2015-2016 TRANSMISSION PLAN

California ISO

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DRAFT

Forward to DRAFT 2015-2016 Transmission Plan

Thank you for your participation in the ISO transmission planning process, and your review of this draft transmission plan. The objective of the draft transmission plan is to represent the current thinking of the ISO in moving towards final recommendations in each year's transmission planning process.

In reviewing the draft transmission plan, it is important to remember that the draft transmission plan is structured and written as a draft and not as a discussion document. Consequently, it is written in the same format and tone as the final transmission plan though it is open to change based on stakeholder input and new information as we move to finalizing the plan in March.

The ISO's objective each year is to provide a comprehensive overview with the goal of providing draft recommendations on all decisions we expect to see made in the course of the planning cycle.

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Executive Summary

The California Independent System Operator Corporation's 2015-2016 Transmission Plan 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. This plan is updated annually, and is prepared in the larger context of supporting important energy and environmental policies while maintaining reliability through a resilient electric system.

Those needs, which were historically driven by customer load growth, are now driven predominantly by the policy-driven transitions in the electricity industry to renewable energy and decarbonizing the grid. As such, the transmission plan is a bellwether of the industry infrastructure transitions, both in the evolving demands placed on the transmission system and the issues that need to be managed in meeting those new demands.

The 2015-2016 Transmission Plan reflects the continuation of the trends established through the past number of previous plans:

- new reliability requirements have consistently declined in a period of relatively low load growth, after experiencing a spike in development activity to address the transition away from coastal once-through cooling gas-fired generation and the early retirement of the San Onofre Nuclear Generating Station;
- transmission needs to access renewable generation development to achieve the state's 33 percent – by 2020 – renewable generation goals have largely been identified and are moving forward;
- economic-driven development has been explored through a number of planning cycles, with a number of major projects initiated but now new projects identified as needed in this cycle; and
- while new policy-driven goals have been established in the state, considerable work is necessary to choose among technologically and geographically diverse resources before transmission decisions can be made to access those renewables and pursue other transmission opportunities. This will be especially challenging given the need to consider the growing benefits of regionalism – considering needs and options on a more west-wide basis and the increasing benefits of resource and geographic diversity in moving to yet higher renewable energy goals.

The 2015-2016 Transmission Plan has continued the trend of a declining amount of new capital transmission projects being identified, and expanding the analysis of the issues that will need to be managed as the grid continues its transition from conventional resources to renewable resources and other preferred resources in meeting those needs. This trend is partially offset by the need to address replacing aging infrastructure and the management of new concerns such as increasing demands on voltage control, which has driven much of the reinforcement projects identified in this plan.

In preparing for the next wave of development to achieve higher renewable energy goals, additional special studies have been conducted within the planning cycle to inform resource discussions and to proactively manage emerging system performance issues resulting from the transitions on the supply side, e.g. resources, and the demand side, e.g. customer needs.

Key analytic components of the plan include the following:

- continuing to refine the plans for transmission needed to support meeting the 33 percent RPS goals, which are based on renewable resource portfolios produced through a process established by the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) of the type and location of renewable resources most likely to be developed to meet the 33 percent renewables portfolio standard (RPS) goal by 2020[1];
- supporting advancement of preferred resources in meeting needs overall, and in particular in southern California;
- identifying transmission upgrades and additions needed to reliably operate the network and comply with applicable planning standards and reliability requirements; and
- performing economic analysis that considers whether transmission upgrades or additions could provide additional ratepayer benefits.

Increased opportunity for non-transmission alternatives, particularly preferred resources and storage, continues to be a key focus of the transmission planning analysis. In this regard, the ISO's transmission planning efforts focus on not only meeting the state's policy objectives through advancing policy-driven transmission, but also to help transform the electric grid in an environmentally responsible way. The focus on a cleaner lower emission future governs not only policy-driven transmission, but our path on meeting other electric system needs as well.

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

- The ISO identified 15 transmission projects as needed to maintain transmission system reliability. The ISO is recommending approval in this Transmission Plan of 14 of those projects with an estimated cost of approximately $306 million. Further coordination with a neighboring planning region will be undertaken for the remaining project with approval being deferred to next year's planning cycle;
- As a part of the 2015-2016 planning efforts, the ISO conducted a separate and standalone review of a large number of local area low voltage transmission projects in the PG&E service territory that were predominantly load forecast driven and whose approvals dated back a number of years. In reviewing the continued need for those projects in light of materially lower load forecast levels since those projects were approved, the ISO took into account existing planning standards, California local capacity requirements, and deliverability requirements for generators with executed interconnection agreements. As a result of the review, 13 predominantly lower-voltage transmission projects that were

[1] SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. The new law establishes targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030. Future planning cycles will focus on moving beyond the 33 percent framework when renewable generation portfolios become available through the process established with the California Public Utilities Commission and California Energy Commission.

found to be no longer required and are recommended to be cancelled. Only one of the 13, a 230 kV to 60 kV transformer addition, had a regional (e.g. greater than 200 kV) component.

- The ISO's analysis indicated in this planning cycle that the authorized resources, forecast load, and previously-approved transmission projects working together continue to meet the forecast reliability needs in the LA Basin and San Diego areas. However, due to the inherent uncertainty in the significant volume of preferred resources and other conventional mitigations, the situation is being continually monitored in case additional measures are needed;
- Consistent with recent transmission plans, no new major transmission projects have been identified at this time to support achievement of California's 33 percent renewables portfolio standard given the transmission projects already approved or progressing through the CPUC approval process.
- No economic-driven transmission projects are recommended for approval; and
- The ISO tariff sets out a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the plan.
- None of the transmission projects in this transmission plan include facilities eligible for competitive solicitation.

Special studies focusing on emerging grid transition and renewable integration issues expanded in the 2015-2016 Transmission Plan from previous years, including the following:

- a preliminary effort studying gas pipeline and electricity coordination given the evolving role of gas fired generation in southern California;
- a preliminary study of the capabilities of the ISO grid to accommodate renewable generation resources on an energy-only basis in moving beyond 33 percent renewables to a 50 percent renewables goal. Note that this is informational only to assist industry in considering options in moving beyond 33 percent; and,
- a preliminary study of the benefits of large energy storage in managing oversupply periods in moving beyond 33 percent; this study explored a 40 percent renewables condition.

A number of interregional projects were raised by stakeholders during the planning cycle. The ISO conducted some analysis of several of these projects reflecting a more limited ISO view of those projects. The ISO will be participating in the interregional Federal Energy Regulatory Commission (FERC) Order No. 1000 interregional planning process with the neighboring western planning regions as that process commences for the first time in the first quarter of 2016, which will allow for a broader consideration of the potential benefits of these projects.

This year's transmission plan is based on the ISO's transmission planning process, which involved collaborating with the CPUC, the CEC and many other interested stakeholders. Summaries of the transmission planning process 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.

Purpose of the Transmission Plan

A core ISO responsibility is to identify and plan the development of solutions, transmission or otherwise, to meet the future needs of the ISO controlled grid. The fulfillment of this responsibility includes conducting an annual transmission planning process (TPP) that culminates in an ISO Board of Governors (Board) approved transmission plan that identifies needed transmission solutions and authorizes cost recovery through ISO transmission rates, subject to regulatory approval, as well as identifying other solutions that will be pursued in other venues to avoid building additional transmission facilities if possible. The plan is prepared in the larger context of supporting important energy and environmental policies and assisting in the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system.

The transmission plan primarily identifies three main categories of transmission solutions: reliability, public policy and economic needs. The plan may also include transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects or provide for merchant transmission projects. The ISO also considers and places a great deal of emphasis on the development of non-transmission alternatives, both conventional generation and in particular, preferred resources such as energy efficiency, demand response, renewable generating resources and energy storage programs. Though the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive plan, these can be identified as the preferred mitigation in the same manner that operational solutions are often selected in lieu of transmission upgrades. Further, load modifying preferred resource assumptions are also incorporated into the load forecasts adopted through state energy agency activities that the ISO supports, and provide an additional opportunity for preferred resources to address transmission needs.

The Transmission Planning Process

The transmission planning process is defined by three distinct phases of activity that are completed in consecutive order across a time frame called a planning cycle. The planning cycle is identified by a beginning year and a concluding year with the beginning year starting in January but extends beyond a single calendar year. The 2015-2016 planning cycle, for example, began in January 2015 and concluded in March 2016. The distinct phases of the planning cycle are defined below:

- Phase 1 - Develop and finalize a study plan that documents the assumptions, models and public policy mandates that will be followed throughout the planning cycle;
- Phase 2 - Performance of all technical assessment where solutions, transmission or otherwise, are identified to as required for the ISO controlled grid or that may be needed to support other state or industry informational requirements. Document the results, conclusions, and recommendations in a transmission plan, which is considered by the Board for approval; and,
- Phase 3 - If required, engagement in a competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan.

State Agency Coordination in Planning

State agency coordination in planning continued to build on the core strengths offered by the CPUC, CEC, and ISO towards building further improvements into the development of unified planning assumptions and other considerations that are a crucial component of the ISO's transmission plan. While the coordination effort not only enhanced this year's plan, it continues to establish a firm foundation over which enhancements in future transmission planning cycles can be successfully achieved.

The 2015-2016 planning assumptions and scenarios were developed through the annual process the ISO, CEC and CPUC have in place and performed in the fall of each year to be used in infrastructure planning activities in the coming year. This alignment effort continues to improve infrastructure planning coordination within the three core processes:

- long-term forecasts of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR),
- biennial long term procurement plan proceedings (LTPP) conducted by the CPUC, and
- annual transmission planning process performed by the ISO.

In this coordination effort, the agencies considered assumptions such as demand, supply and system infrastructure elements, and the 33 percent RPS generation portfolios proposed by the CPUC. The results of the CPUC's annual process feeding into this 2015-2016 transmission planning process were communicated via an assigned commissioner's ruling in the 2014 LTPP.[2] These assumptions were further vetted by stakeholders through the ISO's stakeholder process which resulted in this year's study plan.[3] The ISO considers the agencies' successful effort coordinating the development of the common planning assumptions to be a key factor in promoting the ISO's transmission plan as a valuable resource in identifying grid expansion necessary to maintain reliability, lower costs or meet future infrastructure needs based on public policies. This coordination is expected to continue and grow, as demonstrated in the Renewable Energy Transmission Initiative discussed below, which will aid in the development of renewable generation portfolios moving beyond 33 percent to the higher goals now in effect that will be addressed in future planning cycles.

Key Reliability Study Findings

During the 2015-2016 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's assessment considered facilities across voltages of 60 kV to 500 kV, and where reliability concerns were identified, the ISO identified transmission solutions to address these concerns. In total, this plan proposes approving 14 reliability-driven transmission projects, representing an investment of approximately $306 million in infrastructure additions to

[2] Rulemaking 13-12-010 "Assigned Commissioner's Ruling on updates to the Planning Assumptions and Scenarios for use in the 2014 Long-Term Procurement Plan and the California Independent System Operator's 2015-2016 Transmission Planning Process" on March 4, 2015 with an update adopted on October 28, 2015.
[3] http://www.caiso.com/Documents/2015-2016FinalStudyPlan.pdf

the ISO controlled grid. All of these projects are estimated to individually cost less than $50 million. The number of projects and their costs are presented by service territory in table 7.2.1.

Table 1 – Summary of Needed Reliability-Driven Transmission Projects in the ISO 2015-2016 Transmission Plan Recommended for Approval

Service Territory	Number of Projects	Cost (in millions)
Pacific Gas & Electric (PG&E)	7	$202
Southern California Edison Co. (SCE)	1	$10
San Diego Gas & Electric Co. (SDG&E)	6	$94
Valley Electric Association (VEA)	0	0
Total	14	$306

Renewables Portfolio Standard Policy-driven Transmission Assessment

The transition to greater reliance on renewable generation has created significant transmission challenges because renewable resource areas tend to be located in places distant from population centers. The ISO's transmission planning process has balanced the need for certainty by generation developers as to where this transmission will be developed with the planning uncertainty of where resources are likely to develop by creating a structure for considering a range of plausible generation development scenarios and identifying transmission elements needed to meet the state's renewables portfolio standard. 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. These transmission upgrades are identified as policy-driven requirements. The ISO 33 percent RPS assessment is described in detail in chapters 4 and 5 of this plan.

Public policy requirements and directives are an element of transmission planning that was added to the planning process in 2010. Planning transmission to meet public policy directives is a national requirement under FERC Order No. 1000. It enables the ISO to identify and approve transmission facilities that system users will need to comply with state and federal requirements or directives. The primary policy directive for last five years' planning cycles and the current cycle is California's renewables portfolio standard that calls for 33 percent of the electric retail sales in the state in 2020 to be provided from eligible renewable resources. California's Clean Energy and Pollution Reduction Act of 2015, SB 350, was signed into law on October 7, 2015 establishing targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030. Future planning cycles will focus on moving beyond the 33 percent framework when renewable generation portfolios become available through the process established with the California Public Utilities Commission and California Energy Commission. As discussed later in this section, the ISO's study work and resource requirements determination for reliably integrating renewable resources is continuing on a parallel track outside of the transmission planning process, but steps are taken in this transmission plan to incorporate those requirements into annual transmission plan activities.

The CEC and CPUC on March 11, 2015 recommended two 33 percent renewable resource portfolios to be studied in the 2015-2016 transmission planning process,[4] with the same base portfolio as the previous year. As stated in the March 11 transmittal letter, the intent was to not re-run the renewables portfolio standard calculator relied upon in the previous planning cycle (RPS Calculator v.5) because the anticipated changes were not envisioned to materially impact the RPS portfolios. After further review, specific and limited changes were made, after which the RPS Calculator (v.5) was re-run and the updated base portfolio was received by the ISO on April 29, 2015.[5]

The reduced number of scenarios from previous transmission planning cycles and the consistency with the previous year's portfolios are indicative of the greater certainty around the portfolios, as utilities have largely completed their contracting for renewable resources to meet the 2020 goals.

The ISO assessment in this planning cycle did not identify a need for new transmission projects to support achievement of California's 33 percent renewables portfolio standard given the transmission projects already approved or progressing through the California Public Utilities Commission approval process.

Table 2 provides a summary of the various transmission elements of the 2014-2015 Transmission Plan for supporting California's renewables portfolio standard in addition to providing other reliability benefits. 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; and
- major transmission projects that have been previously approved by the ISO but are not yet permitted.

