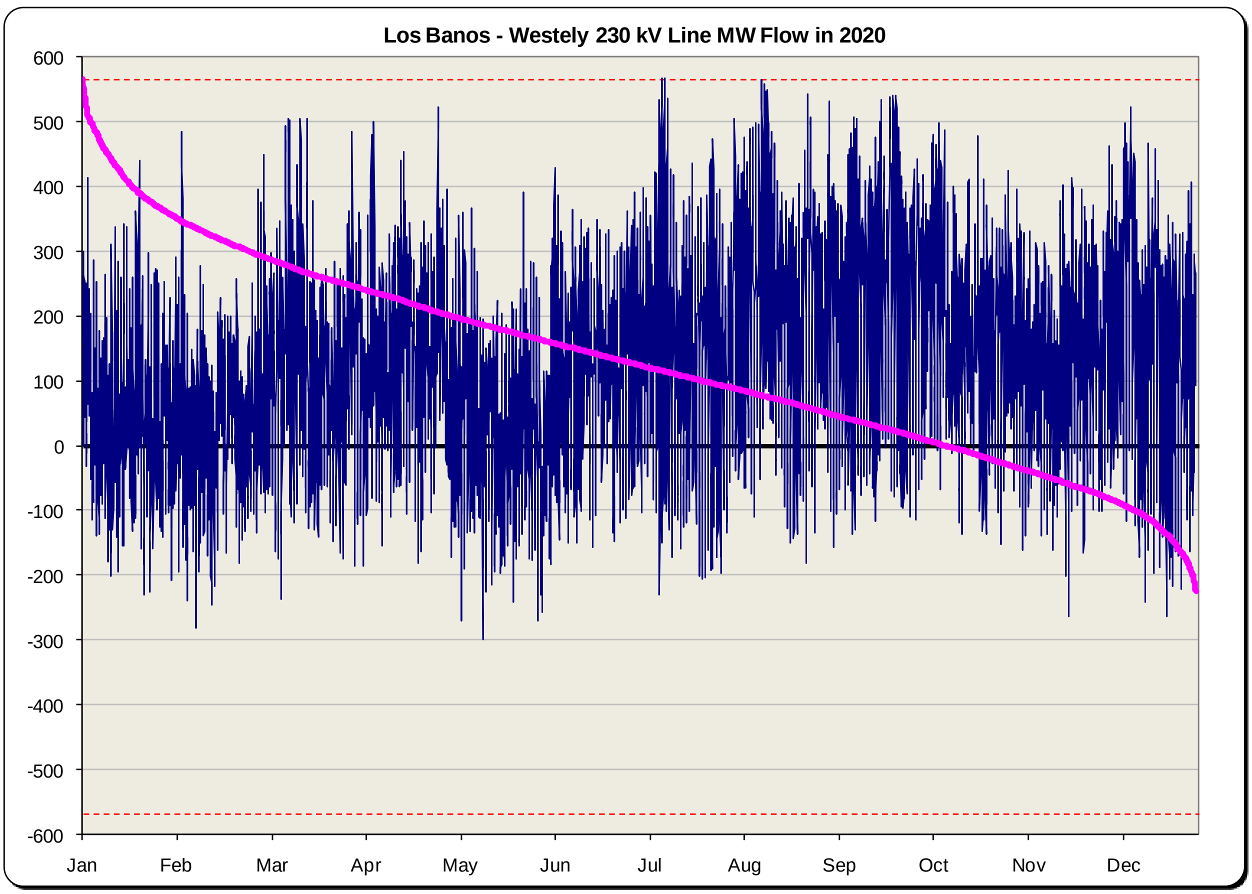
Table 6.4-6 lists study results regarding identified congestion in the Los Banos North (LBN) area.

Table 6.4-6: Congestion Identification in Los Banos North (LBN) – Congestion Hours and Costs

#	Transmission Facilities	2015		2020	
		Congestion Duration (Hours)	Congestion Cost ($M)	Congestion Duration (Hours)	Congestion Cost ($M)
1	Los Banos – Westley 230 kV line	-	-	3	0.012
2	Los Banos – Westley 230 kV line, subject to loss of Tesla – Los Banos 500 kV line	-	-	47	1.099
	Total:	-	-	50	1.112

Figure 6.4-7 below shows the simulated MW flow on the Los Banos – Westley 230 kV line in the year 2020.

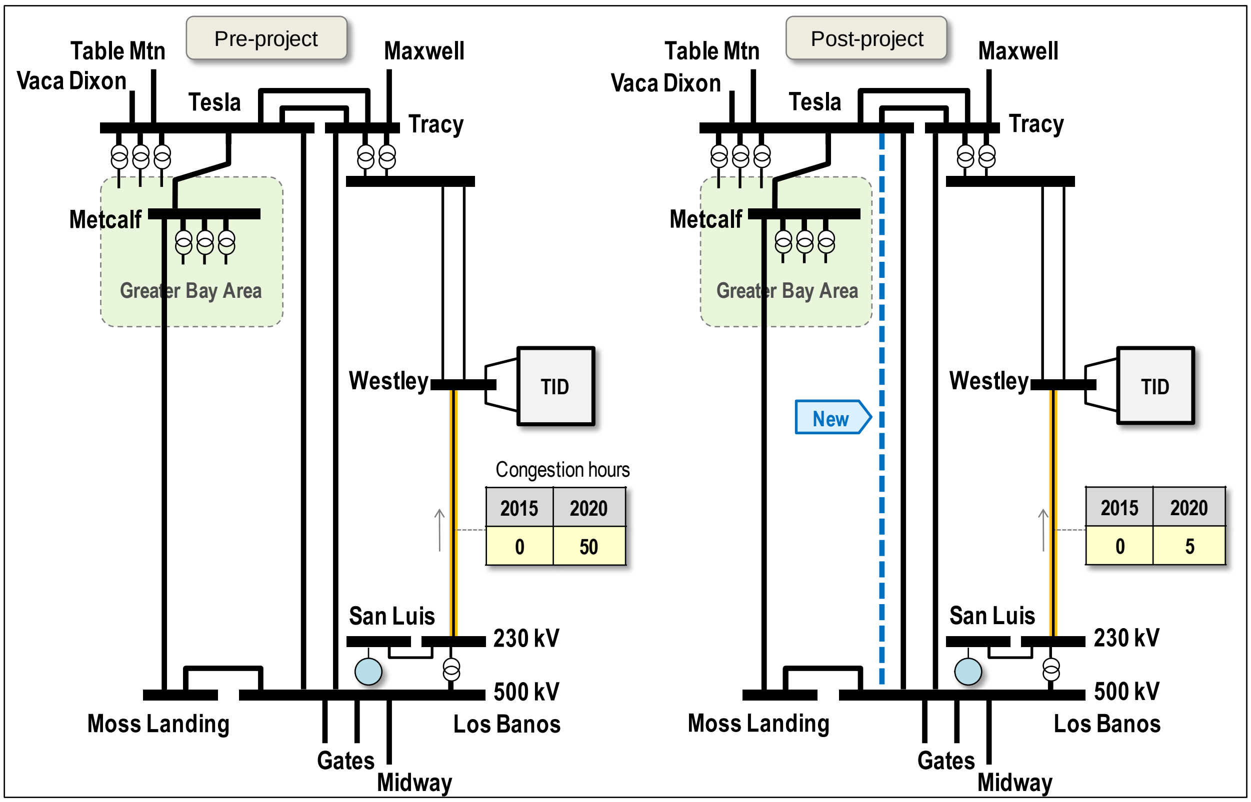
Figure 6.4-7: Simulated MW Flow on the Los Banos– Westley 230 kV Line (2020)



The identified congestion is caused by heavy south-to-north flow on Path 15 (Midway to Los Banos). As more renewables are developed in southern California, the south-to-north flow is expected to increase. Relieving this congestion with an economically-driven project or element[41] could facilitate delivery of renewable energy on California grid.

To mitigate the congestion on the Los Banos – Westley 230 kV line, the stakeholders submitted a number of proposed projects through the 2008-2009 request windows. Figures 6.4-8 through 6.4-11 show the pre-project and post-project conditions regarding congestion relief by different alternatives.

Figure 6.4-8: Congestion Mitigation for LBN –
Alternative 1: Build a New Los Banos – Tesla 500 kV Line #2



[41] An economic project or element is determined when benefits outweigh its cost.

Figure 6.4-9: Congestion Mitigation for LBN –
Alternative 2: Build a New Los Banos – Westley 230 kV Line #2

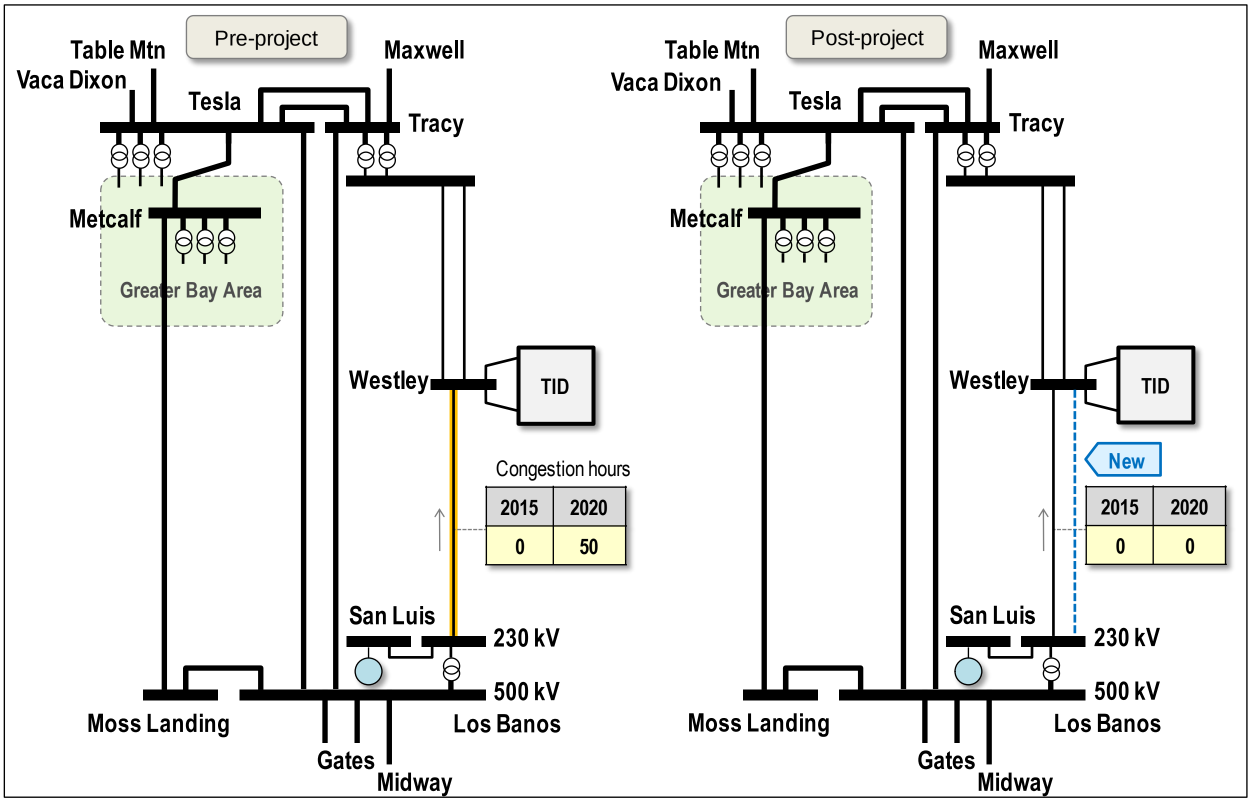


Figure 6.4-10: Congestion Mitigation for LBN –
Alternative 3: Reconductor the Existing Los Banos – Westley 230 kV Line

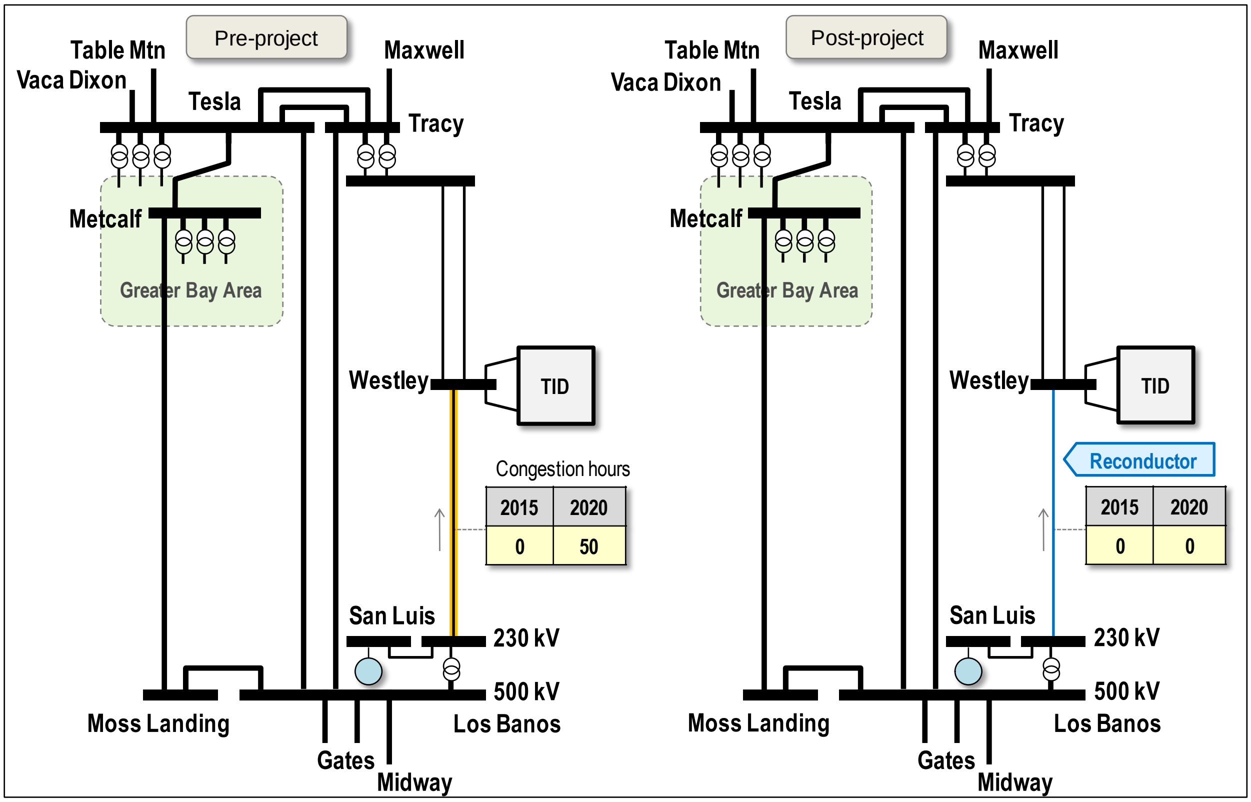


Figure 6.4-11: Congestion Mitigation for LBN –
Alternative 4: Build a New Los Banos – Metcalf 500 kV Line

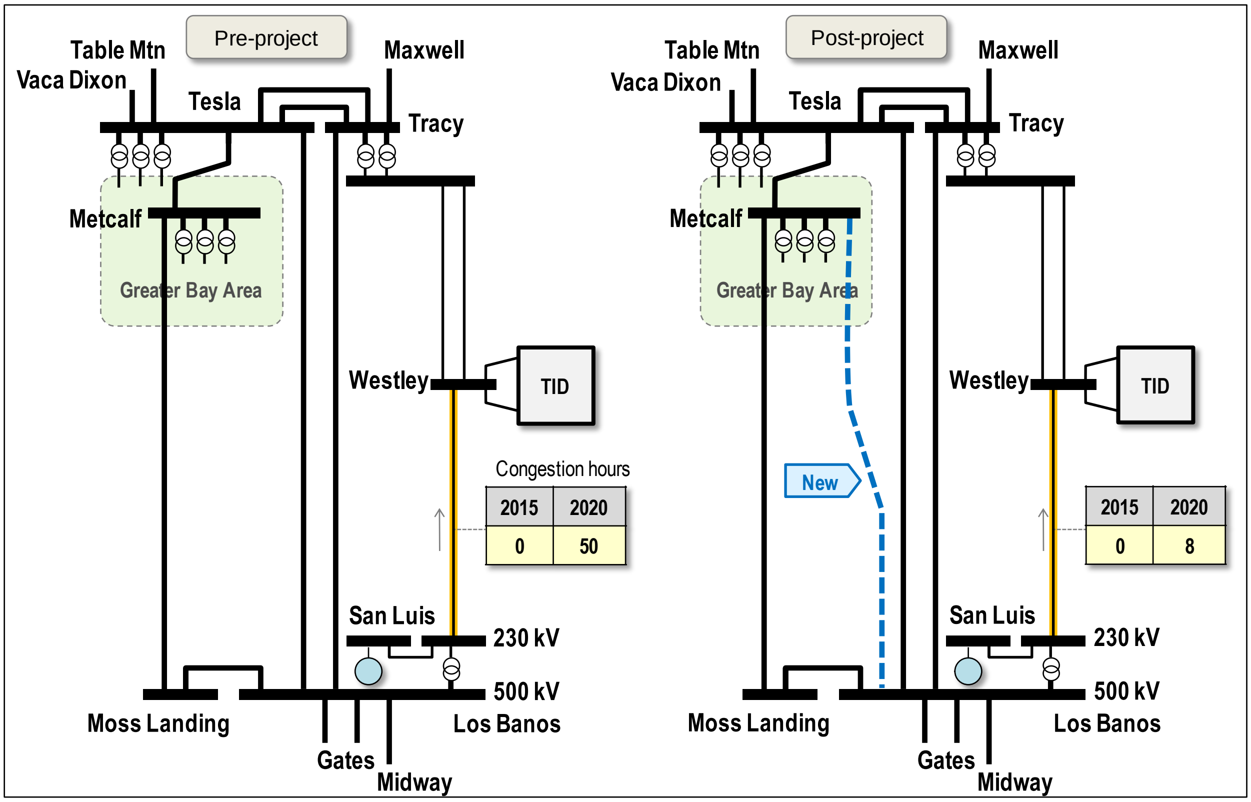


Table 6.4-7 below lists study results for cost-benefit analysis for various alternative mitigation plans considered for the Los Banos North (LBN) area.

Table 6.4-7: Congestion Mitigation in Los Banos North (LBN) –
Economic Benefits (in 2010 Dollars) for Four Different Alternatives

Alt.	Description	Year 2015 Benefits ($M)	Year 2020 Benefits ($M)	Total Benefits ($M)	Total Cost ($M)	Net Benefit ($M)
1	Build a new Los Banos – Tesla 500 kV line #2 (Proposed by Pattern Power Development Company LLC in 2009 RW)	2	2	33	300	-267
2	Build new Los Banos – Westley 230 kV line #2 (Proposed by Green Energy Express, LLC in 2009 RW)	0	0	0	175	-175
3	Re-conductor Los Banos – Westley 230 kV line (Proposed by PG&E in 2009 RW)	0	0	0	45	-45
4	Build new Los Banos – Metcalf 500 kV line (Proposed by the ISO)	10 (=4+6)	8 (=2+6)	131 (=38+93)	400	-269

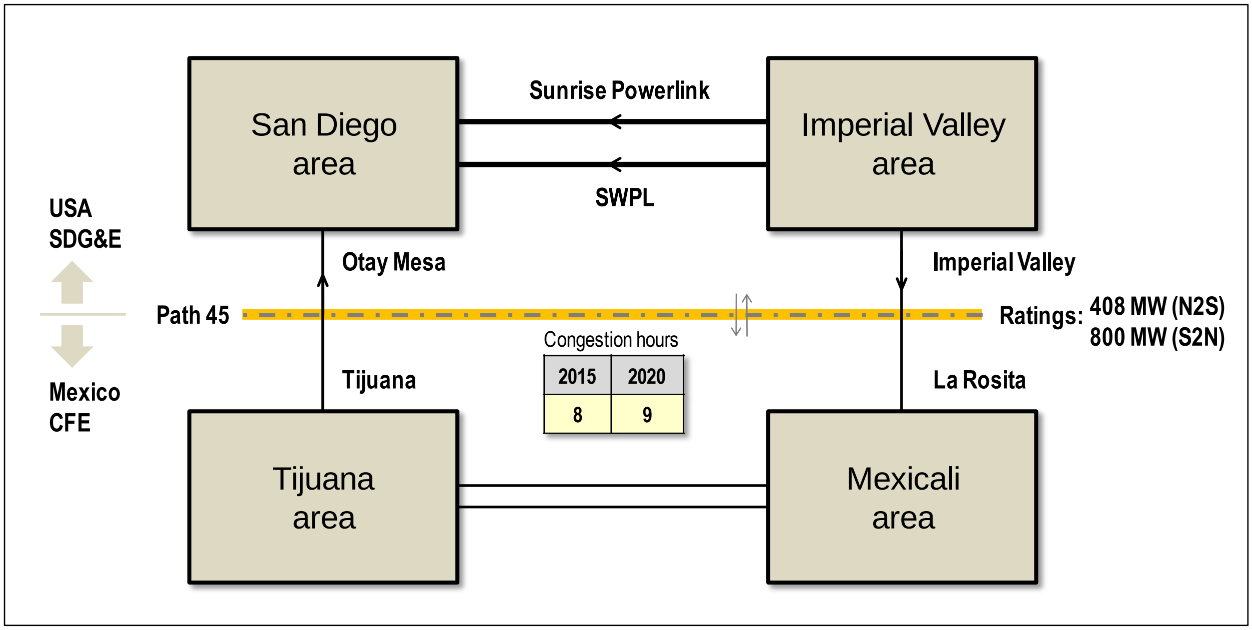
For Alternative #4, as the Los Banos – Metcalf 500 kV line was proposed to connect to the Greater Bay Area (GBA), the project would offer LCR reduction benefits. It was assumed that the Los Banos – Metcalf 500 kV transmission line could bring at least 1000 MW of additional import capability into the GBA. It was further assumed that the increased import capability would result in a 300 MW of LCR reduction in the GBA. The amount of LCR reduction would translate to an economic benefit of about $6 million for each year.

As seen from the analysis summary above, all four mitigation plans were able to relieve the south-to-north congestion on the Los Banos – Westley 230 kV line. Of the four alternatives, Alternative #4 (Los Banos – Metcalf 500 kV line) had the most economic benefit, as the project not only offered energy benefits (computed by production simulation) but also offered capacity benefits (due to LCR reduction in the GBA). However, for all the alternatives, none of the mitigation plans delivered positive net benefits due to high project costs. Therefore, there is no economic justification for considering network upgrades to relieve the identified congestion issue.

6.4.4 Path 45 (SDG&E – CFE)

Path 45 is the transmission interface between SDG&E and CFE. Figure 6.4-12 illustrates network configuration and congestion that was identified on this path.

Figure 6.4-12: Path 45: SDG&E – CFE



Due to lack of data, the CFE system was not well represented in the TEPPC production simulation database. As a result, the ISO could not perform an analysis for Path 45 congestion in detail. Path 45 will be studied in the future when a detailed network model becomes available for the CFE system.

6.4.5. Greater Fresno Area

Table 6.4-8 lists study results regarding identified congestion in the Greater Fresno Area (GFA).

Table 6.4-8: Congested Facilities in the Greater Fresno Area (GFA)

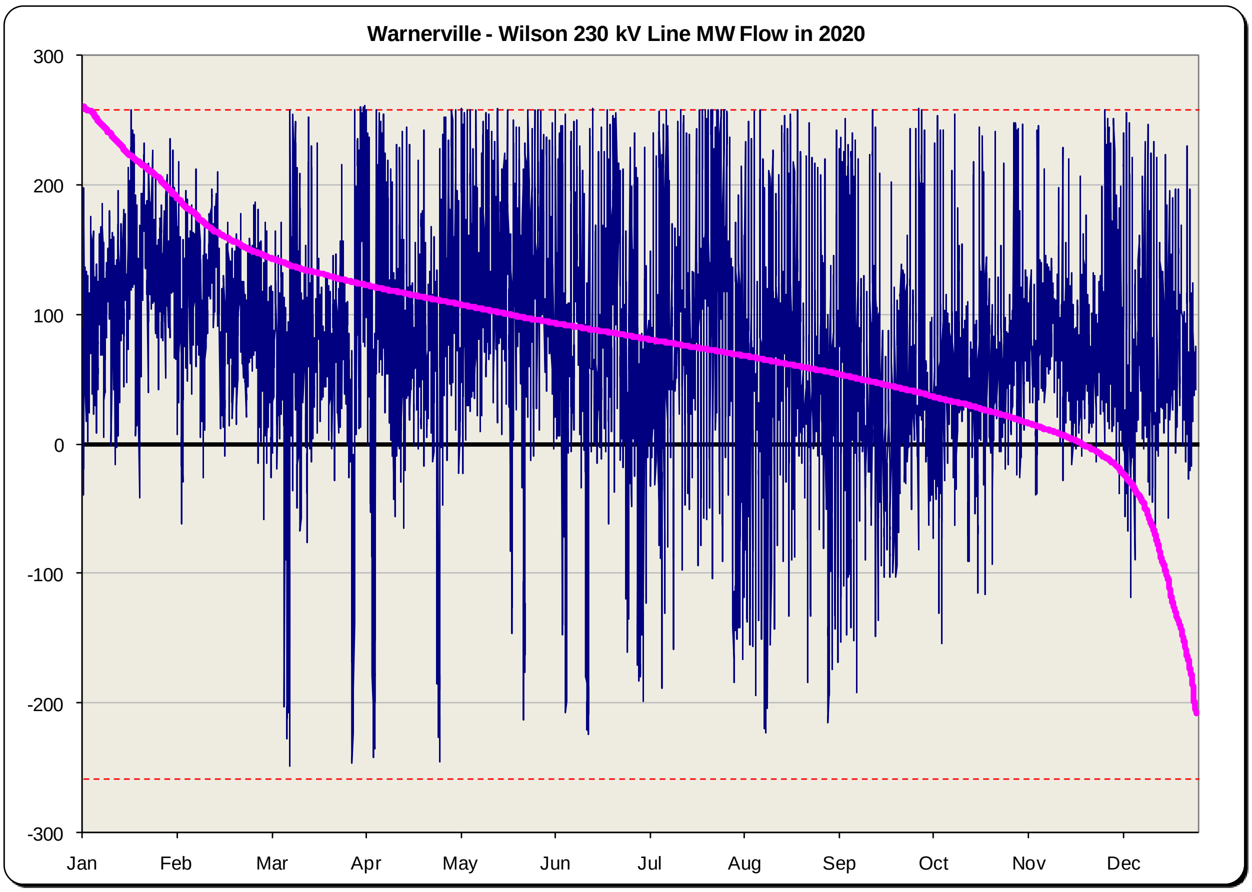
#	Transmission Facilities	Year 2015		Year 2020	
		Congestion Duration (Hours)	Congestion Costs ($M)	Congestion Duration (Hours)	Congestion Costs ($M)
1	Cottle B-Warnerville 230 kV #1	1	0.000	6	0.028
2	Bellota - Cottle B 230 kV line	6	0.029	6	0.024
3	Bellota - Cottle B 230 kV line subject to loss of Belotta - Cottle A 230 kV line	1	0.001	6	0.040
4	Warnerville - Wilson 230 kV line	44	0.093	55	0.154
5	Warnerville - Wilson 230 kV line, subject to loss of Melones - Wilson 230 kV line	-	-	3	0.013
6	Kearney - Herndon 230 kV line	1	0.001	1	0.003

#	Transmission Facilities	Year 2015		Year 2020	
		Congestion Duration (Hours)	Congestion Costs ($M)	Congestion Duration (Hours)	Congestion Costs ($M)
7	Borden - Gregg 230 kV line	1	0.002	-	-
	Total:	54	0.126	77	0.263

In the Greater Fresno Area (GFA), congestion was identified on some different transmission lines. Among them, the major congested facility was identified to be the Warnerville – Wilson 230 kV line. The congestion duration on the line was estimated to be 44 hours in year 2015 and 55 hours in year 2020, respectively.

Figure 6.4-13 shows the simulated MW flow on the Warnerville – Wilson 230 kV line in year 2020.

Figure 6.4-13: Simulated Flows on the Warnerville – Wilson 230 kV Line in Year 2020 Study



From the above figure, it can be observed that the Warnerville – Wilson 230 kV line was projected to have congestion in all seasons of the year. Also, the line could be congested in both directions.

To mitigate the identified congestion, a potential measure is to reconductor the Warnerville – Wilson 230 kV line. Because the Warnerville – Wilson line is an LCR bottleneck for the GFA, upgrading this line was thought to have potential capacity benefits in addition to the energy benefit due to congestion relief. Figure 6.4-13 shows the pre-project and post-project conditions regarding congestion relief.

Figure 6.4-13: Considered Congestion Mitigation for GFA
Alternative 1: Reconductor Warnerville – Wilson 230 kV Line

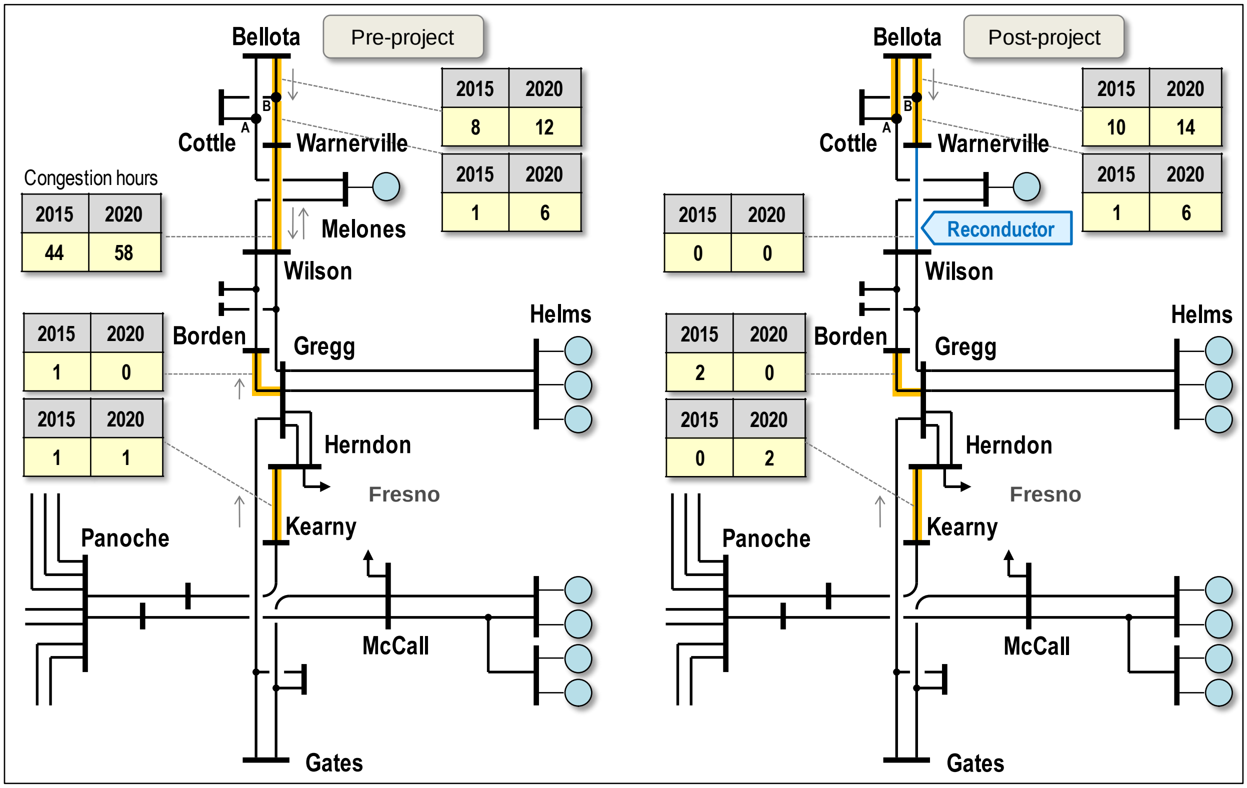


Table 6.4-9 provides a summary of study results for cost-benefit analysis for mitigating identified congestion in the Greater Fresno Area (GFA).

Table 6.4-9: Congestion Mitigation in Greater Fresno Area (GFA): Economic Benefits (in 2010 Dollars)

#	Description	Year 2015 Benefit ($M)	Year 2020 Benefit ($M)	Total Benefit ($M)	Total Cost ($M)	Net Benefit ($M)
1	Re-conductor Warnerville – Wilson 230 kV line (Proposed by the ISO)	1	0	2	57	-55

In the above table, the listed yearly benefits are energy benefits. The capacity benefits, however, are zero even though there is LCR reduction. This is because the most effective resource to mitigate the LCR bottleneck is the Helms generation owned by PG&E. With the line reconductoring option, the LCR reduction would result in less dependence on Helms generation. As the generation is owned by the same utility, there is no net cost reduction. In this situation, there is no net savings for the ISO ratepayers.

The ISO therefore concluded that the total economic benefit was not sufficient to justify the reconductoring project.

6.5 Summary

In this economic planning study, grid congestion was identified using production simulation and congestion mitigation plans were evaluated with cost-benefit analysis. To perform economic studies, two study phases were undertaken: congestion identification and congestion mitigation. In the first study phase (congestion identification), grid congestion was simulated for 2015 (the 5th planning year) and 2020 (the 10th planning year). The identified congestion issues were ranked by severity in terms of congestion hours and congestion costs and the top-five congestion issues were selected as high-priority studies. In comparison with the congestion study performed in the last planning cycle, the identified congestion in this study was identified as less severe due to a lower load forecast and net short renewable energy requirements.

In the second study phase (congestion mitigation), for each of the top-five congestion issues, congestion mitigation plans were analyzed. A total of 10 congestion mitigation proposals were evaluated. Out of 10 proposed projects, seven were submitted by the stakeholders through the ISO 2008-2009 request windows and three were proposed by the ISO.

In this economic planning study, the costs and benefits of the proposed congestion mitigation plans were evaluated. Based on the results of ISO analyses, no proposed projects demonstrated a positive net benefit. Therefore, there are no economic upgrades that were determined to be needed in this planning cycle.

Chapter 7 Evaluations of the 2008/09 Request Window Project Submittals

7.1 Overview of the 2008 and 2009 Request Window Project Evaluations

As part of the 2010/2011 RTPP planning cycle and in compliance with tariff section 24.4.6.8, the ISO reviewed 41 projects submitted in the 2008 and 2009 request windows. Those projects, comprising all submissions other than reliability project submissions, were carried forward into the 2010/2011 planning cycle. However, seven of these projects were submitted as "information only". As described in the tariff, the ISO conducted its analysis of these projects as part of its comprehensive review of the transmission needed to achieve the 33% RPS goals by 2020 target and the results are documented below. The ISO evaluated the 2008 and 2009 request window projects to determine whether they were needed as either economically-driven or policy-driven projects in this planning cycle. The evaluation approach for both of these parameters is set out below.

<u>Assessment of Policy Requirements</u>

Pursuant to the RTPP tariff, for a project to be classified as a policy-driven project it must be needed in the base case and other scenarios. As documented in chapter 5, the ISO analysis identified one category 1 element and eight category 2 elements. The ISO then reviewed the request window projects and determined if any aligned with the category 1 or category 2 elements. One project (the Mirage-Devers reconductoring) aligned with a category 1 element, and no projects aligned with the category 2 elements.

<u>Economic Evaluations</u>

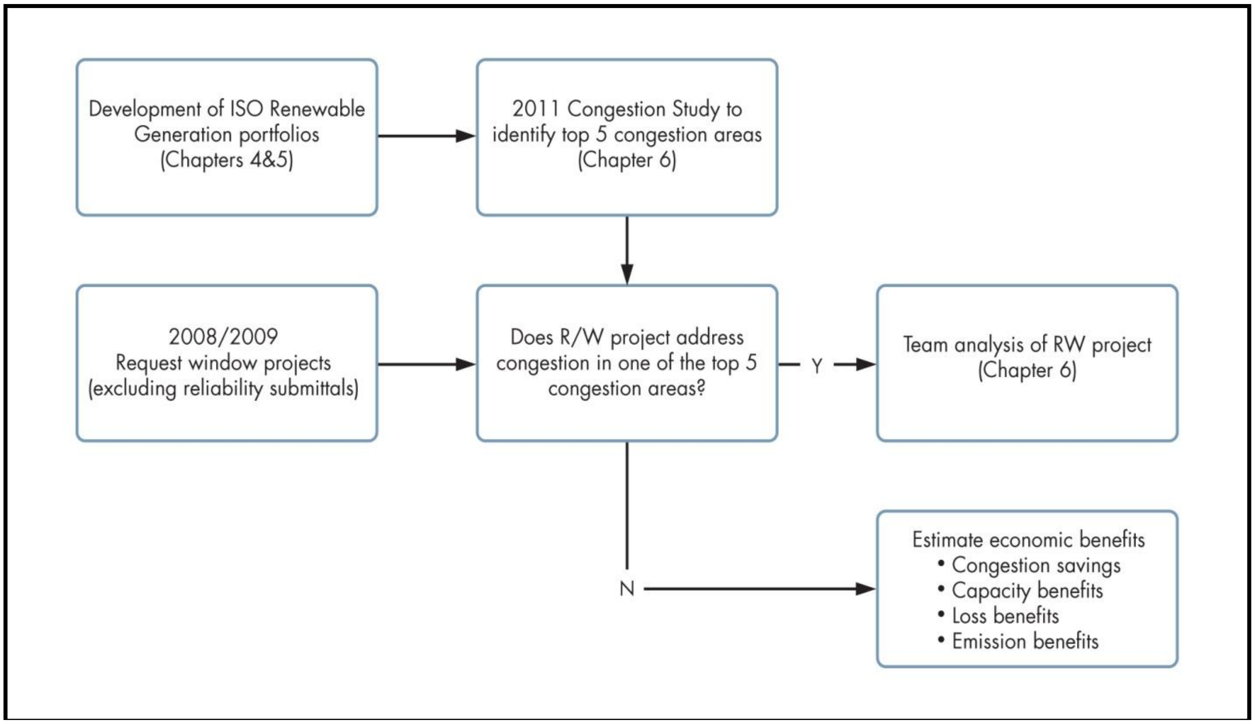
The 41 2008 and 2009 request windows projects were also evaluated to determine if they could provide net economic benefits to ISO ratepayers. The following steps were taken to assess economic-related benefits:

- Using production simulation analysis, as set out in chapter 6, the ISO identified future congestion on the ISO system over the five to 10 year planning horizon;
- For the top five congestion areas identified in the production simulation analysis, the ISO assessed which of the request window projects could potentially address the congestion in those areas and determined that seven of the 2008 and 2009 request window projects addressed congestion in those areas. Of those seven, excluding one project submitted as "information only", six were analyzed using the TEAM methodology as described in chapter 6. The result of that analysis is also documented in chapter 6, and is summarized in the corresponding analysis summaries provided below;
- Of the 34 remaining request window projects that did not address congestion in any of the top five congestion areas, six were submitted as "information only" projects, and were not evaluated further; The remaining 28 request window projects were examined by evaluating the expected energy cost savings relating to the amount of congestion mitigation the project would provide; and.

- In addition to the expected energy cost savings analysis described above, the ISO considered capacity benefits, system resistive loss benefits, and emission reduction benefits for all 35 projects studied.

Figure 7.1-1 below sets out the steps outlined above.

Figure 7.1-1: Method for Assessing Economic Benefits



A summary of the results from applying the methodology described above to the 41 request window projects is provided in Tables 7.1-1 and 7.1-2.

These results indicate that while the request window projects generally address some level of congestion, the economic benefits do not merit the capital expenditures. The bulk of the projects have benefit to cost ratios below 0.2, and the remaining projects have benefit to cost ratios below 0.5.

Table 7-1: Summary of TEAM Analysis of Request Window Projects Associated with Top Five Congestion Areas

	Total Cost ($million)	Total NPV savings ($million)	Benefit to Cost Ratio	Final Assessment
Central Valley Transmission Line	$400	$5	0.01	Not needed
Los Banos-Tesla Transmission Line	$300	$33	0.11	Not needed
Los Banos-Westlley #2 Transmission	$175	$0	-	Not needed
Midway-Antelope	$524	$2	0.00	Not needed
Midway-Antelope	$524	$2	0.00	Not needed
North of Los Banos (Economic Request)	$50	$0	-	Not needed
Midway-Kramer 500 kV Lines - two circuit	no cost provided		-	

Table 7.1-2: Summary of Economic Analysis of Request Window Projects not associated with Top 5 Congestion Areas

Project Name	Total Cost ($million)	Annualized Carrying Charges ($million)	Benefits ($million)							
			Energy cost savings	Capacity savings	Loss savings	Emission savings (estimate)	Total annual savings	Benefit to Cost Ratio	Final Assessment
Sierra Green Link	$1250	**$188**	$1.8	0	$24.2	$26	**$52**	0.28	Not needed
Carizzo to Midway Transmission	$200	**$30**	0	0	$0.16	$0.16	**$0.32**	0.01	Not needed
Malin-Cottonwood-Table Mountain-Tesla 500 kV									"For information only"
Malin-Cottonwood-Teble Mountain-Vaca Dixon Tesla 500 kV	$1700	**$255**	$1.8	$5	$22.7	$24.5	**$54**	0.21	Not needed
Round Mountain to Alturas/Ravendale 345 kV AC Line	$250	**$37.5**	$0.14	$1.5	$1.67	$1.81	**$5.12**	0.14	Not needed
Vaca Dixon-Rio Oso Transmission	$300	**$45**	0	$1	$6	$6	**$13**	0.29	Not needed
AV Clearview Transmission	$900	**$135**	0	0	0	0	**0**	-	Not needed
Bay Area Green Link	$400	**$60**	0	$8.3	$1.2	$1.2	**$10.7**	0.18	Not needed
Greater Bay Area (GBA) Transmission	$685	**$102.7**	0	0	0	0	**0**	-	Not needed
Contra Costa to San Francisco Transmission	$575	**$86.2**	0	0	$5.1	$5.1	**$10.2**	0.12	Not needed
Sobrante to Embarcadero	$699	**$104.9**	0	0	$1.1	$1.1	**$2.2**	0.02	Not needed
Imperial Valley-Blythe Area Renewable Transmission Integration	$1100	**$165**	0	$20	$2.2	$2.2	**$24.4**	0.15	Not needed
North Gilla-Imperial Valley #2	$490	**$73.5**	0	$20	$1.4	$1.4	**22.8**	0.31	Not needed

Project Name	Total Cost ($Million)	Anualized Carrying Charges	Energy cost savings	Capacity savings	Loss savings	Emission savings (estimate)	Total annual savings	Benefit to Cost Ratio	Final Assessment
New 3rd 500/230 kV Transformer Bank (82) at Imperial Valley Substation									LGIP Approved. LGIA Signed
New ECO 500/230/69 kV Substation & New 69 kV Transmission Line to Boulevard Substation									A similar project is in LGIA
North Gila - Imperial Valley #2 Double Circuit Project	$395	$59.25	0	$20	$3.9	$3.9	$**27.8**	0.47	Not needed
New Imperial Valley - Bannister - Devers 500 kV line									"For information only"
Canada/Pacific Northwest - Northern California Transmission Project									"For information only"
Morro Bay - Midway 230 kV Lines No 1 &2 reconductoring project									LGIA tendered
San Luis Obispo Solar Switching Station #3									LGIA tendered
Vaca Dixon - Sobrante - Moraga 230 kV Reinforcement project									"For information only"
Mirage - Devers 230 kV Transmission System Upgrade									Needed policy-driven element
Eldorado - Ivanpah Transmission Project									CPUC approved
Mirage - Devers 230 kV Transmission System Upgrade									Needed policy-driven element
Gregg-Bellota 500 kV line #1 and #2 project									"For information only"
Midway - Tesla 500 kV #1 and #2 Line Project									"For information only"

Project Name	Total Cost ($Million)	Anualized Carrying Charges	Energy cost savings	Capacity savings	Loss savings	Emission savings (estimate)	Total annual savings	Benefit to Cost Ratio	Final Assessment
Desert Southwest Transmission Project	$199	$29.85	0	$5	0	0	$**5**	0.17	Not needed
Devers - Mira Loma DC Line Project (GEET 3)	$925	$138.75	0	0	$21.5	$21.5	$**43**	0.31	Not needed
Eldorado - Devers Project (GEET 2)	$800	$120	0	$7.5	$0.74	$0.74	$**8.98**	0.07	Not needed
Green Energy Express Transmission Line Project (GEET 1)	$395	$59.25	0	$5	0	0	$**5**	0.08	Not needed
Las Vegas to Los Angeles Double Circuit 500 kV Transmission Project	$1059	$158.85	0	$7.5	$7.7	$7.7	$22.9	0.14	Not needed
Mohave-San Bernardino-Devers Renewable Integration Transmission Project	$1000	$150	0	$7.5	$0.74	$0.74	$8.98	0.06	Not needed
MPP/MAP Capacity Transfer Project	$36.6	$5.49	0	0	0	0	0	-	Not needed
Meads Green Upgrade (Mead Adelanto Project and Mead - Phoenix Project Direct Current Conversion)	$300	$45	$2	$5	0	$2	$9	0.20	Not needed

7.2 Summary of Individual Request Window Projects - Potential to Address Congestion in Top Five Areas of Congestion

General Information

Project Name: **Central Valley Transmission Line (CVTL) Project**

Project Sponsor(s): **Central Valley Transmission Line LLC**

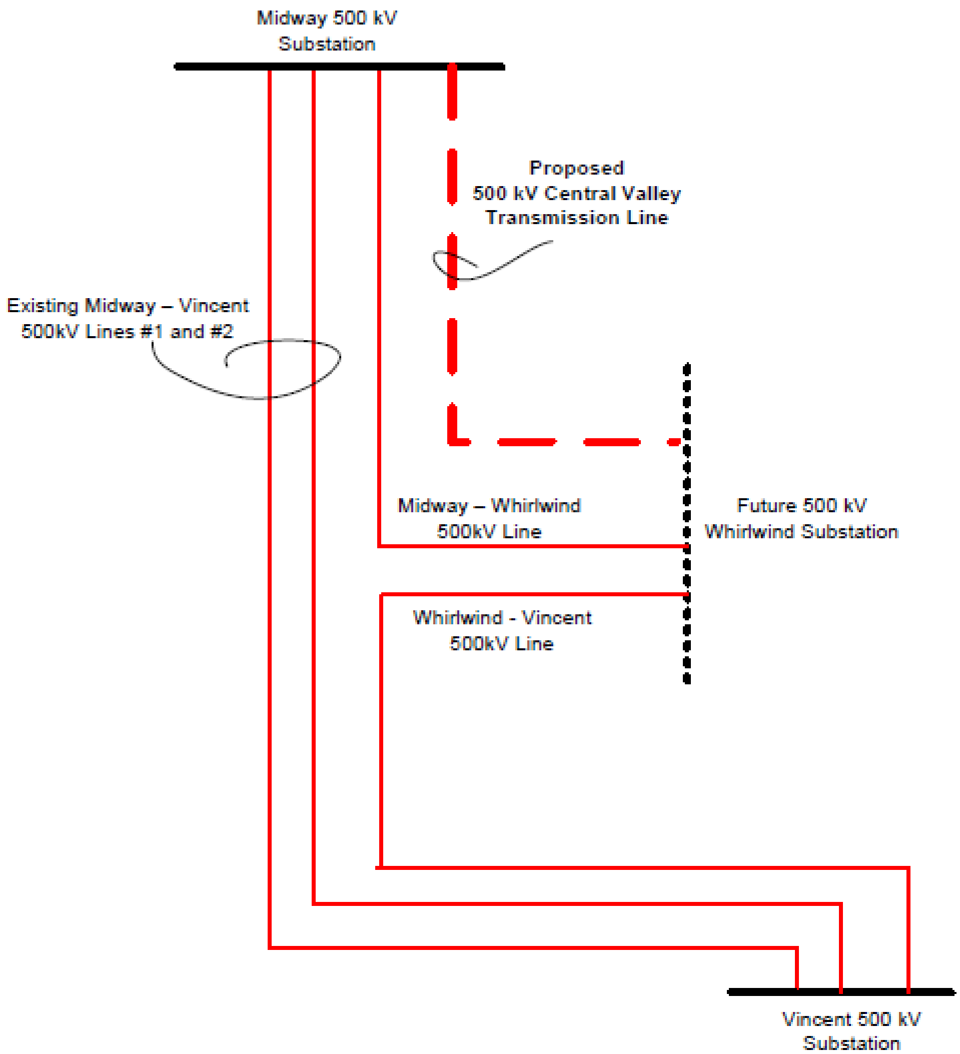
Type of Submission

☒ Economic Planning Study Request

Project Description

- 500 kV transmission line from PG&E's Midway substation to SCE's proposed Whirlwind substation;
- 35% series compensation at Midway;.
- Line length approximately 80 miles;
- The thermal capacity of this line will be 3420 MVA normal and 4616 MVA emergency; and
- The series compensation is rated 2078 MVA normal and 3031 MVA emergency.

Central Valley Transmission Line (CVTL) Project One-Line



Benefits of Project Identified by Project Sponsor

The proponent states that the project:

- Significantly reduces congestion on Path 26, cost-to-load and energy production costs, and provide for a net societal benefit for California ratepayers.
    - Net reduction in Energy Cost: $222,295,707
    - Net reduction in Congestion Cost: $36,262,205
    - Net reduction in Marginal Cost of Losses: $2,880,830

- Net reduction in Production Cost: $165,222,726

- Increases Path 26 rating from 4,000 MW to 5,200 MW.
- Increases SCIT overall capability by 1,200 MW.
- Reduces reliance on approximately 19,000 MW of once-through cooling generation in Southern California.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios which are described in chapter 4 of this plan. In these portfolios, Path 26 is defined as the cut plane across the Midway-Vincent 500 kV lines #1 and #2 and the Midway-Whirlwind 500 kV line. The results of the ISO's study identified 18 hours of congestion on Path 26 in 2020. The study also identified 133 hours of congestion on the Midway-Vincent 500 kV # 1 & #2 lines in 2020. Although the CVTL relieves the congestion on Path 26, it does not completely relieve all of the congestion on the Midway-Vincent 500 kV lines #1 and #2. Based on this analysis, the cost-benefit analysis showed that the CVTL yielded a negligible energy benefit compared to the CVTL's project cost.

Based on the findings of the ISO's analysis, the project sponsor's claim that the CVTL would provide a cost savings of more than $400 million in annual energy costs savings is not supported. There are several factors to which the ISO attributes these results including but not limited to the following:

- Difference in the database used;
- Difference in renewable portfolio modeled; and
- Difference in economic benefit calculation approach.

Capacity benefits

As part of the CVTL assessment, the ISO considered local capacity and system capacity benefits. Based on the ISO's assessment, the CVTL does not provide any local capacity benefits because it does not reduce LCR. Nor does the CVTL provide any system capacity benefits because it does not increase import capability into the ISO. Based on this assessment, the ISO concluded that the project sponsors claim of an annual capacity benefit of $11 million is not supported.

System-loss reduction benefits

The cost-benefit analysis using the ISO's TEAM approach includes all benefits that are derived from system-loss reduction. As discussed in the energy cost savings section, the TEAM analysis showed that the CVTL yielded a negligible energy benefit compared to the CVTL's project cost. Based on the findings of the ISO's analysis, the project sponsor's claim that the CVTL would provide an annual benefit of $2.88 million from loss reduction is not supported.

Emission reduction benefits

The TEAM analysis does not show any significant WECC-wide congestion benefit from this project. Since there are no significant congestion and loss reduction benefits resulting in less fossil fuel consumption, it follows that there would not be any significant emission reduction benefits created by this transmission project. As such, the project sponsor's claim regarding annual emission reduction benefit of $8.78 million is not supported by the ISO's analysis.

Policy need

Based on the ISO's hybrid portfolio, a policy-driven transmission line in the area of the CVTL is not needed. The project sponsor's claims regarding benefits attributed to an increased Path 26 rating, increased SCIT nomogram capability, and a reduction in reliance on the OTC generation in Southern California are not supported by the ISO's analysis.

Overall Assessment

Based on its assessment of the CVTL, the ISO concluded that the CVTL would provide little or no economic benefits in each category assessed. The project is also not policy-driven because it is not needed to meet 33% RPS goals in the ISO's hybrid portfolio based on application of tariff section 24.4.6.6.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: **Los Banos to Tesla Transmission Line**

Project Sponsor(s): **Pattern Power Development Company LLC**

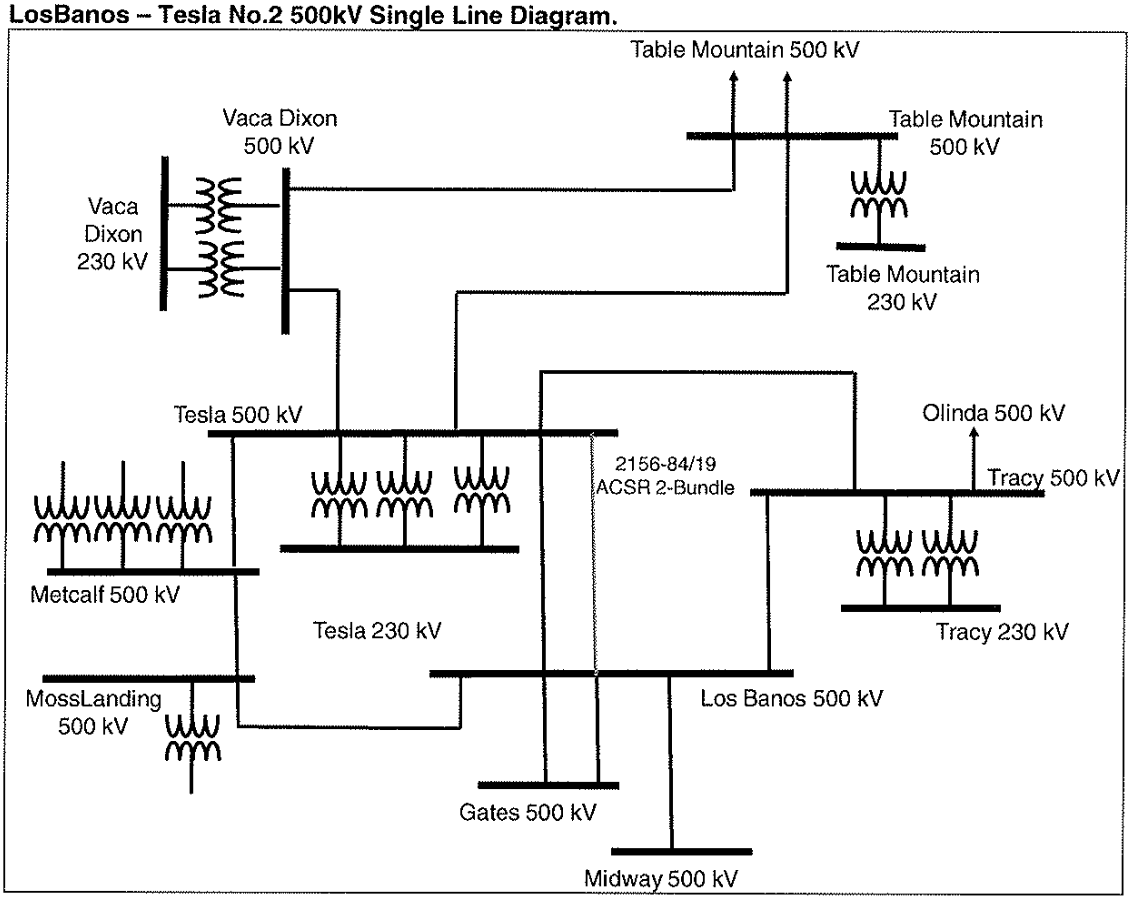
Type of Submission

☒ Economic Transmission Project

Project Description

- Single circuit 500 kV overhead line from PG&E's Los Banos substation to PG&E's Tesla substation;
- Line length approximately 60 miles; and
- The thermal capacity of this line will be 2272 MVA normal and 2648 MVA emergency.

LosBanos – Tesla No.2 500kV Single Line Diagram.



Benefits of Project Identified by Project Sponsor

The proponent states that the project:

- Reduces congestion relating to energy transfer from south to north along the central California trunk lines;
- Provides following economic benefits:
    - Societal benefit of $170 million:
    - 21% increase in solar production: and
    - 2.6 million tons of carbon emission reduction.
- Reduces the Los Banos-Westley 230 kV line flow by about 10%;
- Increase south-to-north Path 15 flow by 860 MW; and
- Reduces IRAS requirement for the Los Banos – North (LBN) contingency.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios which are described in chapter 4 of this plan. The results of the ISO's study identified 50 hours of congestion at North of Los Banos in 2020 which is a reduction from the 421 hours of congestion found at North of Los Banos in 2019 in the ISO's 2010 transmission plan. The reduction in congestion hours from 2019 to 2020 is due to the following key factors:

- In the ISO's 2010 transmission plan, the net short requirements for 2019 was 75 TWh. Based on revised information provided by the CPUC this past year, the net short requirement forecast was reduced by approximately 25% to 55 TWh in this transmission plan; and
- The load forecast for 2020 was 5% lower compared to the load forecast used in the 2010 transmission planning assessment.

Largely due to these two factors, the results of the ISO's benefit analysis performed using the ISO's TEAM approach yielded a negligible energy benefit for this project compared to the Los Banos-Tesla Transmission Line's project cost. Based on this assessment, the ISO concluded that the project sponsor's claim that the Los Banos-Tesla transmission line would provide an annual societal benefit of $170 million is not supported.

The project sponsor also claimed that the Los Banos-Tesla transmission line would result in a 21% increase in solar production in the PG&E service area. The results from the ISO's analysis showed no net increase in the solar production with the Los Banos-Tesla transmission line.

Capacity benefits

As part of the Los Banos-Tesla transmission line assessment, the ISO considered local capacity and system capacity benefits. Based on the ISO's assessment, the Los Banos-Tesla transmission line does not provide any local capacity benefits because it does not reduce LCR. Nor does the Los Banos-Tesla Transmission Line provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

The cost-benefit analysis using the ISO's TEAM approach includes all benefits that are derived from system-loss reduction. As discussed under "Energy Cost Savings", the TEAM analysis showed that the Los Banos-Tesla Transmission Line yielded a negligible energy benefit compared to the project's cost.

Emission reduction benefits

The TEAM analysis does not show any significant WECC-wide congestion benefit from the Los Banos-Tesla transmission line. Since there are no significant congestion and loss reduction benefits resulting in less fossil fuel consumption, it follows that there would not be any significant emission reduction benefits created by this transmission project. As such, the project sponsor's claim regarding a WECC-wide reduction of 2.6 million tons of carbon emission due to this project is not supported by ISO analysis.

Policy need

The Los Banos-Westley 230 kV line was found to be overloaded in the high utilization sensitivity case studied as part of the ISO's 33% RPS Renewable Portfolio analysis. The ISO notes that an alternative project, the reconductoring of the Los Banos-Westley 230 kV line, provides similar benefits at a much lower capital cost. Reconductoring is estimated to cost $40 million, which is significantly less than an estimated $300 million for the Los Banos to Tesla Transmission Line. This overload was not identified in the hybrid portfolio; as such, a policy-driven transmission line in this area is not needed.

The project sponsor also identified other benefits of the Los Banos-Tesla transmission line:

- 10% reduction in the Los Banos-Westley 230 kV line flow;
- 860 MW increase in south-to-north Path 15 flow; and
- Reduction of IRAS requirement for the Los Banos – North (LBN) contingency

As discussed in the policy need section, The Los Banos-Westley 230 kV line was found to be overloaded in one sensitivity case studied as part of the ISO's 33% RPS Renewable Portfolio analysis. Reconductoring the line would be the most cost-effective solutions under the assumptions of this sensitivity scenario. Therefore, even though the Los Banos-Tesla transmission line reduces the flow on the Los Banos-Westley 230 kV line, it is not the most cost effective solution. With respect to the increase in the Path 15 flow and reduction of IRAS requirement, ISO analyses have not identified such needs and hence, these benefits claimed are not supported.

Overall Assessment

Based on its assessment of the Los Bano-Tesla transmission line, the ISO concluded that this line would provide little or no economic benefits in each category assessed. The project is also not policy-driven because it is not needed to meet 33% RPS goals based on application of tariff section 24.4.6.6 the need for a project arises only in one of the three sensitivity studies and does not arise in the ISO's hybrid portfolio.

Based on the analysis performed and presented in this plan, the ISO has concluded that this project is not needed.

General Information

Project Name: **Los Banos - Westley #2 Transmission Project**

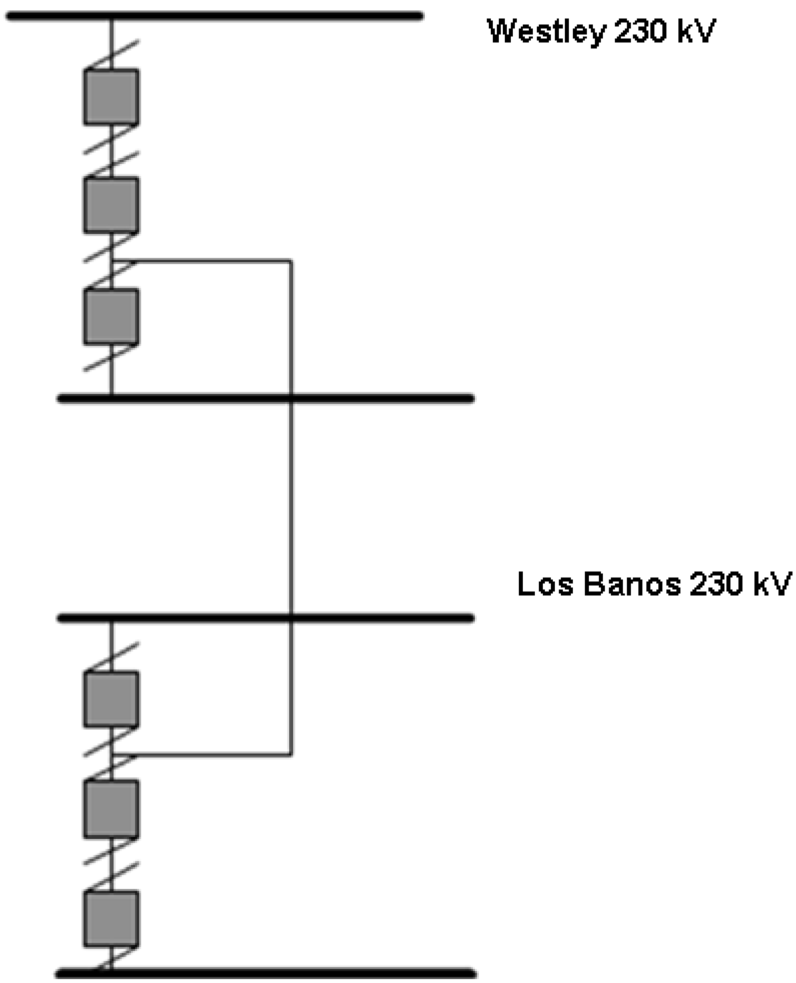
Project Sponsor(s): **Green Energy Express, LLC**

Type of Submission

☒ Economic Transmission Project

Project Description

- Second 230 kV line from PG&E’s Los Banos 230 kV substation to MID/TID’s Westley 230 kV substation;
- Line length approximately 35 miles; and
- The thermal capacity of this line will be 591 MVA.



Benefits of Project Identified by Project Sponsor

The proponent states the project:;

- Relieves North of Los Banos area congestion. $6.475 million of congestion in 2014 and $16.463 million of congestion in 2019; and
- Mitigates overload on the Los Banos-Westley 230 kV line for the loss of the Los Banos-Tesla 500 kV line.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios which are described in chapter 4 of this plan. The results of the ISO's study identified 50 hours of congestion at North of Los Banos in 2020 which is a reduction from the 421 hours of congestion found at

North of Los Banos in 2019 in the ISO's transmission plan. The reduction in congestion hours from 2019 to 2020 is due to the following key factors

- For 2019, the net short requirements used in the ISO's 2010 transmission plan was 75 TWh. Based on revised information provided by the CPUC this past year, the net short requirement was reduced by approximately 25% to 55 TWh; and

- The load forecast for 2020 5% lower compared to the load forecast used in the 2010 transmission planning assessment

Between these two factors, the results of the ISO's benefit analysis performed using the TEAM approach yielded a negligible energy benefit for the Los Banos-Westly #2 Transmission Project compared to its project cost. Based on this assessment, the ISO concluded the project sponsor's claim that the Los Banos-Westly #2 Transmission Project would provide an annual benefit of $6.475 million of congestion in 2014 and $16.463 million of congestion in 2019 million is not supported.

Capacity benefits

As part of the Los Banos-Westly #2 Transmission Project assessment, the ISO considered local capacity and system capacity benefits. Based on the ISO's assessment, the Los Banos-Westly #2 Transmission Project does not provide any local capacity benefits because it does not reduce LCR. Nor does the Los Banos-Westly #2 Transmission Project provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

The cost-benefit analysis using the ISO TEAM approach includes all benefits that are derived from system-loss reduction. As discussed in the energy cost savings section, the TEAM analysis showed that the Los Banos-Westley #2 Transmission Project yielded a negligible energy benefit compared to the project's cost.

Emission reduction benefits

The TEAM analysis does not show any significant WECC-wide congestion benefit from the Los Banos-Westly #2 Transmission Project. Since there are no significant congestion and loss reduction benefits resulting in less fossil fuel consumption, it follows that there would not be any significant emission reduction benefits created by this transmission project.

Policy need

The Los Banos-Westley 230 kV line was found to be overloaded only in the high utilization sensitivity case studied as part of the ISO's 33% RPS Renewable Portfolio analysis. Reconductoring the line would be a more cost-effective solution under the assumptions of this scenario. Reconductoring is estimated to cost $40 million, which is significantly less than an estimated $175 million for the Los Banos-Westley #2 230 kV transmission line. In any event, this overload was not identified in the hybrid portfolio; as such, a policy-driven transmission line in this area is not needed, nor is reconductoring.

The project sponsor also identified the following benefit of the Los Banos-Westley #2 230 kV transmission line:

- Mitigates overload on the Los Banos-Westley 230 kV line for the loss of the Los Banos-Tesla 500 kV line.

As discussed in the policy need section, The Los Banos-Westley 230 kV line was found to be overloaded in one sensitivity case studied as part of the ISO's 33% RPS Renewable Portfolio analysis. To address this overload, a more cost effective solution would be reconductoring. Therefore, even though the Los Banos-Westley #2 230 kV transmission line addresses this overload, it is not the most cost effective solution.

Overall Assessment

Based on the ISO's assessment of the Los Banos-Westley #2 230 kV transmission line, the ISO concluded that this line would provide little or no economic benefits in each category assessed. The project is also not policy-driven because it is not needed to meet 33% RPS goals based on application of tariff section 24.4.6.6. The need for a project is not identified in the ISO's hybrid portfolio.

Based on the analysis performed and presented in this plan, the ISO has concluded that this project is not needed.