[4] https://www.caiso.com/Documents/2015-2016RenewablePortfoliosTransmittalLetter.pdf
[5] https://www.caiso.com/Documents/Revised2015-2016RenewablePortfoliosTransmittalLetter.pdf

Table 2: Elements of 2015-2016 ISO Transmission Plan Supporting Renewable Energy Goals

Transmission Facility	Online
Transmission Facilities Approved, Permitted and Under Construction	
Tehachapi Transmission Project	2016
Path 42 and Devers-Mirage 230 kV Upgrades	2016
Additional Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
Borden Gregg Reconductoring	2018
South of Contra Costa Reconductoring	2016
West of Devers Reconductoring	2021
Coolwater-Lugo 230 kV line[6]	cancelled
Policy-Driven Transmission Elements Approved but not Permitted	
Sycamore – Penasquitos 230kV Line	2017
Imperial Valley Area Collector Station[7]	cancelled
Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Swap	2017
Lugo – Eldorado series cap and terminal equipment upgrade	2019
Warnerville-Bellota 230 kV line reconductoring	2017
Wilson-Le Grand 115 kV line reconductoring	2020
Suncrest 300 Mvar SVC	2017
Lugo-Mohave series capacitors	2019
Additional Policy-Driven Transmission Elements Recommend for Approval	
None identified in 2015-2016 Transmission Plan	

[6] The project was cancelled after conventional generation in the area retired and the project was no longer required in order to provide requested generation interconnection service.

[7] The ISO received notice from the Imperial Irrigation District on November 24, 2015 exercising its right to terminate the Approved Project Sponsor Agreement. As the project was dependent on IID's participation, the project has been cancelled.

Key Economic Study Findings

While reliability analysis provides essential information about the electrical characteristics and performance of the ISO controlled grid, an economic analysis provides essential information about transmission congestion. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load. It follows then that minimizing or resolving transmission congestion can be cost effective to the ratepayer if solutions can be implemented to generate savings that are greater than the cost of the solution. For a proposed solution to qualify as an economic project, the benefit has to be greater than the cost. If there are multiple alternatives, the solution that has the largest net benefit is considered the most economical solution. Note that other benefits and risks must also be taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven project.

An economic planning analysis was performed as part of the 2015-2016 transmission planning cycle in accordance with the unified planning assumptions and study plan. All approved reliability and policy network upgrades were modeled in the economic planning database. This ensured that the results of the analysis would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan.

The economic planning analysis was performed in two steps: 1) congestion identification; and 2) congestion mitigation. Using production cost simulation and traditional power flow software, grid congestion was identified for the 5th and 10th planning years (2020 and 2025). Congestion results were aggregated across specific branch groups and local capacity areas and then ranked by severity in terms of congestion hours and congestion costs. From this “ranked” information, as well the consideration of nine economic study requests that had been submitted to the ISO as possible economic projects, five high priority congestion areas or projects were selected for further assessment.

Once the five high priority congestion areas or projects were selected, further economic planning analysis was performed on them to identify possible solutions to mitigate the congestion in these areas and to assess the economic benefits the mitigations or the projects can bring to ratepayers. Considering the five high priority studies, the ISO determined that there were no economic upgrade recommendations needed in this plan.

Policies and Initiatives that Influenced the Plan

The transmission planning process is influenced by a number of other evolving processes and initiatives in which the ISO has varying degrees of influence, input and control. These processes and initiatives are briefly summarized below, with an emphasis on their relationship to the current transmission planning cycle.

Interregional Transmission Coordination per FERC Order No. 1000

The reforms FERC Order No. 1000 required transmission utility providers to implement affected the ISO’s existing regional transmission planning process and directed the ISO to collaborate with neighboring transmission utility providers and planning regions across the Western Interconnection to develop a coordinated process for considering interregional projects. These regional and interregional reforms were designed to work together to ensure an opportunity for more transmission projects to be considered in transmission planning processes on an open and non-discriminatory basis both within planning regions and across multiple planning regions.

The ISO's tariff is compliant with the regional and interregional requirements of FERC Order No. 1000. While the ISO's prior tariff was largely compliant with the new regional requirements, tariff adjustments were necessary to fully align with the order in a number of areas including the establishment of the ISO as one of four western planning regions established within the Western Interconnection[8].

The ISO received FERC's final order on interregional transmission coordination on June 1, 2015. During 2015 the ISO and its neighboring western planning regions considered approaches to develop certain business practices that would provide stakeholders visibility and clarity on how the western planning regions would implement interregional coordination requirements into their respective regional planning processes. Ultimately the ISO, NTTG, and WestConnect collaborated in developing a set of business practices that would be beneficial to stakeholders and to facilitate successful interregional transmission coordination engagement among the western planning regions. NTTG and WestConnect will each determine how these business practices will be incorporated into their regional processes. The ISO will incorporate the procedures into its transmission planning business practice manual.

While ColumbiaGrid chose to pursue a different approach to business practices, the western planning regions are committed to proactively engage in interregional transmission coordination activities across all four regional planning processes.

Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

The principal objective of the GIDAP is to ensure that going forward all major transmission additions and upgrades to be paid for by ratepayers would be identified and approved under the transmission planning process. The most significant implication for the 2015-2016 transmission planning process relates to the planning of policy-driven transmission focused on achieving the state's 33 percent renewables portfolio standard. In that context and commensurate with the base renewables portfolio scenario provided by the CPUC and the ISO's generator interconnection queue up to and including queue cluster 8, the ISO planned transmission solutions that provided deliverability for new renewable energy projects unless specifically noted otherwise.[9]

Renewable Integration

As the amount of renewable generation on the ISO system grows, whether grid-connected or behind-the-meter at end customer sites, the transmission planning process must examine a broader range of considerations to ensure the overall safe, reliable and efficient operation of the ISO controlled grid. The ISO currently conducts a range of studies to support the integration of renewable generation into the ISO controlled grid. However, given the further increase in renewable generation being achieved and forecast further analysis on a programmatic basis was

[8] Western planning regions are the California ISO, ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect.

[9] Every RPS Calculator portfolio submitted by the Commission into the ISO's transmission planning process for purposes of identifying policy-driven transmission to achieve 33 percent RPS has assumed deliverability for new renewable energy projects.

considered in the transmission planning process to address additional emerging issues including the implications of significant displacement of conventional generation with renewable resources that do not have the same inherent fundamental operating characteristics; the exploration of system frequency response performance; transient and dynamic system performance; voltage control performance; and flexible needs throughout the system ramping spectrum.

The additional renewable integration studies undertaken in 2015 either as part of the 2015-2016 planning cycle or coordinated with it included further analysis of expected frequency response performance at higher renewable generation levels, which built on preliminary studies conducted in the 2014-2015 cycle, and a preliminary analysis of the benefits of large scale energy storage in addressing ramping and potential oversupply challenges – e.g., the "duck curve."[10] These efforts are documented in special studies in chapter 3. At this time, voltage control issues tend to be more localized, and are being considered throughout existing reliability analysis, which is documented in chapter 2.

Non-Transmission Alternatives and Preferred Resources

Building on efforts in past planning cycles, the ISO is continuing to make material strides in facilitating the use of preferred resources to meet local transmission system needs. Continuing to build on the ISO's proposed methodology[11] to support California's policy emphasis on the use of preferred resources,[12] the ISO has explored opportunities as noted below:

- identify areas where reinforcement may be necessary in the future but the reasonable timelines to develop conventional alternatives do not require immediate action. The ISO believes that this will provide developers opportunity to develop preferred resource proposals in their submissions into utilities' procurement processes;
- consider energy storage as part of the overall preferred resource umbrella in transmission planning, in particular opportunities for large scale energy storage to help address flexible capacity needs; and,
- integrate demand response whether they be supply side resources or load-modifying resources. These activities, such as participating in the CPUC's demand response related proceedings, support identification of the necessary operating characteristics so that the demand response role in meeting transmission system increases as design and implementation issues are addressed.

Southern California Reliability Assessment and Renewable Generation in Imperial area

The reliability needs in southern California and the complex interrelationship with deliverability of generation from the Imperial and Riverside areas have received considerable emphasis in past planning cycles. As in the 2014-2015 transmission planning cycle, efforts were made in this 2015-2016 planning cycle to monitor the progress of the basket of forecast procurement of conventional

[10] http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf
[11] http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf
[12] To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

and preferred resources and ISO-approved transmission upgrades, and test the collective effectiveness of those solutions to meet the area's reliability needs.

Clean Energy and Pollution Reduction Act of 2015

On October 7, 2015 Governor Jerry Brown signed into law SB 350, the Clean Energy and Pollution Reduction Act of 2015. The bill establishes, among other goals, a 50 percent renewables portfolio standard (RPS) by 2030 and is summarized below:

- existing RPS counting rules remain unchanged;
- requires load serving entities to increase purchases of renewable energy to 50 percent by December 31, 2030; and
- Sets steadily higher interim targets for compliance periods ending in 2024 and in 2027.

The bill also sets the stage for the ISO to transform into a regional organization and empowers the ISO to proceed to complete a series of analytic and legislative requirements that consider structural changes to the ISO's governance.

SB 350 creates a pathway to higher levels of renewable generation and lower greenhouse gas emissions. The ISO looks forward to helping make these goals achievable and working with the Legislature and interested parties to move forward with structural changes to ISO governance in order to increase benefits to California and the region.

Renewable Energy Transmission Initiative (RETI) 2.0

Another outcome of SB 350 is that new investments in the state's electric transmission system will be required to achieve the renewable energy goals, which will necessarily require planning and coordination across California and the West. To this end, the ISO has partnered with the CEC and the CPUC to conduct the Renewable Energy Transmission Initiative (RETI) 2.0. This initiative is an open, transparent, and science-based process that will explore the viability of renewable generation resources in California and throughout the West, consider critical land use and environmental constraints, and identify potential transmission opportunities that could access and integrate renewable energy with the most environmental, economic, and community benefits.

While RETI 2.0 is not a regulatory proceeding in itself, the insights, scenarios, and recommendations it will generate will frame and inform future transmission planning processes and proceedings with stakeholder-supported strategies to help reach the state's 2030 renewable energy goals. RETI 2.0 will enable input from stakeholders and is expected to feed into the 2017-2018 transmission planning process.

Distributed Energy Resources Growth Scenarios

Through the Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiative, the ISO has been actively engaged in enhancing the ability of distributed energy resources (DERs) to participate in the ISO markets. At the same time the CPUC has placed an increased emphasis on incorporating DERs into its planning and procurement framework for jurisdictional utilities. Based on the expected growth in DERs in upcoming years, the ISO believes that a collaborative effort of the CPUC, CEC, ISO and interested stakeholders should be initiated to consider possible growth scenarios that may be crucial foundational elements to be used in future transmission planning and state procurement activities for achieving the state's energy goals. Depending on how the process is designed, development of DER growth scenarios may involve different activities performed by different parties in different venues, the results of which must be integrated into the set of scenarios that are formally adopted for use in procurement and planning.

The ISO believes that 2016 would be the right time to focus on the specific activities and methodologies that would comprise an effective DER growth scenario development process. The CEC will have just completed the 2015 Integrated Energy Policy Report (IEPR), with the next full IEPR demand forecast due at the end of 2017 and as such, these methods could be applied during 2017 in developing the next full IEPR demand forecast.

Conclusions and Recommendations

The 2015-2016 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately meet California's policy goals, address grid reliability requirements and bring economic benefits to consumers. This year's plan identified 14 transmission projects, estimated to cost a total of approximately $306 million, as needed to maintain the reliability of the ISO transmission system, meet the state's renewable energy mandate, and deliver material economic benefits. As well, the ISO has identified the need to continue study in future cycles focusing on the following:

- continuing the coordinated and iterative process of assessing southern California (LA Basin and San Diego area) needs with an emphasis on preferred resources, and in particular, assessing the progress made on the planned mitigations;
- continuing to explore and refine methodologies to ensure the maximum opportunity for preferred resources to meet transmission system needs; and
- exploring the range of system impacts and challenges associated with steadily increasing levels of renewable generation, and developing proactive plans to manage those issues reliably and economically.

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Chapter 1

1 Overview of the Transmission Planning Process

1.1 Purpose

A core ISO responsibility is to identify and plan the development of solutions to meet the future needs of the ISO controlled grid. Fulfilling this responsibility includes conducting an annual transmission planning process (TPP) that culminates in an ISO Board of Governors (Board) approved, comprehensive transmission plan. The plan identifies needed transmission solutions and authorizes cost recovery through ISO transmission rates, subject to regulatory approval, as well as identifying other solutions that will be pursued in other venues to avoid building additional transmission facilities if possible. The plan is prepared in the larger context of supporting important energy and environmental policies and assisting in the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system. This document serves as the comprehensive transmission plan for the 2015-2016 planning cycle.

The plan primarily identifies needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy and economic needs. The plan may also include transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects or provide for merchant transmission projects. The ISO also considers and places a great deal of emphasis on the development of non-transmission alternatives; both conventional generation and in particular, preferred resources such as energy efficiency, demand response, renewable generating resources and energy storage programs. Though the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive plan, these can be identified as the preferred mitigation in the same manner that operational solutions are often selected in lieu of transmission upgrades. Further, load modifying preferred resource assumptions are also incorporated into the load forecasts adopted through state energy agency activities that the ISO supports, and provide an additional opportunity for preferred resources to address transmission needs.

The ISO's activities to find opportunities for preferred resources have continued to progress in this transmission planning cycle, both within the planning process and in parallel activities in other processes. The further refinement of the policy and implementation frameworks for preferred resources across the industry will be critical in enabling these resources to play a greater role in addressing transmission needs beyond the specific geographic areas targeted to date. The ISO identifies needed reliability solutions to ensure transmission system performance is compliant with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria as well as with ISO transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2015-2016 planning cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to verify compliance with applicable NERC reliability standards. The analysis was performed across a 10-year planning horizon and it modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities across a voltage range of 60 kV to 500 kV. The ISO also identified plans to mitigate any observed concerns that included upgrading transmission infrastructure, implementing new operating procedures and installing automatic special protection schemes, and identifying the potential for conventional and non-conventional resources to meet these needs. To increase awareness of the ISO's reliance on preferred resources, that reliance to address specific reliability needs has been summarized in section 7.4 in addition to being discussed throughout chapter 2 and Appendix B on an area-by-area study basis. In recommending solutions for the identified needs, the ISO takes into account an array of considerations; furthering the state's objectives of transitioning to a cleaner future plays a major part in those considerations.