General Information

Project Name: North of Los Banos Economic Planning Study Request

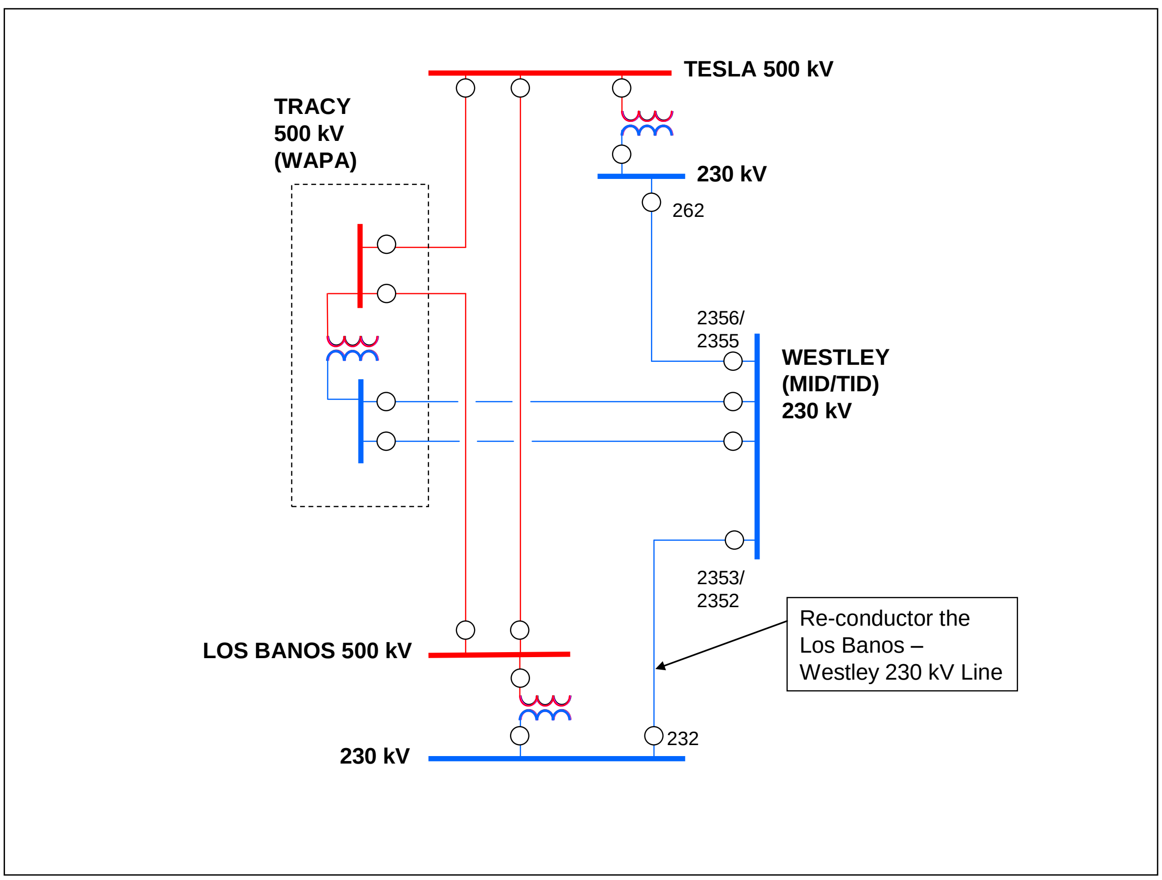
Project Sponsor(s): Pacific Gas & Electric Company

Type of Submission

☒ Economic Planning Study Request

Project Description

- Reconductor the existing Los Banos-Westley 230 kV line;
- Line length approximately 35 miles; and
- The thermal capacity of this line will be 727 MVA normal and 835 MVA emergency.



Benefits of Project Identified by Project Sponsor

The proponent states that the project:

- Relieves North of Los Banos area congestion. $6.475 million of congestion in 2014 and $16.463 million of congestion in 2019; and

- Increases power flow limit on the Los Banos-Westley 230 kV line for an outage of the Tesla-Los Banos 500 kV line.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS Renewable Portfolios which are described in chapter 4 of this plan. The results of the ISO's study identified 50 hours of congestion at North of Los Banos in 2020 which is a reduction from the 421 hours of congestion found at North of Los Banos in 2019 in the ISO's 2010 transmission plan. The reduction in congestion hours from 2019 to 2020 is due to the following key factors:

- For 2019, the net short requirements used in the ISO's transmission plan was 75 TWh. Based on revised information provided by the CPUC this past year, the net short requirement was reduced by approximately 25% to 55 TWh; and

- The load forecast for 2020 was 5% lower compared to the load forecast used in the 2010 transmission planning assessment.

Between these two factors, the results of the ISO's benefit analysis performed using the ISO TEAM approach yielded a negligible energy benefit for this project compared to the project cost of $40 million to $50 million. Based on this assessment, the ISO concluded that the project sponsor's claim regarding congestion relief benefits on the North of Los Banos system is not supported.

There is however a potential need in one sensitivity case studied as part of the ISO's 33% RPS Renewable Portfolio analysis for increased capacity of the Los Banos-Westley 230 kV line and this project potentially could be one of a number of projects that might be able to meet such need in that scenario. However, no such need was identified in the base case.

Capacity benefits

As part of the North of Los Banos Economic Planning Study Request assessment, the ISO considered local capacity and system capacity benefits. Based on the ISO's assessment, the proposed Los Banos-Westley 230 kV line reconductoring does not provide any local capacity benefits because it does not reduce local capacity requirements (LCR). Nor does it provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

The cost-benefit analysis using the TEAM approach includes all benefits that are derived from system-loss reduction. As discussed in the energy cost savings section, the TEAM analysis showed that the proposed Los Banos-Westley 230 kV line reconductoring yielded a negligible energy benefit compared to the project cost.

Emission reduction benefits

The TEAM analysis does not show any significant WECC-wide congestion benefit from this project. Since there are no significant congestion and loss reduction benefits resulting in less fossil fuel consumption, it follows that there would not be any significant emission reduction benefits created by this transmission project.

Policy need

As noted in the energy cost savings section above, the Los Banos-Westley Line was found to be overloaded only in one sensitivity study. To address this overload, reconductoring of the line would be the most cost effective approach. However, the need for a project in this area does not arise in the hybrid case or in two of the sensitivity scenarios. Thus, a policy-driven transmission line in the area of the proposed Los Banos-Westley 230 kV line reconductoring is not needed.

Overall Assessment

Based on the ISO's assessment of the North of Los Banos Economic Planning Study Request, the ISO concluded that the proposed Los Banos-Westley 230 kV line reconductoring would provide little or no economic benefits in each category assessed. The project is also not policy-driven because it is not needed to meet 33% RPS goals based on application of tariff section 24.4.6.6. The project is not identified as needed in the ISO's hybrid portfolio.

Based on the analysis performed and presented in this plan, the ISO has concluded that this project is not needed.

General Information

Project Name: Midway-Antelope Project

Project Sponsor(s): California Transmission Development, LLC

Type of Submission

☒ Others

Project Description

- 500 kV transmission line between 500 kV bus at PG&E Midway substation and 500 kV bus at SCE's Antelope substation;.
- Line length approximately 88 miles; and
- The thermal capacity of this line will be 3421 MVA normal and 4616 MVA emergency.

Benefits of Project Identified by Project Sponsor

The proponent states that the expansion/upgrade of Path 26 in the form of construction of a new Midway-Antelope 500 kV line will strengthen the tie between northern and southern California and would allow for a state-wide dissemination of these new renewable resources and would facilitate the development of the Tehachapi wind resource zone to its maximum potential. Furthermore, this upgrade will make for a more robust Intertie transmission system and would allow the ISO to utilize all of the available generation resources in an efficient and cost effective manner, thereby improving the system reliability while minimizing the total system cost. Finally, this new line would help remove congestion and increase the robustness of the transmission system connecting the Northern and Southern California.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios which are described in chapter 4 of this plan. In these portfolios, Path 26 is defined as the cut plane across the Midway-Vincent 500 kV lines #1 and #2 and the Midway-Whirlwind 500 kV line. The results of the ISO's study identified 18 hours of congestion on Path 26 in 2020. The study also identified 133 hours of congestion on the Midway-Vincent 500 kV #1 & #2 lines in 2020. Although the Midway-Antelope project relieves the congestion on Path 26, it does not completely relieve all of the congestion on the Midway-Vincent 500 kV lines #1 and #2. Based on this analysis, the cost-benefit analysis performed using the ISO TEAM approach showed that the Midway-Antelope project yielded a negligible energy benefit compared to the project cost.

Capacity benefits

As part of the Midway-Antelope project assessment, the ISO considered local capacity and system capacity benefits. Based on the ISO's assessment, the Midway-Antelope project does not provide any local capacity benefits because it does not reduce LCR. Nor does the Midway-Antelope project provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

The cost-benefit analysis using the TEAM approach includes all benefits that are derived from system-loss reduction. As discussed in the energy cost savings section, the TEAM analysis showed that the Midway-Antelope project yielded a negligible energy benefit compared to the project cost.

Emission reduction benefits

The TEAM analysis does not show any significant WECC-wide congestion benefit from this project. Since there are no significant congestion and loss reduction benefits resulting in less fossil fuel consumption, it follows that there would not be any significant emission reduction benefits created by this transmission project.

Policy need

Based on the ISO's hybrid portfolio, a policy-driven transmission line in the area of the Midway-Antelope 500 kV line is not needed.

The project sponsor also stated that the Midway-Antelope project would facilitate the development of Tehachapi wind resource zone to its maximum potential. The ISO's hybrid 33% RPS portfolio modeled about 3,200 MW of renewable capacity in the Tehachapi area. Furthermore, one of the sensitivity portfolios modeled about 5,780 MW of renewable capacity in the Tehachapi area. The results of the plan studies show that no additional upgrades are needed to deliver the above mentioned renewable capacity from the Tehachapi area with the Tehachapi Renewable Transmission Project (TRTP) in place. There is available capacity on the TRTP to accommodate significant additional quantities of renewable resources. Therefore, the project sponsor's claim regarding the Midway-Antelope project facilitating the development of theTehachapi wind resource zone to its maximum potential is not supported by the ISO's analysis. As such, there is no public policy-driven transmission need that the Midway-Antelope 500 kV line project could meet.

Overall Assessment

Based on the ISO's assessment of the Midway-Antelope Project, the ISO concluded that the project would provide little or no economic benefits in each category assessed. The project is also not policy-driven because it is not needed to meet 33% RPS goals based on application of tariff section 24.4.6.6. The project has not been identified as needed in the ISO's hybrid portfolio.

Based on the analysis performed and presented in this plan, the ISO has concluded that this project is not needed.

General Information

Project Name: Midway-Antelope 500 kV Project

Project Sponsor(s): Pacific Gas & Electric Company

Type of Submission

☒ Others

Project Description

- 500 kV transmission line from PG&E's Midway substation to SCE's proposed Antelope substation;
- Line length approximately 125 miles; and
- Project Capacity: 1500 – 2000 MW.

Benefits of Project Identified by Project Sponsor

There is no benefit claimed by the project sponsor.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in the 2008 and 2009 request windows for information only. As it had the potential to address congestion in one of the top five areas of congestion, it was included in the TEAM analysis for that area. The TEAM analysis concluded that the project was not economically justified as documented in chapter 6. The ISO has concluded that the Midway-Antelope 500 kV project is not needed to meet the 33% RPS goals based on the portfolios developed in chapter 4 for this transmission plan.

General Information

Project Name: **Midway – Kramer 500 kV Lines – two circuit**

Project Sponsor(s): **Pacific Gas & Electric Company**

Type of Submission

☒ Other (Submitting for information only)

Project Description

The 500 kV Midway-Kramer #1 and #2 Lines project consists of:

- Two 500 kV line terminations at Midway substation in central California;
- Two 500 kV transmission lines from Midway substation to Kramer substation- approximately 170 mile; and
- Two 500 kV line terminations at Kramer substation in southern California.

Benefits of Project Identified by Project Sponsor

The proponent states this project is projected to interconnect new renewable resources in the southern California and central California regions to improve transmission reliability in the regions.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in the 2008 and 2009 request windows for information purposes only, and therefore was not studied further.

7.3 Summary of Individual Request Window Projects - Not Associated with Top Five Areas of Congestion

General Information:

Project Name: **Sierra Green Link Transmission project**

Project Sponsor(s): **Starwood, LLC**

Type of Submission

☒ Economic Transmission Project

Project Description

Sierra Green Link is a north-south transmission project in the western U.S. aimed at delivering electricity generated by renewable resources in the Pacific Northwest and the Sierra Nevada region to load centers in central California.

The primary features of Sierra Green Link are:

- The addition of one 500 kV line position at the existing Malin 500 kV substation. This additional line position will house the new Malin-Raven 500 kV line;

- A new Raven 500 kV renewable collector substation. This new 500 kV substation will have two 500 kV line positions. One line position will house the new Malin-Raven 500 kV line, and the other position will house the new Raven-Valley Road 500 kV line;

- A new Valley Road 500 kV substation near the existing Valley Road 345 kV substation in Reno Nevada. This new 500 kV substation will have two 500 kV line positions. One line position will house the new Raven-Valley Road 500 kV line and the other position will house the new Valley Road-Rancho Seco 500 kV line;

- A new overhead single circuit Malin-Raven 500 kV transmission line. The line will be 35% series compensated at both the ends. The Malin-Raven 500 kV line will run along the existing Reno-Alturas 345 kV transmission line;

- A new overhead single circuit Raven-Valley Road 500 kV transmission line. The line will be 35% series compensated at both the ends. The Raven-Valley Road 500 kV will run along the existing Reno-Alturas 345 kV transmission line;.

- A new Rancho Seco 500 kV bus near the existing Rancho Seco 230 kV substation. This new 500 kV substation will have two 500 kV line positions. One line position will house the new Valley Road-Rancho Seco 500 kV line, and the other position will house the new Rancho Seco 500 kV/230 kV transformer bank;

- A new overhead single circuit Valley Road-Rancho Seco 500 kV line. The line will be 35% series compensated at both ends. The Valley Road-Rancho Seco 500 kV line will run along I-80;
- A new Rancho Seco 500 kV/230 kV transformer bank; and
- Address reliability concerns on the existing Rancho Seco-Hedge 230 kV line and the Procter - Hurley S 230 kV Line.

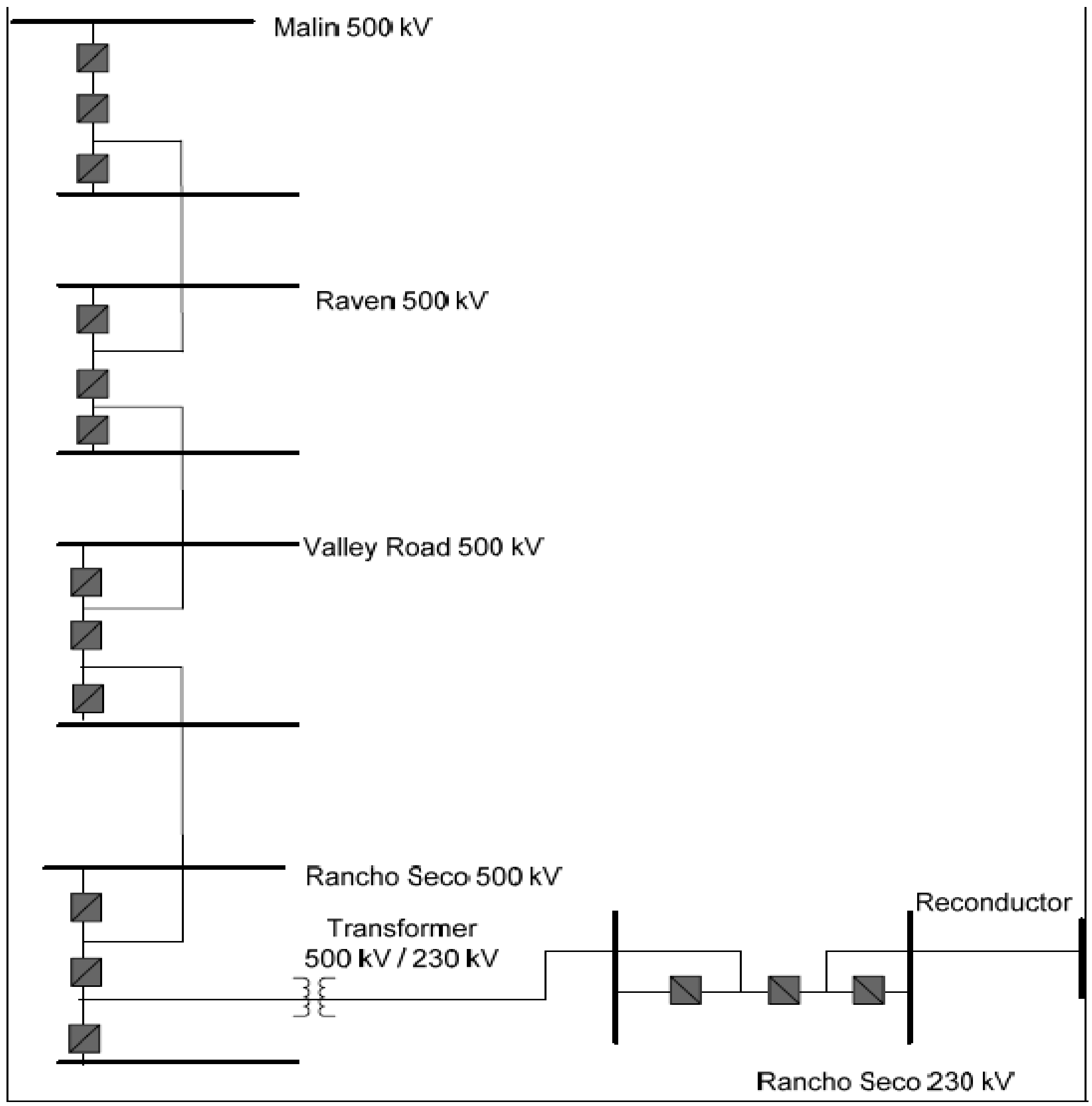


Figure 1 – One Line Diagram

Benefits of Project Identified by Project Sponsor

The proponent states the Sierra Green Link will create up to 1,100 MW of new transmission capacity from the Malin substation in Oregon to the Rancho Seco substation in northern California, passing through Nevada.

The proponent states the Sierra Green Link will have numerous benefits for California ratepayers. It will provide a significant amount of capacity in a region that is currently constrained thereby increasing access to renewable generation sources and improving network reliability.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There was no substantial congestion identified on Path 66 (COI), Path 25 (PacificCorp/PG&E 115 kV Interconnection) or the North Valley area (in parallel with the 500 kV system). Congestion on Path 66 is estimated at $0.129 million for 12 hours; on Path 25 at $0.008 for 17 hours; on Delevan-Cortina at $1.661 million for 67 hours and on Table Mountain-Vaca Dixon at $0.001 million for 1 hour for a total of $1.799 million. Therefore the project sponsors claim regarding congestion relief benefits on the northern California system are not supported by the ISO analysis of ISO developed base case and two of the three sensitivity portfolios. The High Out-of-State sensitivity scenario required a new major 500 kV line to the Pacific Northwest. There were several transmission lines to the Northwest, including this one, which potentially could meet that need. This need did not arise in the base case or in the other two sensitivity studies.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR.

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This project could potentially provide broader system capacity benefits because it increases import capability into California from the north; however it is unlikely to increase import capability for the ISO because it has no connection to the ISO controlled grid. The ISO estimates an increase in northwest import capability into the state of about 1,000 MW due to this project. The ISO estimated difference in price between the Pacific Northwest system capacity and California system capacity to be about $5/kW/year. Thus, the ISO estimates that benefits due to this additional import capability to be about $5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Northwest and California. This capacity cost difference is in addition to the energy cost savings that was estimated by the production cost model described above. The production cost model is designed to estimate energy cost differences but not resource adequacy capacity cost differences.

System-loss reduction benefits

The ISO estimates that on average this project would reduce system losses by 97 MW, or about 431,824 MWh for an annual loss reduction savings of about $24.24 million at the PG&E Valley average cost of $56.15 per MWh.

Emission reduction benefits

There are very few hours with congestion benefits resulting in less fossil fuel consumption. Also, there are some energy loss benefits which may result in emission reduction benefits.

Policy need

Based on the hybrid portfolio described in this transmission plan, there is no policy-driven transmission need that the Sierra Green Link project could meet. The need for a new major 500 kV line to the Northwest was only identified in one study -- the High-Out-Of-State sensitivity scenario.

Overall Assessment

Although this project's footprint is outside of the ISO's controlled grid, the ISO evaluated the project as it had committed to reviewing the 2008 and 2009 request window projects in this planning cycle.

The annual estimated savings associated with this project of approximately $26 million are the sum of the energy cost savings of $1.8 million and transmission line loss savings of $24.2 million. The cost of this project is estimated at $1.25 billion with annualized carrying charges estimated at $188 million. Economically it cannot be justified on energy cost savings and transmission line loss savings since the annual carrying charge is over six times higher than total annual benefits. Annual carrying charges were approximated as 15% of the total capital cost of the project. The value of the potential emission benefits are difficult to quantify. However, assuming a proxy value of $26 million based on the sum of the energy and loss savings would still not be enough to justify this project.

The project also cannot be approved as a policy-driven project because it is not needed to meet the 33% RPS goals based on application of tariff section 24.4.6.6. A major transmission line to the Northwest is identified only in one of three sensitivity studies and is not identified in the ISO's hybrid portfolio.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: **Carrizo to Midway Transmission project**

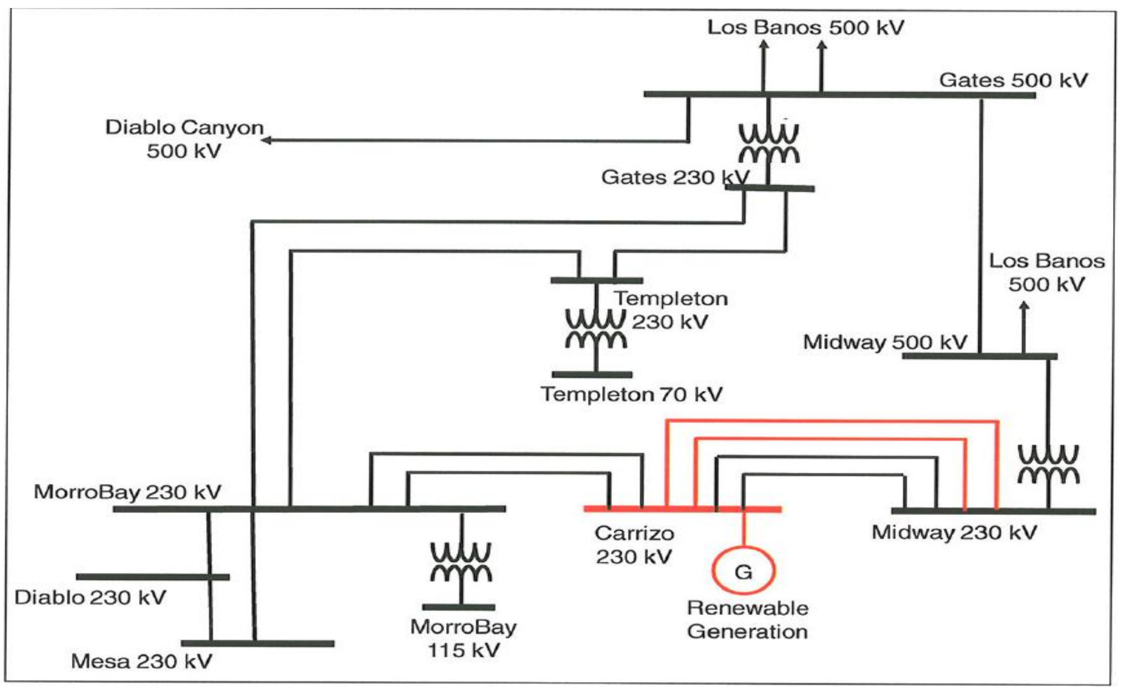
Project Sponsor(s): **Pattern Power Development Company, LLC**

Type of Submission

☒ Economic Transmission Project

Project Description

The proposed project involves the construction of a new approximately 35 mile, double circuit 230 kV overhead transmission line between PG&E's Carrizo substation and PG&E's Midway substation. The addition of this project allows the addition of 588 MW of new renewable generation to the ISO controlled grid at Carrizo without creating any additional thermal overloads.



Benefits of Project Identified by Project Sponsor

The proponent states that the Carrizo to Midway project is expected to produce tens of millions of dollars in production cost savings within California and throughout the WECC. The project is also an important project in ensuring that California meets its RPS goals. It has the potential to substantially increase deliveries of solar energy from the Carrizo CREZ zones to California's load centers and is therefore an essential project as renewable development in those areas proceeds. It was also shown to support hundreds of GWhs of additional renewable energy delivery.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in Chapter 4. There was no congestion identified in the Midway-Morro Bay area. Therefore the project sponsors claim regarding congestion relief benefits are not supported by the ISO's analysis of ISO-developed portfolios. Compared to the assumptions used in the proponent's report, the ISO assumptions on the renewable generation development include substantially less development in the Carrizo area and potentially different transmission configuration. Therefore, the congestion that was cited in the Carrizo to Midway Transmission Project Report was not observed in the ISO's analysis.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR. It also does not provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

The ISO estimates that on average this project would reduce system losses by 0.6 MW, or about 2891 MWh for a loss reduction savings of about $0.16 million annually at PG&E Valley average cost of $56.15 per MWh.

Emission reduction benefits

There will be no material emission reduction benefits as there was no congestion identified on the existing lines. The energy loss benefits may result in some emission reduction benefits.

Policy need

The ISO's base case already included the Midway-Morro Bay #1 and #2 230 kV line reconductoring project. That project supports interconnection of new generation projects in the ISO interconnection queue. The ISO evaluated its need based on the study results from the Large Generation Interconnection Studies. According to the transition cluster Phase II study in San Luis Obispo, Kern, and Fresno areas, this upgrade was identified as a required delivery network upgrade. The Phase II transition cluster studies were completed and the final reports were issued.

The LGIA has been tendered and is awaiting signature from all parties.

The Midway-Morro Bay #1 and #2 230 kV line reconductoring project is a relatively low cost project because it is a replacement of existing conductor with larger conductor and is expected to use the same transmission towers and the same right-of-way. It will accommodate all the resources in the Carrizo area identified in the hybrid portfolio. Therefore, there is not a policy-driven transmission need that the Carrizo to Midway transmission project would meet.

Overall Assessment

The cost of this project is estimated at $200 million with the first year carrying charges estimated at $30 million. Economically it cannot be justified on loss savings alone since they are about 180 times less than the annual carrying charges, which were approximated to be 15% of the total capital cost of the project. The value of the potential emission benefits are difficult to quantify. However, assuming a proxy value of $0.16 million based on the loss savings would still not be enough to justify this project. The marginal benefits provided by the project fall far short of the annual carrying costs of the project.

The project is not needed as a policy-driven project to meet the 33% RPS goals in the ISO's hybrid portfolio based on application of the criteria applied in tariff section 24.4.6.6.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: **Malin-Cottonwood-Table Mountain-Tesla 500 kV**

Project Sponsor(s): **Pacific Gas and Electric Company**

Type of Submission

☒ Other Project

Project Description

The preliminary plan of service for the proposed Malin-Cottonwood-Table Mountain and Table Mountain-Tesla 500 kV HVAC line projects are:

- 500 KV terminations at Malin Substation in Southern Oregon, Cottonwood and Table Mountain substations in northern California;
- 500 kV transmission line from Malin to Cottonwood to Table Mountain substation - approximately 250 mile;
- 500 kV line from Table Mountain to Tesla/Tracy in the Central Valley area - approximately 150 miles; and
- Termination of Table Mountain-Tesla 500 kV line at either the Tesla or Tracy 500 kV substation in the central Valley in northern California.

Alternative configurations for this line including 500 KV AC via Collinsville substation and 500 kV DC to the Collinsville or Tracy area, are also being considered as part of the project development plan.

Benefits of Project Identified by Project Sponsor

The project proponent states that this project provides an opportunity to interconnect new renewable resources in the Pacific Northwest and Canada with the northern California region and improve transmission reliability in the region. The California portion of the project may be coordinated with a larger regional project being considered by a collaborative group of California POUs, Western, BPA, and other utilities and project sponsors who may, or may not, be ISO participating transmission owners.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in 2008 and 2009 Request Window for information purposes only. It did not address one of the top five areas of congestion and therefore was not studied further.

General Information

Project Name: **Malin-Cottonwood-Table Mountain-Vaca Dixon-Tesla 500 kV**

Project Sponsor(s): **California Transmission Development LLC**

Type of Submission

☒ Other Project

Project Description

The proposed project involves construction of new 350 mile long 500 kV transmission line between 500 kV bus at BPA Malin substation and the 500 kV bus at PG&E's Vaca Dixon and Tesla substations. The project is also planned to have the ability to tie into the existing system at the existing Cottonwood 230 kV substation through a new Cottonwood 500 kV substation, and at the existing Table Mountain 500 kV substation, if such interconnections prove beneficial.

Benefits of Project Identified by Project Sponsor

The project proponent states that congestion exists at the COI, and it is projected to increase with the addition of other high voltage transmission lines which terminate in the area, such as the Gateway West project terminating at Captain Jack. This and other projects do not continue in to provide increased delivery of this power from the Oregon border to load within California. As the existing COI capacity is almost completely utilized and accounted for, expansion or upgrade of COI on the California side would be required in order to import new renewable energy (especially wind energy) and deliver it to the bulk of ISO load.

The construction of new Malin-Tesla 500 kV line will strengthen the tie between Oregon and northern California and would aid import of new renewable resources into California. Furthermore, by increasing the import capability into California, this line would also help for normalization of Locational Marginal Pricing (LMP) at the California-Oregon border (COB) and at the buses serving the northern California load center thereby reducing the cost of energy to the California ratepayers. The proposed line would also improve the reliability of the bulk transmission grid, help remove congestion, and create a more robust Intertie transmission system that would allow the ISO to utilize all of the available generation resources in an efficient and cost effective manner, thereby improving the system reliability while minimizing the total system cost.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There was no substantial congestion identified on Path 66 (COI), Path 25 (Pacific Corp/PG&E 115 kV Interconnection) or the North Valley area (in parallel with the 500 kV system). Congestion on Path 66 is estimated at $0.129 million for 12 hours; on Path 25 at $0.008 for 17 hours; on

Delevan-Cortina at $1.661 million for 67 hours and on Table Mountain-Vaca Dixon at $0.001 million for 1 hours for a total of $1.799 million. Therefore the project sponsors claim regarding congestion relief benefits on the northern California system are not supported by the ISO's analysis of ISO developed base and two of the three sensitivity portfolios. The High-Out-Of-State sensitivity portfolio identified the need for a major new 500 kV line to the Pacific Northwest under that scenario. There were several proposed transmission lines from the Northwest. As indicated above, the need arises only in one sensitivity study and does not arise in the base case.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR. It does provide system capacity benefits because it increase import capability into the ISO from the north. The ISO estimates and increase in northwest import capability of about 1,000 MW due to this project. The ISO estimated difference in price between the Pacific Northwest system capacity and ISO system capacity to be about $5/kW/year as such the ISO estimates RA Import Capability benefits to be about $5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Northwest and California. This capacity cost difference is in addition to the energy cost savings that was estimated by the production cost model described above. The production cost model is designed to estimate energy cost differences but not resource adequacy capacity cost differences.

System-loss reduction benefits

The ISO estimates that on average this project would reduce system losses by 46.2 MW, or about 405,028 MWh for an annual loss reduction savings of about $22.7 million at PG&E Valley average cost of $56.15 per MWh.

Emission reduction benefits

There are very few hours with congestion benefits resulting in less fossil fuel consumption, there are also small emission reduction benefits due to reduction in losses created by this transmission project.

Policy need

Based on the ISO's hybrid portfolio, there is not a policy-driven transmission need that the Malin-Cottonwood-Table Mountain-Vaca Dixon-Tesla 500 kV project could meet.

The High Out-of-State sensitivity portfolio identifies the need for a new major 500 kV line to the Pacific Northwest under that scenario. This project potentially could meet that need.

Overall Assessment

The cost of this project is estimated at $1.7 billion with the first year carrying charges estimated at $255 million. Economically it cannot be justified on energy cost savings and line loss savings alone since they are over eight times less than the annual carrying charges. Annual carrying charges were approximated as 15% of the total capital cost of the project. The value of the potential emission benefits are difficult to quantify. However, assuming a proxy value of $24.5 million based on the sum of the energy and loss savings would still not be enough to justify this project.

The project also cannot be approved as a policy-driven project because it is not needed to meet the 33% RPS goals based on application of tariff section 24.4.6.6. A project to the Pacific Northwest is identified only in one of three sensitivity studies and is not identified in the in the ISO's hybrid portfolio.

Based on this analysis, the ISO has therefore concluded that this project is not needed.

General Information

Project Name: **Round Mountain to Alturas/Ravendale 345 kV AC Line**

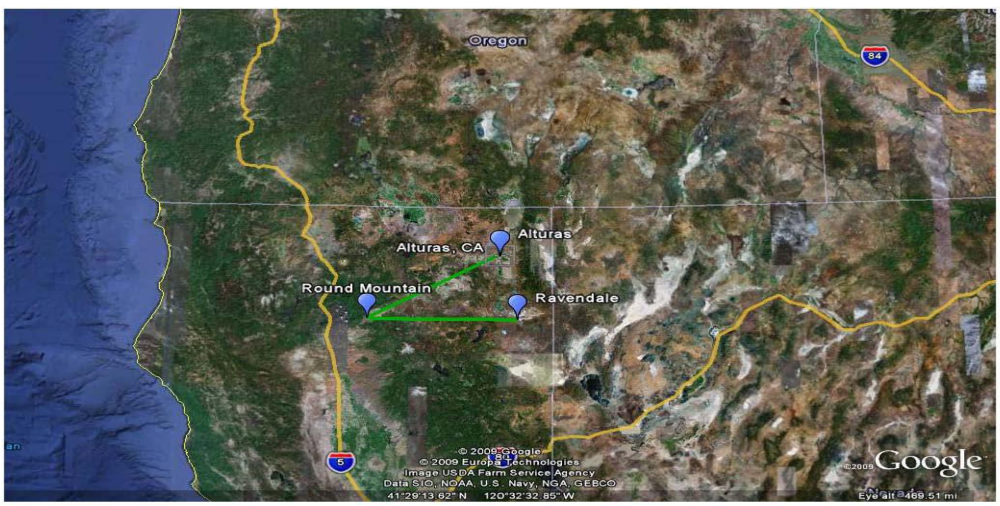
Project Sponsor(s): **California Transmission Development, LLC**

Type of Submission

☒ Location Constrained Resource Interconnection Facility (LCRIF)

Project Description

The project will connect to the Round Mountain 345 kV substation to either a new substation near Ravendale or the existing Alturas 345 kV substation. The line is planned to be an overhead line approximately 90 miles in length.



Benefits of Project Identified by Project Sponsor

The project proponent states that the objectives of the project are to:

- Facilitate the delivery and integration of renewable resources from NE California, Oregon and Nevada to Northern California load centers including the Bay Area; and
- Improve the security and diversity of the transmission system in the area.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There was no congestion identified on deliveries from Lassen North and Lassen South CREZ. Congestion on Path 66 (COI) is estimated at $129,000 for 12 hours and on Path 25 at $0.008 for 17 hours for a total of $137,000. Therefore the project sponsors claim regarding congestion relief benefits on the northern California system are not supported by the ISO's analysis of the ISO-developed base and two of the three sensitivity portfolios. There is however a potential need in the High Out-of-State sensitivity portfolio for a new major 500 kV line to the Northwest and this project potentially could be one of a number of projects that might be able to meet a small part of such a need under the High Out-of-State sensitivity portfolio. The need is only in one of the three sensitivity portfolios, and is not in the hybrid case.

These savings are estimated based on the assumption that the Hilltop-Round Mountain 345 kV line is connected before the phase shifter at Hilltop and the flows would be from Hilltop towards Round Mountain. The ISO has modeled this project as such and the flows are actually reversed, from Round Mountain to Hilltop, in both the on-peak and the off-peak cases due to the strong power movement of the phase shifter at Hilltop. As such, this project will potentially add to the congestion cost at Path 66 (COI) rather than subtract from it. If the project is connected after the phase shifter, then the existing flow on the Alturas project will split between California and Nevada.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR. It does provide system capacity benefits because it increase import capability into the ISO from the north. The ISO estimates a increase in North West import capability of ranging from 0 to 300 MW due to this project. Based on the ISO's estimated difference in price between the Pacific Northwest system capacity and the ISO system capacity of about $5/kW/year, the ISO estimates the RA Import Capability benefits to be about $1.5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Pacific Northwest and California. This capacity cost benefit is in addition to the energy cost savings that was estimated by the production cost model described above. The production cost model is designed to estimate energy cost differences but not resource adequacy capacity cost differences.

System-loss reduction benefits

The ISO estimates that on average this project (connected before the Hilltop Phase shifter) would reduce system losses by 3.4 MW, or about 29,696 MWh for an annual loss reduction savings of about $1.67 million at PG&E Valley average cost of $56.15 per MWh.

If the project is connected after the phase shifter at Hilltop then on average it actually increases the total system losses by 1.1 MW or about 9,636 MWh for a loss increased cost of about $540,000 at PG&E Valley average cost of $56.15 per MWh.

Emission reduction benefits

There are very few hours with congestion benefits resulting in less fossil fuel consumption. There are also small emission reduction benefits due to reduction in losses created by this transmission project.

Policy need

Based on the ISO's hybrid portfolio, there is no policy-driven transmission need that the Round Mountain-Alturas/Ravendale 345 kV AC Line project could meet.

The High Out-of-State sensitivity portfolio identified the need for a new major 500 kV line to the Pacific Northwest under the assumptions of that scenario, and this project could meet a portion of that need. However, the need for such a project was not identified in the hybrid case or the other two sensitivity studies.

Overall Assessment

The cost of this project is estimated at $250 million with the annual carrying charges estimated at $37.5 million. It is not economically justified on the basis of energy, capacity and loss cost savings alone since they are over 11 times less than the annual carrying charges. Carrying charges were approximated to be 15% of the total capital cost of the project. The value of the potential emission benefits are difficult to quantify. However, assuming a proxy value of $1.8 million based on the sum of the energy and loss savings would still not be sufficient to justify this project.

The project is not policy-driven because it is not needed in order to meet 33% RPS goals based on application of tariff section 24.4.6.6. It is not reflected in the ISO's hybrid portfolio or in two of the three sensitivity studies.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: **Vaca Dixon-Rio Oso Transmission Line**

Project Sponsor(s): **Pattern Power Development Company LLC**

Type of Submission

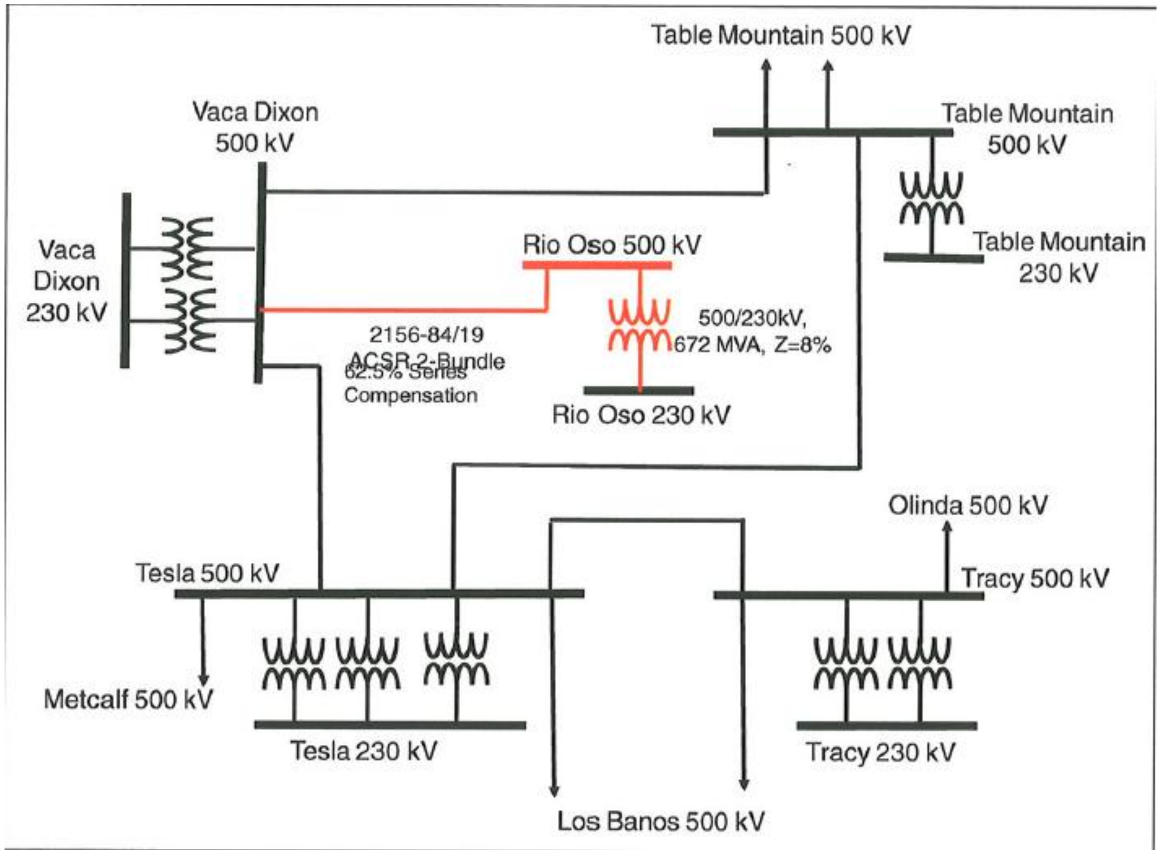
☒ Economic Transmission Project

Project Description

The Vaca Dixon to Rio Oso Transmission Line Project includes:

- The construction of a new approximately 60 mile, 500 kV single circuit overhead transmission line on lattice structures, with 2156 – 84/19 ACSR 2-Bundle conductor and 62.5% series compensation, between PG&E's Vaca-Dixon substation and PG&E's Rio Oso substation;
- The 62.5% series compensation will be located at the Vaca-Dixon substation; and
- The proposed line's conductor thermal rating is 2623 A (2272 MVA) normal and 3058 A (2648 MVA emergency).

The proponent noted that the series compensation will be sized based upon additional system studies to be performed as the project is further defined after consultation with the ISO and other relevant stakeholders. For purposes of this application, the proponent assumed the series compensation to have a rating of 2667 A (2310 MVA) normal and 4000 A (3454 MVA) 30 minute emergency, identical to the series compensation of the Table Mountain – Vaca Dixon 500 kV line.



Benefits of Project Identified by Project Sponsor

The proponent states that the project will provide $117 million per year in California consumer benefits, significantly reducing congestion at several California transmission constraints including the Tesla transformer bank ($18.3 million reduction in congestion) and Sierra Cal Sub to Cal S PS ($11.5 million reduction in congestion). In addition, the project reduces production costs, creating a social benefit of nearly $20 million per year within California and nearly $30 million per year WECC-wide.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There was no congestion identified on deliveries from or to the Sierra region in PG&E system. Therefore the project sponsors claim regarding congestion relief benefits on the northern California system are not supported by the ISO's analysis of the ISO-developed portfolios.

Capacity benefits

This project does not provide system capacity benefits because it does not increase import capability into the ISO.

This project does provide some local capacity benefits because it decreases the LCR need especially for the Sierra area overall requirement and some of the sub areas north of Rio Oso; however, it increases the LCR requirements for sub areas south of Rio Oso. Among the units situated north of Rio Oso, all but two are either under a long-term contract (e.g. QF) or hydro capacity already owned by a Load Serving Entity (LSE) so there will be very little LCR capacity cost displacement that this project brings. From the two market units that can be displaced, one is needed for the Pease sub area and those requirements will still be there even if this new project were to be constructed. Thus, the ISO estimates that one unit or about 50 MW of local resource capacity will actually be displaced by this project. At the ISO estimated difference in price between local area capacity cost and the system capacity cost of about $20/kW/year the ISO estimates LCR capacity reduction benefits to be about $1 million per year.

System-loss reduction benefits

The ISO estimates that on average this project would reduce system losses by 12.3 MW or about 107,589 MWh, for a loss reduction savings of about $6.04 million at PG&E Valley average cost of $56.15 per MWh.

Emission reduction benefits

There are no hours with congestion benefits resulting in less fossil fuel consumption, however there are small emission reduction benefits due to reduction in losses created by this transmission project.

Policy need

Based on the ISO's hybrid portfolio, there is not policy-driven transmission need that the Vaca Dixon-Rio Oso Transmission project could meet.

Overall Assessment

The cost of this project is estimated at $300 million with the annual carrying charges estimated at $45 million. The project is not economically justified on the basis of capacity and loss cost savings alone since they are over six times less than the annual carrying charges. Annual carrying charges as approximated to be 15% of the total capital cost of the project. The value of the potential emission benefits are difficult to quantify. However, assuming a proxy value of $6 million based on the loss savings would still not be sufficient to justify this project.

The project is not policy-driven since it is not needed in order to meet 33% RPS goals based on application of tariff section 24.4.6.6. The need for such a project is not identified in the ISO's hybrid portfolio or in any of the sensitivity studies.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: AV Clearview Transmission Project

Project Sponsor(s): Critical Path Transmission, LLC

Type of Submission

☒ Economic Transmission Project

Project Description

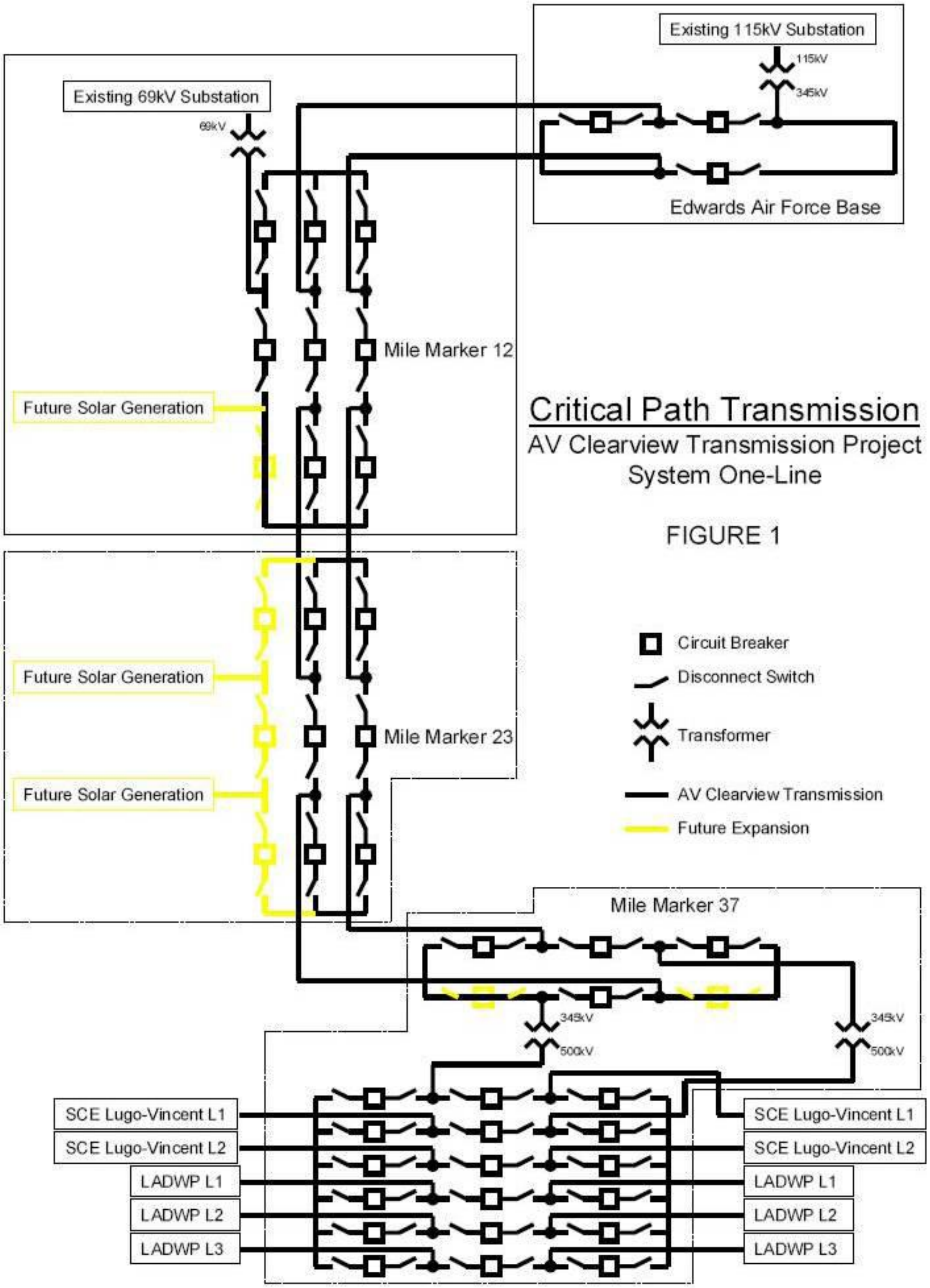
The four primary components of the project are:

- A 345 kV underground transmission line connecting the existing 115 kV SCE South Base substation on Edwards Air Force Base to a new substation in proximity to the 230 kV SCE Pearblossom substation in the community of Littlerock;
- Upgrading the existing South Base substation with 115/345 kV transformers and associated equipment;
- Building a new 345/500 kV substation near the existing SCE Pearblossom substation that will interconnect with the SCE Vincent-Lugo Lines with an option to connect to the LADWP Rinaldi-Victorville Transmission Lines and the LADWP Toluca-Adelanto Transmission Line; and
- Building a new substation with 66/345 kV transformers and associated equipment and connecting it to the existing 66 kV SCE Redman substation.

The project would be completed in two phases:

- Phase 1 consists of:
  - Building the 37.5 mile transmission line to the initial capacity of 1,100 MW and laying conduit for future capacity;
  - Upgrading the South Base substation;
  - Building part of the new 345/500 kV substation and interconnecting with the SCE Vincent-Lugo Transmission Line;
  - Building the substation that connects to the 66kV Redman substation; and

- Phase 2 consists of upgrading the capacity of the AV Clearview Transmission Line to approximately 2,100 MW by adding additional cables (in the extra conduit laid in phase 1 and adding corresponding upgrades at the three substations.


Existing 115kV Substation
115kV
345kV
Existing 69kV Substation
69kV
Edwards Air Force Base
Mile Marker 12
Future Solar Generation
Critical Path Transmission
AV Clearview Transmission Project
System One-Line
FIGURE 1
Circuit Breaker
Disconnect Switch
Transformer
AV Clearview Transmission
Future Expansion
Future Solar Generation
Mile Marker 23
Future Solar Generation
Mile Marker 37
345kV
500kV
345kV
500kV
SCE Lugo-Vincent L1
SCE Lugo-Vincent L2
LADWP L1
LADWP L2
LADWP L3
SCE Lugo-Vincent L1
SCE Lugo-Vincent L2
LADWP L1
LADWP L2
LADWP L3

Benefits of Project Identified by Project Sponsor

The proponent states that:

- The project relieves congestion at SCE's Kramer substation by allowing power to bypass the Kramer-Lugo lines and flow through the Antelope Valley onto SCE's Vincent-Lugo lines, which are rarely at capacity; and

- The project allows, for the first time, the ISO to directly balance the growing wind generation in the Tehachapi area with the solar generation in the Mojave Desert in the eastern Antelope Valley, the Kramer/Barstow region and points east.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on 2020 base cases modeling the four ISO 33% RPS portfolios described in chapter 4. There was no congestion identified on SCE's Kramer-Lugo system in the ISO studies. Therefore, the project sponsor's claim regarding congestion relief benefits on the Kramer-Lugo system is not supported by the ISO's analysis of the ISO-developed portfolios.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR requirements. It also does not provide system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

This project does not provide significant loss reduction benefits because it is essentially a generation collector line.

Emission reduction benefits

Since there are no congestion benefits that would result in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project.

Policy need

The proponent claims the project relieves congestion at SCE's Kramer substation by allowing power to bypass the Kramer-Lugo lines and flow through the Antelope Valley onto SCE's Vincent-Lugo lines. This project connects to the Kramer 115 kV system which is connected to the Kramer 230 kV bus. The Cool Water-Lugo 230 kV line project, which is included in an executed LGIA, connects to the Cool Water 230 kV bus which is connected to the Kramer 230 kV bus through the existing Cool Water-Kramer 230 kV lines. The Cool Water-Lugo 230 kV line project delivers renewable generation located north and east of Kramer, to Lugo substation. The AV Clearview transmission project could provide some of the benefits that are provided by the Cool Water-Lugo 230 kV line project. However, the Cool Water-Lugo 230 kV line project is more effective because it is directly connected to the 230 kV system, whereas the AV Clearview project is connected to the 115 kV system which is a higher impedance path. The existing transfer capability from Kramer 115 kV substation to South Base 115 kV substation where the AV Clearview project is connected to is less than 200 MW. With the Cool Water-Lugo 230 kV line project in the ISO plan, there is no policy-driven transmission need that the Clearview project could meet.

In addition, the project sponsor's claim regarding AV Clearview transmission project's critical role in meeting the RPS goals by accessing renewable generation in the eastern Antelope Valley is not supported by the ISO's analysis of the ISO-developed portfolios. The TRTP can accommodate this generation (which is in the Fairmont CREZ) in the ISO-developed portfolios. As discussed previously, there is available capacity on the TRTP to accommodate significant additional quantities of renewable resources. Many of the resources that would connect to the AC Clearview Project have filed interconnection requests to interconnect to Tehachapi. Therefore, there is no need for the AV Clearview transmission project to accommodate the generation in the Fairmont CREZ in the ISO's portfolios.

Overall Assessment

The cost of this project is estimated at about $900 million with annual carrying charges estimated at $135 million. The annual carrying charges were approximated to be 15% of the total capital cost of the project. The marginal benefits are not material relative to the annual carrying costs of the project.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals based on application of the tariff section 24.4.6.6. In particular, the project is not identified as needed in the ISO's hybrid portfolio.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: **Bay Area Green Link**

Project Sponsor(s): **Startrans IO, LLC**

Type of Submission

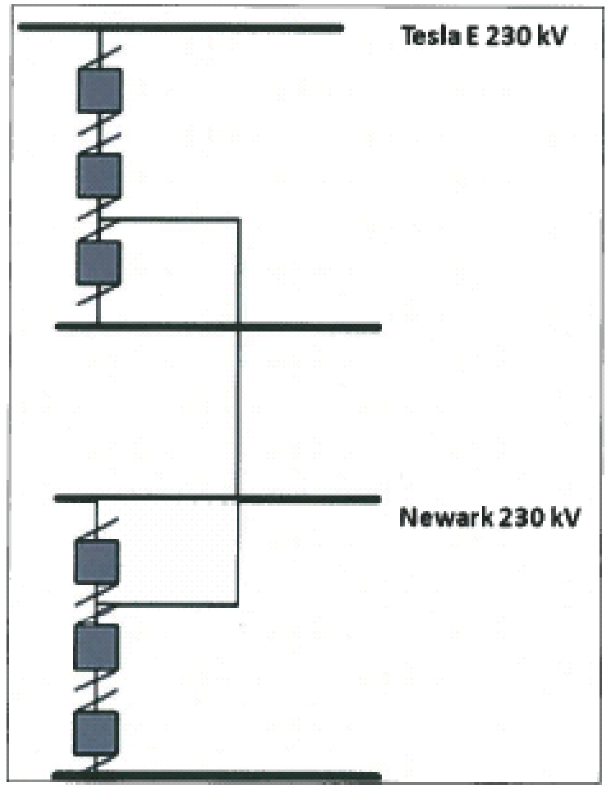
☒ Economic Transmission Project

Project Description

The project consists of a new 230 kV transmission line between the Tesla and Newark substations with 650 MVA thermal capacity and approximately 27 miles long. The project also includes a 150 MVAR SVC proposed to be installed at the Newark Substation.

The proposed operational date for the project is June 30, 2014.

The project geographical location and one-line diagram are shown in the following figures.



Benefits of Project Identified by Project Sponsor

The project proponents state that this project will relieve congestion in the Bay area that was identified in the 2010 ISO Transmission Plan economic study. The project proponents state that this project will reduce the total cost of energy including the cost of congestion by displacing high cost generation with low cost generation and that the project's economic benefits will exceed its cost. The project cost was estimated at $400 million. The project's benefits were estimated as $228.6 million for consumer benefits in 2014, a $36.344 million decrease in capacity payments, a $6.925 million decrease in start-up cost, and a $7.47 million reduction in emission costs. These benefits total to annual benefits of $279 million with a present value of $4,756 million.

With the present value of the cost of the project estimated at $1,571 million, the benefits-to-cost ratio was estimated to be 3.027.

The project proponents also state that the new Newark-Tesla 230 kV line will have reliability benefits such as reduction in line loadings in the Bay Area, which will allow higher import into the area, and that it will also decrease the Bay Area LCR.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There was no meaningful congestion identified in the Bay area that this project would relieve in all three sensitivity cases and the hybrid case. Therefore the project sponsors claim regarding congestion relief benefits on the San Francisco Bay area system are not supported by the ISO's analysis of the ISO-developed portfolios. Compared to the assumptions that apparently were used in the Project's proponent report, the ISO assumptions on the renewable generation development include substantially less development in the Solano area. Therefore, the congestion that was cited in the Bay Area Green Link Transmission Project Report was not observed in the ISO's analysis.

Capacity benefits

The project provides some benefits that come from reduction in the local capacity requirements (LCR). The ISO agrees with the project proponent that the range of Bay Area LCR needs decrease and by a maximum of 415 MW. However, at the ISO-estimated difference in price between the Bay Area capacity cost and the system capacity cost of about $20/kW/year, the ISO estimates LCR reduction benefits to be about $8.3 million per year.

The capacity cost difference is identified in addition to the energy cost savings that is estimated by the production cost model described above. The production cost model is designed to estimate energy cost differences but not resource adequacy capacity cost differences. In the case of Bay Area Green Link, there were no energy cost savings.

The project does not provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

This project does not provide significant loss reduction benefits. It causes only slight reduction in losses, for the PG&E system reduction in losses is only about 0.4% for the peak load conditions and 0.13% for the off-peak. The expected energy savings would be approximately 20.1 GWh in 2020 which will correspond to approximately $1.16 million savings per year.

Emission reduction benefits

There are no congestion benefits and only very small reduction in losses resulting in less fossil fuel consumption, however there are small emission reduction benefits due to reduction in losses created by this transmission project.

Policy need

Based on the ISO's hybrid portfolio, there is no policy-driven transmission need that the Bay Area Green Link project could meet.

Overall Assessment:

The annual estimated savings associated with this project of approximately $9.5 million are the sum of the capacity savings of $8.3 million per year and transmission line loss savings of $1.16 million per year. The cost of this project is estimated at $400 million with annual carrying charges estimated at $60 million. It is not economically justified on the basis of capacity cost savings and transmission line loss savings since the annual carrying charge is over six times higher than total annual benefits. Also, assuming a proxy value of $1.2 million based on the loss savings would still not be sufficient to justify this project. Carrying charges were approximated to be 15% of the total capital cost of the project.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals based on application of tariff section 24.6.6.6. No need for a policy project in this area is identified in the ISO's hybrid portfolio or any of the three sensitivity studies.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: Greater Bay Area (GBA) Transmission Project

Project Sponsor(s): San Francisco Public Utilities Commission (SFPUC)

Type of Submission

☒ Reliability and Economic Transmission Project

Project Description

The project would deliver power via a 230 kV HVDC submarine cable running under the San Francisco Bay from an AC/DC converter station co-located at or near PG&E's Newark substation to a converter station located at Alameda Point. From the Alameda Point converter station, AC transmission lines will directly connect to the San Francisco electric grid at the Embarcadero (230 kV) and Potrero (115 kV) substations. AC transmission lines will also connect to the Oakland electric grid at either the Davis (115 kV) or Cartwright (115 kV) substations which in turn connect to the Oakland C (115 kV) substation.

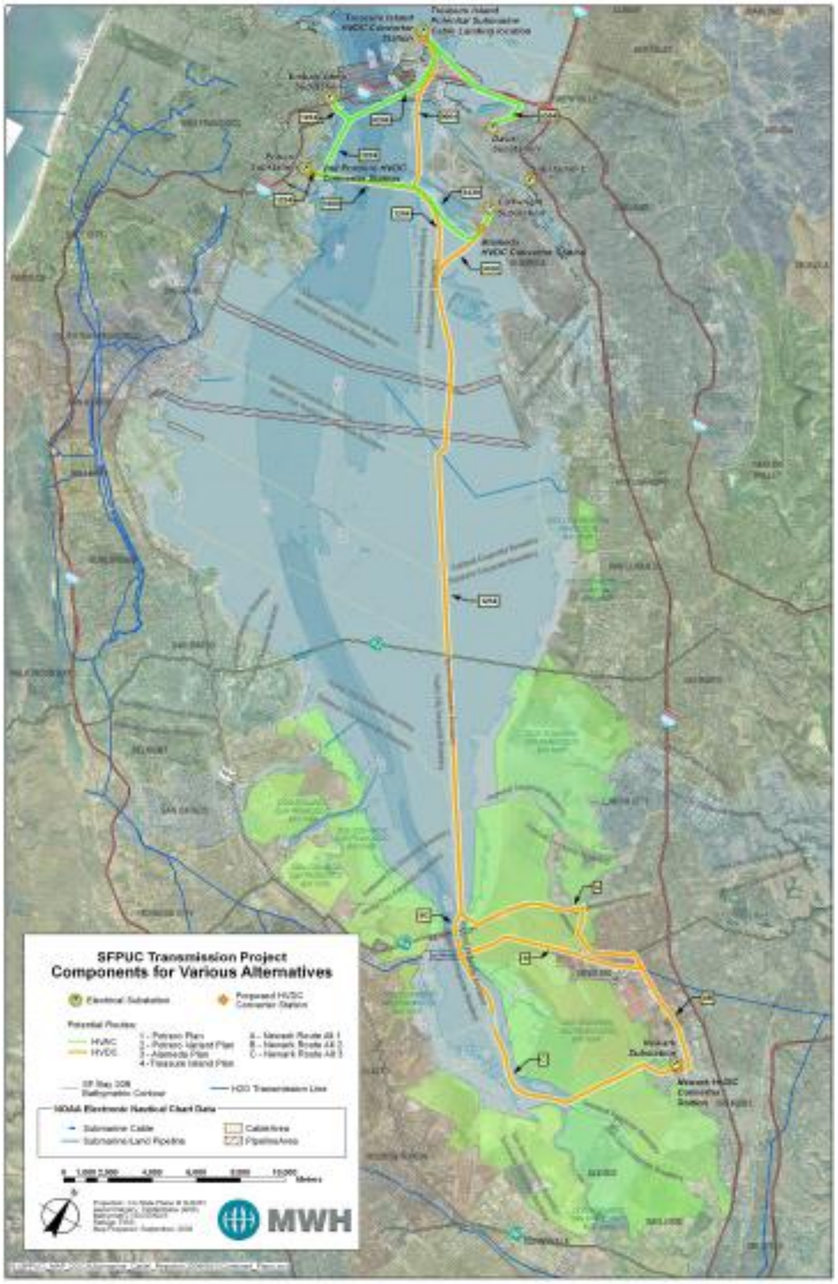
The project net capacity would be 400 MW.

The proposed project includes the following major components:

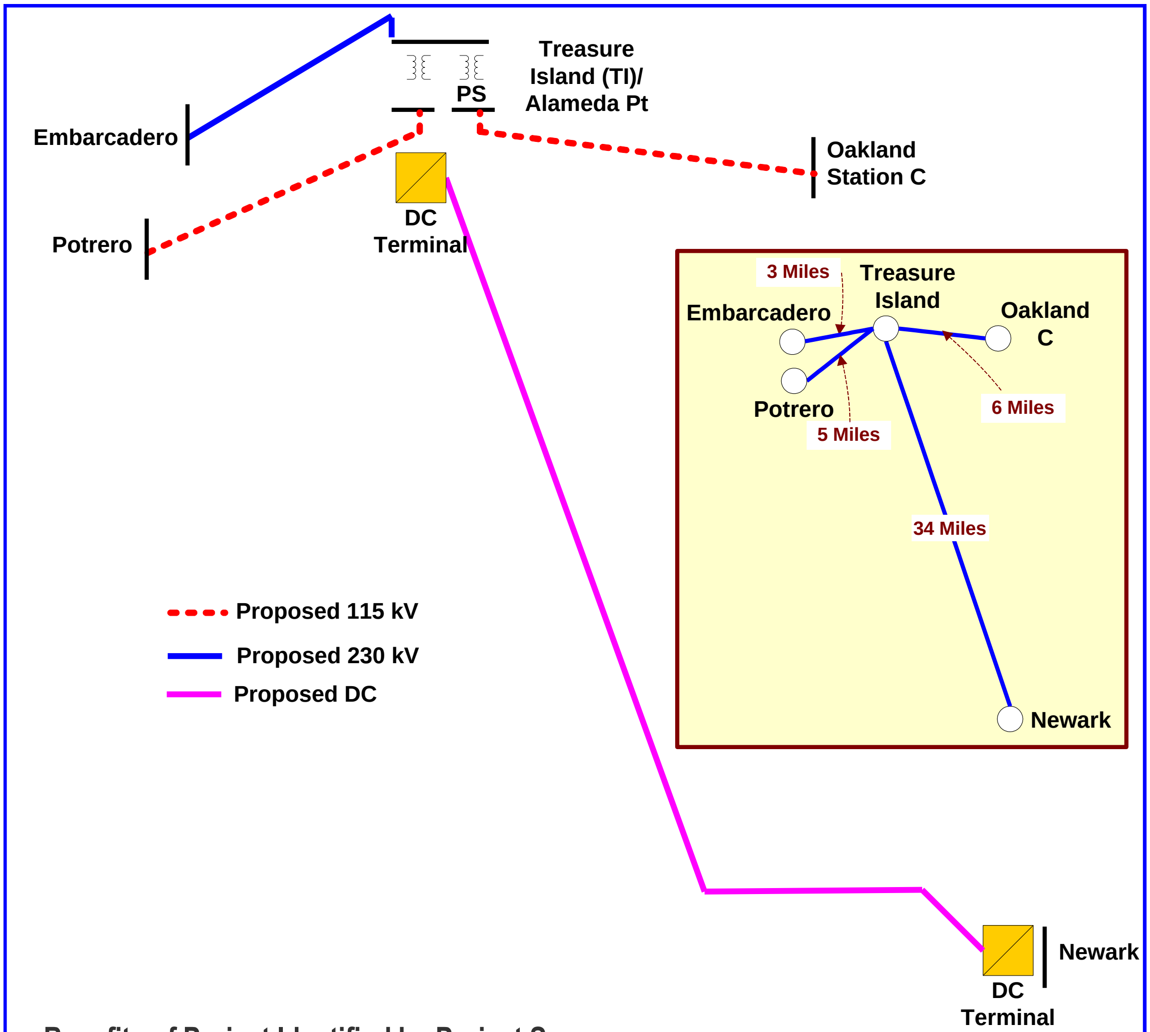
- A 400 MW DC convertor station at Newark;
- A new 400 MW DC underground and undersea cable from Newark Substation to Alameda Point/Oakland;
- A 400 MW DC convertor station at Alameda Pt/Oakland.;
- A regular and a phase shifting 230/115 kV transformer bank at Alameda Pt./Oakland;
- A 230 kV undersea cable from Alameda Pt./Oakland to Embarcadero substation;
- A 115 kV undersea cable from Alameda Pt./Oakland to Potrero substation; and
- A 115 kV cable from Alameda Pt./Oakland to Oakland Station C substation via 115 kV Cartwright or 115 kV Davis substations

The proposed operational date for the project is September 1, 2016.

The project geographical location and one-line diagram are shown in the following figures.



SFPUC Transmission Project
Components for Various Alternatives
HVAC
HVDC
1 - Potrero Plan
3 - Alameda Plan
4 - Treasure Island Plan
HDD Transmission Line
Submarine Cable
MWH



Benefits of Project Identified by Project Sponsor

The project proponents state that this project will relieve congestion in the Bay area that was identified in the 2010 ISO Transmission Plan economic study, particularly between Contra Costa and Moraga. In addition, the project's sponsors identified potential benefits as:

- Providing a "Transmission Only" solution to San Francisco's electric system allowing for the retirement of all remaining in-city generation;
- Ensuring the reliability of San Francisco's downtown 230 kV transmission system by providing a third interconnection to the downtown area;
- Improving the reliability of the Oakland/East Bay grid by providing a new transmission pathway to the East Bay;

- Increasing the ability to import energy into the Greater Bay Area, through upgrading to 230 kV SFPUC's existing 115 kV lines that enter the Bay Area; and

- Reducing overloads along the Peninsula due to power that currently flows through the Peninsula to San Francisco over existing lines.