As in previous transmission plans, the ISO placed considerable emphasis in the 2015-2016 planning cycle on the Los Angeles basin and San Diego area requirements that address the implications of the San Onofre Nuclear Generating Station's early retirement coupled with the anticipated retirement of once-through-cooling gas fired generation. The high expectations on preferred resources playing a part of a comprehensive solution, which also includes transmission reinforcement and conventional generation, has also resulted in the analysis of preferred resources continuing to focus heavily in that area.

ISO analyses, results and mitigation plans are documented in this transmission plan.[13] These topics are discussed in more detail below.

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support state and federal directives. As in recent past transmission planning cycles, the focus of public policy analysis continues to be on plans to ensure achievement of California's renewable energy goals. The trajectory to achieving the renewables portfolio standard set out in the state directive SBX1-2, requiring 33 percent of the electricity sold annually in the state to be supplied from qualified renewable resources by the year 2020, becomes more firm each year. As a result, the 33 percent renewable energy portfolios received only minor and specific modifications from the preceding year. As well, SB 350 came into effect which, among other requirements, raised the longer term renewable energy goal to 50 percent by 2030. SB 350 - the Clean Energy and Pollution Reduction Act of 2015 – is discussed later in this chapter. While considerable work remains to be done to ensure that the plans in place are achieved, the ISO's focus in the 2015-2016 planning cycle was to confirm the effectiveness of current plans, and beginning analysis that will support moving beyond the 33 percent goal and driving to the 50 percent goal. Recognizing that one or more planning cycles will occur before actionable direction from state resource planners can be provided in the form of renewable generation portfolios – please refer to the

[13] As part of efforts focused on the continuous improvement of the transmission plan document, the ISO has made several changes in documenting study results from prior years' plans. This document continues to provide detail of all study results necessary to transmission planning activities. However, consistent with the changes made in the 2012/2013 transmission plan, additional documentation necessary strictly for demonstration of compliance with NERC and WECC standards but not affecting the transmission plan itself is being removed from this year's transmission planning document and compiled in a separate document for future NERC/FERC audit purposes. In addition, detailed discussions of material that may constitute Critical Energy Infrastructure Information (CEII) are restricted to appendices that are shared only consistent with CEII requirements. High level discussions are provided in the publicly available portion of the transmission plan, however, to provide a meaningful overview of the comprehensive transmission system needs without compromising CEII requirements.

discussion of the Renewable Energy Transmission Initiative later in this chapter - the ISO has conducted in this planning cycle exploratory information special studies to help inform future resource planning that can be further refined in future planning cycles.

Economic-driven solutions are those that offer economic benefits to consumers that exceed their costs as determined by ISO studies, which includes a production simulation analysis. Typical economic benefits include reductions in congestion costs and transmission line losses, as well as access to lower cost resources for the supply of energy and capacity.

1.2 Structure of the Transmission Planning Process

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. The 2014-2015 planning cycle, for example, began in January 2014 and concluded in March 2015.

Phase 1 includes establishing the assumptions and models for use in the planning studies, developing and finalizing a study plan, and specifying the public policy mandates that planners will adopt as objectives in the current cycle. This phase takes roughly three months from January through March of the beginning year.

Phase 2 is when the ISO performs studies to identify the needed solutions to the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months that ends with Board approval. Thus, phases 1 and 2 take 15 months to complete. The identification of non-transmission alternatives that are being relied upon in lieu of transmission solutions also takes place at this time. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

Phase 3 includes the competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan. In any given planning cycle, phase 3 may or may not be needed depending on whether the final plan includes transmission facilities that are open to competitive solicitation in accordance with criteria specified in the ISO tariff.

In addition, specific transmission planning studies necessary to support other state or industry informational requirements can be incorporated into the annual transmission planning process to efficiently provide study results that are consistent with the comprehensive transmission planning process. In this cycle, these studies focus primarily on beginning the transition of incorporating renewable generation integration studies into the transmission planning process.

1.2.1 Phase 1

Phase 1 generally consists of two parallel activities: 1) developing and completing the annual unified planning assumptions and study plan; and 2) developing a conceptual statewide transmission plan, which may be completed during phase 1 or phase 2. Continuing with the timelines and coordination achieved in past planning cycles, the generating resource portfolios used to analyze public policy-driven transmission needs were developed as part of the unified planning assumptions in phase 1 for the 2015-2016 planning cycle. Further efforts were made in 2015 to improve the level of coordination between both the policy-driven generating resource portfolios and other planning assumptions — in particular the load forecast and preferred resource forecasts.

The purpose of the unified planning assumptions is to establish a common set of assumptions for the reliability and other planning studies the ISO will perform in phase 2. The starting point for the assumptions is the information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The ISO adds other information, including network upgrades and additions identified in studies conducted under the ISO's generation interconnection procedures and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions the ISO also specifies the public policy requirements and directives that will affect the need for new transmission infrastructure.

The development of the unified planning assumptions for this planning cycle benefited from further coordination efforts between the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the ISO building on the staff-level inter-agency process alignment forum in place to improve infrastructure planning coordination within the three core processes:

- Long-term forecast of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR),
- Biennial long term procurement plan proceedings (LTPP) conducted by the CPUC, and
- Annual transmission planning process (TPP) performed by the ISO.

That forum results in improved alignment of the three core processes, and agreement on an annual process to be performed in the fall of each year to develop planning assumptions and scenarios to be used in infrastructure planning activities in the coming year. The assumptions include demand, supply and system infrastructure elements, including the renewables portfolio standard (RPS) portfolios discussed in more detail below as a key assumption.

The results of that CPUC-led annual process fed into this 2015-2016 transmission planning process and were communicated via a ruling in the 2014 LTPP[14]. These process efforts will continue in 2016 emphasizing the broad load forecast impacts of distributed generation and other material changes in customer needs, as well as further consideration of renewable integration challenges and the market impacts of increased renewable generation on the existing conventional generation fleet.

Public policy requirements and directives are an element of transmission planning that was added to the planning process in 2010. Planning transmission to meet public policy directives is a national requirement under Federal Energy Regulatory Commission (FERC) Order No. 1000. It enables the ISO to identify and approve transmission facilities that system users will need to comply with state and federal requirements or directives. The primary policy directive for the last number of years' planning cycles is California's renewables portfolio standard that calls for 33 percent of the electric retail sales in the state in 2020 to be provided from eligible renewable resources. As discussed later in this section, the ISO's study work and resource requirements determination for reliably integrating renewable resources is continuing on a parallel track outside of the transmission planning process, but steps are taken in this transmission plan to incorporate those requirements into annual transmission plan activities.

The ISO formulates the public policy-related resource portfolios in collaboration with the CPUC, with input from other state agencies including the CEC and the municipal utilities within the ISO balancing authority area. The CPUC plays a primary role formulating the resource portfolios as the agency that oversees the supply procurement activities of the investor-owned utilities and retail direct access providers, which collectively account for 95 percent of the energy consumed

[14] [14] Rulemaking 13-12-010 "Assigned Commissioner's Ruling on updates to the Planning Assumptions and Scenarios for use in the 2014 Long-Term Procurement Plan and the California Independent System Operator's 2015-2016 Transmission Planning Process" on March 4, 2015 with an update adopted on October 28, 2015..

annually within the ISO area. The proposed portfolios are reviewed with stakeholders to seek their comments, which are then considered for incorporation into the final portfolios.

The resource portfolios have played a crucial role in identifying public policy-driven transmission elements. Meeting the renewables portfolio standard has entailed developing substantial amounts of new renewable generating capacity, which will in turn required new transmission for delivery. The uncertainty as to where the generation capacity will locate has been managed recognizing this uncertainty and balancing the requirement to have needed transmission completed and in service in time to support the renewables portfolio standard against the risk of building transmission in areas that do not realize enough new generation to justify the cost of such infrastructure. This entailed applying a “least regrets” principle, which first formulates several alternative resource development portfolios or scenarios, then identifies the needed transmission to support each portfolio followed by selecting for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

As we move progressively closer to the 33 percent renewables portfolio standard compliance date of 2020, however, much of the uncertainty about which areas of the grid will actually realize most of this new resource development through the utilities’ procurement and contracting processes has been addressed. As noted earlier, the portfolios designed to meet the 33 percent renewables portfolio standard are therefore showing less variation each year as we move closer to 2020 and the portfolios relied upon in this planning cycle received only minor and specific modifications from the preceding year. The ISO’s focus in the 2015-2016 planning cycle was to confirm the effectiveness of current plans for achieving the 33 percent renewables portfolio standard, and beginning analysis that will support moving beyond the 33 percent goal and driving to the 50 percent goal by 2030 established by SB 350. This latter effort took the form of informational special studies exploring preliminary and non-binding 50 percent renewable energy scenarios that are discussed in chapter 3.

The study plan describes the computer models and methodologies to be used in each technical study, provides a list of the studies to be performed and the purpose of each study, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The ISO posts the unified planning assumptions and study plan in draft form for stakeholder review and comment, during which stakeholders may request specific economic planning studies to assess the potential economic benefits (such as congestion relief) in specific areas of the grid. The ISO then specifies a list of high priority studies among these requests (i.e., those which the engineers expect may provide the greatest benefits) and includes them in the study plan when it publishes the final unified planning assumptions and study plan at the end of phase 1. The list of high priority studies may be modified later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

The conceptual statewide transmission plan, also added to the planning process in 2010, was initiated based on the recognition that policy requirements or directives such as the renewables portfolio standard apply throughout the state, not only within the ISO area. The conceptual statewide plan takes a whole-state perspective to identify potential upgrades or additions needed to meet state and federal policy requirements or directives such as renewable energy targets. The ISO performs this activity in coordination with regional planning groups and neighboring balancing authorities to the extent possible. In the initial years of this process, the ISO developed its conceptual statewide plan in coordination with other California planning authorities and load serving transmission providers under the structure of the California Transmission Planning Group (CTPG). As CTPG activities have been placed on hold indefinitely, the ISO, therefore, developed this year's conceptual state-wide plan by updating the previous plan using current ISO information and publicly available information from our neighboring planning entities. This approach will need to be revisited as new interregional processes coalesce in response to FERC approvals of regional planning tariffs and steps being taken to advance interregional coordination ahead of approvals on interregional processes as discussed below.

Turning to a broader landscape of the western interconnection, the ISO participated in an interregional planning coordination meeting along with ColumbiaGrid, Northern Tier Transmission Group, and WestConnect early in 2014. As established FERC Order No. 1000 planning entities, the four planning regions organized the meeting to provide stakeholders throughout the western interconnection an opportunity to hear about each planning region's planning activities and to discuss near-term interregional coordination opportunities notwithstanding the interregional processes were not yet approved and in effect. Stakeholders were also provided the opportunity to offer their suggestions and proposals for possible interregional transmission opportunities that could be considered by the planning regions. FERC has subsequently recently approved the ISO's interregional process filing effective October 1, 2015, subject to a second compliance filing. The planning regions held another informal planning coordination meeting early in 2015 despite the interregional tariff provisions not yet being in effect at that time, and have now scheduled the first formal coordination meeting for early 2016.

1.2.2 Phase 2

In phase 2, the ISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the ISO controlled grid. The comprehensive transmission plan specifies the transmission solutions to system limitations needed to meet the infrastructure needs of the grid. This includes the reliability, public policy, and economic-driven categories. In phase 2, the ISO conducts the following major activities:

- performs technical planning studies as described in the phase 1 study plan and posts the study results;
- provides a request window for submitting reliability project proposals in response to the ISO's technical studies, demand response storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- completes the conceptual statewide plan if it is not completed in phase 1, which is also used as an input during this phase, and provides stakeholders an opportunity to comment on that plan;
- evaluates and refines the portion of the conceptual statewide plan that applies to the ISO system as part of the process to identify policy-driven transmission elements and other infrastructure needs that will be included in the final comprehensive transmission plan;

- coordinates transmission planning study work with renewable integration studies performed by the ISO for the CPUC long-term procurement proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);
- reassesses, as needed, significant transmission facilities starting with the 2011-2012 planning cycle that were in GIP phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;
- performs a "least regrets" analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[15] which is based on balancing the two objectives of minimizing the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;
- identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;
- performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;
- performs technical studies to assess the reliability impacts of new environmental policies such as new restrictions on the use of coastal and estuarine waters for power plant cooling, which is commonly referred to as once through cooling and AB 1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin;
- conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and
- consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan to post in draft form for stakeholder review and comment at the end of January and present to the Board for approval at the conclusion of phase 2 in March.

When the Board approves the comprehensive transmission plan at the end of phase 2, its approval constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities and the economic-driven facilities in the plan. The

[15] In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven solutions. The use of these categories better enable the ISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key factors that materially affect the determination of what transmission is needed. The criteria to be used for this evaluation are identified in section 24.4.6.6 of the revised tariff.

Board's approval authorizes implementation and enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval under current tariff provisions.[16] As indicated above, the ISO will solicit and accept proposals in phase 3 from all interested project sponsors to build and own the transmission solutions that are open to competition.

By definition, the category 2 solutions in the comprehensive plan will not be authorized to proceed after Board approval, but will instead be identified for a re-evaluation of need during the next annual cycle of the planning process. At that time, based on relevant new information about the patterns of expected development, the ISO will determine whether the category 2 solutions now satisfy the least regrets criteria and should be elevated to category 1 status, should remain category 2 projects for another cycle, or should be removed from the transmission plan.

As noted earlier, phases 1 and 2 of the transmission planning process encompass a 15-month period. Thus, the last three months of phase 2 of one planning cycle will overlap phase 1 of the next cycle, which also spans three months. The ISO will conduct phase 3, the competitive solicitation for sponsors to build and own eligible transmission facilities of the final plan, following Board approval of the comprehensive plan and in parallel with the start of phase 2 of the next annual cycle.[17]

1.2.3 Phase 3

Phase 3 will take place after the approval of the plan by the Board, if projects eligible for competitive solicitation were approved by the Board in the draft plan at the end of phase 2. Projects eligible for competitive solicitation are reliability-driven, category 1 policy-driven or economic-driven elements, excluding projects that are modifications to existing facilities or local transmission facilities.[18]

If transmission solutions eligible for competitive solicitation are identified in phase 2 and approved, phase 3 will start with the ISO opening a project submission window for the entities who propose to sponsor the facilities. The ISO will then evaluate the proposals and, if there are multiple qualified project sponsors seeking to finance, build and own the same facilities, the ISO will select the project sponsor by conducting a comparative evaluation using tariff selection criteria. Single proposed project sponsors who meet the qualification criteria can move forward to project permitting and siting.