The cost of the project was estimated at $684.6 million. The project sponsors did not provide estimates for the project's benefits.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in the 2009 request window as both an economic and reliability project. As reliability benefits, the project proponents cited multiple Category C overloads that this project will mitigate. Although the project indeed mitigates some Category C overloads, these overloads may be mitigated by existing SPS and by a transmission project that is already in service (San Francisco re-cabling).

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios which are described in chapter 4 of this plan. In these portfolios, the ISO assumptions on the renewable generation developments include substantially less development in the Solano area compared to the assumptions that were used in the project proponent's report. As such, the ISO's study showed no congestion in the Bay area that this project could relieve and no congestion on the Contra Costa – Moraga 230 kV lines. Therefore the project sponsor's claim regarding congestion relief benefits in the San Francisco Bay area system is not supported.

Capacity benefits

This project provides small local capacity benefits because it will most likely eliminate the Oakland LCR sub area, with needs estimated at about 150 MW. However, the resources located in this sub area are either under a long-term contract (municipal owned) or have a very low capacity cost (lower than the rest of the Bay Area). As such, this decrease in LCR will not yield any economic savings.

It also does not provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

This project does not provide significant loss reduction benefits.

Emission reduction benefits

Since there are no congestion or material loss reduction benefits resulting in less fossil fuel consumption, there are no significant emission reduction benefits created by this transmission project.

Policy need

Based on the ISO's hybrid portfolio, there is no policy-driven transmission need that the Greater Bay Area Transmission Project could meet.

Overall assessment

The ISO assessment of this project concluded that it there are marginal benefits which are not offset by the cost of the project.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals based on application of tariff section 24.4.6.6. The ISO's hybrid portfolio did not identify the need for such a project, nor did any of the sensitivity scenarios.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: Contra Costa to San Francisco Transmission Line

Project Sponsor(s): Pattern Power Development Company LLC

Type of Submission

☒ Economic Transmission Project

Project Description

The project consists of a new 230 kV high voltage DC transmission line between the Contra Costa and Hunters Point substations with 400 MW or higher capacity.

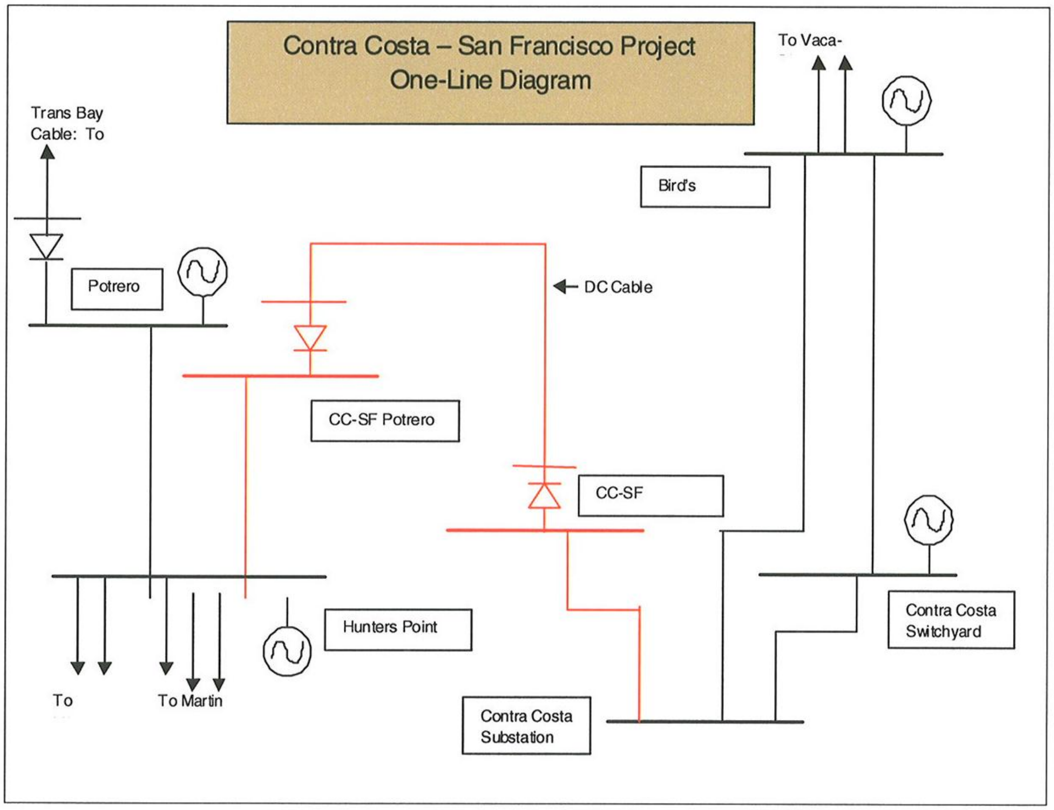
Other San Francisco substations, such as Embarcadero or Potrero could also be considered as a termination point for the new line instead of the Hunters Point Substation.

The proposed project includes the following major components:

- Approximately 7 miles of single circuit 230 kV AC line from the Contra Costa Substation to a converter station in Pittsburg;
- A 400 MW HVDC voltage source converter station in Pittsburg;
- Approximately 53 miles of underwater HVDC transmission line to a converter station in San Francisco;
- A 400 MW HVDC voltage source converter station in San Francisco; and
- Approximately 2.5 miles of single circuit underwater 115 kV AC transmission line from the San Francisco converter station to the Hunters Point Substation.

The proposed operational date for the project is September 31, 2015.

The project one-line diagram is shown in the following figure.



Benefits of Project Identified by Project Sponsor

The project proponent states that this project will relieve congestion in the Bay area that was identified in the 2010 ISO Transmission Plan economic study, particularly congestion on the Contra Costa-Moraga 230 kV transmission lines. In addition, the project will allow a significant amount of renewable generation to be delivered to load centers in San Francisco and Peninsula.

The cost of the project was estimated at $575 million for a 400 MW HVDC line. The project annual benefit for 2017 was estimated by the project proponent at $393.8 million for California and $403.3 million for WECC for the 400 MW HVDC line and approximately 35% higher for the 600 MW HVDC line.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios which are described in chapter 4 of this plan. In these portfolios, the ISO assumptions on the renewable generation developments include substantially less development in the Solano area compared to the assumptions that were used in the project proponent's report. As such, the ISO's study showed no congestion in the Bay area that this project could relieve and no congestion on the Contra Costa - Moraga

230 kV lines. Therefore the project sponsor's claim regarding congestion relief benefits in the San Francisco Bay area system is not supported.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR. It also does not provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

This project does not provide significant loss reduction benefits. It causes only a slight reduction in losses, for the PG&E system at about 1.7% for the peak load conditions and 1.4% for the off-peak. The expected energy savings would be approximately 88.6 GWh in 2020 which will correspond to approximately $5.14 million savings per year.

Emission reduction benefits

Since there are no congestion benefits that this project can relieve and no significant loss reduction benefits resulting in less fossil fuel consumption, it follows that there would not be any significant emission reduction benefits created by this transmission project. As such, a WECC-wide emission reduction due to this project is not supported by the ISO's analysis.

Policy need

Based on the ISO's hybrid portfolio, there is not a policy-driven transmission need that the Contra Costa to San Francisco transmission line project could meet.

Overall Assessment

Based on the assessment of the Contra Costa to San Francisco Transmission Line Project, the ISO concluded that the project would result in an annual transmission line loss savings of approximately $5.14 million per year and no energy, capacity or emission reduction benefits. The cost of this project is estimated at $575 million with annual carrying charges estimated at $86.25 million per year. Assuming a proxy value for emission benefits of $5 million based on the loss savings would still not be sufficient to justify this project.

The project is not policy-driven as it is not needed to meet 33% RPS goals based on application of tariff section 24.4.6.6. A need for such a project was not identified in the ISO's hybrid portfolio or in any of the sensitivity scenarios.

Based on the analysis performed and presented in this plan, the ISO has concluded that this project is not needed.

General Information

Project Name: **Sobrante to Embarcadero 230 kV AC Line**

Project Sponsor(s): **California Transmission Development, LLC**

Type of Submission

☒ Economic Transmission Project

Project Description

The project would interconnect the Sobrante 230 kV Substation in the East Bay with the Embarcadero 230 kV substation in downtown San Francisco.

The primary components of the project are:

- A new switching/transition station near Claremont substation and a 7-mile- long 230 kV overhead transmission line to this station from Sobrante;

- A new substation in the southwest side of Oakland and a 230 kV underground transmission line from the switching/transition station to this substation; and

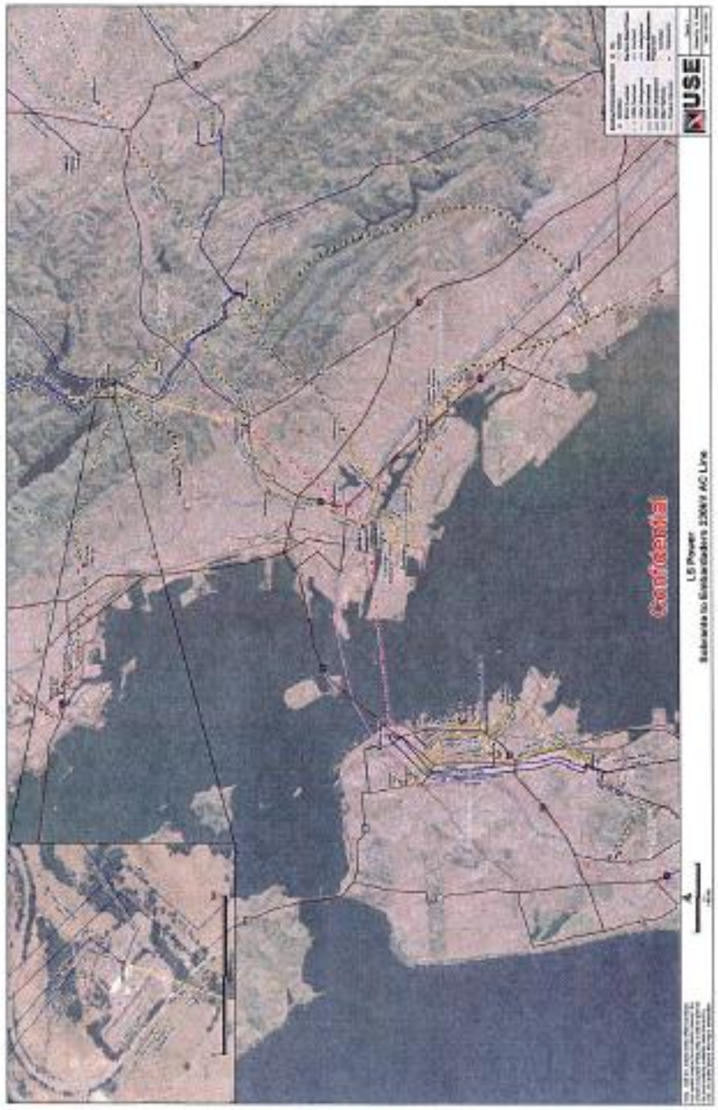
- A 230 kV submarine/underground line from the new substation in southwest Oakland to the 230 kV Embarcadero substation in San Francisco.

The proposed project also includes an option to connect to the 115 kV transmission systems at Claremont and/or west Oakland.

The proposed operational date for the project is June 1, 2016.

The project location and potential route is shown in the following figure.

Project Location



Benefits of Project Identified by Project Sponsor

The project proponent states that this project will:

- Relieve congestion between the East Bay area and San Francisco;
- Assist in enabling all fossil fuel generation between San Francisco and Oakland to be retired;
- Improve the delivery and integration of renewable resources in the Bay Area; and
- Improve the security and diversity on the transmission system in the area.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There was no congestion identified between the East Bay area and San Francisco in the base case or in the three sensitivity portfolios. Therefore the project sponsors claim regarding congestion relief benefits on the San Francisco Bay area system are not supported by the ISO's analysis of ISO-developed portfolios.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR. It also does not provide any system capacity benefits because it does not increase import capability into the ISO.

System-loss reduction benefits

This project does not provide significant loss reduction benefits. It causes only slight reduction in losses, for the PG&E system of about 0.4% for the peak load conditions and 0.12% for the off-peak. The expected energy savings would be approximately 19.6 GWh in 2020 which will correspond to approximately $1.14 million savings per year.

Emission reduction benefits

Since there are no congestion benefits and only a slight reduction in losses resulting in less fossil fuel consumption, there are also no material emission reduction benefits created by this transmission project.

Policy need

Based on the ISO's hybrid portfolio, there is not policy-driven transmission need that the Sobrante to Embarcadero transmission line project could meet.

Overall Assessment

Based on the assessment of the Sobrante to Embarcadero 230 kV AC Line, the ISO concluded that the project would result in an annual transmission line loss savings of approximately $1.14 million per year and no energy, capacity or emission reduction benefits. The cost of this project is estimated at $699 million with the annual carrying charges estimated at $104.85 million per year. Assuming a proxy value for emission benefits of $1 million based on the loss savings would still not be sufficient to justify this project.
The project is not policy-driven as it is not needed to meet 33% RPS goals based upon application of tariff section 24.4.6.6. A need for such a project is not identified in the ISO's hybrid portfolio or in any of the three sensitivity studies
. Based on the analysis performed and presented in this plan, the ISO has concluded that this project is not needed.

General Information

Project Name: **Imperial Valley-Blythe Area Renewable Transmission Integration**

Project Sponsor(s): **California Transmission Development, LLC**

Type of Submission

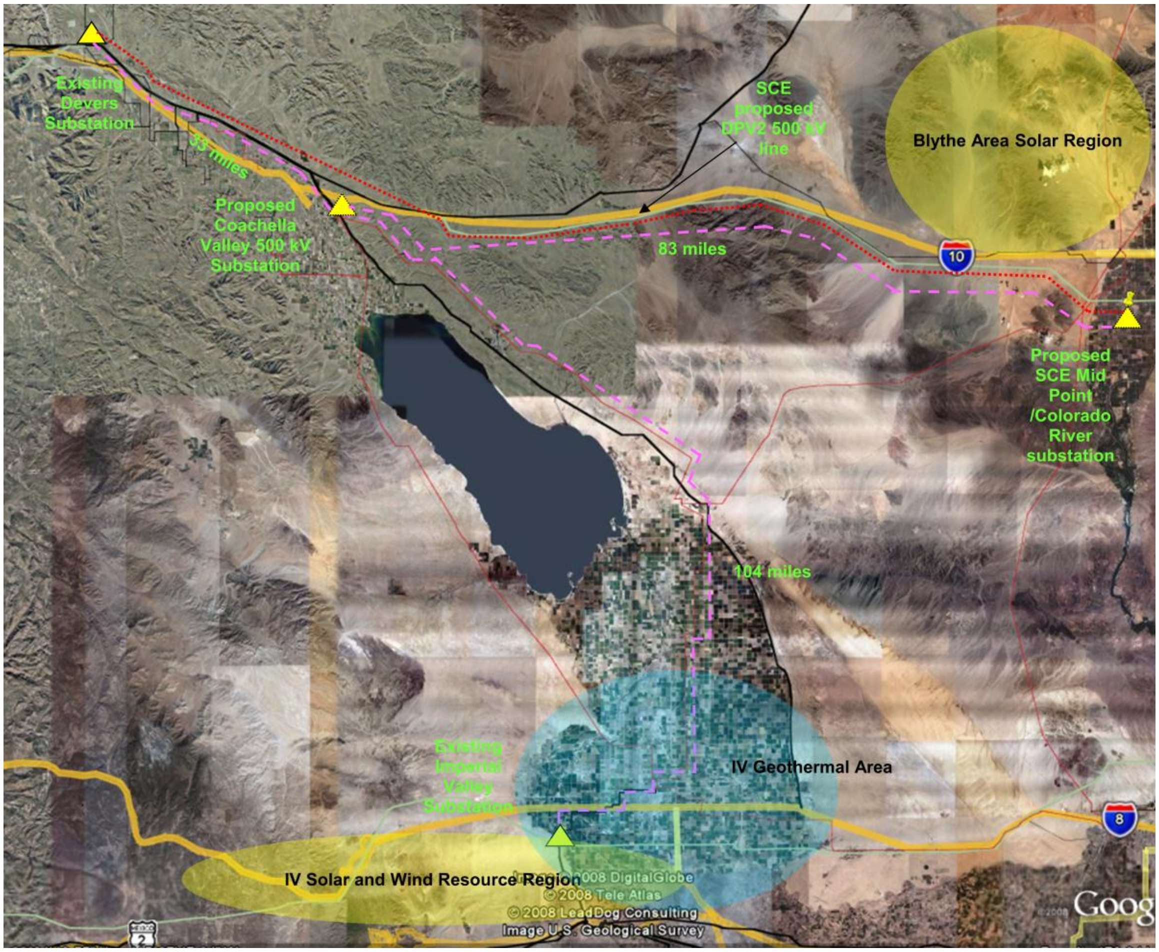
☒ Others (Transmission System Study)

Project Description

The proposed project involves the construction of approximately 220 miles of new 500 kV AC transmission line that connects the 500 kV buses at Imperial Valley substation, Devers substation, planned Mid Point/Colorado River substation via a new 500 kV substation at Coachella Valley.

The proposed in-service date of the project is June 1, 2014.

The project is expected to cost approximately $1.1 billion in 2008 dollars. The estimate is accurate +/-20%.



Benefits of Project Identified by Project Sponsor

The project proponent states that:

- The project is designed to deliver 1,800 to 2,000 MW of the in excess of 6,000 MW of potential solar, wind and geothermal resources located in Imperial Valley region on the California-Mexico border and energy from solar generation projects proposed in the Blythe region in California to the load centers in Southern California

- In addition to facilitating the California Load Serving Entities in attaining the California RPS goals, the project would also aid economically efficient and environmentally friendly generation from conventional thermal resources located in Arizona to reach the southern California load center thereby having a positive impact on the energy prices in the southern part of the state; and

- The project will also reduce transmission system losses and reduce congestion between different regions in Southern California.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There were no binding transmission constraints, and therefore no congestion, that would be expected to be relieved by this project. Therefore the project sponsor's claim that the project will reduce congestion between different regions in southern California was not supported by the ISO studies.

Capacity benefits

This project could potentially reduce or even eliminate LCR for the Greater San Diego/Imperial Valley area. The Greater San Diego/Imperial Valley area requirement is expected to be eliminated when the San Diego internal requirements exceed the Greater Imperial Valley/San Diego area requirements. This may happen as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these control areas to the ISO control area. The construction of new generation in the Imperial Valley area may also help to eliminate the Greater Imperial Valley/San Diego requirement. The ISO 33% RPS portfolios modeled a significant amount of new generation in the Imperial Valley area.

The ISO has estimated that, at most, the proposed transmission project could reduce the LCR for the Greater Imperial Valley/San Diego area by approximately 1000 MW based on the difference in the LCR for the internal San Diego LCR and the Greater Imperial Valley/San Diego LCR being approximately 1000 MW. At the ISO-estimated difference in price between local area capacity cost and the system capacity cost of about $20/kW/year, the ISO estimates the LCR capacity reduction benefits to be, at most, about $20 million per year.

This project may potentially increase system capacity benefits by increasing import capability into the ISO; however the need for the increased import has not been identified. There is a significant amount of renewable generation that is expected to come on-line at Imperial Valley, so importing more power from Arizona is expected to have minimal economic value.

System-loss reduction benefits

The project provides some energy savings of approximately $2.2 million each year.

Emission reduction benefits

Since there are no congestion benefits resulting in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project other than indirectly through reductions in line losses.

Policy need

The proposed project could be a potential solution to address the concern of Sunrise Powerlink potentially exceeding its 1000 MW path rating that was identified in the ISO 33% RPS analysis. The ISO's proposed solution to address this concern, however, is to re-rate Sunrise to allow flow higher than 1000 MW and to add a new 500/230 kV Miguel bank #3. The ISO's proposed solution serves the same purpose as the proposed transmission project, but at a significantly lower cost. Accordingly, this project is not needed. Adding the third bank at Miguel has been identified as a category 2 policy-driven element in this transmission plan.

Overall assessment

The proposed transmission project has some benefits in some categories. The estimated annual carrying charge of the project is approximately $165 million. The annual carrying charge is over seven times higher than the total annual benefits.

The project is also not needed as a policy-driven element because its cost is significantly higher than the ISO's proposed solution that would mitigate the identified needs.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: North Gila - Imperial Valley #2

Project Sponsor(s): California Transmission Development, LLC

Type of Submission

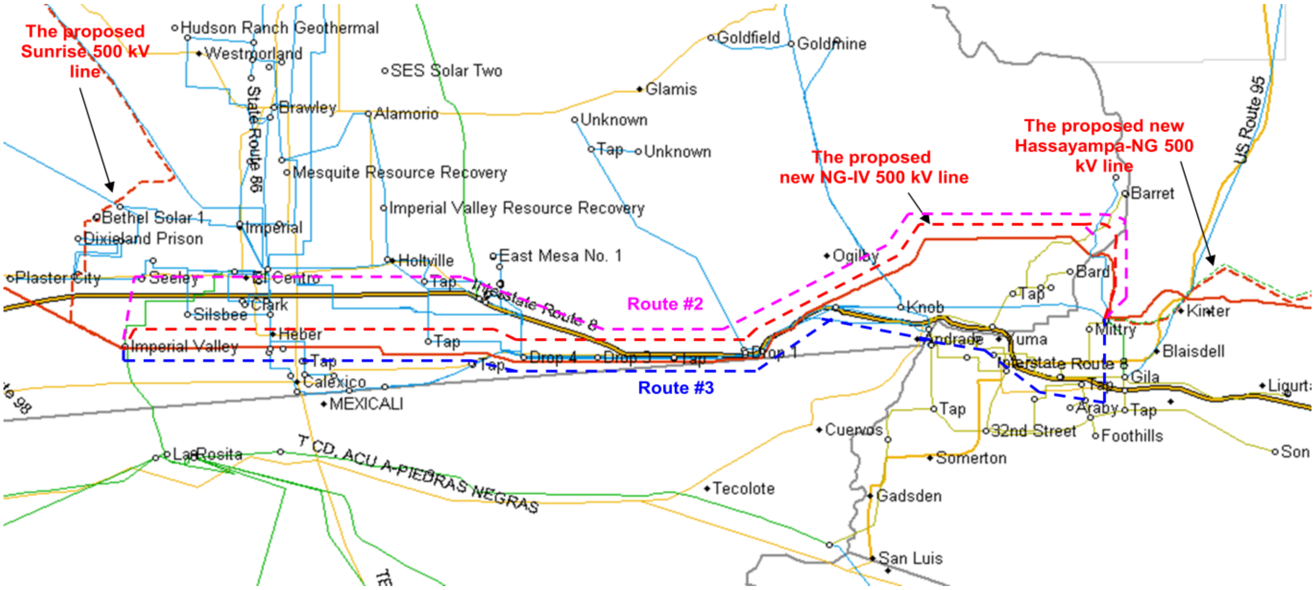
☒ Others

Project Description:

The proposed project involves the construction of approximately 84 miles of new 500 kV AC line between the 500 kV buses existing North Gila substations and the Imperial Valley substation. The project capacity rating will be determined through studies and rating process.

The proposed in-service date is June 2014.

The proponent states that, based upon initial estimate,s the proposed NG-IV #2 500 kV line is expected to cost approximately $490 million in 2008 dollars. The estimate is accurate +/- 20%.


The proposed Sunrise 500 kV line
The proposed new NG-IV 500 kV line
The proposed new Hassayampa-NG 500 kV line
Route #2
Route #3
US Route 95
Interstate Route 8
State Route 86
Hudson Ranch Geothermal
Westmorland
SES Solar Two
Glamis
Goldfield
Goldmine
Brawley
Alamorio
Unknown
Tap
Mesquite Resource Recovery
Imperial Valley Resource Recovery
Bethel Solar 1
Dixieland Prison
Imperial
Holtville
East Mesa No. 1
Ogilby
Barret
Bard
Plaster City
Seeley
El Centro
Clark
Silsbee
Heber
Imperial Valley
Calexico
MEXICALI
Drop 4
Drop 3
Drop 1
Knob
Andrade
Yuma
Mittry
Kinter
Blaisdell
Gila
Araby
Foothills
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Cuervos
32nd Street
Somerton
Gadsden
San Luis
Tecolote
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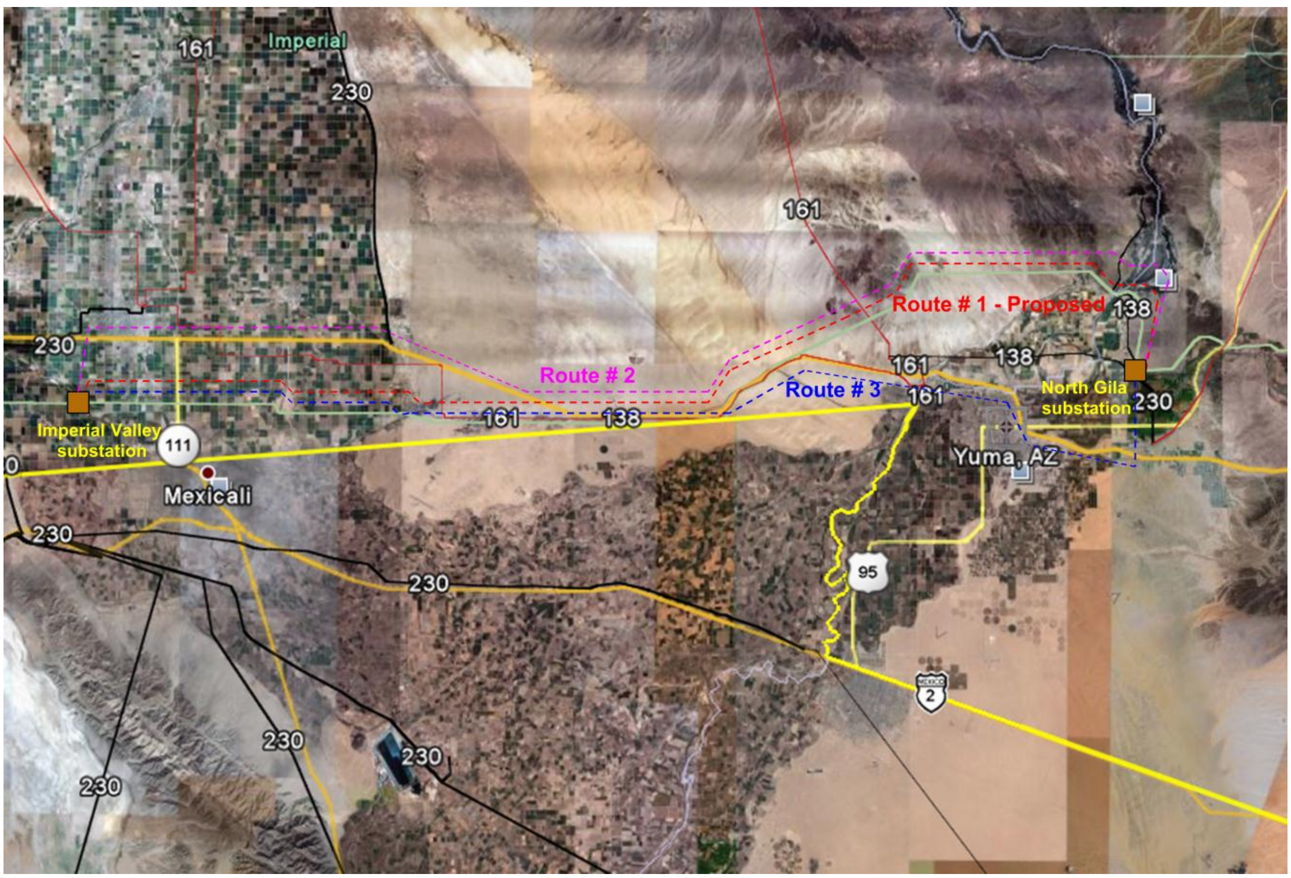

Imperial
161
230
138
111
95
2
Route # 1 - Proposed
Route # 2
Route # 3
Imperial Valley substation
North Gila substation
Mexicali
Yuma, AZ

Benefits of Project Identified by Project Sponsor

The proponent states that:

- Along with the APS proposed Hassayampa-North Gila 500 kV and the Sunrise Powerlink approved by the ISO Board of Governors, the proposed North Gila-Imperial Valley transmission line is expected to complete the second path between Palo Verde and Imperial Valley;

- The project will project a complete a path for the delivery of renewable resources located in Imperial Valley region located on the California-Mexico border and in and around Yuma area to the load centers in Arizona and Southern California; and

- The line will also reduce transmission system congestion between Arizona and Southern California, identified as a National Electric Transmission Corridor by the U.S. Department of Energy.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There were no binding transmission constraints, or no congestion, that would be expected to be relieved by this project. Therefore the project sponsor's claim that the project will reduce congestion between different regions in southern California was not supported by the ISO studies.

The ISO studies did not identify a need to increase the transfer capability between southern Arizona and southern California.

Capacity benefits

This project could potentially reduce or even eliminate LCR for the Greater San Diego/Imperial Valley area. The Greater San Diego/Imperial Valley area requirement is expected to be eliminated when the San Diego internal requirements exceed the Greater Imperial Valley/San Diego area requirements. This may happen as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these balancing authority areas to the ISO balancing authority area. The construction of new generation in the Imperial Valley area may also help to eliminate the Greater Imperial Valley/San Diego requirement. The ISO 33% RPS portfolios modeled a significant amount of new generation in the Imperial Valley area.

The ISO has estimated that, at most, the proposed transmission project could reduce the LCR for the Greater Imperial Valley/San Diego area by approximately 1000 MW based on the difference in the LCR for the internal San Diego LCR and the Greater Imperial Valley/San Diego LCR being approximately 1000 MW. At the ISO-estimated difference in price between local area capacity cost and the system capacity cost of about

$20/kW/year, the ISO estimates the LCR capacity reduction benefits to be, at most, about $20 million per year.

This project may potentially increase system capacity benefits by increasing import capability into the ISO; however the need for the increased import has not been identified. There is a significant amount of renewable generation that is expected to come on-line at Imperial Valley, so importing more power from Arizona is expected to have minimal economic value.

System-loss reduction benefits

The project provides energy savings of approximately $1.4 million each year.

Emission reduction benefits

Since there are no congestion benefits resulting in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project other than indirectly through reductions in line losses.

Policy need

There is no policy-driven transmission need that this project could meet.

Overall Assessment

The proposed transmission project has some benefits in some categories. The estimated annual carrying charge of the project is approximately $73.5 million. The annual carrying charge is over three times higher than the total annual benefits.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals on application of tariff section 24.4.6.6. The need for such a project is not identified in the ISO's hybrid portfolio or in any of the sensitivity studies.

The ISO has therefore concluded that the project is not needed.

General Information

Project Name: New 3rd 500/230 kV Transformer Bank (82) at Imperial Valley Substation

Project Sponsor(s): San Diego Gas & Electric

Type of Submission

☒ Economic Transmission Project from Participating Transmission Owner (PTO)

Project Description

This project consists of adding a third 500/230 kV transformer bank, 1120/1194 MVA in capacity, at Imperial Valley substation. This bank would be parallel to the two existing 500/230 kV banks: 600 MVA Bank 80 and 1120 MVA Bank 81.

The proposed in-service date of the project was June 1, 2010.

The conceptual cost estimate for the addition of Bank 82 at Imperial Valley is $36M.

Benefits of Project Identified by Project Sponsor

The project proponent states that:

- The addition of a third 500/230 kV transformer at IV effectively mitigates existing congestion across the current 500/230 kV transformers. The ISO OASIS shows over 75,000 MWh of border generation decrements to manage intra-zonal IV bank congestion during the fall of 2008. Congestion is expected to increase substantially in the future considering the large amount of renewable generation that is anticipated to connect to the Imperial Valley 230 kV bus, within the IID control area, and at the planned ECO substation on the Imperial Valley-Miguel segment of the existing Southwest Powerlink 500 kV line; and

- The third bank at the IV substation would increase grid efficiency for the WECC in aggregate (reduced fuel use, and corresponding reductions in WECC air emissions, compared to the current bank configuration). At high levels of new renewable resource development in the Imperial Valley area, there could be physical curtailment of renewable generation absent the third bank (curtailment of fossil-fuel generation in the Imperial Valley area may not be sufficient to mitigate congestion absent the third bank).

ISO Analysis of the Project

Capacity in excess of, or in addition to, amounts reflected in LGIP studies must be approved through the transmission planning process. This project was identified in a Phase 2 LGIP study as needed to connect generation in the interconnection queue and has been included as a Delivery Network Upgrade in Q78 signed

LGIA. As part of its transmission planning process review, the ISO did not find any need to approve a larger project or add capacity beyond that reflected in the LGIP studies and executed LGIAs.

General Information

Project Name: New ECO 500/230/69kV Substation & New 69 kV Transmission Line to Boulevard Substation

Project Sponsor(s): San Diego Gas & Electric

Type of Submission

☒ Reliability Transmission Facility

☒ Location Constrained Resource Interconnection Facility

Project Description

This project includes the construction of a new 500/230/69 kV substation between the Imperial Valley substation and Miguel substation near the Southwest Powerlink (SWPL), and extending 69 kV from the new substation to Boulevard Substation. It also includes rebuilding Boulevard substation on a neighboring site to accommodate renewable generation interconnection at Boulevard. The proposed 69 kV transmission line between the proposed ECO substation and the Boulevard substation would increase the reliability of the existing 69 kV transmission system by transforming the existing 13-mile radial system into a SCADA–controlled normally open loop, which will improve reliability (maintenance, operations, outage restoration) to the Boulevard and Crestwood substations.

The proposed in-service date of the project is September 1, 2011.

The conceptual cost estimate of the project is less than $280 million.

Benefits of Project Identified by Project Sponsor

The project proponent states that:

- The primary purpose of the project is generation interconnection in southeastern San Diego County. Without the ECO Project each generator would have to decide whether to build a much longer gen-tie (to interconnect at the Miguel substation or Imperial Valley substation (82 miles apart) or to build a new substation to interconnect directly into the SWPL. There are currently six active generator applications submitted to the ISO for connections to the SWPL transmission line, through the ECO Substation, totaling approximately 2,000 MW of wind generation. In addition, there is one active generator application that has been submitted to the ISO for connection to the Boulevard substation, totaling approximately 200 MW of wind generation; and

- The proposed 69 kV transmission line between the proposed ECO substation and the Boulevard substation will increase the reliability of the existing 69 kV transmission system by transforming the existing 13-mile radial system into a SCADA-controlled normally open loop, which will improve reliability (maintenance, operations, outage restoration) to the Boulevard and Crestwood substations.