[16] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. Such projects are included in the comprehensive plan as pre-approved by ISO management and not requiring further Board approval.

[17] These details are set forth in the BPM for Transmission Planning.

[18] The description of transmission solutions eligible for the competitive solicitation process was modified as part of the ISO's initial Order 1000 compliance filing. It was accepted by FERC in an April 18, 2013 order and became effective on October 1, 2013 as part of the 2013-2014 transmission planning process. Further tariff modifications were submitted on August 20, 2013 in response to the April 18, 2013 order and a final ruling March 20, 2014.

1.3 Other processes and initiatives influencing the Transmission Plan

The transmission planning process is influenced by a number of other evolving processes and initiatives in which the ISO has varying degrees of influence, input and control. These processes and initiatives are briefly summarized below, with an emphasis on their relationship to the current transmission planning cycle.

Interregional Transmission Coordination per FERC Order No. 1000

Past ISO transmission plans have reported on FERC Order No. 1000 and the ISO's efforts to address its compliance obligations among its stakeholders and neighboring planning regions. FERC issued its final rule in July 2011[19] thus adopting certain reforms to the electric transmission planning and cost allocation requirements for public utility transmission providers that were established through Order No. 890. This new order, while instituting certain requirements to clearly establish regional transmission planning processes, also instituted a requirement to improve coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. These additional reforms affected the ISO's existing regional transmission planning process and directed the ISO to collaborate with neighboring transmission utility providers and planning regions across the Western Interconnection to develop a coordinated process for considering interregional projects. These regional and interregional reforms were designed to work together to ensure an opportunity for more transmission projects to be considered in transmission planning processes on an open and non-discriminatory basis both within planning regions and across multiple planning regions.

Regional Tariff

The ISO's tariff complies with the regional tariff requirements of FERC Order No.1000, following the ISO's last supplemental compliance filing of August 20, 2013. While the ISO's prior tariff was largely compliant with the tariff, adjustments were necessary to fully align with the order in a number of areas including the establishment of the ISO as one of four western planning regions established within the Western Interconnection[20]. These adjustments have been put in place and implemented.

Interregional Tariff

The ISO received FERC's final order on interregional transmission coordination on June 1, 2015. As of the compliance date of October 1, 2015, the ISO's tariff complies with the interregional tariff requirements. During 2015 the ISO and its neighboring western planning regions considered approaches to develop certain business practices that would provide stakeholders visibility and clarity on how the western planning regions would implement interregional coordination requirements into their respective regional planning processes. Ultimately the ISO, NTTG, and WestConnect collaborated in developing a set of business practices that we believed would be beneficial not only to stakeholders but to facilitate successful interregional transmission coordination engagement among the western planning regions. NTTG and WestConnect will each

[19] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities.

[20] Western planning regions are the California ISO, ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect.

determine how these business practices will be incorporated into their regional processes. The ISO will incorporate the procedures into its transmission planning business practice manual.

While ColumbiaGrid chose to pursue a different approach to business practices, the western planning regions are committed to proactively engage in interregional transmission coordination activities across all four regional planning processes.

Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

In July 2012 the ISO received FERC approval for the GIDAP, which represented a major revision to the existing generator interconnection procedures to better integrate those procedures with the transmission planning process. The GIDAP has been applied to cluster 5 in March 2012 and all subsequent queue clusters. Interconnection requests submitted into cluster 4 and earlier with continue to be subject to the provisions of the prior generation interconnection process (GIP).

The principal objective of the GIDAP was to ensure that going forward all major transmission additions and upgrades to be paid for by transmission ratepayers would be identified and approved under a single comprehensive process — the transmission planning process — rather than some projects coming through the transmission planning process and others through the GIP.

The most significant implication for the transmission planning process at this time relates to the planning of policy-driven transmission focused on achieving the state's 33 percent renewables portfolio standard, which has been the dominant factor in policy-driven transmission. In that context, the ISO plans the necessary transmission upgrades that the renewable generation forecast in the base renewables portfolio scenario provided by the CPUC is deliverable unless specifically noted otherwise. Every RPS Calculator portfolio submitted by the Commission into the ISO's transmission planning process for purposes of identifying policy-driven transmission to achieve 33 percent RPS has assumed deliverability for new renewable energy projects.[21]

Through the GIDAP, the ISO then allocates the resulting MW volumes of transmission plan deliverability to those proposed generating facilities in each area that are determined to be most viable based on a set of project development milestones specified in the tariff. Interconnection customers proposing generating facilities that are not allocated transmission plan deliverability but still want to build their projects and obtain deliverability status would be responsible for funding their needed delivery network upgrades at their own expense without being eligible for cash reimbursement from ratepayers.

Transmission Plan Deliverability

As set out in Appendix DD (GIDAP) of the ISO tariff, the available transmission plan deliverability (TPD) is calculated in each year's transmission planning process in areas where the amount of generation in the interconnection queue is greater than the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability

[21] RPS Calculator User Guide, Version 6.1, p. A-17. ("In prior versions of the RPS Calculator (v.1.0 – v.6.0), all new renewable resources were assumed to have full capacity deliverability status (FCDS).")

is sufficient. In this year's transmission planning process, the ISO's generator interconnection queue was considered up to and including queue cluster 8.

Distributed Generation (DG) Deliverability

The ISO's streamlined, annual process for providing resource adequacy (RA) deliverability status to distributed generation (DG) resources from transmission capacity was developed in 2012 and implemented in 2013, and the ISO completed the first cycle of the new process in 2013 in time to qualify additional distributed generation resources to provide RA capacity for the 2014 RA compliance year.

The ISO annually performs two sequential steps. The first step is a deliverability study, which is performed within the context of the transmission planning process, to determine nodal MW quantities of deliverability status that can be assigned to DG resources. The second step is an apportionment of these quantities to utility distribution companies — including both the investor-owned and publicly-owned distribution utilities within the ISO controlled grid — who then assign deliverability status, in accordance with ISO tariff provisions, to eligible distributed generation resources interconnected or in the process of interconnecting to their distribution facilities.

In the first step, the transmission planning process performs a DG deliverability study to identify available transmission capacity at specific grid nodes to support deliverability status for distributed generation resources without requiring any additional delivery network upgrades to the ISO controlled grid and without adversely affecting the deliverability status of existing generation resources or proposed generation in the interconnection queue. In constructing the network model for use in the DG deliverability study, the ISO models the existing transmission system plus new additions and upgrades that have been approved in prior transmission planning process cycles, plus existing generation and certain new generation in the interconnection queue and associated upgrades. The DG deliverability study uses the nodal DG quantities that were specified in the base case resource portfolio that was adopted in the latest transmission planning process cycle for identifying public policy-driven transmission needs, both as a minimal target level for assessing DG deliverability at each network node and as a maximum amount that can be used by distribution utilities for assigning deliverability status to generators in the current cycle. This ensures that the DG deliverability assessment is aligned with the public policy objectives addressed in the current transmission planning process cycle and precludes the possibility of apportioning more DG deliverability in each cycle than was assumed in the base case resource portfolio used in the transmission planning process.

In the second step, the ISO specifies how much of the identified DG deliverability at each node is available to the utility distribution companies that operate distribution facilities and interconnect distributed generation resources below that node. FERC's November 2012 order stipulated that FERC-jurisdictional entities must assign deliverability status to DG resources on a first-come, first-served basis, in accordance with the relevant interconnection queue. In compliance with this requirement, the ISO tariff specifies the process whereby investor-owned utility distribution companies must establish the first-come, first-served sequence for assigning deliverability status to eligible distributed generation resources.

Although this new DG deliverability process is performed as part of and in alignment with the annual transmission planning process cycle, its only direct impact on the transmission planning process is the addition of the DG deliverability study to be performed in the latter part of Phase 2 of the transmission planning process.

Renewable Integration Issues

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – a broader range of considerations need to be addressed to ensure overall safe, reliable and efficient operation.

The ISO currently conducts a range of studies to support the integration of renewable generation that includes planning for reliable deliverability of renewable generation portfolios (chapter 4), generation interconnection process studies conducted outside of the transmission planning process but strongly coordinated with the transmission planning process, and renewable integration operational studies that have also been conducted outside of the transmission planning process.

Renewable integration operational studies to date have focused in particular on the need for flexible resource capabilities. In the CPUC 2010-2011 Long-term Procurement Plan (LTPP) proceeding, docket R.10-05-006, the ISO completed an initial study of renewable integration flexible generation requirements under a range of future scenarios, and further analysis has continued on those issues.

Given the further increase in renewable generation being achieved and forecast, and additional clarity of the physical and operational characteristics of these resources, further analysis on a programmatic basis is necessary to identify, test and address additional emerging issues. This includes understanding the implications of significant displacement of conventional generation with renewable resources that do not have the same inherent fundamental operating characteristics. These include exploring system frequency response performance, transient and dynamic system performance and voltage control performance, as well as flexible needs throughout the ramping spectrum. This broader analysis is necessary to ensure that we maintain reliability and achieve the greatest resource value increasing capacity and energy benefits, and decreasing curtailment costs and integration costs.

The additional renewable integration studies undertaken in 2015 either as part of, or coordinated with, the 2015-2016 planning cycle included further analysis of expected frequency response performance at higher renewable generation levels that built on preliminary studies conducted in the 2014-2015 cycle and a preliminary analysis of the benefits of large scale energy storage in addressing ramping and oversupply – e.g. the "duck curve".[22] These efforts are documented in special studies in chapter 3. At this time, voltage control issues tend to be more localized, and are being considered throughout existing reliability analysis (see chapter 2).

Non-Transmission Alternatives and Preferred Resources

Building on efforts in past planning cycles, the ISO is continuing to make material strides in facilitating use of preferred resources to meet local transmission system needs.

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

The ISO's approach, as noted in last year's 2014-2015 Transmission Plan, has focused on specific area analysis and testing the resources provided by the market into the utility procurement processes for preferred resources as potential mitigations for reliability concerns.

This approach has built on a methodology presented in a paper[23] the ISO issued on September 4, 2013, as part of the 2013-2014 transmission planning cycle to support California's policy emphasis on the use of preferred resources[24] — energy efficiency, demand response, renewable generating resources and energy storage — by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. In addition to developing a methodology to be applied annually in each transmission planning cycle, the paper also described how the ISO would apply the proposed methodology in future transmission planning cycles. While the Board cannot "approve" non-transmission solutions, these solutions can be identified as the preferred solution to transmission projects and the ISO can work with the appropriate state agencies to support their development. This is particularly viable in areas where the transmission solution would not need to be implemented immediately — where time can be set aside to explore the viability of non-conventional alternatives first and relying on the transmission alternative as a backstop.

Also, the ISO has explored other methods to examine benefits in other geographic areas in this transmission planning process. This relies on the preferred resources proposed as alternatives in the request window and other stakeholder comment opportunities in the transmission planning processes.

High potential areas:

Each year's transmission plan identifies areas where reinforcement may be necessary in the future but the reasonable timelines to develop conventional alternatives do not require immediate action. The ISO expects that developers interested in this approach have been reviewing those areas and highlighting potential benefits of preferred resource proposals in their submissions into utilities' procurement processes. To assist interested parties, the areas where preferred resources are being targeted in lieu of transmission solutions to address reliability issues have been summarized in section 7.4.

Energy storage:

In addition to considering energy storage as part of the overall preferred resource umbrella in transmission planning, the ISO is engaged in a number of parallel activities to assist energy storage development overall that include refining the generator interconnection process to better address the needs of energy storage developers. One such effort is the preliminary analysis of the benefits of large scale energy storage in helping address flexible capacity needs, documented in chapter 3.

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

[24] To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

Use-limited resources, including demand response:

The ISO continues to support integrating demand response, which includes the bifurcation and clarification of the various programs as either supply side resources or load-modifying resources. These activities, such as participating in the CPUC's demand response related proceedings, support identification of the necessary operating characteristics so that the demand response role in meeting transmission system increases as design and implementation issues are addressed. More progress in this area, for demand response and other use-limited resources, is anticipated to be undertaken in 2016 as well.

Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[25] Release of this information also follows tariff requirements. In the course of previous transmission planning cycles, we determined that — out of an abundance of caution on this sensitive area — additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed through the ISO's market participant portal after the appropriate nondisclosure agreements are in place.

Southern California Reliability Assessment and Renewable Generation in Imperial area

The reliability needs in southern California — the LA Basin and San Diego areas in particular — and the complex interrelationship with deliverability of generation from the Imperial and Riverside areas have received considerable emphasis in past planning cycles.

The LA Basin and San Diego area needs have largely been impacted by the retirement of the San Onofre Nuclear Generating Station generation coupled with the impacts of potential retirement of gas-fired generation in the San Diego and LA Basin areas. As in the 2014-2015 transmission planning cycle, efforts were made in this 2015-2016 planning cycle to monitor the progress of the basket of forecast procurement of conventional and preferred resources and ISO-approved transmission plans, and test the collective effectiveness of those solutions to meet the area's reliability needs.

Successfully mitigating reliability concerns remains dependent on materially higher forecast levels of preferred resources than have previously been achieved. Given the uncertainty regarding all of the forecast resources materializing as planned, the ISO is continuing to monitor the progress of the basket of forecast procurement of conventional and preferred resources and ISO-approved transmission upgrades underway. Sections 2.6 and 3.3 touch on these issues.

Further, based on the studies undertaken in the 2014-2015 planning cycle, the ISO developed solutions that increased the forecast deliverability from the Imperial area from the levels

[25] CAISO tariff section 20 addresses how the ISO shares Critical Energy Infrastructure Information (CEII) related to the transmission planning process with stakeholders who are eligible to receive such information. The tariff definition of CEII is consistent with the meaning given the term in FERC regulations at 18 C.F.R. Section 388.113, *et. seq.* According to the tariff, eligible stakeholders seeking access to CEII must sign a non-disclosure agreement and follow the other steps described on the CAISO website.

determined in the 2013-2014 planning cycle. The CPUC incorporated that information into adjustments to the renewable generation portfolios provided to the ISO for the 2015-2016 planning cycle. This is discussed in chapter 4.

The ISO's studies documented in the 2015-2016 Transmission Plan are based on the transmission planning input provided by the Imperial Irrigation District (IID) for its system in the spring of 2015. However, in October, 2015, IID provided new base cases modifying its future transmission plans as comments into the ISO's planning process. As IID surmised in its comments, the ISO's study timelines do not permit restarting the process within a given cycle and thus these results do not take into account that information. IID's input will be taken into account in preparing the study plan for the future 2016-2017 transmission planning cycle, and the ISO will coordinate with IID to ensure use of the best possible and current information at that time.

Clean Energy and Pollution Reduction Act of 2015

On October 7, 2015 Governor Jerry Brown signed into law SB 350, the Clean Energy and Pollution Reduction Act of 2015 authored by Senator Kevin De León. The bill establishes the following goals:

- By 2030, double energy efficiency for electricity and natural gas by retail customers
- 50% renewables portfolio standard (RPS) by 2030
    - Existing RPS counting rules remain unchanged
    - Requires LSEs to increase purchases of renewable energy to 50 percent by December 31, 2030
    - Sets interim targets as follows
        - 40% by the end of the 2021-2024 compliance period
        - 45% by the end of the 2025-2027 compliance period
        - 50% by the end of the 2028-2030 compliance period

The bill also sets the stage for the ISO to transform into a regional organization and empowers the ISO to proceed by requiring the following:

- Regional market impact studies to determine the overall benefits to ratepayers including:
    - The creation and retention of jobs and other benefits to the California economy
    - Environmental impacts in California and elsewhere
    - Impacts to disadvantaged communities
    - Emissions of greenhouse gases and other air pollutants
    - Reliability and integration of renewable energy resources.

- Potential new ISO governance structure
- Inter-agency public workshops to consider the study results and changes to ISO governance necessary to enable its transformation into a regional organization
- New legislation before governance change may take effect

SB 350 creates a pathway to higher levels of renewable generation and lower greenhouse gas emissions. The ISO looks forward to helping make these goals achievable and working with the Legislature and interested parties to move forward with structural changes to ISO governance in order to increase benefits to California and the region.

Renewable Energy Transmission Initiative (RETI) 2.0

Another outcome of SB350 is that new investments in the state's electric transmission system will be required to achieve the renewable energy goals, which will necessarily require planning and coordination across California and the West.

To assist in this effort, the ISO has partnered with the CEC and the CPUC, to conduct the Renewable Energy Transmission Initiative (RETI) 2.0. RETI 2.0 is an open, transparent, and science-based process that will explore the viability of renewable generation resources in California and throughout the West, consider critical land use and environmental constraints, and identify potential transmission opportunities that could access and integrate renewable energy with the most environmental, economic, and community benefits.

California faced similar challenges in 2007, as the state implemented a renewable energy target of 20 percent, while looking forward to a 33 percent goal. The 2008 Renewable Energy Transmission Initiative (RETI), a non-regulatory statewide planning process, was established to identify the transmission projects needed to support the renewable generation that would help meet the 33 percent target.

While RETI 2.0 is not a regulatory proceeding in itself, the insights, scenarios, and recommendations it will generate will frame and inform future transmission planning processes and proceedings with stakeholder-supported strategies to help reach the state's 2030 renewable energy goals.

RETI 2.0 was officially launched on September 10, 2015 in with a public workshop. Since then, the ISO and State agencies have collaborated on a structure for engaging stakeholders in the RETI 2.0 process. Three work groups have been established – an over-arching plenary group and two working groups that support the plenary group:

- The Plenary Group will:
    - Discuss and vet planning assumptions, utilizing data from CEC, CPUC, ISO, that support the overall goals of RETI 2.0 process, in light of statewide GHG and renewable energy goals
    - Qualitatively discuss what the state should be looking for in selecting resource areas

- Consider potential environmental and land use information to assist with identifying lower conflict areas for potential renewable energy development
- Construct and discuss combinations of renewable energy resource areas and associated transmission improvements that can help achieve California's 2030 climate and renewable energy goals

- The Environmental and Land Use Technical Group, led by the CEC in close coordination with local governments, tribes, and other agencies with relevant environmental and land use expertise, will assist in assessing environmental and land use considerations related to possible locations for renewable energy development.
- The Transmission Technical Input Group, led by the ISO, will work with California planning entities to assemble relevant in-state and west-wide transmission capability and upgrade cost information to inform resource development combinations on the reasonably-needed transmission system implications and to assist in developing potential corridor scenarios.

RETI 2.0 will enable input from stakeholders and is expected to serve as an input to the 2017-2018 transmission planning process.

Distributed Energy Resources Growth Scenarios

Through the Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiative, the ISO has been actively engaged in enhancing the ability of distributed energy resources (DERs) to participate in the ISO markets. At the same time, the CPUC has placed an increased emphasis on incorporating DERs into its planning and procurement framework for jurisdictional utilities. Based on the expected growth in DERs in upcoming years, the ISO has highlighted a need to undertake a collaborative effort to design processes for developing DER growth scenarios and updating those growth scenarios on a cyclical basis.

The ISO believes that this collaborative effort should include the CPUC, the CEC, the ISO and interested stakeholders. DER growth scenarios are a crucial foundational element for achieving the state's energy goals, and will be used in future transmission planning and state procurement activities. Depending on how the process is designed, development of DER growth scenarios may involve different activities performed by different parties in different venues, the results of which must be integrated into the set of scenarios that are formally adopted for use in procurement and planning.

The ISO believes that the first quarter of 2016 would be the most opportune time to address this topic as the CEC will have just completed the 2015 Integrated Energy Policy Report (IEPR), with the next full IEPR demand forecast due at the end of 2017. Thus, 2016 would be the right time to focus on the specific activities and methodologies that would comprise an effective DER growth scenario development process, so that these methods could be applied during 2017 in developing the next full IEPR demand forecast.

Because the development of DER growth scenarios will have a significant impact on future transmission planning, the ISO intends to continue to work toward a process for developing those growth scenarios in 2016.

Planning Coordinator Footprint

The ISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area[26] in 2014, in part in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities. ISO staff have further supported WECC efforts to clarify planning coordinator area boundaries through 2015, including chairing a WECC task force clarifying methodologies for identifying planning coordinator area boundaries.

As well, in 2015, the ISO has reached out to several "adjacent systems" that are inside the ISO's balancing authority area; had been confirmed as transmission owners; but did not appear to be registered as or be represented by an entity that was registered as a planning coordinator to first determine whether they needed to have a planning coordinator and had one, and if not, to offer providing planning coordinator services to them for the relevant facilities through a fee based agreement.

To date, the ISO and Hetch Hetchy Water and Power have executed a planning coordinator services agreement. At the end of 2015 the ISO had initiated negotiation with two additional "Adjacent Systems" to provide planning coordinator services on their behalf. The ISO expects to conclude these negotiations during the early part of Q1 2016.

The study efforts to meet the mandatory standards requirements for Hetch Hetchy Water and Power, and the others if the ISO ultimately becomes their planning coordinator, is being conducted within the framework of the annual transmission planning process. Unlike the requirements for the ISO's participating transmission owners who have placed their facilities under the ISO's operational control, the ISO is not responsible for planning and approving mitigations to identified reliability issues – but only verifying that mitigations have been identified and that they address the identified reliability concerns.

New Planning Standards

While mandatory compliance requirements continue to grow each year with incremental effects on transmission planning activities, the 2015-2016 transmission marked a significant change with the full implementation of the new NERC TPL-001-4 standard that replaced the previous TPL-001, TPL-002, TPL-003 and TPL-004 standards. The changes included broad reframing of the disturbance-performance requirements replacing the previous Category A through D disturbances with Planning Events 0 through 7 and extreme events outside of the Planning Events. Also, additional sensitivity analysis is called for, significantly increasing the amount of analysis performed in completing this year's plans. The sensitivity analysis included different load, resource, and transmission project in-service date assumptions. For example, by employing various levels of CEC-forecast "additional achievable energy efficiency" to perform

[26] http://www.caiso.com/Documents/TechnicalBulletin-CaliforniaISOPlanningCoordinatorAreaDefinition-Aug_4_2014.pdf

load sensitivities, the ISO was able to achieve some of the sensitivity analysis required to achieve compliance with the planning standard, and was further able to demonstrate the reliance the ISO is placing on energy efficiency as a preferred resource in addressing a number of local reliability challenges.

Chapter 2

2 Reliability Assessment – Study Assumptions, Methodology and Results

2.1 Overview of the ISO Reliability Assessment

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

- power flow studies;
- transient stability analysis; and
- voltage stability studies.

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

This study is part of the annual transmission planning process and performed in accordance with section 24 of the ISO tariff and as defined in the Business Process Manual (BPM) for the Transmission Planning Process. The Western Electricity Coordinating Council (WECC) full-loop power flow base cases provide the foundation for the study. The detailed reliability assessment results are given in Appendix B and Appendix C.

2.1.1 Backbone (500 kV and selected 230 kV) System Assessment

Conventional and governor power flow and stability studies were performed for the backbone system assessment to evaluate system performance under normal conditions and following power system contingencies for voltage levels 230 kV and above. The backbone transmission system studies cover the following areas:

- Northern California — Pacific Gas and Electric (PG&E) system; and
- Southern California — Southern California Edison (SCE) system and San Diego Gas and Electric (SDG&E) system.

2.1.2 Regional Area Assessments

Conventional and governor power flow studies were performed for the local area non-simultaneous assessments under normal system and contingency conditions for voltage levels 60 kV through 230 kV. The regional planning areas were within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories and are listed below.

- PG&E Local Areas
    - Humboldt area;
    - North Coast and North Bay areas;
    - North Valley area;
    - Central Valley area;
    - Greater Bay area;
    - Greater Fresno area;
    - Kern Area; and
    - Central Coast and Los Padres areas.

- SCE local areas
    - Tehachapi and Big Creek Corridor;
    - North of Lugo area;
    - East of Lugo area;
    - Eastern area; and
    - Metro area.

- Valley Electric Association (VEA) area
- San Diego Gas Electric (SDG&E) local area

2.2 Reliability Standards Compliance Criteria

The 2015-2016 transmission plan spans a 10-year planning horizon and was conducted to ensure the ISO-controlled-grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, Western Electricity Coordinating Council (WECC) regional criteria, and ISO planning standards across the 2016-2025 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2015-2016 study.

2.2.1 NERC Reliability Standards

2.2.1.1 *System Performance Reliability Standards*

The ISO analyzed the need for transmission upgrades and additions in accordance with NERC reliability standards, which provide criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following TPL NERC reliability standards are applicable to the ISO as a registered NERC planning authority and are the primary drivers determining reliability upgrade needs:

- TPL-001-4 Transmission System Planning Performance Requirements[27]; and
- NUC-001-2.1 Nuclear Plant Interface Coordination.

2.2.2 WECC Regional Criteria

The WECC TPL system performance criteria are applicable to the ISO as a planning authority and sets forth additional requirements that must be met under a varied but specific set of operating conditions.[28]

2.2.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.[29] These standards cover the following:

- address specifics not covered in the NERC reliability standards and WECC regional criteria;
- provide interpretations of the NERC reliability standards and WECC regional criteria specific to the ISO-controlled grid; and
- identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

[27] Analysis of Extreme Events or NUC-001 are not included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.
[28] https://www.wecc.biz/Standards/Pages/Default.aspx
[29] http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

2.3 Study Methodology and Assumptions

The following sections summarize the study methodology and assumptions used for the reliability assessment.

2.3.1 Study Methodology

As noted earlier, the backbone and regional planning region assessments 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 regional planning areas consistent with NERC TPL-001-4, WECC regional criteria and ISO planning 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, which could include multiple units. An example of such a power generating facility is the Delta Energy Center, which is composed of three combustion turbines and a single steam turbine.

2.3.1.3 *Transient Stability Analyses*

Transient stability simulations were performed as part of the backbone system assessment to ensure system stability and positive dampening of system oscillations for critical contingencies. This ensured that the transient stability criteria for performance levels B and C as shown in were met.

2.3.2 Preferred Resources Methodology

The ISO is committed to exploring opportunities for preferred resources to address transmission needs, both as supply side resources and demand side resources.

As noted in last year's 2014-2015 Transmission Plan, supply side analysis has focused on specific area analysis and testing the resources provided by the market into the utility procurement processes for preferred resources as potential mitigations for reliability concerns.

This approach has built on a paper[30] the ISO issued on September 4, 2013, as part of the 2013-2014 transmission planning cycle in which it presented a methodology to support California's policy emphasis on the use of preferred resources[31] — energy efficiency, demand response, renewable generating resources and energy storage — by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. In addition to developing a methodology to be applied annually in each transmission planning cycle, the paper also described how the ISO would apply the proposed methodology in future transmission planning cycles. While the Board cannot "approve" non-transmission solutions, these solutions can be identified as the preferred solution to transmission projects and the ISO can work with the appropriate state agencies to support their development. This is particularly viable in areas where the transmission solution would not need to be implemented immediately — where time can be set aside to explore the viability of non-conventional alternatives first and relying on the transmission alternative as a backstop.

In addition to the above efforts that in past planning cycles focused heavily on the overall LA Basin and San Diego needs, the ISO also continued integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified. The reliability assessments considered a range of existing demand response amounts as potential mitigations to transmission constraints.

The reliability studies also incorporated demand side resource considerations such as the incremental uncommitted energy efficiency amounts as projected by the CEC, as well as supply side distributed generation (DG) based on the CPUC Commercial-Interest Renewables Portfolio Standard (RPS) Portfolio and a mix of proxy preferred resources including energy storage based on the CPUC Long-Term Planning Process (LTPP) 2012 local capacity authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation embedded in the CEC load forecast.

For each planning area, reliability assessments are initially performed without using preferred resources other than the additional energy efficiency and the base amounts of preferred resources that are embedded in the CEC load forecast to identify reliability concerns in the area.

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

[31] To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

If reliability concerns are identified in the initial assessment, additional rounds of assessments are performed using potentially available demand response, distributed generation, energy storage to determine whether these resources are a potential solution. If preferred resources are identified as a potential mitigation, a second step – a preferred resource analysis as described in September 4, 2013 ISO paper – may then be performed if necessary considering the mix of resources in the particular area, to account for the specific characteristic of each resource, which includes diurnal variation in the case of solar DG and use or energy limitation in the case of demand response and energy storage. As noted in the analysis below, due to the relatively small number of reliability issues identified requiring mitigation, the second step described above was only conducted in the LA Basin and San Diego area to continue with previous years' analysis.