ISO Analysis of the Project

A similar project was identified in phase 2 LGIP studies and is included as a Reliability Network Upgrade in the Q32 LGIA. The scope of the project included in the LGIA is for a 500/230/138 kV East County substation between Miguel and Imperial Valley, a new 138/12 kV Boulevard substation, and a new 13.5 mile 138 kV line from Boulevard to ECO. The LGIA has been tendered.

The ECO 500/230/138 kV substation is assumed to be in-service because it was identified as needed in phase 2 LGIP studies and is reflected in the Q106A executed LGIA. The Q106A LGIA also includes a second ECO-Boulevard 138 kV line as a Reliability Network Upgrade.

The ECO 500/230/138 kV substation and new ECO-Boulevard 138 kV line were modeled in the ISO 33% RPS study hybrid portfolio base case. The new substation and line were needed to connect approximately 330 MW of new generation that was modeled in the San Diego South CREZ. As indicated above, these facilities were identified in phase 2 LGIP studies and LGIAs.

Capacity in excess of, or in addition to, amounts reflected in LGIP studies must be approved through the transmission planning process. This project was identified in a phase 2 LGIP study as needed to connect generation in the interconnection queue. As part of its transmission planning process review, the ISO did not find any need to approve a larger project or add capacity beyond that reflected in the LGIP studies and executed LGIAs.

General Information

Project Name: **North Gila - Imperial Valley #2 Double Circuit Project**

Project Sponsor: **Energy Capital Partners, LLC, (Southwest Transmission Partners and on behalf of Energy Capital Partners)**

Type of Submission

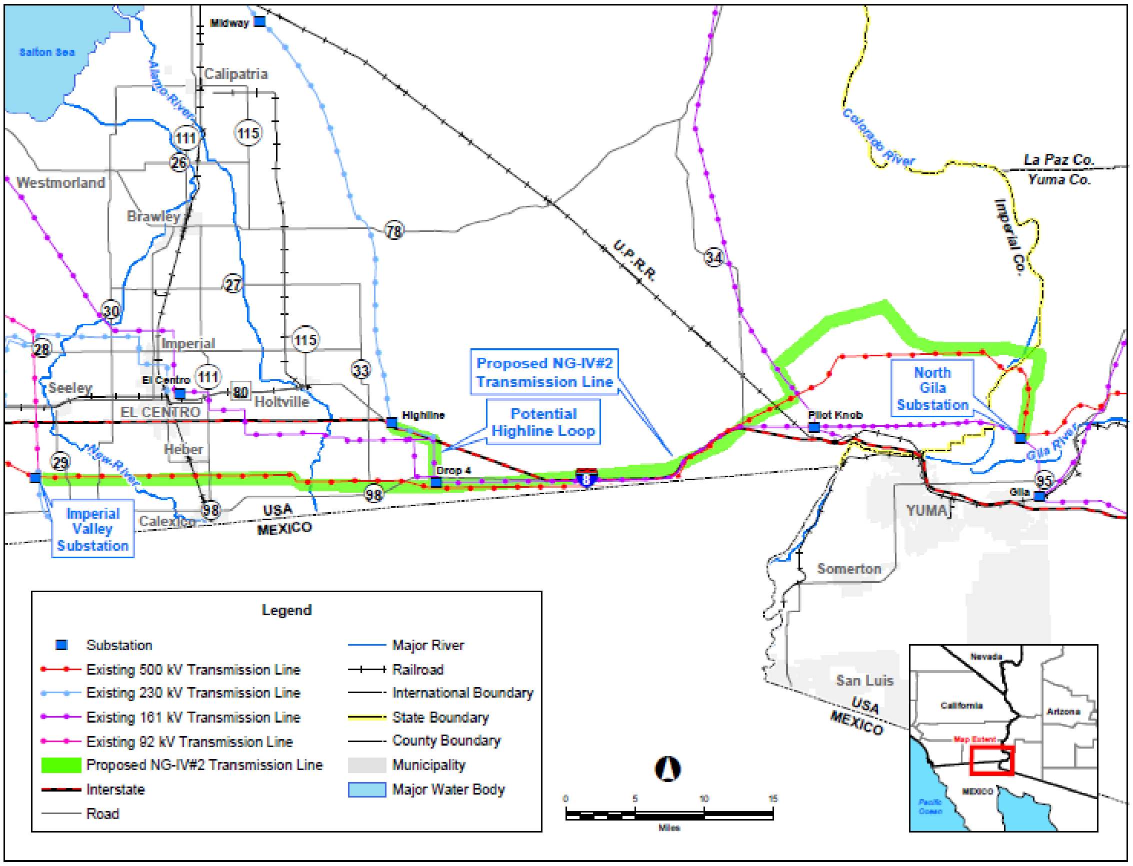
☒ Economic Transmission Project

Project Description

The proposed North Gila – Imperial Valley #2 double circuit 500 kV project is designed to increase the West of River transfer capability by up to 3000 MW, deliver significant amounts of renewable resources bi-directional between Arizona and southern California, utilize existing transmission corridors by paralleling the existing North Gila – Imperial Valley line, and provide for an interconnection for one of the circuits at the IID Highline substation to improve reliability of their 230 kV system. The project proponents plan to discuss further with IID a possible structure whereby IID would control and possible own all or a portion of one circuit that is looped in or out of their Highline substation. The remaining line would be proposed to be controlled by the ISO and revenues recovered through the ISO Transmission Access Charge. The project sponsors would be willing to consider other potential existing ISO PTO's to also participate in the project depending on the level of interest. This project has currently filed a BLM right of way application (SF-299) to initiate the NEPA EIS process. BLM will be the lead federal agency for the project.

The proposed in-service date of the project is May 1, 2015.

The cost of the project is estimated to be $395 million.



Benefits of Project Identified by Project Sponsor

The project proponent states that:

- The proposed addition of the North Gila-Imperial Valley double circuit 500 kV line is a major intertie expansion between the North Gila area and the Imperial Valley area;

- The proposed project would become an additional component of the West of Colorado Transmission Path (WOR) and is expected to provide a significant increase in the transfer capability between southern Arizona and southern California while enabling substantial amounts of renewable energy access to the additional transmission transfer capability; and

- The proposed project will also increase the reliability of the system both to the ISO and to IID with the proposed 500 kV substation at the existing IID Highline 230 kV substation, and help to complement the SDG&E planned Sunrise Power Link.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios described in chapter 4. There were no binding transmission constraints, and therefore no congestion, that would be expected to be relieved by this project. Therefore the project is not expected to reduce congestion between different regions in southern California.

The ISO studies did not identify a need to increase the transfer capability between southern Arizona and southern California.

Capacity benefits

This project could potentially reduce or even eliminate LCR for the Greater San Diego/Imperial Valley area The Greater San Diego/Imperial Valley area requirement is expected to be eliminated when the San Diego internal requirements exceed the Greater Imperial Valley/San Diego area requirements. This may happen as additional transmission is constructed between the IID/CFE systems and Imperial Valley and more power is flowing in real-time from these balancing authority areas to the ISO balancing authority area. The construction of new generation in the Imperial Valley area may also help to eliminate the Greater Imperial Valley/San Diego requirement. The ISO 33% RPS portfolios modeled a significant amount of new generation in the Imperial Valley area.

The ISO has estimated that, at most, the proposed transmission project could reduce the LCR for the Greater Imperial Valley/San Diego area by approximately 1000 MW based on the difference in the LCR for the internal San Diego LCR and the Greater Imperial Valley/San Diego LCR being approximately 1000 MW. At the ISO-estimated difference in price between local area capacity cost and the system capacity cost of about $20/kW/year, the ISO estimates the LCR capacity reduction benefits to be, at most, about $20 million per year.

This project may potentially increase system capacity benefits by increasing import capability into the ISO, however the need for the increased import has not been identified. There is a significant amount of renewable generation that is expected to come on-line at Imperial Valley, so importing more power from Arizona is expected to have minimal economic value.

System-loss reduction benefits

The project provides energy savings of approximately $3.9 million each year.

Emission reduction benefits

Since there are no congestion benefits resulting in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project.

Policy need

There is no policy-driven transmission need that this project could meet. A need for such a project was not identified in the hybrid case or in any of the sensitivity studies.

Other identified benefits

There were no reliability needs identified in the ISO studies that could be addressed by the addition of the proposed project. Therefore, the project sponsor's claim that the project would increase the reliability of both the ISO and IID systems is not supported by the ISO studies.

The project sponsor identified that the transfer capability of the WOR path could be increased to 13,691 MW from the pre-project level of 10,623 MW, an increase of 3,068 MW of transfer capability. ISO studies did not identify the need to increase the WOR transfer capability.

The total benefit-to-cost ratio of the project was identified by the project sponsor as 1.83. The assumptions used to arrive at this conclusion included 2,000 MW of solar generation with a capacity factor of 30% at North Gila and 1,000 MW of geothermal generation with a capacity factor of 95% at Highline. The ISO 33% RPS hybrid portfolio modeled 924 MW in the Imperial South CREZ (which includes both Imperial Valley 230 kV and North Gila 500 kV interconnections), 330 MW in the San Diego South CREZ, and 725 MW and 594 MW in the Imperial North-A and Imperial North-B CREZ's, respectively. Therefore, in the ISO studies the new renewable generation was not concentrated at the North Gila and Highline areas and there was no congestion identified that would be relieved by the addition of the transmission project.

Overall Assessment

The proposed transmission project has some benefits in some categories. The estimated annual carrying charge of the project is approximately $59 million which is over two times higher than the total annual benefits. Assuming a proxy value of $3.9 million based on the loss savings would still not be sufficient to justify this project. The project is also not policy-driven since it is not needed in order to meet 33% RPS goals based on tariff section 24.4.6.6. The need for such a project was not identified in the ISO's hybrid portfolio or in any of the three sensitivity studies.

The ISO has therefore concluded that the project is not needed.

General Information

Project Name: New Imperial Valley-Bannister-Devers 500 kV line

Project Sponsor(s): SDG&E

Type of Submission

☒ Economic Planning Study Request (refer to section 3 of attachment A)

☒ Submitting for information only (not requiring ISO approval in this planning cycle)

Project Description

This project consists of adding a new 500 kV line between the Imperial Valley substation and Devers substation, with a loop-in to the IID control area at a new 500/230 kV Bannister substation. The new line would provide an efficient means of moving significant amounts of new geothermal and solar energy in the IID control area to other load centers in California.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in 2008 and 2009 Request Window for information purposes only and did not address one of the top five areas of congestion, and therefore was not studied further.

General Information

Project Name: **Canada/Pacific Northwest-Northern California Transmission Project**

Project Sponsor(s): **PG&E**

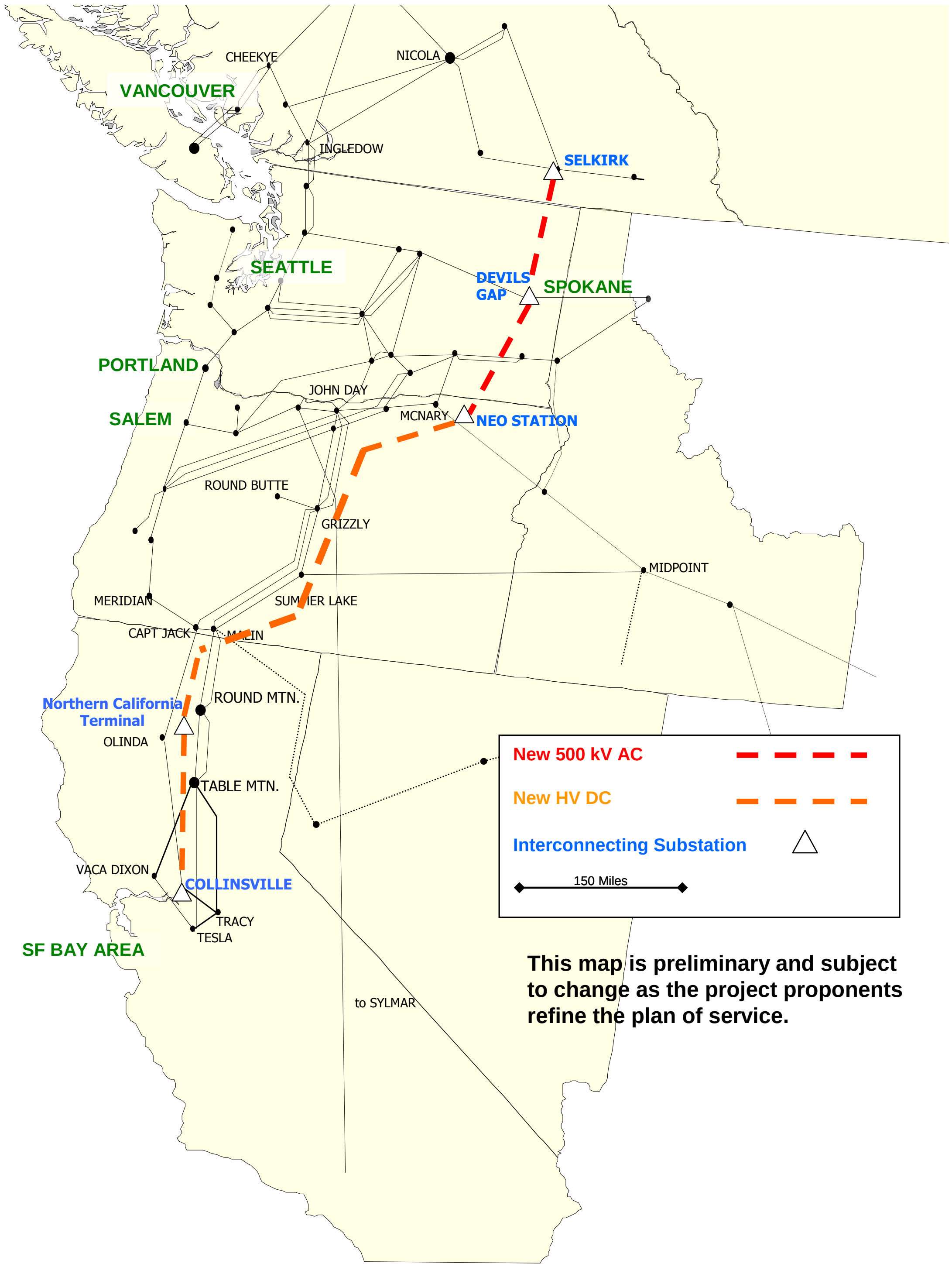
Type of Submission

☒ Economic Transmission Project

Project Description

The Canada/Pacific Northwest-Northern California Transmission Project (CNC) is a proposal of 500 kV hybrid transmission line and associated facilities from British Columbia to Northern California via the Pacific Northwest. According to the latest WECC phase 1 rating study, the elements of the plan of service for the proposed Canada/Pacific Northwest-Northern California projects are:

- A series compensated (up to 70%) 500 kV HVAC Double Circuit Tower Line (DCTL) from Selkirk substation in the southeast British Columbia to Devil's Gap near Spokane, Washington and then to the proposed Northeast Oregon (NEO) station (AC Segment);
- A 3000 MW, 500 kV HVAC to +/-500 kV HVDC converter at the NEO station;
- A +/-500 kV HVDC line from the NEO station to the proposed Collinsville substation in the San Francisco Bay Area (DC Segment);
- A 3000 MW, 500 kV HVAC to +/-500 kV HVDC converter at Collinsville substation;
- +/- 600 MVAR static var compensators at each of the interconnection substations: Selkirk, Devil's Gap, NEO Station, Collinsville, Tracy and Cottonwood Area (if installed); and
- A third HVDC terminal may be installed in the Olinda/Cottonwood area in northern California consisting of a 1500 MW, 500 kV HVAC to +/- 500 kV HVDC Converter. This potential terminal could be installed at the same time as, or after, the CNC project is operational.



Benefits of Project Identified by Project Sponsor

The proposed project is intended to meet three primary objectives:

1. Enhance access to significant incremental renewable resources in Canada and the Pacific Northwest;

2. Improve regional transmission reliability; and

3. Provide market participants with beneficial opportunities to use the facilities.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in the 2008 and 2009 request window for information purposes only and did not address one of the top five areas of congestion, and therefore was not studied further.

General Information

Project Name: Morro Bay–Midway 230 kV Lines No1&2 reconductoring project

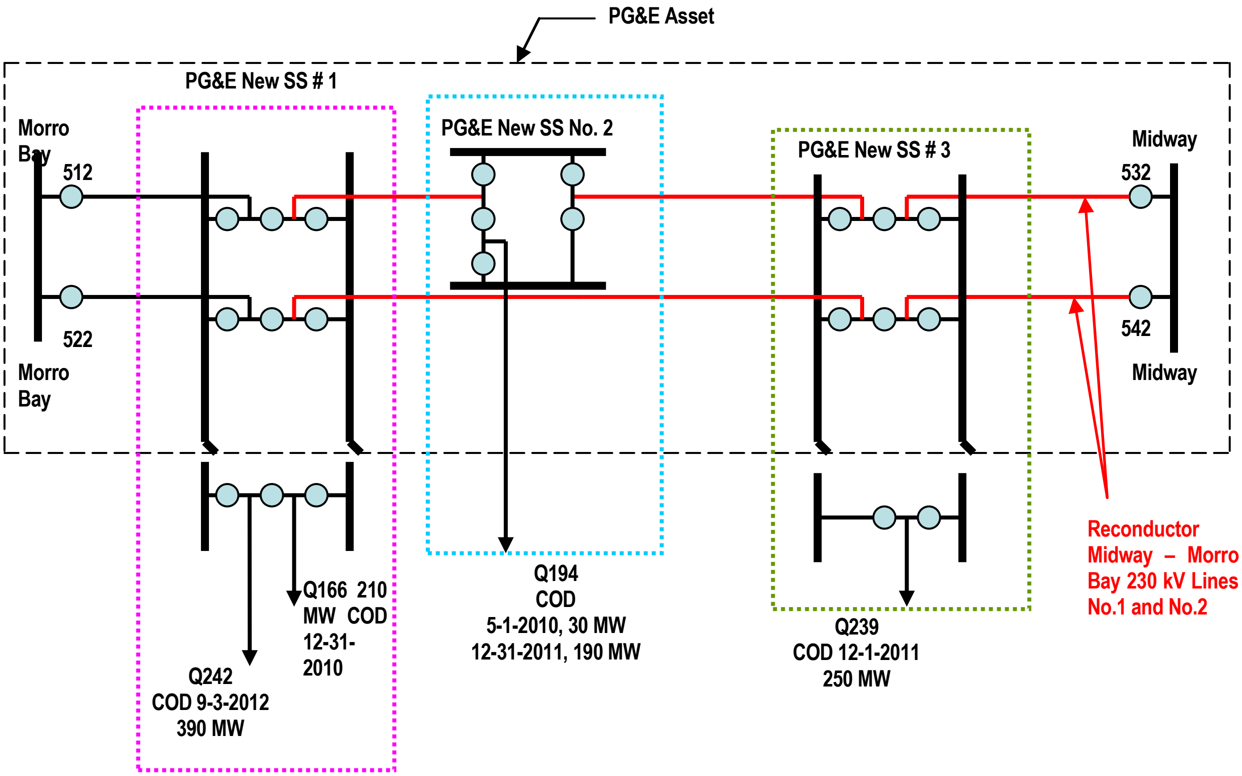
Project Sponsor(s): PG&E

Type of Submission

☒ Reliability (however, this project is part of Transition Cluster Generation Interconnection)

Project Description

The project scope is to reconductor 34 miles of the Morro Bay – Midway 230 kV Nos. 1 and 2 lines between the proposed San Luis Obispo solar switching station #1 and Midway substation with conductors capable of carrying a minimum of 1,700 A. In addition, this project scope will also include the upgrade of associated line terminal equipment to accommodate the higher conductor ratings.



Benefits of Project Identified by Project Sponsor

The project sponsor states that this project relieves potential overloads on Morro Bay – Midway 230 kV Line No 1 and 2. These potential overloads are triggered mainly by interconnection of generation projects in the Transition Cluster San Luis Obispo, Kern, and Fresno groups. In order to reliably interconnect the planned generation facilities, increasing capacity on these 230 kV lines would be required to allow the reliable full delivery of this solar power to the grid.

ISO Analysis of the Project Benefits

This project was designed to accommodate new generation projects in the ISO interconnection queue. Its needs and benefits were evaluated based on the study results from generation interconnection studies. According to the transition cluster Phase II study in San Luis Obispo, Kern, and Fresno areas, this upgrade was identified as a required delivery network upgrade. The Phase II transition cluster studies were completed and the final reports were issued. The LGIA has be tendered and awaiting signature from all parties.

Capacity in excess of, or in addition to, amounts reflected in LGIP studies must be approved through the transmission planning process. This project was identified in a Phase 2 LGIP study as needed to connect generation in the interconnection queue. As part of its transmission planning process review, the ISO did not find any need to approve a larger project or add capacity beyond that reflected in the LGIP studies and executed LGIAs.

General Information

Project Name: San Luis Obispo Solar Switching Station #3

Project Sponsor(s): PG&E

Type of Submission

☒ Other (Submitted under Reliability category but this project is part of Transition Cluster Generation Interconnection)

Project Description

The project scope is to construct a new 230 kV switching station, electrically loop the Morro Bay – Midway 230 kV Nos. 1 and 2 into this new switching station and construct a generation tie line that interconnects solar generation into this new switching station. Specifically, this project scope has two components: Network Upgrades and Direct Assignment.

Network Upgrade Component:

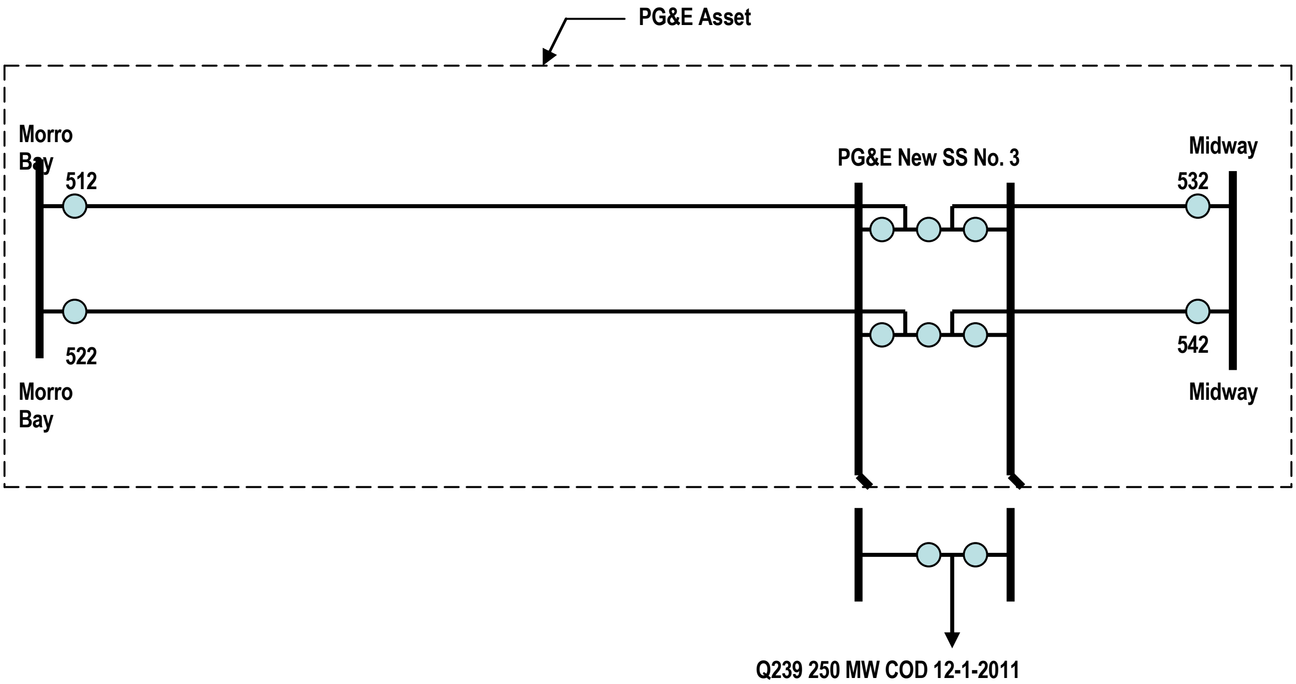
- Construction of a new switching station that is configured in a breaker-and-a-half arrangement with two 3-breaker bays; and

- Electrically loop this new switching station into the Morro Bay – Midway 230 kV Nos. 1 and 2 lines.

Direct Assignment Component:

- Construction of a new 230 kV generation tie line (up to 2.5 miles long) from the site of Project Q239 to the new switching station; and

- Construction of a two-breaker-bay in the new switching station to interconnect the new 230 kV generation tie line.



Benefits of Project Identified by Project Sponsor

The project sponsor states this project is necessary to interconnect new generation projects in the ISO interconnection queue in this area. As shown in the diagram above, it is required to integrate project Q239 into the grid.

ISO Analysis of the Project Benefits

This project was designed to accommodate new generation projects in the ISO interconnection queue. Its needs and benefits were evaluated based on the study results from Generation Interconnection Studies. According to the transition cluster Phase II study in San Luis Obispo, Kern, and Fresno areas, this upgrade was identified as a required delivery network upgrade. The Phase II transition cluster studies were completed and the final reports were issued. The LGIA has been tendered and awaiting signature from all parties.

Capacity in excess of, or in addition to, amounts reflected in LGIP studies must be approved through the transmission planning process. This project was identified in a Phase 2 LGIP study as needed to connect generation in the interconnection. As part of its transmission planning process review, the ISO did not find any need to approve a larger project or add capacity beyond that reflected in the LGIP studies and executed LGIAs.

General Information

Project Name: **Vaca Dixon – Sobrante – Moraga 230 kV Reinforcement Project**

Project Sponsor(s): **PG&E**

Type of Submission

☒ Other (integrating renewable resouces)

Project Description

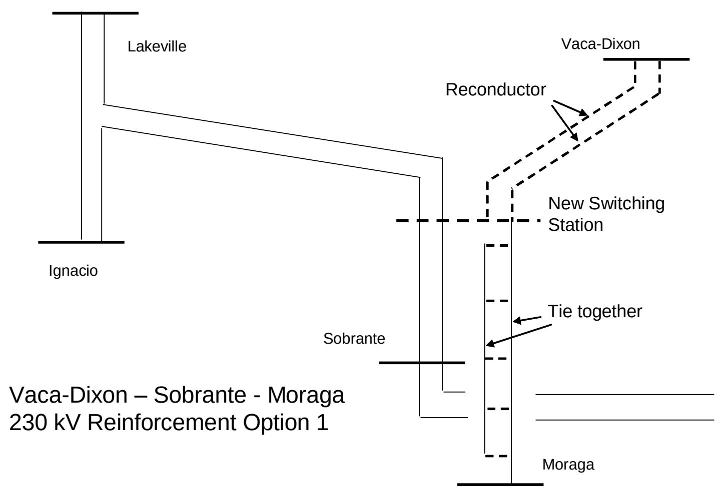
The Vaca Dixon – Sobrante – Moraga 230 kV reinforcement project is a proposal of 230 kV transmission line reinforcement and associated facilities to increase electric transmission capacity and reliability for access to renewable resources in northern California. The scope of this project includes:

- Reconductor approximately 20 miles of the Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines with 1113 SSAC conductor;
- Install a switching station (with 8 line terminations) to connect together Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines and Lakeville – Sobrante 230 kV Nos. 1 and 2 lines; and
- Tie together the conductors of Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines to form one 230 kV line between the new switching station and Moraga (about 30 miles).

At the time this proposal was submitted to the ISO, PG&E indicated it was investigating several options to implement this project. These options include the following alternatives:

Option 1:

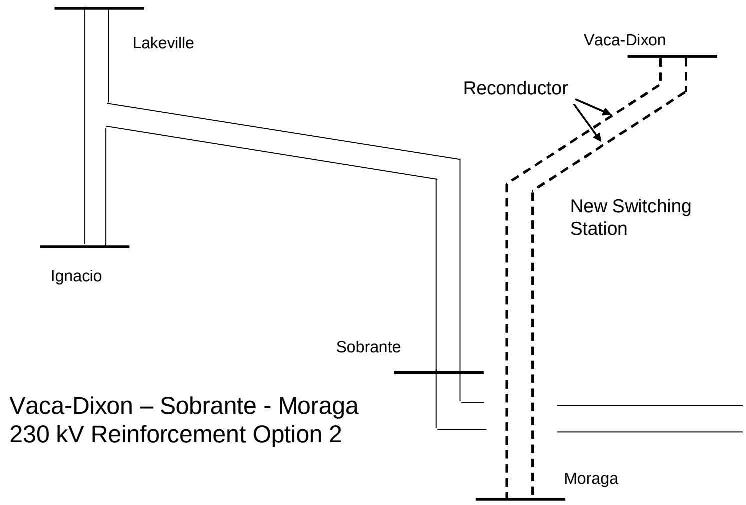
- Reconductor approximately 20 miles of the Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines with 1113 SSAC conductor;
- Install a switching station (with 8 line terminations) to connect together Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines and Lakeville – Sobrante 230 kV Nos. 1 and 2 lines; and
- Tie together the conductors of Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines to form one 230 kV line between the new switching station and Moraga (about 30 miles).



Scope Diagram - Option 1

Option 2:

- Reconductor the Vaca Dixon and Moraga 230 kV Nos. 1 and 2 lines.



Scope Diagram - Option 2

ISO Analysis of the Project Benefits

This project was submitted to the ISO in the 2008 and 2009 request window for information purposes only and did not address one of the top five areas of congestion, and therefore was not studied further.

General Information

Project Name: Mirage – Devers 230 kV Transmission System Upgrade

Project Sponsor(s): Imperial Irrigation District

Type of Submission

☒ Other

Project Description

IID proposes to upgrade the 230 kV transmission system between IID's Coachella Valley substation and SCE's Devers substation, which includes the IID and SCE intertie referred to as WECC Path 42. The request window submission scope relates SCE's portion of Path 42 upgrades, which is necessary in order for IID to move forward with its portion.

Benefits of Project Identified by Project Sponsor

The proponent states the project will increase transfer capability between IID and SCE and help meet the 33% RPS goals.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios. Congestion was identified on WECC Path 42 if no upgrades are implemented. The proposed project relieves congestion on WECC Path 42 enabling delivery of renewable generation in IID to the ISO controlled grid.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR. It increases import capability into the ISO and provides some system capacity benefits.

System-loss reduction benefits

This project reduces system loss by 25 MW under the peak condition and 2 MW under the off-peak condition. Assuming an average energy price of $55.09/MWh, the system loss reduction benefit is about $6.5 million per year.

Emission reduction benefits

The project increases deliverability of the renewable generation in IID and results in less fossil fuel consumption.

Policy need

The elements of WECC Path 42 upgrades are identified in the ISO 33% RPS comprehensive transmission planning study in order to deliver the renewable generation located inside IID area under the base-case scenario. Details of the analysis are provided in Section 5.5.2 of this transmission plan. The project meets the public policy-driven transmission need identified in the ISO's studies.

Overall Assessment

This project meets a policy-driven transmission need to achieve the 33% RPS goals. It also provides some energy cost saving benefits, capacity benefits, system-loss reduction benefits and emission reduction benefits. The ISO has concluded that this project is needed.

General Information

Project Name: Eldorado – Ivanpah Transmission Project

Project Sponsor(s): Southern California Edison

Type of Submission

☒ Generation Project (under Economic Planning Study)

Project Description

The proposed Eldorado – Ivanpah Transmission Project (EITP) consists of:

- A new Ivanpah 220/115 kV substation;
- Removal of a portion of the existing Eldorado – Baker – Dunn Siding – Eldorado – Mountain Pass 115 kV line between the Ivanpah Dry Lake area and the Eldorado Substation; and
- New double circuit Eldorado – Ivanpah 220kV transmission line.

Benefits of Project Identified by Project Sponsor

The proponent states the project is designed to accommodate up to 1400 MW of new generation near the new Ivanpah Substation.

ISO Analysis of the Project Benefits

The elements of the proposed project are among the base assumptions in the ISO 33% RPS comprehensive transmission planning study. The project scope, except for the proposed 2nd circuit, has been identified in Phase 2 LGIP studies and reflected in the executed LGIAs for interconnection projects No. 131, 162 and 233 in the ISO's generation interconnection queue. The project has been approved by the CPUC.

General Information

Project Name: Mirage – Devers 230 kV Transmission System Upgrade

Project Sponsor(s): South California Edison (SCE)

Type of Submission

☒ Other

Project Description

In response to IID's proposed project to upgrade its portion of WECC Path 42, SCE requested a joint study to evaluate the proposed Devers – Mirage (WECC Path 42) upgrades.

Benefits of Project Identified by Project Sponsor

The proponent states the project increases transfer capability between IID and SCE and helps meet the 33% RPS goals.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS portfolios.. Congestion was identified on WECC Path 42 without any upgrades. The project proposed relieves congestion on WECC Path 42 for delivering renewable generation in IID to the ISO controlled grid.

Capacity benefits

This project does not provide any local capacity benefits because it does not reduce LCR. It increases import capability into the ISO and provides some system capacity benefits.

System-loss reduction benefits

This project reduces system loss by 25 MW under the peak condition and 2 MW under the off-peak condition. Assuming an average energy price of $55.09/MWh, the system loss reduction benefit is about $6.5 million per year.

Emission reduction benefits

The project increases deliverability of the renewable generation in IID and results in less fossil fuel consumption.

Policy need

The elements of WECC Path 42 upgrades are identified in the ISO 33% RPS comprehensive transmission planning study to deliver the renewable generation located inside IID area. Details of the analysis are provided in Section 5.5.2 of this transmission plan. The project meets the public policy-driven transmission need.