The additional sensitivity study requirements imposed by the new NERC TPL-001-4 planning standard has created an additional opportunity to demonstrate the reliance placed on preferred resources. By employing various levels of CEC-forecast "additional achievable energy efficiency" create load sensitivities cases, the ISO was able to achieve some of the sensitivity analysis required to achieve compliance with the planning standard, and was further able to demonstrate the reliance the ISO is placing on energy efficiency as a preferred resource in addressing a number of local reliability challenges.

2.3.3 Study Assumptions

The study horizon and assumptions below were modeled in the 2015-2016 transmission planning analysis.

2.3.3.1 *Study Horizon and Study Years*

The studies that comply with TPL-001-4 were conducted for the near-term (2016-2020) and longer-term (2021-2025) periods as per the requirements of the reliability standards. Within the near- and longer-term study horizon, the ISO conducted detailed analysis on 2017, 2020 and 2025. Some additional years were identified as required for assessment in specific planning regions.

2.3.3.2 *Peak Demand*

The ISO-controlled grid peak demand in 2015 was 47,358 MW and occurred on September 10 at 4:53 p.m. The PG&E peak demand occurred on August 17, 2015 at 4:53 p.m. with 20,586 MW. The SCE peak occurred on September 8, 2015 at 4:50 p.m. with 23,126 MW and for VEA, it occurred on December 30, 2015 at 7:01 a.m. with 126 MW. Meanwhile, the peak demand for SDG&E occurred on September 9, 2015 at 3:39 p.m. with 4,758 MW.

Most of the ISO-controlled grid experiences summer peaking conditions and thus was the focus 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 2.3-1 summarizes these study areas and the corresponding peak scenarios for the reliability assessment.

Table 2.3-1: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2017	2020	2025
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak Summer Partial Peak Spring Off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Light Load	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak
Southern California Bulk Transmission System	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak Summer Partial Peak
SCE Metro Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak

San Diego Gas and Electric (SDG&E) area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak Winter Peak
Valley Electric Association	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak

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

Sensitivity study cases:

In addition to the base scenarios that the ISO assessed in the reliability analysis for the 2015-2016 transmission planning process, the ISO assessed the sensitivity scenarios identified in Table 2.3-2. The sensitivity scenarios are to assess impacts of specific assumptions on the reliability of the transmission system. These sensitivity studies include impacts of load forecast, generation dispatch, generation retirement and transfers on major paths.

Table 2.3-2: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2017	**2020**	**2025**
Summer Peak with high CEC forecasted load	-	-	PG&E Local Areas SCE Metro SCE Northern SDG&E Area
Summer Peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas SCE Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SDG&E Area	-
Summer Off-peak with heavy renewable output and minimum gas generation commitment (renewable generation addition)	-	VEA Area	-
Summer Peak with OTC plants replaced	-	SCE Metro Area SDG&E Area	-
Summer Peak with low hydro output	-	SCE Northern Area	-
Retirement of QF Generations	-	-	PG&E Local Areas
Summer Peak and Summer Off-peak with heavy renewable output			SDG&E Area

2.3.3.3 *Stressed Import Path Flows*

The ISO balancing authority interacts with neighboring balancing authorities through interconnections over which power can be imported to or exported from the ISO area. The power that flows across these import paths are an important consideration in developing the study base cases. For the 2015-2016 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 (BAA) load. These import paths are discussed in more detail in section 2.3.2.10.

2.3.3.4 *Contingencies*

In addition to the system under normal conditions (P0), the following contingencies were evaluated as part of the study. These contingencies lists have been made available on the ISO secured website.

Single contingency (Category P1)

The assessment considered all possible Category P1 contingencies based upon the following:

- Loss of one generator (P1.1)[32]
- Loss of one transmission circuit (P1.2)
- Loss of one transformer (P1.3)
- Loss of one shunt device (P1.4)
- Loss of a single pole of DC lines (P1.5)
- Loss of both poles of the Pacific DC Intertie (WECC exemption)

Single contingency (Category P2)

The assessment considered all possible Category P2 contingencies based upon the following:

- Loss of one transmission circuit without a fault (P2.1)
- Loss of one bus section (P2.2)
- Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
- Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Multiple contingency (Category P3)

The assessment considered the Category P3 contingencies with the loss of a *generator unit* followed by system adjustments and the loss of the following:

- Loss of one generator (P3.1)[33]
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)
- Loss of a single pole of DC lines (P3.5)
- Loss of both poles of the Pacific DC Intertie (WECC exemption)

[32] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.
[33] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

Multiple contingency (Category P4)

The assessment considered the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:

- Loss of one generator (P4.1)
- Loss of one transmission circuit (P4.2)
- Loss of one transformer (P4.3)
- Loss of one shunt device (P4.4)
- Loss of one bus section (P4.5)
- Loss of a bus-tie-breaker (P4.6)

Multiple contingency (Category P5)

The assessment considered the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following:

- Loss of one generator (P5.1)
- Loss of one transmission circuit (P5.2)
- Loss of one transformer (P5.3)
- Loss of one shunt device (P5.4)
- Loss of one bus section (P5.5)

Multiple contingency (Category P6)

The assessment considered the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.

Multiple contingency (Category P7)

The assessment considered the Category P7 contingencies for the loss of a common structure as follows:

- Any two adjacent circuits on common structure[34] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme contingencies (TPL-001-4)

As a part of the planning assessment the ISO assessed Extreme Event contingencies per the requirements of TPL-001-4; however the analysis of Extreme Events have not be included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

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

2.3.3.5 *Generation Projects*

In addition to generators that are already in-service, new generators were modeled in the studies depending on the status of each project. The RPS portfolios provided to the ISO by the CPUC and CEC[35] were used in developing the base cases. For the reliability assessment the commercial interest portfolio was used.

Generation Retirements: Existing generators that have been identified as retiring are listed in table A2-1 of Appendix A. These generators along with their step-up transformer banks are modeled as out of service starting in the year they are assumed to be retired.

In addition to the identified generators the following assumptions were made for the retirement of generation facilities.

- Nuclear Retirements – Diablo Canyon was modeled online and was assumed to have obtained renewal of licenses to continue operation,
- Once Through Cooled (OTC) Retirements – As identified below.
- Renewable and Hydro Retirements – Assumed these resource types stay online unless there is an announced retirement date.
- Other Retirements – Unless otherwise noted, assumed retirement based resource age of 40 years or more.

2.3.4 OTC Generation:

Modeling of the once-through cooled generating units followed the compliance schedule from the State Water Resources Control Board's (SWRCB) policy on OTC plants with the following exceptions:

- base-load Diablo Canyon Power Plant (DCPP) nuclear generation units were modeled online;
- generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology; and
- all other OTC generating units were modeled off line beyond their compliance dates.

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Tracks 1 and 4 were considered along with the procurement activities to date from the utilities. Table 2.3-4 provides the local capacity resource additions and the study year in which the amounts were first modeled based on the CPUC LTPP Tracks 1 and 4 authorizations. Table 2.3-5 provides details of the study assumptions using the utilities' procurement activities to date, as well as the ISO's assumptions for potential preferred resources for San Diego area.

35 http://www.caiso.com/Documents/2014-2015RenewablePortfoliosTransmittalLetter.pdf

Table 2.3-3: Once-through cooled generation in the California ISO Balancing Authority Area

Area	Generating Facility (Total Plant MW)	Owner	Unit	State Water Resources Control Board (SWRCB) Compliance Date	Net Qualifying Capacity (NQC) (MW)	Final Capacity, if Already Repowered or Under Construction (MW)
Humboldt LCR Area	Humboldt Bay (135 MW)	PG&E	1	12/31/2010	52	Retired 135 MW (Mobile 2&3 non-OTC) and repowered with 10 CTs (163 MW) - (July 2010)
			2	12/31/2010	53	
Greater Bay Area LCR	Contra Costa (674 MW)	GenOn	6	12/31/2017	337	Replaced by Marsh Landing power plant (760 MW) – (May 2013)
			7	12/31/2017	337	
	Pittsburg (1,311 MW) Unit 7 is non-OTC	GenOn	5	12/31/2017	312	GenOn proposed to utilize cooling tower of Unit 7 for Units 5&6 if it can obtain long-term Power Purchase & Tolling Agreement (PPTA) with the CPUC and the utilities.
			6	12/31/2017	317	
	Potrero (362 MW)	GenOn	3	10/1/2011	206	Retired 362 MW (Units 4, 5 & 6 non-OTC)
Central Coast (non-LCR area) *Non-LCR area has no local capacity requirements	Moss Landing (2,530 MW)	Dynegy	1	12/31/2017*	510	These two OTC combined cycle plants were placed in service in 2002
			2	12/31/2017*	510	
			6	12/31/2017*	754	
			7	12/31/2017*	756	
	Morro Bay (650 MW)	Dynegy	3	12/31/2015	325	Retired 650 MW (February 5, 2014)
			4	12/31/2015	325	
	Diablo Canyon (2,240 MW)	PG&E	1	12/31/2024	1122	Alternatives of cooling system were evaluated by the consultants to the utility and the State Water Resources Control Board (SWRCB). Review process on the Special Studies Final Report is on-going at the SWRCB.
			2	12/31/2024	1118	
Big Creek-Ventura LCR Area	Mandalay (560 MW)	GenOn	1	12/31/2020	215	Unit 3 is non-OTC
			2	12/31/2020	215	
	Ormond Beach (1,516 MW)	GenOn	1	12/31/2020	741	
			2	12/31/2020	775	
Los Angeles (LA) Basin LCR Area	El Segundo (670 MW)	NRG	3	12/31/2015	335	Replaced by El Segundo Power Redevelopment (560 MW) – (August 2013)
			4	12/31/2015	335	
	Alamitos (2,011 MW)	AES	1	12/31/2020	175	AES proposes to repower with non-OTC generating facilities. This plan is dependent on whether AES can obtain Power Purchase and
			2	12/31/2020	175	
			3	12/31/2020	332	

Area	Generating Facility (Total Plant MW)	Owner	Unit	State Water Resources Control Board (SWRCB) Compliance Date	Net Qualifying Capacity (NQC) (MW)	Final Capacity, if Already Repowered or Under Construction (MW)
			4	12/31/2020	336	Tolling Agreement (PPTA) from the CPUC and the utilities.
			5	12/31/2020	498	
			6	12/31/2020	495	
	Huntington Beach (452 MW)	AES	1	12/31/2020	226	
			2	12/31/2020	226	
			3	12/31/2020	227	Retired 452 MW and converted to synchronous condensers (2013). Modeled as off-line in the post 2017 studies as contract expires.
			4	12/31/2020	227	
	Redondo Beach (1,343 MW)	AES	5	12/31/2020	179	
			6	12/31/2020	175	
			7	12/31/2020	493	
			8	12/31/2020	496	
	San Onofre (2,246 MW)	SCE/ SDG&E	2	12/31/2022	1122	Retired 2246 MW (June 2013)
			3	12/31/2022	1124	
San Diego/I.V. LCR Area	Encina (946 MW)	NRG	1	12/31/2017	106	NRG proposes repowering with a new 600 MW project (Carlsbad Energy Center) – this plan is dependent on whether NRG can obtain PPTA from the CPUC and the utilities.
			2	12/31/2017	103	
			3	12/31/2017	109	
			4	12/31/2017	299	
			5	12/31/2017	329	
	South Bay (707 MW)	Dynegy	1-4	12/31/2011	692	Retired 707 MW (CT non-OTC) – (2010-2011)

Notes:

* A 12/31/2020 compliance date was proposed Amendment to the OTC Policy to be considered for adoption by the State Water Resources Control Board at the April 7, 1015 Board Meeting.

Table 2.3-4: Summary of 2012 LTPP Track 1 & 4 Authorized Procurement

LCR Area	LTTP Track-1		LTTP Track-4[36]	
	Amount (MW)(1)	Study year in which addition is to be first modeled	Amount (MW) (1)	Study year in which addition is to be first modeled
Greater Bay Area	0	N/A	0	N/A
Moorpark Sub-area	290	2021	0	N/A
West LA Basin / LA Basin	1400-1800	2021	500-700	2021
San Diego	308	2018	500-800	2018

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

Table 2.3-5: Summary of 2012 LTPP Track 1 & 4 Procurement Activities to date

	LTPP EE (MW)	Behind the Meter Solar PV (NQC MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE-submitted selected procurement to the CPUC for approval	124.04	37.92	263.64	75	1,382	1,882.60
SDG&E's procurement	0	82*	25	0	600**	707

Notes:

* The ISO is making an assumption of solar distributed generation to meet preferred resources procurement in San Diego.

** Pio Pico (300 MW) from LTPP Track 1 already received Power Purchase Agreement from the CPUC and is treated as existing generation for long-term reliability studies. The 600 MW conventional resources assume Carlsbad Energy Center project, which was filed by SDG&E at the CPUC in seeking for approval of Power Purchase Agreement.

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

2.3.4.1 *Transmission Projects*

The study included all existing transmission in service and the expected future projects that have been approved by the ISO but are not yet in service. Refer to tables 7.1.1 and 7.1.2 of chapter 7 (Transmission Project Updates) for the list of projects that were modeled in the base cases but are not yet in service. Also included in the study cases were generation interconnection related transmission projects that were included in executed Large Generator Interconnection Agreements (LGIA) for generation projects included in the base case.

As discussed in section 2.5 and section 2.5.9, the ISO conducted a separate and standalone review of a large number of local area low voltage transmission projects in the PG&E service territory that were predominantly load forecast driven and whose approvals dated back a number of years. A number of those projects are recommended to be cancelled, and these recommendations are noted on tables 7.1.1 and 7.1.2 of chapter 7.

2.3.4.2 *Load Forecast*

The assessment used the California Energy Demand Updated Final Forecast 2015-2025 adopted by CEC on January 14, 2015 (posted February 9, 2015) using the Mid Case LSE and Balancing Authority Forecast spreadsheet of January 20, 2015.

The CEC, CPUC and ISO during 2013 engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in planning and procurement processes. To that end, the 2013 Integrated Energy Policy Report (IEPR) final report, published on January 23, 2014, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC LTPP and ISO transmission planning process cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low-Mid AAEE scenario for local studies is more prudent at this time.