Overall assessment

This project meets the policy-driven transmission need to achieve the 33% RPS goals. It also provides some energy cost saving benefits, capacity benefits, system-loss reduction benefits and emission reduction benefits. Further discussion is provided in chapter 5. The ISO has concluded that this project is needed.

General Information

Project Name: Gregg-Bellota 500 kV Line #1 and #2 Project

Project Sponsor(s): PG&E

Type of Submission

☒ Other (refer to section 4 of attachment A)

The project sponsor is submitting for information only (not requiring ISO approval in this planning cycle).

Project Description

The project consists of the construction of two 500 kV transmission lines between Gregg substation and Bellota substation, or other substations in the Central California vicinity. The proposed project has been identified as a project in the RETI process, which was evaluating transmission projects necessary to integrate renewable resources in California.

The conceptual plan of service for the proposed Gregg-Bellota 500 kV line #1 and #2 project is:

- Two 500 kV line terminations at Gregg substation in central California;
- Two 500 kV transmission lines from Gregg substation to Bellota substation or other substation in the vicinity - approximately 125 mile; and
- Two 500 kV line terminations at Bellota substation in central California.

Benefits of Project Identified by Project Sponsor

This project is projected to increase the south-to-north transfer capability in the state. This added capacity would assist in meeting the state's RPS goals and improve transmission reliability in the region.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in the 2008 and 2009 request window for information purposes only and did not address one of the top five areas of congestion, and therefore was not studied further.

General Information

Project Name: Midway-Tesla 500 kV #1 and #2 Line Project

Project Sponsor(s): PG&E

Type of Submission

☒ Other (refer to section 4 of attachment A)

The project sponsor submitted this project for information only (not requiring ISO approval in this planning cycle)

Project Description

The project consists of the construction of two 500 kV transmission lines between Midway substation in Central California and Tesla substation in central California. The proposed project has been identified as a project in the RETI process, which was evaluating transmission projects necessary to integrate renewable resources in California.

The conceptual plan of service for the proposed 500 kV Midway-Tesla #1 and #2 line projects are:

- Two 500 kV line terminations at Midway substation in central California;
- Two 500 kV transmission lines from Midway substation to Gregg substation - approximately 170 miles;
- Two 500 kV line terminations at Gregg substation in central California;
- Two 500 kV transmission lines from Gregg substation to Bellota substation - approximately 125 miles;
- Two 500 kV line terminations at Bellota substation in central California;
- Two 500 kV transmission lines from Bellota substation to Tesla substation- approximately 50 miles; and
- Two 500 kV line terminations at Tesla substation in central California.

Benefits of Project Identified by Project Sponsor

This project is projected to increase the south-to-north transfer capability in the state. This added capacity will assist in meeting the state's RPS goals and improve transmission reliability in the region.

ISO Analysis of the Project Benefits

This project was submitted to the ISO in the 2008 and 2009 request window for information purposes only and did not address one of the top five areas of congestion, and therefore was not studied further.

General Information

Project Name: Desert Southwest Transmission Project

Project Sponsor(s): Desert Southwest Power, LLC

Type of Submission

☒ Economic Transmission Project

Project Description

The Desert Southwest Transmission Project (DSWTP) involves the construction of a single circuit, 500 kV transmission line interconnecting to the Colorado River substation and SCE's Devers substation. The proposed line is approximately 110 miles. The objective of the DSWTP is to provide increased import capacity between the renewable rich region of Eastern Riverside County and the load center of southern California.

Benefits of Project Identified by Project Sponsor

The proponent of the DSWTP states that this project can provide significant amounts of energy saving benefit. The study provided by the proponent estimated that the DSWTP has a capital cost at $350 million. The proponent also estimated the levelized annual costs at $54.8 million and the levelized annual benefits at $199 million; hence the benefit-to-cost ratio of 3.63.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on 2020 base cases modeling the four ISO 33% RPS portfolios described in chapter 4. There was no substantial congestion identified on SCE's Colorado River-Devers 500 kV line in the ISO studies for all four portfolios, although more renewable generation has been modeled in one of four portfolios than the assumption used by the project sponsor. The ISO's studies indicated that with the existing SCE's system in the Riverside East area reinforced by the CPUC-approved transmission project (the Colorado River-Devers-Valley #2 line), the 500 kV system in this area will not be the bottleneck for delivering renewable energy from Riverside East and Arizona to the load center of southern California.

Therefore the project proponent's claim regarding the energy cost benefits on the project are not supported by the ISO's analysis of the ISO-developed portfolios.

Capacity benefits

This project is in parallel with the existing DPV1 500 kV line and the approved Colorado River – Devers – Valley # 2 line. In the ISO's LCR studies, these two 500 kV lines are not binding; hence an additional 500 kV line on the same corridor does not provide any local capacity benefits and system capacity benefits.

The project does provide system capacity benefits because it increases import capability into the ISO balancing authority area from Desert Southwest. The ISO estimates the increase in import capability to be about 1,000 MW due to this project. Based on the ISO-estimated difference in price between eastern systems capacity and ISO system capacity of about $5/kW/year, the ISO estimated the RA Import Capability benefits to be about $5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Desert Southwest and California. This capacity cost difference is in addition to the energy cost savings that was estimated by the production cost model described above. The production cost model is designed to estimate energy cost differences but not resource adequacy capacity cost differences.

System-loss reduction benefits

Testing the ISO's 2020 summer peak and off-peak base cases with the hybrid portfolio, the loss reduction benefit was determined to be negligible. In fact, the total losses increased by 10 MW in the peak case in the ISO's balancing authority area. Therefore, there is no system-loss reduction benefit due to this project.

Emission reduction benefits

Since there are no congestion benefits or transmission line loss benefits resulting in less fossil fuel consumption, no emission reduction benefits are created by this transmission project.

Policy need

The existing transmission systems and the approved projects (Colorado River – Devers – Valley 500 kV #2 line) will provide sufficient transmission capacity to deliver renewable energy to the Devers, based on the ISO's 2010/2011 comprehensive transmission planning studies. Neither the hybrid scenario nor any of the sensitivity studies identify the need for an additional 500 kV line in the same corridor as existing lines and lines that have already gone through the generation interconnection process and proceeded to LGIAs.

Overall Assessment

The ISO's analysis identified benefits in increasing import capacity. However, the annual benefits are approximately one tenth the estimated annual carrying costs of $52 million. Annual carrying costs were approximated as 15% of the total capital cost of the project. The value of the potential emission benefits are difficult to quantify, but could not be expected to be sufficient to bridge the gap between annual costs and benefits.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals in the ISO's hybrid portfolio. A project such as this is not identified in either the hybrid portfolio or the three sensitivity studies.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: Devers – Mira Loma DC Line Project (GEET 3)

Project Sponsor(s): Green Energy Express, LLC

Type of Submission

☒ Economic Transmission Project

Project Description

The Devers – Mira Loma DC Line Project (GEET 3) is an east-west transmission project aimed at delivering electricity generated by renewable resources in the Desert Southwest and the southern Nevada region to load centers in southern California.

The proposed project consists of:

- The addition of one 500 kV line position at the existing Devers 500 kV substation. This additional line position would house the new Devers DC – Devers 500 kV line/tap;
- The addition of one 500 kV line position at the existing Mira Loma 500 kV substation. This additional line position would house the new Mira Loma DC - Mira Loma 500 kV line/tap;
- A new Devers +/- 300 kV AC/DC converter station. This new converter station would have 1950 MW total capability with three 650 MW converters, and connect to the existing Devers 500 kV substation;
- A new Mira Loma +/- 300 kV AC/DC converter station. This new converter station would have 1950 MW total capability with three 650 MW converters, and connect to the existing Mira Loma 500 kV substation; and
- Two new approximately 60 mile underground DC conductor circuits, each rated 1000 MW, would connect the DC converter stations at Devers and Mira Loma.

Benefits of Project Identified by Project Sponsor

The proponent of the project states that the benefits are mainly from relieving the congestion on West of Devers 230 kV lines. The study provided by the project proponent estimated that the capital cost is $925 million. It was estimated that the benefit-to-cost ratio is 2.69.

ISO Analysis of the Project Benefits

Energy cost savings

The GEET 3 project can mitigate the potential congestion on the West of Devers 230 kV lines when there are certain amounts of renewable generation interconnecting to SCE's system in the Riverside East area.

In the ISO's generation interconnection studies, reconductoring the West of Devers 230 kV lines was identified to mitigate the constraint. According to the transition cluster Phase II study, this upgrade was identified as a required delivery network upgrade. The Phase II transition cluster studies were completed and the final reports were issued. The need for the upgrade has been triggered by an executed LGIA.

Capacity benefits

There is not a significant capacity benefit from the GEET 3 project. With the Tehachapi transmission projects in service in future years, the Eastern LA Basin system will not be the binding constraint in future LCR studies. In fact, more power injection at Mira Loma because of the GEET 3 project could potentially increase the LCR need in the Western LA Basin due to increased loading on Miraloma – Walnut and Miraloma - Olinda lines.

System-loss reduction benefits

This project is expected to provide loss reduction benefits because it reduces the impedance on the corridor. The ISO calculated the loss reductions in the peak hour and off-peak hour, which are 50 MW and 37 MW respectively, estimated using the ISO's transmission planning basecase. According to the ISO's production cost simulation results for the 33% RPS portfolios, the average LMP is approximately $56.34 per MW and $53.14 per MW for peak and off-peak, respectively. To ensure loss savings were not undervalued, line loss savings were estimated using the higher, peak LMP value resulting in an estimate of $21.5 million per year.

Emission reduction benefits

The GEET 3 project would provide emission reduction benefits similar in magnitude to the West of Devers reconductoring project, by reducing congestion into the load center.

Policy need

The GEET 3 project can deliver renewable energy into the load center. However, the need for this project was not identified in the hybrid case or any of the three sensitivity cases.

Overall Assessment

The annual carrying charge for the proposed project is estimated at $138 million. Therefore, the cost of this project exceeds its loss reduction benefits by six times. Annual carrying charges were approximated as 15% of the total capital cost of the project. The value of the potential emission benefits are difficult to quantify. Assuming a proxy emission reduction benefit of $21 million (based on the estimated loss reduction) would still not make this project economic.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: Eldorado-Devers Project (GEET 2)

Project Sponsor(s): Green Energy Express LLC

Type of Submission

☒ Economic Transmission Project

Project Description

The Eldorado Devers Transmission Project is a north-south transmission project aimed at delivering electricity generated by renewable resources in southern Nevada and southeastern California regions to load centers in southern California. The proposed project consists of:

- The addition of one 500 kV line position at the existing Eldorado 500 kV substation;
- The addition of a new 500 kV substation adjacent and connecting to existing MWD;
- Iron Mountain substation;
- The addition of a pair of 500/230 kV phase shifting transformers at Iron Mountain;.
- The addition of a new Palm Desert 500 kV substation near Twentynine Palms, California;
- The addition of a single circuit, series compensated 500 kV line from the existing SCE Eldorado substation to the new Iron Mountain 500 kV substation;
- The addition of a single circuit 500 kV line from the new Iron Mountain 500 kV substation to the new Palm Desert 500 kV substation;
- The addition of a single circuit 500 kV line from the new Palm Desert 500 kV substation to the existing SCE Devers 500 kV substation; and
- The addition of one 500 kV line position at the existing SCE Devers 500 kV substation.

This project would be capable of transferring up to 1200 MW of mainly green energy from the surrounding area to the Southern California load centers. The estimated cost for the project is approximately $800 million, including 280 miles of line and the phase shifter at Iron Mountain.

Benefits of Project Identified by Project Sponsor

The project proponent states that the GEET 2 project can provide the following benefits:

- Reduction in energy or re-dispatch cost by displacing the expensive energy from LA Basin with cheaper, cleaner energy mostly from renewable energy located outside the southern California load center. The reduction of energy cost is $248.2 million;
- Total cost of losses decreased by a net of $3.2 million;
- Emission cost was reduced by $22.2 million. The GEET2 will allow more renewable to interconnect to the grid thus displacing gas fired plants;
- The consumer benefit is calculated to be $273.6 million for 2015;
- Production cost was reduced by $379 million;
- Producer revenue decreased by $464 million;
- Congestion revenue to PTOs increased by $7.1 million; and
- Societal benefits are defined by the TEAM approach to be the sum of consumer benefit, production surplus and congestion revenue. The societal benefit is calculated to be $501 million.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed power flow analyses and production cost simulations on 2020 base cases modeling the four ISO 33% RPS portfolios, at least one of which assumed over 2500 MW of renewable generation in the East of Lugo areas. It has been identified that the 500 kV and 230 kV lines in the corridor of East of Lugo can provide sufficient transmission capacity to deliver renewable generation in the East of Lugo areas to the LA Basin. Therefore, it is expected that the proposed project will not provide energy cost savings. There were no binding transmission constraints that would be expected to be relieved by this project with more than $1 million per year of congestion.

Therefore the project proponent’s claim regarding the energy cost benefit and other benefits from the GEET2 project are not supported by the ISO’s analysis of the ISO-developed portfolios.

Capacity benefits

This project shifts power injection into the LA Basin from Lugo to Devers; hence it can reduce the flow on the South of Lugo transmission lines by increasing the flow on West of Devers transmission lines. However, the ISO’s LCR studies show that the South of Lugo lines will not be the binding constraints after TRTP are in-service at 2015. Therefore the addition of one 500 kV line from El Dorado -Devers will not provide local capacity benefits.

The project does provide system capacity benefits because it increases import capability into the ISO from the east. The ISO estimates the increase in import capability at about 1,500 MW due to this project. Based on the ISO-estimated difference in price between Southwest systems capacity and ISO system capacity of about $5/kW/year, the ISO estimated the RA Import Capability benefits to be about $7.5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Southwest and California.

System-loss reduction benefits

The ISO calculated the loss reductions in the 2020 peak hour and off-peak hour to be 2 MW and 1 MW respectively, estimated using the ISO's transmission planning basecase. According to the ISO's production cost simulation results for the 33% RPS portfolios, the average LMP is approximately $56.34 per MW and $53.14 per MW for peak and off-peak, respectively. To ensure loss savings were not undervalued, line loss savings were estimated using the higher, peak LMP value resulting in an estimate of $740,000 per year.

Emission reduction benefits

Since there are no congestion benefits resulting in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project.

Policy need

The existing transmission systems, the approved projects (Colorado River – Devers – Valley 500 kV #2 line), and the LGIA identified projects (Pisgah – Lugo 500 kV line) will provide sufficient transmission capacity to deliver renewable energy to Devers and Lugo substations, based on the ISO's 2010/2011 comprehensive transmission planning studies. Hence the need for an additional 500 kV line from El Dorado – Devers is not identified in the hybrid portfolio or any of the sensitivity scenarios. The need identified by the proponent depends largely on assumptions of generation in the Iron Mountain area that are not reflected in the ISO's RPS portfolios.

Overall Assessment

This project is not considered economic, as the annual carrying charge is estimated to be $120 million, which is over 15 times higher than the total annual benefits. Assuming a proxy emission reduction benefit of $700,000 (based on the estimated loss reduction) would still not be sufficient to make this project economic. Annual carrying costs were approximated as 15% of the total capital cost of the project.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals based on application of the criteria in tariff section 24.4.6.6. The need for such a project is not identified in the ISO's hybrid portfolio or any of the sensitivity scenarios.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: Green Energy Express Transmission Line Project (GEET 1)

Project Sponsor(s): Green Energy Express LLC

Type of Submission

☒ Economic Transmission Project

Project Description

The proposed project involves the construction of a new Green Energy substation, a new 70 mile double circuit (single tower) 500 kV transmission line between the new substation and SCE's Devers substation; and a new single tower double circuit 230 kV (~1 mile) to SCE's Eagle Mountain substation providing a 2000 MW power transfer capacity. The aim of the project will be to facilitate the delivery of existing queued renewable energy facilities and projects, and to provide capacity for the rapidly growing future development of renewable energy. The study provided by the project proponent estimated the total cost at $395 million.

Benefits of Project Identified by Project Sponsor

The project proponent states that the GEET 1 project can deliver an additional 2000 MW renewable energy to the load centers. The project proponent states the following benefits from the project:

Project Benefit	Estimated 4-week savings	Estimated Yearly savings	Comments
Energy Cost	$67,915,855	$882,906,115	
Production Cost	$57,584,029	$748,592,377	
Net of Energy and Production Cost	n/a	$134,313,738	(Energy Cost Savings)-(Production Cost Savings)
Congestion Cost	$1,042,457	$13,551,941	
Marginal Loss Cost	$46,206	$600,678	
Emissions Cost		$7.5 million	

Project Benefit	Estimated 4-week savings	Estimated Yearly savings	Comments
Capacity Cost		$13 million	
Total Estimated Reduction in Costs		$168.6 million	Total includes only the net difference between Energy Cost and Production Cost Savings.

The project proponent also states that the project can bring ancillary service benefit and reduce reliance on OTC generators.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis in its 2010/2011 ISO comprehensive transmission planning studies. There was no congestion identified on SCE's Colorado River-Devers 500 kV lines in the ISO studies for all four portfolios, although more renewable generation has been modeled in at least one of four portfolios than the assumptions used by the project proponent. The ISO's studies indicated that the SCE's transmission system in the Riverside East area, including the existing DPV #1 500 kV and the CPUC-approved Colorado River – Devers – Valley 500 kV #2 line, and the West of Devers upgrade that is identified in LGIAs, can accommodate about 4,700 MW total new generation in the Riverside East area. The ISO's power flow studies and congestion assessments identified that the 500 kV system in this area will not be the bottleneck for delivering renewable energy from Riverside East and Arizona to the load center of southern California. There were no binding transmission constraints with more than $1 million per year of congestion expected to be relieved by this project.

Therefore the project proponent's claim regarding the energy cost benefit and other benefits from the GEET #1 project are not supported by the ISO's analysis of the ISO-developed portfolios.

Capacity benefits

This project is in parallel with the existing DPV1 500 kV line and the previously approved Colorado River – Devers – Valley #2 line. In the ISO's LCR studies, these two 500 kV lines are not binding; hence an additional 500 kV line on the same corridor does not provide any local capacity benefits and system capacity benefits.

It does provide system capacity benefits because it increase import capability into the ISO from the east. The ISO estimates the increase in import capability of about 1,000 MW due to this project. Based on the ISO-estimated difference in price between the Southwest systems capacity and ISO system capacity of about $5/kW/year, the ISO estimates the RA Import Capability benefits to be about $5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Southwest and California.

System-loss reduction benefits

Using the 2020 summer peak and off-peak base cases, and the ISO's baseline scenario portfolio, transmission line losses actually increased by 11 MW in the ISO's balancing authority area. Therefore there is no system-loss reduction benefit.

Emission reduction benefits

Since there are no congestion benefits resulting in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project.

Policy need

The existing transmission systems and previously approved projects (Colorado River – Devers – Valley 500 kV #2 line) will provide sufficient transmission capacity to deliver renewable energy to Devers, based on the ISO's 2010/2011 comprehensive transmission planning studies. Hence there is no policy need for the additional 500 kV line in the same corridor.

Overall Assessment

The ISO does not consider this project to be economic, as the annual carrying charge is estimated to be $59 million, which is over 10 times higher than the total annual benefits. Annual carrying costs were approximated to be 15% of the total capital cost of the project.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals based on application of tariff section 24.4.4.6. The need for a project such as this is not identified in the hybrid portfolio or any of the sensitivity scenarios.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: **Las Vegas to Los Angeles Double Circuit 500 kV Transmission Project**

Project Sponsor(s): **Energy Capital Partners, LLC**

Type of Submission

☒ Economic Transmission Project

Project Description

This project is proposed as a double circuit, 130 mile 500 kV (or a 500/230 kV double circuit) transmission line from Eldorado or Marketplace substation to a proposed Iron Mountain 500 kV substation, and a double circuit, 120 mile 500 kV (or a 500/230 kV double circuit) to the Rancho Vista 500 kV substation. The 500 kV lines will each have 70% compensation.

The proposed project is designed to increase the West of River transfer capability by up to 3000 MW, deliver significant amounts of renewable resources from the Eldorado Valley to Los Angeles load centers, and utilize existing and new transmission corridors to reduce the congestion on the South of Lugo ISO path.

The project proponent estimated the total cost of the proposed project at $1.059 billion.

Benefits of Project Identified by Project Sponsor

The project proponent states that with its renewable generation assumption at Marketplace and Iron Mountain areas, the annual load serving cost of the ISO at 2015 will be reduced by $376 million (in nominal dollars). The generation assumption used in the project proponent's study is that wind and solar generation will develop totaling 2000 MW with a 40% aggregate capacity factor at Marketplace and totaling 500 MW with a 35% capacity factor at Iron Mountain.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed power flow analyses and production cost simulations in the 2010/2011 ISO comprehensive transmission planning studies modeling the four ISO 33% RPS portfolios. The 500 kV and 230 kV lines in the corridor of East of Lugo, which refers to the paths from El Dorado to Lugo and from Mohave to Lugo, can provide sufficient transmission capacity to deliver renewable generation in the East of Lugo areas to the LA Basin. Therefore, the proposed project will not provide substantial energy cost savings. There were no binding transmission constraints with more than $1 million per year of congestion that would be expected to be relieved by this project.

Capacity benefits

This project is in parallel with the 500 kV and 230 kV lines that are not binding in the ISO's LCR studies; hence an additional 500 kV line on the same corridor does not provide any local capacity benefits and system capacity benefits.

It does provide system capacity benefits because it increase import capability into the ISO from the east. The ISO estimates the increase in import capability of about 1,500 MW due to this project. Based on the ISO-estimated difference in price between Southwest system capacity and ISO system capacity of about $5/kW/year, the ISO estimates the RA Import Capability benefits to be about $7.5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Southwest and California.

System-loss reduction benefits

The ISO calculated the loss reductions in the 2020 peak hour and off-peak hour to be 21 MW and 10 MW, respectively estimated using the ISO's transmission planning basecase. According to the ISO's production cost simulation results for the 33% RPS portfolios, the average LMP is approximately $56.34 per MW and $53.14 per MW for peak and off-peak, respectively. To ensure loss savings were not undervalued, line loss savings were estimated using the higher, peak LMP value resulting in an estimate of $7.7 million per year.

Emission reduction benefits

Since there are no congestion benefits resulting in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project.

Policy need

The existing transmission systems and the approved projects will provide sufficient transmission capacity to deliver the renewable energy that is reflected in the ISO's studies. Neither the hybrid portfolio nor any of the sensitivity studies identify a policy need for an additional 500 kV line in the same corridor.

In addition, the ISO's comprehensive transmission planning study evaluated the portfolios based on both of environmental impact and commercial interest, as well as the available transmission capacity. The generation in the Iron Mountain area that the project sponsor assumed did not pass the criteria of the renewable portfolio development.

Overall Assessment

The ISO's analysis identified benefits in increasing import capacity. However, the annual benefits are approximately one-tenth the estimated annual carrying cost of $150 million. Assuming a proxy emission reduction benefit of $7.7 million (based on the estimated loss reduction) would still not be sufficient to make this project economic. Annual carrying costs were approximated as 15% of the total capital cost of the project. The project is also not policy-driven since it is not needed in order to meet 33% RPS goals in the ISO's hybrid portfolio.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: Mohave-San Bernardino-Devers Renewable Integration Transmission Project

Project Sponsor(s): California Transmission Development, LLC

Type of Submission

☒ Other

Project Description

The proposed project involves the construction of an approximately 230 mile 500 kV AC transmission line connecting the 500 kV buses at the existing Mohave substation and Devers substation via a new 500 kV San Bernardino substation. It is estimated that the project will cost approximate $1 billion in 2008 dollars.

Benefits of Project Identified by Project Sponsor

The project proponent did not provide study results.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed power flow analyses and production cost simulations in the 2010/2011 ISO comprehensive transmission planning studies modeling the four ISO 33% RPS portfolios. It has been identified that the 500 kV and 230 kV lines in the corridor of East of Lugo, which refers to the paths from El Dorado to Lugo and from Mohave to Lugo, can provide sufficient transmission capacity to deliver renewable generation in the Mohave area. Therefore, it is expected that the proposed project will not provide substantial energy cost savings. There were no binding transmission constraints expected to be relieved by this project with more than $1 million per year of congestion.

Capacity benefits

This project is in parallel with the 500 kV and 230 kV lines that are not binding in LCR studies; hence an additional 500 kV line on the same corridor does not provide any local capacity benefits and system capacity benefits.

The project does provide system capacity benefits because it increases import capability into the ISO from the east. The ISO estimates the increase in import capability of about 1,500 MW due to this project. Based on the ISO-estimated difference in price between the Southwest systems capacity and the ISO system capacity of about $5/kW/year, the ISO estimated the RA Import Capability benefits to be about $7.5 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the Southwest and California.

System-loss reduction benefits

The ISO calculated the loss reductions in the 2020 peak hour and off-peak hour to be 2 MW and 1 MW respectively estimated using the ISO's transmission planning basecase. According to the ISO's production cost simulation results for the 33% RPS portfolios, the average LMP is approximately $56.34 per MW and $53.14 per MW for peak and off-peak, respectively. To ensure loss savings were not under-valued, line loss savings were estimated using the higher, peak LMP value resulting in an estimate of $740,000 per year.

Emission reduction benefits

Since there are no congestion benefits or material transmission line loss benefits resulting in less fossil fuel consumption, there are no emission reduction benefits created by this transmission project.

Policy need

The existing transmission systems and the approved projects will provide sufficient transmission capacity to deliver renewable energy that is reflected in the ISO's studies to the load center, based on the ISO's comprehensive transmission planning studies. Hence there is not policy need for additional 500 kV lines in the same corridor.

Overall Assessment

The ISO's analysis identified benefits in increasing import capacity. However, the annual benefits are approximately one eighteenth the estimated annual carrying costs of $150 million. Assuming a proxy emission reduction benefit of $ 0.7 million, based on the estimated loss reduction, would not be sufficient to make this project economic. Annual carrying costs were approximated as 15% of the total capital cost of the project.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals based on application of tariff section 24.4.6.6. The need for a project such as this was not identified in the ISO's hybrid portfolio or any of the sensitivity studies.

The ISO has therefore concluded that this project is not needed.

General Information

Project Name: **MPP/MAP Capacity Transfer Project**

Project Sponsor(s): **Startrans IO, LLC**

Type of Submission

☒ Economic Transmission Project

Project Description:

Startrans IO, LLC (Startrans), an ISO PTO, is proposing to add 200 MW of transmission capacity to the ISO. The proposed MPP/MAP Capacity Transfer Project entails transferring existing capacity on the Mead-Adelanto Project (MAP) and the Mead-Phoenix Project (MPP) to the ISO. In addition the seller of the interests in MPP and MAP will assign to Startrans firm transmission rights from the Adelanto Substation to the mid-point of Victorville-Lugo in order to tie into the ISO grid. The project does not involve any transmission upgrade component. The project cost is estimated to be $36.6 million capital cost or $9.4 million in annual revenue requirement in present value.

Benefits of Project Identified by Project Sponsor

The proponent states the benefits as:

- The MPP/MAP Capacity Transfer will entail the transfer of existing interests in MPP/MAP from a non-participating transmission owner in MAP/MPP to Startrans, which will then provide the ISO operational control over those interests under its current Transmission Control Agreement ("TCA").

This will offer benefits to the ISO and its ratepayers: Immediate increase of needed ISO transmission capacity: The capacity of certain elements of MPP/MAP is not available during up to 42% of on-peak hours. Transferring existing transmission capacity to the ISO provides immediate benefits to ISO ratepayers since the capacity that can be put to immediate use to access efficient supply;

- Access to low marginal cost renewable generation: The MPP/MAP Capacity Transfer will benefit ISO ratepayers by increasing access to low marginal cost renewable generation situated in desert areas of California, Arizona and Nevada which have the best solar resources in the country;
- Lower cost: the MPP/MAP Capacity Transfer will result in additional capacity under ISO's operational control at a significantly lower cost compared to the cost of comparable new-build transmission capacity; and
- Low execution risk: There is very low execution risk associated with obtaining capacity through the MPP/MAP.

An economic analysis was conducted to evaluate the economic benefit to transfer 200 MW transmission capacity to the ISO, which shows significant economic value with a benefit to cost ratio of 1.47.

ISO Analysis of the Project Benefits

Energy cost savings

There was no congestion identified on MAP and MPP, based on the ISO production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS Renewable Portfolios and the 2010/2011 ISO Transmission Reliability Assessment. This project does not involve any physical network upgrade and will not increase transmission system capability. The project may increase ISO's capacity of scheduling right to access lower cost generation from out-of-state, which may avoid transmission service charges or wheeling access charges to be paid to LADWP, the neighboring utility. However, according to the latest historic OASIS data since the MRTU went operational on April 2009, the Available Transmission Capacity (ATC) of the existing MAP and MPP components under ISO operational control were not fully utilized. The MPP and MAP were not fully utilized for 97% to 99% of the continuing 12 months (8760 hours).

- For the Westwing–Mead component, the average ATC after the close of the ISO hour-ahead market was 127 MW. There was no available capacity for only about 3% of the 8760 hours in 2010;
- For the Mead–Marketplace component, the average ATC was 483 MW. There was no available capacity for only about three hours during the year 2010; and
- For the Marketplace-Adelanto component, the average ATC was 380 MW. There was no available capacity for only about 3% of the continuing 12 months (8760 hours) from April 2009 to March 2010.

Instead of putting additional shares of MAP & MPP into the ISO transmission access charge, ISO customers could utilize this transmission by paying wheeling charges for it. The ISO has estimated these wheeling charges to be about $1.1 million per year with the proposed transmission capacity transfer. Below is the detail of the estimate:

Transmission Service Charge Avoided with MAP/MPP Capacity Transfer

Maximum Capacity Transfer	Utilization Factor*	Average Transfer Capacity Utilized	Expected Energy Delivered to CAISO	Wheeling Access Charge	
				WAC Rate**	Annual Total
MW	%	MW	MWh	$/MWh	$1,000
73	57%	41.6	364504	5.4	$1,968,319

Note:* Utilization Factor is estimated based on ISO Production Simulation assuming transmission service were purchased on a monthly basis.

** Transmission Charge is based LADWP's monthly Firm Point-To-Point service rate

Capacity benefits

The capacity transfer project does not increase physical transmission capacity, but rather scheduling rights under the ISO operational control. The transferred transmission capacity only provides 73 MW transmission schedule rights for the ISO to import lower generation resources from out-of-state. The project does not increase import capability into any LCR areas and therefore does not provide potential capability to reduce local generation capacity requirements. This proposed transfer of transmission rights also does not increase import capability into the ISO because it does not increase the capability of the Victorville-Lugo 500 kV intertie. Therefore it does not provide any system capacity benefits.

System-loss reduction benefits

The project sponsor did not identify the transmission system-loss savings for the project. In fact, based on ISO estimates ISO ratepayers would need to pay an additional $195,000 transmission energy loss costs per year due to increased usage of the MPP/MAP 500 kV lines. The estimate is based on additional 3508 MWh transmission loss sharing, LMP of $55.5 /MWh, and the line loading factors from the ISO production simulation model.

Emission reduction benefits

Since there are no congestion relief benefits resulting in less fossil fuel consumption, there are also no emission reduction benefits created by this transmission project.

Policy need

The existing MAP and MPP transmission scheduling rights under ISO operational control have not been heavily utilized since MRTU went operational. And the existing transmission systems, the approved projects and the LGIA identified projects, such as Colorado River – Devers – Valley 500 kV #2 line, and Pisgah – Lugo 500 kV line, are expected to provide sufficient transmission capacity to deliver renewable energy to the ISO controlled grid, based on the ISO’s 33% RPS comprehensive transmission planning studies. Hence there is no expected policy need for the ISO to obtain this additional transmission capacity.

Overall Assessment

This project is not expected to provide any congestion cost savings, loss savings, or capacity benefits. The ISO has estimated avoided wheeling charges to be about $1.1 million per year with the proposed transmission capacity transfer. This is not sufficient to justify the total of $36.6 million capital cost or $9.4 million in annual revenue requirement in present value. The ISO's analysis does not support the cost because the annual revenue requirement is a multiple higher than total annual benefits estimated by the ISO. The project is also not policy-driven since it is not needed in order to meet 33% RPS goals in the ISO's most likely portfolio.

The ISO has concluded that this project is not needed.

General Information

Project Name: **Meads Green Upgrade (Mead - Adelanto Project and Mead – Phoenix Project Direct Current Conversion)**

Project Sponsor(s): **Startrans IO, LLC**

Type of Submission

☒ Economic Transmission Project

Project Description

Startrans is proposing to increase the transmission capacity of MAP and MPP by converting MAP and MPP from an AC configuration to DC utilizing the existing towers, conductors and right- of-way. Startrans is planning to work with the other owners of MAP and MPP to jointly develop the Meads Green Upgrade Project. The primary components of the project are:

- Building three new AC-DC converter stations, located at the Adelanto, Perkins and Mead or Marketplace substations;
- Building a tie line between the new converter station at either the Mead or Marketplace substation to the other substation; and
- Converting MAP and MPP lines to DC, originally designed, permitted and constructed as DC lines but energized as AC lines in 1996.

Benefits of Project Identified by Project Sponsor

The proponent states that the Meads Green Upgrade will increase the current rating of MAP and MPP to 3,200 MW. Startrans is proposing to place a portion of that additional capacity under the operational control of the ISO. The additional capacity that will be placed under the ISO's operational control is expected to be between 1,176 MW (scenario 1) and 3,337 MW (scenario 2). The initial capital cost of the Project is estimated to be $300 million and $539 million for scenario 1 and 2 respectively.

Startrans is planning to work with the other owners of MAP and MPP to jointly develop the Meads Green Upgrade. The Meads Green Upgrade remains subject to the approval of the owners. Startrans may structure the Meads Green Upgrade as a public-private partnership with the Western Area Power Administration, which is a major participant in MAP and MPP.

An economic analysis was conducted to evaluate the economic benefit to place additional transmission capacity from MPP and MAP under the ISO's operational control, which shows significant economic value with a benefit-to-cost ratio of 1.43~1.54 under different scenarios. The new capacity will enable the ISO to import lower marginal cost renewable energy resources into the ISO grid thus displacing expensive thermally-generated energy. In addition, the incremental capacity will reduce emissions costs and losses.

ISO Analysis of the Project Benefits

Energy cost savings

The ISO performed production cost simulation analysis on a 2020 base case modeling the four ISO 33% RPS Renewable Portfolios, which includes the savings associated with low operating costs from out-of-state to meet the State's 33% RPS goals. There was no congestion identified on its major interfaces, Paths 49/46/58/63/27. However, there was a very small amount of congestion identified on the Moenkopi-Eldorado 500 kV line resulting in less than $2 million per year.

Capacity benefits

The project does not increase import capability into any LCR areas and therefore does not provide potential capability to provide local generation capacity benefits. The project could potentially increase ISO capability to import generation from out-of-state via MPP/MAP, if the 500 kV tie line from Victorville (LADWP) to Lugo (SCE/ISO) Path 61 was upgraded. In addition, there was no specific plan to upgrade this 500 kV tie line. If the project were to increase import capability into California from the southwest, the ISO estimates an increase in import capability into the state of about 938 MW due to this project. The ISO estimated difference in price between the Southwest system capacity and the California system capacity to be about $5 kW/year. As such the ISO estimates that benefits due to this additional import capability to be about $4.7 million per year. The $5 estimate is considered to be a reasonable upper bound on the difference in long-term system capacity costs between the southwest and California. This capacity cost difference is in addition to the energy cost savings that was estimated by the production cost model described above. The production cost model is designed to estimate energy cost differences but not resource adequacy capacity cost differences.

The ISO notes that Startrans calculated the capacity increases by summing capacities of individual segments, which operate largely in series. The ISO has instead assessed the capacity benefit based on the amount of increased capacity from Westwing to Adelanto.

System-loss reduction benefits

The project sponsor did conduct studies to demonstrate the transmission system-loss saving benefit or loss to convert the AC to DC system, and did not provide sufficient technical data for the ISO to estimate system-losses at this point.

However, increasing imports into California would actually increase system losses. During periods when imports were not increased the project could save some losses. It is roughly estimated that the loss increases and loss savings over the course of a year, would net to no change in system losses.

Emission reduction benefits

Since there were some identified congestion relief benefits resulting in less fossil fuel consumption, there may also be some emission reduction benefits created by this transmission project. However, an upper bound on these benefits would be to assume they are equal to the Moenkopi-Eldorado 500 kV line congestion costs of $2 million per year.

Policy need

Existing transmission lines, along with the approved projects and the LGIA identified projects will provide sufficient transmission capacity to deliver renewable energy to the ISO controlled grid that the proposed project otherwise might deliver, based on the ISO's 33% RPS comprehensive transmission planning studies. The need for a project such as this was not identified in the hybrid scenario or in any of the sensitivity studies. Hence there is no policy need for the proposed project.

Overall Assessment

The annual estimated savings associated with this project of approximately $8.7 million are the sum of the energy cost savings of $2 million, emission cost savings of $2 million and system capacity cost benefits of $4.7 million. The cost of this project is estimated at over $300 million with annualized carrying charges estimated at $45 million. Economically it cannot be justified on the estimated savings since the annual carrying charge is five times higher than the total annual benefits. Annual carrying charges were approximated as 15% of the total capital cost of the project.

The project is also not policy-driven since it is not needed in order to meet 33% RPS goals in the ISO's hybrid portfolio.

The ISO has therefore concluded that this project is not needed.

Chapter 8 Transmission Project Lists

8.1 Transmission Project Updates

Tables 8.1-1 and 8.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous ISO transmission plans, the ISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location constrained resource interconnection facility (LCRIF) project or enhance economic efficiencies.

Table 8.1-1: Status of previously approved projects costing less than $50M

No	Project	PTO Area	Expected In-Service Date
1	Pease-Marysville #2 60 kV Line	PG&E	Dec-11
2	Rio Oso 115 kV Reactor	PG&E	May-11
3	Atlantic – Lincoln Transmission – over $50M has Board approval	PG&E	Dec-11
4	Mendocino Coast Reactive Support	PG&E	2011
5	Palermo – Rio Oso 115 kV Line Reconductoring – over $50M has Board approval	PG&E	May-12
6	Pittsburg – Tesla 230 kV Reconductoring	PG&E	Mar-14
7	Tesla 115 kV Capacity Increase	PG&E	May-11
8	West Point – Valley Springs 60 kV Line	PG&E	Dec-12
9	Bay Meadows 115 kV Reconductoring	PG&E	2011
10	Contra Costa – Moraga 230 kV Line Reconductoring	PG&E	May-13
11	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	2011
12	Cortina 60 kV Reliability	PG&E	2012
13	East Nicolaus 115 kV Area Reinforcement	PG&E	2012
14	Half Moon Bay Reactive Support	PG&E	2011
15	Lakeville – Ignacio #2 230 kV Line Project	PG&E	2011

No	Project	PTO Area	Expected In-Service Date
16	Missouri Flat - Gold Hill 115 kV Line	PG&E	2014
17	Moraga Transformer Capacity Increase	PG&E	Dec-12
18	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	2011
19	Soledad 115/60 kV Transformer Capacity	PG&E	2011
20	South of San Mateo Capacity Increase	PG&E	2011
21	Table Mountain – Rio Oso 230 kV Line Reconductor and Tower Raises	PG&E	May-11
22	Tesla-Newark 230 kV Path Upgrade	PG&E	2011
23	Vaca Dixon - Birds Landing 230 kV Reconductoring	PG&E	2011
24	West Fresno Reactive Support (Scope Change) (Sanger - California Ave 70 kV to 115 kV Voltage Conversion)	PG&E	5/1/2011
25	Wheeler Ridge 230/70 kV Transformer	PG&E	5/1/2012
26	Metcalf-Evergreen 115 kV	PG&E	2012
27	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	2012
28	Monta Vista - Los Altos 60 kV Reconductoring	PG&E	2012
29	Rio Oso 230/115 kV Transformer Upgrades	PG&E	2013
30	Ignacio-San Rafael (Ignacio – San Rafael and Ignacio – Las Gallinas 115 kV Reconductoring)	PG&E	2013
31	Vaca Dixon - Lakeville 230 kV Reconductoring	PG&E	2015
32	San Leandro - Oakland J 115 kV Line Reconductoring	PG&E	2015
33	San Mateo and Moraga Synchronous Condenser Replacement	PG&E	2015
34	Woodward 115 kV Reinforcement	PG&E	2016
35	Lodi-industrial 60 kV Line Switch Upgrade Project	PG&E	2011
36	Garberville Reactive Support	PG&E	2012

No	Project	PTO Area	Expected In-Service Date
37	Gold Hill-Horseshoe 115 kV Reinforcement	PG&E	2011
38	Guernsey-Henrietta 70 kV Line Reconductor Project	PG&E	5/1/2011
39	Herndon 230/115 kV Transformer Project	PG&E	5/1/2012
40	Maple Creek Reactive Support	PG&E	2013
41	Sanger-California Ave 70 kV to 115 kV Voltage Conversion Project	PG&E	5/1/2011
42	Sanger-Reedley 70 kV to 115 kV Conversion Project	PG&E	5/1/2012
43	Shepherd Substation	PG&E	12/1/2013
44	Clear Lake 60 kV System Reinforcement	PG&E	2016
45	Midway-Renfro 115 kV Reconductor	PG&E	5/31/2012
46	Valley Spring 230/60 kV Transmission Addition:	PG&E	May-12
47	Fulton-Fitch Mountain 60 kV Line Reconductor	PG&E	2013
48	Glenn #1 60 kV Reconductoring	PG&E	May-13
49	Occidental of Elk Hills 230 kV Interconnection Project	PG&E	10/1/2011
50	Humboldt 115/60 kV Transformer Replacements	PG&E	2012 and 2013
51	Del Monte - Fort Ord 60 kV Reinforcement Project	PG&E	May 2010 and May 2012
52	Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor	PG&E	5/1/2019
53	Corcoran 115/70 kV Transformer Replacement Project	PG&E	May-12
54	Divide Transmission	PG&E	May-11
55	Mare Island - Ignacio 115 kV Reconductoring Project	PG&E	2013
56	Moraga-Oakland "J" SPS Project	PG&E	May-11
57	Morro Bay 230/115 kV Transformer Addition Project	PG&E	May-13
58	Mountain View/Whisman-Monta Vista 115 kV Reconductoring	PG&E	May-14

No	Project	PTO Area	Expected In-Service Date
59	Pittsburg-Lakewood SPS Project	PG&E	May-11
60	Reedley-Dinuba 70 kV Line Reconductor	PG&E	May-14
61	Reedley-Orosi 70 kV Line Reconductor	PG&E	May-13
62	Stockton 'A' -Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	May-12
63	Weber 230/60 kV Transformer Nos. 2 and 2A Replacement	PG&E	May-13
64	West Sacramento Transmission Project	PG&E	March-11
65	Kramer 115 kV Circuit Breakers Upgrades	SCE	2011
66	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	2011
67	East Kern Wind Resource Area 66 kV Reconfiguration Project	SCE	Dec-13
68	New 230/138 kV transformer: Miguel Substation	SDG&E	2012
69	Reconductor TL6915, TL6924: Pomerado-Sycamore	SDG&E	2011
70	New 138 Tap: TL13835 Talega to San Mateo-Laguna Niguel	SDG&E	TBD
71	Shadowridge-Calavera Tap 138 kV upgrade	SDG&E	2011
72	New and/or Upgrade of 69 kV Capacitors	SDG&E	2011-2014
73	Removal of Carlton Hills Tap-Sycamore reconfiguration	SDG&E	2012
74	New Escondido-Ash 69 kV line TL6956	SDG&E	2012
75	TL6913, Upgrade Pomerado - Poway	SDG&E	2014
76	Upgrade Los Coches 138/69 kV bank 51	SDG&E	2012
77	Upgrade TL13802D, Encina-Calavera Tap	SDG&E	2011
78	Upgrade TL667, Penasquitos - Del Mar #2 69 kV line	SDG&E	2011
79	Upgrade TL680A, San Luis Rey - Melrose Tap 69 kV line	SDG&E	2011
80	Upgrade TL6927, Eastgate-Rose Canyon	SDG&E	2011

No	Project	PTO Area	Expected In-Service Date
81	P01141: Reconductor TL13836, Talega – Pico	SDG&E	TBD

Table 8.1-2: Status of previously approved projects costing $50M or more

No	Project	PTO Area	Expected In-Service Date
1	Highwind Location Constrained Resource Interconnection Facility	SCE	TBD
2	Tehachapi Transmission Project	SCE	2015
3	Sunrise Powerlink	SDG&E	2012
4	Alberhill 500 kV Method of Service	SCE	2014
5	Bayfront Substation Project	SDG&E	2012
6	Fresno Reliability Transmission Projects	PG&E	2014

8.2 Transmission Projects Found to Be Needed in The 2010/11 Planning Cycle

In the 2010/2011 transmission planning process, the ISO determined that 32 transmission projects, submitted through the ISO 2010 request window, were needed to mitigate identified reliability concerns. Table 8.2-1 is the summary of these 32 transmission projects. In addition, the ISO also identified one policy-driven project (category 1) to be recommended to the ISO Board of Governors for approval (please see Table 8.2-2).

Table 8.2-1: New reliability projects found to be needed

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
1	Reconductor TL663, Mission-Kearny	SDG&E	$17.9M	San Diego	Reliability Project	6/1/2015
2	Reconductor TL670, Mission-Clairemont	SDG&E	$14.7M	San Diego	Reliability Project	6/1/2015
3	Reconductor TL676, Mission-Mesa Heights	SDG&E	$18.6M	San Diego	Reliability Project	6/1/2015
4	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	$9M	San Diego	Reliability Project	6/1/2013
5	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	$33.6M	San Diego	Reliability Project	6/1/2013
6	TL644, South Bay-Sweetwater: Reconductor	SDG&E	$8.9M	San Diego	Reliability Project	6/1/2013
7	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	$16.9M	San Diego	Reliability Project	6/12/2012
8	Southern Orange County Reliability Upgrade Project - Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	$365M	San Diego	Reliability Project	6/1/2015
9	New Sycamore - Bernardo 69 kV line	SDG&E	$30M	San Diego	Reliability Project	6/1/2015
10	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	$3-6M	Fresno/Kern	Reliability Project	5/1/2013

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
11	Wilson 115 kV Area Reinforcement	PG&E	$35-45M	Fresno/Kern	Reliability Project	5/1/2015
12	West Point - Valley Springs 60 kV Line Project	PG&E	$20-25M	North/Central Valley	Reliability Project	12/1/2013
13	Vierra 115 kV Looping Project	PG&E	$10-15M	North/Central Valley	Reliability Project	5/1/2014
14	Rio Oso - Atlantic 230 kV Line Project	PG&E	$30-40M	North/Central Valley	Reliability Project	5/1/2016
15	Table Mountain – Sycamore 115 kV Line	PG&E	$25-35M	North/Central Valley	Reliability Project	5/1/2015
16	Stagg – Hammer 60 kV Line	PG&E	$5-10M	North/Central Valley	Reliability Project	5/1/2014
17	South of Palermo 115 kV Reinforcement Project	PG&E	$80-100M	North/Central Valley	Reliability Project	5/1/2014
18	Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project	PG&E	$43-57M	North/Central Valley	Reliability Project	5/1/2016
19	Oro Loma 70 kV Area Reinforcement	PG&E	$35-45M	Fresno/Kern	Reliability Project	5/1/2015
20	Oro Loma - Mendota 115 kV Conversion Project	PG&E	$25-35M	Fresno/Kern	Reliability Project	5/1/2015
21	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	$1-5M	Greater Bay	Reliability Project	5/31/2013
22	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	$5-10M	Central Coast/Los Padres	Reliability Project	5/31/2014
23	Kerchhoff PH #2 - Oakhurst 115 kV Line	PG&E	$25-35M	Fresno/Kern	Reliability Project	5/1/2015
24	Lemoore 70 kV Disconnect Switches Replacement	PG&E	$1-3M	Fresno/Kern	Reliability Project	5/1/2013
25	Hammer – Country Club 60 kV Switch Replacement	PG&E	$1-2M	North/Central Valley	Reliability Project	5/1/2012
26	Jefferson-Stanford #2 60 kV Line	PG&E	$25-35M	Greater Bay	Reliability Project	5/31/2014
27	Gill Ranch Gas Storge 115 kV Interconnection	PG&E	$11.8M	Fresno/Kern	Reliability Project	5/1/2011
28	Fulton 230/115 kV Transformer	PG&E	$10-14M	Humboldt,North Coast/Bay	Reliability Project	5/1/2014

No	Project Name	Project Sponsor(s)	Project Cost ($ Million)	Service Area	Type of Submission	In-Service Date
29	Cayucos 70 kV Shunt Capacitor	PG&E	$5-10M	Central Coast/Los Padres	Reliability Project	5/31/2014
30	Cortina No.3 60 kV Line Reconductoring Project	PG&E	$4-7M	North/Central Valley	Reliability Project	5/1/2013
31	Cascade 115/60 kV No.2 Transformer Project and Cascade - Benton 60 kV Line Project	PG&E	$20-30M	North/Central Valley	Reliability Project	5/1/2014
32	Vaca – Davis Voltage Conversion Project	PG&E	$70-107M	North/Central Valley	Reliability Project	5/1/2015

The following table 8.2-2 provides a list of policy-driven transmission project found to be needed in the ISO 2010/2011 planning cycle. The ISO has determined that WECC Path 42 and Devers – Mirage 230 kV Upgrades to qualify for category 1 policy-driven project for recommendation to the ISO Board of Governors for approval. For further discussion on this category 1 project, please refer to chapter 5 of the transmission plan.

Table 8.2-2: Category 1 Transmission Upgrades

No.	Name of Project	Description of Project
1	Path 42 and Devers – Mirage 230 kV Upgrades	This is a joint transmission upgrade on IID's portion of Path 42 (i.e. IID's portion on the Coachella Valley – Devers and Coachella Valley – Ramon 230 kV lines) and SCE's Devers – Mirage and Mirage – Ramon 230 kV lines. Considered upgraded path rating, subject to further WECC review and approval as part of its path rating study process, is 1,440 MW.

8.3 Policy Driven Transmission Projects To Be Evaluated in The Next Planning Cycle (2011/2012)

Table 8.3-1 lists category 2 policy-driven transmission upgrades to be evaluated further in the 2011/2012 planning cycle. For further discussions on these category 2 transmission upgrades, please see chapter 5 of the transmission plan.

Table 8.3-1: Category 2 Transmission Upgrades

No.	Name of Project	Description of Project
1	Install Reactive Supports at Various SDG&E's 230 kV Substations	Install a total of 400 MVAr reactive power support at Sycamore, Mission, and Talega 230 kV Substations
2	Third Miguel 500 kV Transformer	Install third 500/230 kV transformer at Miguel Substation
3	Upgrade El Dorado – Pisgah 500 kV Series Capacitors	Upgrade El Dorado - Pisgah 500 kV series capacity to higher emergency rating (2700 A)
4-8	Upgrade and construct new transmission lines in Fresno area:	1) Build the new Midway - Gregg 500 kV line 2) Reconductor Gregg - Herndon 230 kV line 3) Reconductor Warnerville - Wilson 230 kV line 4) Reconductor Barton - Herndon 115 kV line 5) Reconductor Manchester - Herndon 115 kV line

8.4 2010 Request Window Submittals

During the 2010/2011 planning cycle, the ISO 2010 request window was open from October 11, 2010, to December 10, 2010. During this time, 118 submittals were received which included proposals related to reliability, economic study requests, LCRIF, and merchant transmission projects. After screening review, 107 submittals remained in the ISO 2010 request window (see summary of this list in Table 8.4-1). Submittals were also made for operating procedures and System Protection Systems (SPS) which do not need ISO approval and were not required to be submitted through the request window. Finally, some projects were submitted as informational items; the intent of which is to provide the ISO information on items which are being considered by the PTOs for future submittal and for maintenance related projects for terminal equipment replacement[42].

[42] SDG&E submitted terminal equipment replacement projects to the ISO for informational only.

Table 8.4-1: 2010 Request Window Submittals

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
1	Telegraph Canyon 138kV Capacitor Addition	SDG&E	SDG&E	Reliability Project	4/1/2011	Project approval	Needs further evaluation	Chapter 2 - SDG&E
2	Reconductor TL663, Mission-Kearny	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
3	Reconductor TL670, Mission-Clairemont	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
4	Reconductor TL676, Mission-Mesa Heights	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
5	Reconductor TL631, El Cajon-Los Coches	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Needs further evaluation	Chapter 2 - SDG&E
6	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
7	TL698E, Pala-Monserate Tap	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
8	TL642A, South Bay-Montgomery Tap - Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
9	TL603B, Sweetwater-Sweetwater Tap - Terminal Equp.	SDG&E	SDG&E	Reliability Project	?	Information Only	N/A	Chapter 2 - SDG&E
10	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
11	TL691C, Pendleton-Avocado Tap: Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed. Project submitted as informational item	Chapter 2 - SDG&E
12	TL644, South Bay-Sweetwater: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	Yes	Chapter 2 - SDG&E
13	TL6916, Sycamore-Scripps Overload Mitigation/ New TL 6942 Sycamore - Miramar 69 kV Line	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
14	TL6912 - Reconductor San Luis Rey-Pendleton	SDG&E	SDG&E	Reliability Project	6/1/2020	Project approval	Needs further evaluation	Chapter 2 - SDG&E
15	TL693 San Luis Rey-Melrose:Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
16	TL694A San Luis Rey - Morro Hill Tap:Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	No	Chapter 2 - SDG&E
17	TL680B - Melrose-Melrose Tap: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2013	Project approval	No	Chapter 2 - SDG&E
18	TL691B - Monserate-Avocado Tap: Terminal Equipment	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed Project submitted as informational item	Chapter 2 - SDG&E
19	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	SDG&E	Reliability Project	6/12/2012	Project approval	Yes	Chapter 2 - SDG&E
20	TL633 Benardo-Rancho Carmel Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	Needs further evaluation	Chapter 2 - SDG&E
21	Upgrade Mission 138/69 kV Transformer Banks 51 and 52	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Needs further evaluation	Chapter 2 - SDG&E
22	TL6915&6924 Sycamore-Pomerado #1 & #2: Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
23	TL648, Poway-Rancho Carmel: 69 kV Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	No	Chapter 2 - SDG&E
24	TL682 Rincon-Warners Reconductor	SDG&E	SDG&E	Reliability Project	6/1/2012	Project approval	No	Chapter 2 - SDG&E
25	TL13835B Reconductor Laguna Niguel - Talega Tap	SDG&E	SDG&E	Reliability Project	6/1/2020	Project approval	Needs further evaluation	Chapter 2 - SDG&E
26	TL689A Bernardo-Felicita Tap: short-term mitigation	SDG&E	SDG&E	Reliability Project	?	Information Only	No approval needed; project submitted as informational item	Chapter 2 - SDG&E

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27	Modified-SOCRUP Project	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes (Alternattive to project submittal is recommended)	Chapter 2 - SDG&E
28	Los Coches Substation 230 kV Expansion	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Needs further evaluation	Chapter 2 - SDG&E
29	New Sycamore - Bernardo 69 kV line	SDG&E	SDG&E	Reliability Project	6/1/2015	Project approval	Yes	Chapter 2 - SDG&E
30	2009 Grid Assessment Category C Violations listings	SDG&E	SDG&E	Other	-	Information Only	No approval needed Project submitted as informational item	Chapter 2 - SDG&E
31	Reconfigure TL23013 and TL23028	SDG&E	SDG&E	Reliability Project	6/1/2011	Project approval	No	Chapter 2 - SDG&E
32	Install Synchronous Condensers at Mission, Penasquitos, and Talega 230 kV Substations	SDG&E	SDG&E	Reliability Project	6/1/2013 6/1/2016 6/1/2019	Project approval	Needs further evaluation	Chapter 2 - SDG&E
33	Antelope A Bank Operating Procedure	SCE	SCE	Reliability Project	6/1/2013	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
34	Bailey Operating Procedure	SCE	SCE	Reliability Project	3/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
35	Big Creek Existing RAS Modification	SCE	SCE	Reliability Project	9/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE

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36	Garnet Operating Procedure	SCE	SCE	Reliability Project	3/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
37	Lancaster OP & RAS	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
38	Neenach Selective Service	SCE	SCE	Reliability Project	12/31/2013	Project approval	No	Chapter 2 - SCE
39	North of Lugo Operating Procedures	SCE	SCE	Reliability Project	Spring 2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
40	Palmdale Remedial Action Scheme	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
41	Path 26 Existing RAS Modification	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
42	Rector RAS Modification	SCE	SCE	Reliability Project	6/1/2011	Project approval	Yes No approval needed for SPS or operating procedure	Chapter 2 - SCE
43	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Fresno/Kern	Reliability Project	5/1/2013	Project approval	Yes	Chapter 2 - PG&E
44	Midway-Gregg 500 kV Line	PG&E	Fresno/Kern	Reliability Project	12/31/2018	Project approval	No	Chapter 2 - PG&E

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45	Wilson 115 kV Area Reinforcement	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
46	Wheeler Ridge Junction 230 kV Substation	PG&E	Fresno/Kern	Reliability Project	5/1/2020	Information Only	No approval needed Project submitted as informational item	Chapter 2 - PG&E
47	West Point - Valley Springs 60 kV Line Project	PG&E	North/Central Valley	Reliability Project	12/1/2013	Project approval	Yes	Chapter 2 - PG&E
48	Vierra 115 kV Looping Project	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
49	Rio Oso - Atlantic 230 kV Line Project	PG&E	North/Central Valley	Reliability Project	5/1/2016	Project approval	Yes	Chapter 2 - PG&E
50	Table Mountain - Sycamore 115 kV Line	PG&E	North/Central Valley	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
51	Stagg - Hammer 60 kV Line	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
52	South of Palermo 115 kV Reinforcement Project	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
53	Cottonwood-Red Bluff No. 2 60 kV Line Project Red Bluff Area 230/60 kV Substation Project	PG&E	North/Central Valley	Reliability Project	5/1/2016	Project approval	Yes	Chapter 2 - PG&E
54	Oro Loma 70 kV Area Reinforcement	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
55	Pittsburg - Clayton #2 115 kV Line Project Moraga-Lakewood 115 kV Reconductoring Project Lakewood-Meadow Lane - Clayton 115 kV Reconductoring Project	PG&E	Greater Bay	Reliability Project	5/31/2015	Project approval	No	Chapter 2 - PG&E
56	Oro Loma - Mendota 115 kV Conversion Project	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
57	Morro Bay - Mesa 230 kV Line Project	PG&E	Central Coast/Los Padres	Reliability Project	5/31/2017	Project approval	No	Chapter 2 - PG&E
58	Moraga-San Leandro/Oakland "J" 115 kV Reconductoring	PG&E	Greater Bay	Reliability Project	5/31/2015	Project approval	Needs further evaluation	Chapter 2 - PG&E
59	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Greater Bay	Reliability Project	5/31/2013	Project approval	Yes	Chapter 2 - PG&E
60	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	Central Coast/Los Padres	Reliability Project	5/31/2014	Project approval	Yes	Chapter 2 - PG&E
61	Mesa - Divide 115 kV Line	PG&E	Central Coast/Los Padres	Reliability Project	5/31/2014	Project approval	No	Chapter 2 - PG&E
62	Kerchhoff PH #2 - Oakhurst 115 kV Line	PG&E	Fresno/Kern	Reliability Project	5/1/2015	Project approval	Yes	Chapter 2 - PG&E
63	Lodi Area 230/60 kV Substation	PG&E	North/Central Valley	Reliability Project	5/1/2016	Project approval	Needs further evaluation	Chapter 2 - PG&E
64	Lemoore 70 kV Disconnect Switches Replacement	PG&E	Fresno/Kern	Reliability Project	5/1/2013	Project approval	Yes	Chapter 2 - PG&E
65	Kirkwood Meadows Public Utility District 115 kV Interconnection	PG&E	North/Central Valley	Reliability Project	11/1/2012	Project approval	Yes	Chapter 2 - PG&E
66	Hammer - Country Club 60 kV Switch Replacement	PG&E	North/Central Valley	Reliability Project	5/1/2012	Project approval	Yes	Chapter 2 - PG&E
67	Jefferson-Stanford #2 60 kV Line	PG&E	Greater Bay	Reliability Project	5/31/2014	Project approval	Yes	Chapter 2 - PG&E
68	Ignacio - Alto 60 kV Reconductoring and Voltage Support Project	PG&E	Humboldt,North Coast/Bay	Reliability Project	5/1/2014	Project approval	No	Chapter 2 - PG&E
69	Gill Ranch Gas Storge 115 kV Interconnection	PG&E	Fresno/Kern	Reliability Project	5/1/2011	Project approval	Yes	Chapter 2 - PG&E

No	Project Name	Project Sponsor(s)	Service Area	Type of Submission	In-Service Date	Project Proponent's Requested Action	Is the Project Found to be Needed?	Reference to ISO 2010/2011 Transmission Plan
70	Drum-Grass Valley-Weimar 60 kV Line Reconductor	PG&E	North/Central Valley	Reliability Project	5/1/2013	Project approval	Needs further evaluation	Chapter 2 - PG&E
71	Fulton 230/115 kV Transformer	PG&E	Humboldt,North Coast/Bay	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
72	Embarcadero-Potrero 230 kV Transmission	PG&E	Greater Bay	Reliability Project	5/31/2015	Project approval	Needs further evaluation	Chapter 2 - PG&E
73	Westwood Area Upgrades	PG&E	North/Central Valley	Reliability Project	12/1/2011	Project approval	Needs further evaluation	Chapter 2 - PG&E
74	Cayucos 70 kV Shunt Capacitor	PG&E	Central Coast/Los Padres	Reliability Project	5/31/2014	Project approval	Yes	Chapter 2 - PG&E
75	Cortina No.3 60 kV Line Reconductoring Project	PG&E	North/Central Valley	Reliability Project	5/1/2013	Project approval	Yes	Chapter 2 - PG&E
76	Cascade 115/60 kV No.2 Transformer Project Cascade - Benton 60 kV Line Project	PG&E	North/Central Valley	Reliability Project	5/1/2014	Project approval	Yes	Chapter 2 - PG&E
77	Borden - Gregg 230 kV Line Reconductor	PG&E	Fresno/Kern	Reliability Project	5/1/2017	Project approval	No approval needed (LGIP project)	Chapter 2 - PG&E
78	Borden 230 kV Reactive Support	PG&E	Fresno/Kern	Reliability Project	5/1/2020	Information Only	No approval needed Project submitted as informational item	Chapter 2 - PG&E
79	Bay Area Reactive Support - Pittsburg SVC	PG&E	Greater Bay	Reliability Project	12/1/2013	Project approval	No	Chapter 2 - PG&E
80	Ames-Palo Alto 115 kV Line	PG&E	Greater Bay	Reliability Project	5/31/2014	Project approval	Needs further evaluation	Chapter 2 - PG&E
81	North of Los Banos Economic Planning Study Request	PG&E	Fresno/Kern	Economic Planning Study	n/a	Request for economic planning study	To be evaluated in upcoming transmission planning	N/A To be addressed in upcoming planning study process

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82	Donnells - Curtis Reconductor - Economic Planning Study Request	PG&E	North/Central Valley	Economic Planning Study	n/a	Request for economic planning study	To be evaluated in upcoming transmission planning	N/A To be addressed in upcoming transmission planning study process
83	Imperial Valley Renewable Transmission Project	Citizens Energy Corporation	SDG&E	Economic Planning Study	9/30/2015	Request for economic planning study	N/A Proponent asked ISO to evaluate project based on reliability need	N/A I To be addressed in upcoming transmission planning study process
84	Imperial Valley Renewable Transmission Project	Citizens Energy Corporation	SDG&E	Reliability Project	9/30/2015	Project approval	No	Chapter 2 - SDG&E
85	Auburn 60 kV Energy Storage Project	Western Grid Development, LLC	Central Coast	Reliability Project	3/30/2015	Project approval	Needs further evaluation	Chapter 2 - PG&E
86	Coppermine 70 kV Energy Storage Project	Western Grid Development, LLC	Fresno	Reliability Project	12/30/2011	Project approval	No	Chapter 2 - PG&E
87	Madison 115 kV Energy Storage Project	Western Grid Development, LLC	Central Valley	Reliability Project	3/30/2014	Project approval	No	Chapter 2 - PG&E
88	Potrero 115 kV Energy Storage Project	Western Grid Development, LLC	San Francisco	Reliability Project	12/30/2011	Project approval	No	Chapter 2 - PG&E
89	Weedpatch 70 kV Energy Storage Project	Western Grid Development, LLC	Fresno	Reliability Project	3/30/2014	Project approval	No	Chapter 2 - PG&E

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90	Barrett Interim Solution (Originally Submitted in 2008 RW)	Transmission Technology Solutions, LLC	SDG&E	Reliability Project	10/30/2012	Project approval	No	Chapter 2 - SDG&E
91	Cal Cement Interim Solution (Originally Submitted in 2008 RW)	Transmission Technology Solutions, LLC	SCE	Reliability Project	11/30/2012	Project approval	No	Chapter 2 - SCE
92	Camp Evers Interim Solution (Originally Submitted in 2008 RW)	Transmission Technology Solutions, LLC	Central Coast	Reliability Project	11/30/2012	Project approval	No	Chapter 2 - PG&E
93	Cottonwood Interim Solution (Originally Submitted in 2008 RW)	Transmission Technology Solutions, LLC	North Valley	Reliability Project	10/30/2012	Project approval	No	Chapter 2 - PG&E
94	Trinity Interim Solution (Originally Submitted in 2008 RW)	Transmission Technology Solutions, LLC	North Valley	Reliability Project	10/30/2012	Project approval	No	Chapter 2 - PG&E
95	Watsonville Interim Solution (Originally Submitted in 2008 RW)	Transmission Technology Solutions, LLC	Central Coast	Reliability Project	11/30/2012	Project approval	No	Chapter 2 - PG&E
96	Delany - Colorado River 500 kV	Arizona Public Service	SCE	Economic Planning Study	n/a	Request for economic planning study	To be evaluated in upcoming transmission planning	N/A To be addressed in upcoming transmission planning study process
97	Zephyr	TransCanada	SCE	Economic Planning Study	n/a	Request for economic planning study	To be evaluated in upcoming transmission planning	N/A To be addressed in upcoming transmission planning study process

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98	North Gila to Imperial Valley #2 Double Circuit	Southwest Transmission Partners and on behalf of Energy Capital Partners, II and it's affilitates	SDG&E	Reliability Project	5/1/2015	Project approval	No	Chapter 2 - SDG&E
99	Oro Verde Transmission Project	Critical Path Transmission, LLC	SCE	Merchant Transmission Facility	Phase 1 - May 1, 2013 Phase 2 - September 1, 2013	Project approval for interconnection to ISO Controlled Grid	N/A Further evaluation is needed prior to ISO Management concurrence on interconnection to ISO Controlled Grid	
100	Brighton 230 kV Reliability Solution	Transmission Technology Solutions, LLC	Central Valley	Reliability Project	5/1/2012	Project approval	Needs further evaluation	Chapter 2 - PG&E
101	Cascade 60 kV Reliability Solution	Transmission Technology Solutions, LLC	North Valley	Reliability Project	5/1/2012	Project approval	No	Chapter 2 - PG&E
102	Red Bluff 60 kV Energy Storage Project	Western Grid Development, LLC	North Valley	Reliability Project	2011	Project approval	No	Chapter 2 - PG&E
103	Vaca Dixon 60 kV Energy Storage Project	Western Grid Development, LLC	North Valley	Reliability Project	2011	Project approval	No	Chapter 2 - PG&E

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104	Cortina 60 kV Energy Storage Project	Western Grid Development, LLC	North Valley	Reliability Project	5/1/2011	Project approval	No	Chapter 2 - PG&E
105	High Temperature Cable	Clear Power, LLC	San Francisco	Reliability Project	1/12/2016	Project approval	No	Chapter 2 - PG&E
106	Great Basin HVDC Project	Great Basin Energy Development, LLC	North Valley	Reliability Project	11/1/2016	Project approval	No	Chapter 2 - PG&E
107	Imperial Valley LCRIF	Cal Energy Operating Corp.	SDG&E	LCRIF	4/15/2015	Project approval	Needs further evaluation	Chapter 3