The 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 backbone system assessments 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 and Off-Peak Conditions

The assessment evaluated the light load and off-peak conditions in all study areas of the ISO balancing authority to satisfy NERC compliance requirement 2.4.2 in TPL-001-4. The ISO light load conditions represented the system minimum load conditions while the off-peak load conditions ranged from 50 percent to 70 percent of the peak load in that area, such as weekends. Critical system conditions in specific study areas can occur during partial peak periods because of loading, generation dispatch and facility rating status and were studied accordingly.

2.3.4.3 *Reactive Power Resources*

Existing and new reactive power resources were modeled in the study base cases to ensure realistic voltage support capability. These resources include generators, capacitors, static var compensators (SVC) and other devices. Refer to area-specific study sections for a detailed list of generation plants and corresponding assumptions. Two of the key reactive power resources that were modeled in the studies include the following:

- all shunt capacitors in the SCE service territory; and
- static var compensators or static synchronous compensators at several locations such as Potrero, Newark, Humboldt, Rector, Devers and Talega substations.

For a complete resources list, refer to the base cases available at the ISO Market Participant Portal secured website (https://portal.caiso.com/Pages/Default.aspx).[37]

2.3.4.4 *Operating Procedures*

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

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

2.3.4.5 *Firm Transfers*

Power flow on the major internal paths and paths that cross balancing authority boundaries represents the transfers modeled in the study. Firm Transmission Service and Interchange represents only a small fraction of these path flows, and is clearly included. In general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 2.3-6 lists the capability and power flows modeled in each scenario on these paths in the northern area assessment[38].

[37] This site is available to market participants who have submitted a non-disclosure agreement (NDA) and is approved to access the portal by the ISO. For instructions, go to http://www.caiso.com/Documents/Regional%20transmission%20NDA.

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

Table 2.3-6: Major paths and power transfer ranges in the Northern California assessment[39]

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

For the summer off-peak cases in the northern California study, Path 15 flow was adjusted to a level close to its rating limit of 5400 MW (S-N). This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. The Path 26 was adjusted between 1800 MW south-to-north and 1800 MW north-to-south to maintain the stressed Path 15 as well as to balance the loads and resources in northern California. Some light load cases model Path 26 flow close to 3000 MW in the south-to-north direction which is its rating limit.

Similarly, Table 2.3-7 lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon and the target flows to be modeled in the southern California assessment.

[39] The winter coastal base cases in PG&E service area will model Path 26 flow at 2,800 MW (N-S) and Path 66 at 3,800 MW (N-S)

Table 2.3-7: Major Path flow ranges in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3,100	3,100	
West of River (WOR)	11,200	5,000 to 11,200	N/A
East of River (EOR)	9,600	4,000 to 9,600	N/A
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to17,870	Summer Peak
Path 45 (N-S)	400	0 to 250	Summer Peak
Path 45 (S-N)	800	0 to 300	Winter Peak

2.3.4.6 *Protection Systems*

To help ensure reliable operations, many special protection systems (SPS), safety nets, UVLS and UFLS schemes have been installed in some areas. Typically, these systems trip load and/or generation by strategically tripping circuit breakers under select contingencies or system conditions after detecting overloads, low voltages or low frequency. The major new and existing SPS, safety nets, and UVLS included in the study are listed in Appendix A.

2.3.4.7 *Control Devices*

Several control devices were modeled in the studies. These control devices are:

- All shunt capacitors in SCE and other areas
- Static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, and Talega substations
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects
- Imperial Valley flow controller

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

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

The figure below provides a simplified map of the PG&E bulk transmission system.

Figure 2.4-1: Map of PG&E bulk transmission system

The 500 kV bulk transmission system in northern California consists 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 accessing 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. In addition, a large number of generation resources in the central California area are delivered over the 500 kV systems into southern California. The typical direction of power flow through Path 26 (three 500 kV lines between the Midway and Vincent substations) is from north-to-south during on-peak load periods and in the reverse direction during off-peak load periods. The typical direction of power flow through Path 15 (Los Banos Gates #1 and #3 500 kV lines and Los Banos-Midway #2 500 kV line) is from south-to-north during off-peak load periods and the flows can be either south-to-north or north-to-south under peak conditions. The typical direction of power flow through California-Oregon Intertie (COI, Path 66) and through the Pacific DC Intertie (bi-pole DC transmission line connecting the Celilo Substation in Washington State with the Sylmar Substation in southern California) is from north-to-south during summer on-peak load periods and in the reverse direction during off-peak load periods in California, which are the winter peak periods in Pacific Northwest.

Because of this bi-directional power flow pattern on the 500 kV Path 26 lines and on COI, both the summer peak (N-S) and spring off-peak (S-N) flow scenarios were analyzed as well as a spring minimum load conditions and partial peak scenarios. Transient stability and post transient contingency analyses were also performed for all flow patterns and scenarios.

2.4.2 Study Assumptions and System Conditions

The northern area bulk transmission system study was performed consistent with the general study methodology and assumptions described in section 2.3. 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 in the next sections. The studies for the PG&E bulk transmission system analyzed the most critical conditions: summer peak cases for the years 2017, 2020 and 2025; spring off-peak cases for 2017 and 2025; spring light load case for 2020; and summer partial peak case for 2025. In addition, sensitivity case with high renewable output was studied for the summer peak of 2020. All single and common mode 500 kV system outages were studied, as well as outages of large generators and contingencies involving stuck circuit breakers and delayed clearing of single-phase-to-ground faults. Also, extreme events such as contingencies that involve a loss of major substations and all transmission lines in the same corridors were studied.

Generation and Path Flows

The bulk transmission system studies use the same set of generation plants that are modeled in the local area studies. In this planning cycle, the scope of the study includes exploring the impacts of meeting the RPS goal in 2025 in addition to the conventional study that models new generators according to the ISO guidelines. Therefore, an additional amount of renewable resources was modeled in the 2020 and 2025 base cases using information in the ISO large generation interconnection queue. Only those resources that are proposed to be online in 2020 or prior to 2020 were modeled in the 2020 cases. 2017 cases modeled new generation projects that are expected to be in service in 2017 or prior to 2017. A summary of generation is provided in each of the local planning areas within the PG&E area.

Because the studies analyzed the most critical conditions, the flows on interfaces connecting northern California with the rest of the WECC system were modeled at or close to the paths' flow limits, or as high as the generation resource assumptions allowed. Due to an assumption of retirement of several large OTC power plants in northern California, flow on Path 26 between northern and southern California was modeled in the 2020 and 2025 cases significantly below its 4000 MW north-to-south rating. Table 2.4-1 lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in the area.

Table 2.4-1: Major import flows for the northern area bulk study

Parameter	2017 Summer Peak	2017 Spring Off-Peak	2020 Summer Peak	2020 Spring Light Load	2025 Summer Peak	2025 Summer Partial Peak	2025 Spring Off-Peak	2020 Sensitivity Summer Peak
California-Oregon Intertie Flow (N-S) (MW)	4800	-2160	4800	890	4800	4800	-3670	4800
Pacific DC Intertie Flow (N-S) (MW)	3100	0	3100	3100	3100	3100	0	3100
Path 15 Flow (S-N) (MW)	-1890	3470	1700	2100	1550	725	5130	2090
Path 26 Flow (N-S) (MW)	4000	-1100	295	-170	400	450	-970	345
Northern California Hydro % dispatch of nameplate	80	30	80	10	80	55	57	80

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 forecast conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50 percent of the 1-in-5 summer peak load level. The light load cases modeled the lowest load in the PG&E area that appears to be lower than the off-peak load. Table 2.4-2 shows the assumed load levels for selected areas under summer peak and non-peak conditions.

Table 2.4-2: Load modeled in the northern area bulk transmission system assessment

Scenario	Area	Load (MW)	Loss (MW)	Total (MW)
2017 Summer Peak	PG&E	29,079	1,097	30,176
	SDG&E	5,175	181	5,356
	SCE	22,833	497	23,330
	ISO	57,087	1,775	58,862
2017 Spring Off-Peak	PG&E	13,497	563	14,060
	SDG&E	3,381	97	3,478
	SCE	8,495	172	8,667
	ISO	25,373	832	26,205
2020 Summer Peak	PG&E	29,439	1,071	30,510
	SDG&E	5,338	190	5,528
	SCE	24,729	380	25,109
	ISO	59,506	1,641	61,147
2020 Spring Light Load	PG&E	10,688	265	10,953
	SDG&E	3,381	82	3,463
	SCE	8,495	140	8,635
	ISO	22,564	487	23,051
2025 Summer Peak	PG&E	29,735	1,053	30,788
	SDG&E	6,031	242	6,273
	SCE	26,032	487	26,519
	ISO	61,798	1,782	63,580
2025 Summer Partial Peak	PG&E	26,172	793	26,965
	SDG&E	6,031	238	6,269
	SCE	26,032	465	26,497
	ISO	58,235	1,496	59,731
2025 Spring Off-Peak	PG&E	13,817	702	14,519
	SDG&E	3,381	92	3,473
	SCE	8,495	158	8,653
	ISO	25,693	952	26,645
2020 Summer Sensitivity	PG&E	29,439	1,173	30,612
	SDG&E	5,338	189	5,527
	SCE	24,729	379	25,108
	ISO	59,506	1,741	61,247

Existing Protection Systems

Extensive SPS or RAS are installed in the northern California area's 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.

2.4.3 Assessment and Recommendations

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standards requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO study assessment of the northern bulk system yielded the following conclusions:

- No Category P0 (normal conditions) overloads on the PG&E bulk transmission system are expected in any of the cases studied with an exception of one 230 kV transmission line in the 2020 Heavy Summer sensitivity case. This transmission line (Cayetano-US Wind section of the Cayetano-Lone Tree 230 kV line) was overloaded due to high wind generation from the project connected to the Cayetano-Lone Tree transmission line. This line section was also identified as overloaded with single and double contingencies in the sensitivity case. A possible solution is to use congestion management to reduce loading on the transmission line.
- Two Category P1 contingency overloads are expected under peak load conditions. These overloads are in addition to the Cayetano-US Wind 230 kV line overload mentioned above. Overloaded facilities under peak summer conditions included Delevan-Cortina 230 kV transmission line and Round Mountain-Table Mountain 500 kV lines. Possible solutions are to use congestion management to reduce loading on the Delevan-Cortina 230 kV transmission line and bypass series capacitors on the Round Mountain-Table Mountain 500 kV lines should they overload. Another solution to mitigate Delevan-Cortina overload is to re-rate or upgrade this line. Another solution to mitigate the Round Mountain-Table Mountain overload is to operate the system within the seasonal COI nomogram. Delevan-Cortina 230 kV line was identified as slightly (about 1 percent) overloaded under Category P1 contingencies in the summer peak cases of 2020 and 2025. Overload on the Round Mountain-Table Mountain # 1 and # 2 500 kV lines was identified with an outage of the parallel circuit in all summer peak cases due to high COI flow and high northern California hydro generation output.
- One Category P1 overload is expected under off-peak conditions: the Moss Landing-Las Aguilas 230 kV line was identified as overloaded in the 2025 spring off-peak case. To mitigate this overload, either short-term rating for this line need to be used, or generation from the future renewable project connected to the Moss Landing-Panoche and Panoche-Coburn 230 kV lines needs to be reduced. This line was also overloaded with the same contingencies in the 2020 Heavy Summer sensitivity case due to the high output of this renewable project.
- The study also identified two heavily loaded facilities under off-peak conditions with Category P1 contingencies due to high generation and two other facilities heavily loaded

under P1 contingencies in the sensitivity case. Under off-peak conditions, the Eight Mile-Lodi 230 kV line was loaded up to 99 percent of its emergency rating with single contingencies due to high generation in Lodi and relatively low load. The second heavily loaded facility was Round Mountain 500/230 kV transformer in the 2025 off-peak case due to high generation and relatively low load in the area. In the sensitivity case, heavily loaded facilities under Category P1 contingency conditions included Table Mountain-Rio Oso 230 kV line (terminal equipment) and the Cayetano-North Dublin 230 kV line, in addition to the overloaded Cayetano-US Wind 230 kV line section.

- A number of potential overloads for Category P6 and P7 contingencies (double outages) was identified.
  - The most critical Category P6 (overlapping outages of two transmission facilities) overload appeared to be overload on the Moss Landing-Las Aguilas 230 kV transmission line that was identified in all the cases studied except for the 2017 Summer Peak and 2020 Spring Light load. This transmission line is expected to overload with an outage of any two 500 kV transmission lines or one 500 kV line and one 500/230 kV transformer between Tesla, Metcalf, Los Banos and Moss Landing, as well as several outages of one of these 500 kV lines together with the underlying 230 kV lines. An outage of the Metcalf-Tesla and Moss Landing-Los Banos 500 kV lines appeared to be the most severe. With this contingency, the 500 kV source to the Metcalf-Moss Landing area will be lost. There were several other transmission facilities in addition to the Moss Landing-Las Aguilas 230 kV line that might overload with the same contingencies. The overload is expected if the Moss Landing power plant is retired and construction of the new renewable project connected to the Moss Landing-Panoche and Panoche-Coburn 230 kV lines. Potential mitigation measures may include: using short-term rating for the overloaded transmission line, dispatching all available generation in San Jose, and/or sectionalizing San Jose 230/115 kV transmission system. If these measures appear not to be sufficient, some load in the Moss Landing area may need to be tripped. Another alternative to mitigate the overload is to delay retirement of some of the Moss Landing power plant units. The analysis has indicated the need for the Moss Landing Power Plant units #1 and #2 at 85% of rated capacity, to meet OTC compliance requirements. The ISO will continue to assess this in the 2016-2017 transmission planning process as well as in future Local Capacity Requirement analysis.
  - Other facilities that are expected to overload with Category P6 contingencies of 500 kV lines between Tesla, Metcalf, Moss Landing and Los Banos include Las Aguilas-Panoche #1 and #2 230 kV transmission lines, Lone Tree-US Wind, Los Esteros-Newark and North Dublin-Cayetano 230 kV lines, Newark 230/115 kV transformer # 11, and Newark-Lockheed Junction #1, Newark-Dixon Landing and Trimble-San Jose B 115 kV lines. In addition, North Dublin-Vineyard 230 kV line may overload with these contingencies in the 2020 summer peak sensitivity case with high renewable generation. The same mitigation measures proposed for the overload of the Moss Landing-Las Aguilas 230 kV transmission line will also mitigate overload on these

facilities. To mitigate the overloads in the Cayetano-Lone Tree-North Dublin-Vineyard area, some wind generation in this area may need to be tripped.

- Transmission facilities overloaded with other Category P6 contingencies appeared to be less severe and are expected in fewer cases. They include overload on the Metcalf 500/230 kV transformer banks with an outage of two parallel transformers, which can be mitigated by dispatching generation in San Jose after the first contingency and, as a last resort, tripping some of the load in San Jose. Other overloaded facilities identified in the P6 contingencies studies were Olinda 500/230 kV transformer under 2025 off-peak conditions, Tracy 500/230 kV transformers #1 and #2 under summer peak conditions starting from 2020 and Cottonwood-Round Mountain # 3 230 kV line under summer peak and 2025 spring off-peak conditions. Potential mitigation for the Olinda 500/230 kV transformer overload is applying existing Colusa SPS, which is currently used for the Category P7 contingency (Malin-Round Mountain 500 kV # 1 and # 2 double line outage). Overload on this transformer was observed for the Category P6 and P7 contingencies only under 2025 off-peak load conditions. To mitigate Tracy 500/230 kV transformer overload, potential solution may be opening of the Tracy-Tesla 230 kV lines and/or tripping some of the Tracy pumping load. Potential mitigation solutions to the Cottonwood-Round Mountain # 3 230 kV line overload, which may also occur with Category P7 contingencies under peak load conditions, may be limiting COI within the seasonal nomograms or upgrade of this transmission line.
- Studies of the 2025 Summer Peak case identified Category P6 overload on the Round Mountain-Table Mountain 500 kV lines #1 and #2 with N-1-1 contingencies of the COI 500 kV lines even if the COI flow was reduced to 3200 MW after the first contingency which is required by the COI Operational procedure. Mitigation solutions may be reducing COI below 3200 MW after the first contingency, or bypassing series capacitors on the overloaded transmission line.
- Studies of the 2017 spring off-peak case identified Category P6 overloads on five 230 kV transmission lines in the Stockton-Lodi area: Eight Mile-Lodi, Gold Hill-Eight Mile, Eight Mile-Tesla, Stagg-Tesla and Stagg-Eight Mile. These overloads were caused by high generation in Lodi at the time of relatively low load in the area. Potential mitigation solution is to reduce generation in Lodi (Lodi Energy Center and/or Stig peaker) after the first contingency.
- Studies of the 2025 spring off-peak case identified three Category P6 overloads caused by high generation in the Round Mountain area at the time of relatively low load. These overloads (Cottonwood-Olinda 230 kV lines #1 and #2 and Round Mountain 500/230 kV transformer) can be mitigated by congestion management.
- Additional overload on the Table Mountain-Rio Oso 230 kV transmission line was identified for Category P6 contingencies in all peak cases. This transmission line may also overload for one Category P7 contingency. The limiting element is terminal equipment which is planned to be upgraded by PG&E.
- Other Category P6 overloads were identified in the 2017 peak case in the Palermo-Rio Oso area (Pease-Palermo 115 kV and Rio Oso-Greenleaf tap 115 kV). They will

be mitigated by the South of Palermo Transmission Project. Prior to this project being implemented, some generation reduction after the first contingency may be required.

- Four Category P6 230 kV transmission line overloads were identified in central and southern PG&E area under off-peak conditions. Gates-Switching Station section of the Gates-Estrella 230 kV line may overload with one N-1-1 outage under 2025 off-peak conditions. This overload can be mitigated by reducing generation from the future renewable project connected to this transmission line. Kearney-Herndon and Borden –Gregg 230 kV lines were identified as overloaded with Category P6 contingencies under 2017 spring off-peak conditions with Helms Pump Storage Power Plant operating with three units in the pumping mode. North Fresno Transmission Reinforcement project that is expected to be in service by 2020 will mitigate these overloads. Prior to the project, some generation reduction, as well as tripping of one of the Helms pumps may be required. The Tesla-Los Banos 500 kV transmission line may slightly (less than 1 percent) overload under off-peak conditions with the N-1-1 contingency of two 500 kV transmission lines from the Los Banos Substation and may require dispatching additional generation in San Jose after the first contingency.

- There was a number of transmission facilities identified as overloaded with Category P7 (two adjacent circuits) contingencies.
  - Potential overloads for Category P7 contingencies under summer peak load conditions included overload on the Captain Jack-Olinda 500 kV line, Cottonwood-Round Mountain 230 kV line #3, Delevan-Cortina and Table Mountain-Rio Oso 230 kV lines and Drum-Brunswick 115 kV line #2, the latest due to high generation from the Drum # 5 hydro unit. Potential mitigation measures for these line overloads are as follows: operate COI within the seasonal nomogram, or re-rate or upgrade Delevan-Cortina 230 kV line, upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line, and reduce generation from the Drum #5 unit in case of the Drum-Brunswick 115 kV line overload.
  - Under off-peak conditions, Category P7 contingency overload included overload on the Olinda 500/230 kV transformer and overload on the Round Mountain 500/230 kV transformer. Both overloads were identified under 2025 spring off-peak conditions. Existing Colusa SPS will mitigate overload on the Olinda transformer, and overload on the Round Mountain transformer may be mitigated by congestion management or tripping some generation in the Round Mountain area. Another solution is operate the system under seasonal COI nomogram.

- No overloads were identified under minimum load conditions.

- In addition to the overloaded facilities observed in the ISO territory, two 500 kV transmission lines were identified with potential overloads in BPA: Captain Jack-Ponderosa 500 kV line and Ponderosa-Summer Lake 500 kV line. Both overloads may occur with the PDCI bi-pole outage (Category P7 contingency). ISO will discuss these results with BPA to develop the mitigation measures.

The ISO-proposed solutions to mitigate the identified reliability concerns are to manage COI flow according to the seasonal nomogram, to implement congestion management and to re-rate Delevan-Cortina 230 kV line and upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line. Additional mitigation measures are being evaluated for the Category P6 (N-1-1) 500 kV contingencies between Metcalf, Tesla, Moss Landing and Los Banos.

The studies did not identify any voltage or reactive margin concerns on the PG&E bulk transmission system with an exception of high voltages under off-peak and light load conditions. These high voltages may require installation of additional shunt reactors. High voltages were also observed on the 60-70 kV sub-transmission system with high output of renewable generation. To mitigate this concern, new renewable projects will need to have the capability to absorb reactive power and to regulate voltage.

Dynamic stability studies did not identify any criteria violations, but identified several modeling issues that will need to be resolved with the owners of the generation units having the questionable models. Also, the studies showed that the California Department of Water Resources (CDWR) irrigational pumps at the Midway 230 kV substation may be tripped by the under-voltage relays in case of three-phase faults on the Midway 230 kV substation or on the 230 kV lines close to the Midway 230 kV bus. In addition, some small solar PV projects connected to the sub-transmission system may trip due to high voltages if they operate with the unity power factor.

Dynamic stability studies had the load in WECC, including the ISO, modeled with composite load models. The studies using this model did not show any criteria violations, but showed some non-consequential loss of load caused by under-voltage tripping of some load elements.

Request Window Proposals

Round Mountain 500 kV Substation Shunt Reactor

The Round Mountain 500 kV Substation Shunt Reactor project was submitted in the 2015 Request Window as a transmission solution to high voltages on the 500 kV transmission system. PG&E proposed to install a 300 Mvar shunt reactor on the Round Mountain 500/230 kV substation. High voltages on its 500 kV bus were observed under off-peak normal conditions in the transmission planning reliability studies as well as in real-time operations. The proposed shunt reactor was estimated to cost between $24 million and $36 million and the forecast operational date is December 2019.

The ISO will continue to assess the high voltage issues in the 2016-2017 transmission planning process to further assess the alternatives, the requirement for static versus dynamic support, and optimal locations for high voltage mitigation on the bulk system. Current operating action plans will be used to mitigate the high voltage interim until the detailed mitigation plan is developed.

Midway – Tesla +/- 400 kV, 1,500 MW HVDC VSC Underground Transmission Cables

This project was proposed by the Trans Bay Cable, LLC as a reliability project to support development of the 50 percent renewables portfolio standard (RPS). The project is intended to mitigate any Path 15 potential congestion issues and associated curtailments, resulting from increased RPS obligations.

The project scope includes construction of an under-ground bi-directional +/- 400 kV, 1,500 MW HVDC VSC cable connecting PG&E's Midway 500 kV bus with PG&E's Tesla 500 kV bus. The project would provide +/- 500 Mvars of reactive capability at the Midway and Tesla substations. TBC proposes to install and place the project in service by May 2020. The estimated cost of the project is from $2.0 to $2.2 billion.

The ISO reviewed the proposal and the associated studies submitted in the request window by the proponent. From the proponent's studies, the need for the project was not clear. The ISO studies in the 2015-2016 transmission planning process did not identify the reliability need for such a project as they did not identify any meaningful congestion on Path 15. It appeared that the project may be needed for reliability purposes only if a sufficient amount of new generation develops in southern California. In addition, detailed cost-benefit analysis wasn't included, therefore it was not clear how the benefits of the project were calculated. Notwithstanding, the ISO's analysis does not support the project at this time.

San Luis Transmission Project (SLTP)

This proposal was first submitted by the Duke-America Transmission Company, Path 15, LLC (DATCP) in the 2014 Request Window as a solution to encourage ISO participation in the proposed transmission line between Western Area Power Administration's (WAPA) Tracy Substation and the Los Banos area. The project is described in more detail in the 2014-2015 ISO Transmission Plan.

The SLTP includes a 500 kV single circuit transmission line between the Tracy substation and the Los Banos area. A new Los Banos 2 substation is proposed to be constructed adjacent to the existing Los Banos substation and the Gates-Los Banos #3 transmission line looped into the new Los Banos 2 substation. The full SLTP includes additional 230 kV facilities and potentially additional lower voltage facilities to interconnect the San Luis pump/generating station and the Dos Amigos pumping plant.

In the 2014-2015 transmission planning process, the ISO reviewed the need for additional capacity to address reliability requirements on the ISO controlled grid, and did not identified reliability requirements addressed by the San Luis Transmission Project. The ISO has also reviewed the reliability benefits identified in the submission and noted that the conditions studied represented flows that exceeded the range of any current forecast scenario.

DATCP re-submitted the project in February of 2015 and in March and April provided additional study results. Upon the review of the study results, ISO does not concur with the modeling assumptions and did not identify a reliability need for the San Luis Transmission Project.

2.5 PG&E Local Areas Assessment

In addition to the PG&E bulk area study, studies were performed for its eight local areas. As well, the ISO conducted a separate and standalone review of a large number of local area low voltage transmission projects in the PG&E service territory that were predominantly load forecast driven and whose approvals dated back a number of years. This review is discussed in section 2.5.9. A number of those projects are recommended to be cancelled, and these recommendations are noted on tables 7.1.1 and 7.1.2 of chapter 7. In reviewing the potential to cancel those projects, the results set out in sections 2.5.1 through 2.5.8 were reviewed to ensure that cancelling those projects did not affect sections 2.5.1 through 2.5.8 results and recommendations.

2.5.1 Humboldt Area

2.5.1.1 *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 composed of 60 kV and 115 kV transmission facilities. Electric supply to this area is provided primarily by generation at Humboldt Bay power plant and local qualifying facilities. Additional electric supply is provided by 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 2015-2016 transmission planning studies, a summer peak and winter peak assessment was performed. In addition, the spring off-peak condition for 2017 and the spring light load condition for 2020 assessments were also performed. For the summer peak assessment, a simultaneous area load of 131 MW in the 2020 and 138 MW in the 2025 timeframes were assumed. These load levels include the Additional Achievable Energy Efficiencies (AAEE). For the winter peak assessment, a simultaneous area load of 145 MW and 151 MW in the 2020 and 2025 timeframes were assumed.

2.5.1.2 *Area Specific Assumptions and System Conditions*

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. Summer peak and winter peak assessments were performed for the study years 2017, 2020 and 2025. In addition, a 2017 spring off-peak condition and a 2020 spring light load condition were studied.

Generation

Generation resources in the Humboldt area consist of market, qualifying facilities and self-generating units. The largest resource in the area is the 166 MW Humboldt Bay Power Plant. This facility was re-powered and started commercial operation in the summer of 2010. It replaced the Humboldt power plant that retired in November 2010. The 12 MW Blue Lake Power Biomass Project was placed into commercial operation on August 27, 2010. The 25 MW Pacific Lumber power plant, which is a qualifying facility, retired earlier in 2015 and resulted in a net reduction in the total amount of generation available in the Humboldt area as compared to previous year. Because the retirement of Pacific Lumber unit happened after the TPP studies were performed, the base results do not capture the impact of the retirement on the Humboldt system. However, the ISO performed additional sensitivity studies that assess the impact of qualifying facility retirements including Pacific Lumber's retirement. Table 2.5-1 lists a summary of the generation in the Humboldt area with detailed generation listed in Appendix A.

Table 2.5-1: Humboldt area generation summary

Generation	Capacity (MW)
Thermal	191
Hydro	5
Biomass	37
Total	**233**

Load Forecast

Loads within the Humboldt area reflect a coincident peak load for 1-in-10-year forecast conditions in each study year. Table 2.5-2 and Table 2.5-3 summarize loads modeled in the studies for the Humboldt area.

Table 2.5-2: Load forecasts modeled in Humboldt area assessment, Summer Peak

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	Summer Peak (MW)		
	2017	2020	2025
Humboldt	128	131	138

Table 2.5-3: Load forecasts modeled in Humboldt area assessment, Winter Peak

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	Winter Peak (MW)		
	2017	2020	2025
Humboldt	140	145	151

2.5.1.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standards requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO study of the Humboldt area yielded the following conclusions:

- no Category P0 thermal violations were identified;
- eight Category P2 thermal violations were identified;
- low voltages and voltage deviations may occur for various contingency categories prior to the new Bridgeville-Garberville 115kV line coming into service;
- the study identified a need for additional reactive support in the Mendocino area in the 5-10 year time frame;
- voltage and voltage deviation concerns were identified on several 60 kV buses in the summer and winter peak conditions for various contingencies categories in and around the Blue Lake Power Plant, Arcata, Orick, Big Lagoon and Trinidad substations; and
- the retirement of Pacific Lumber generating unit (QF) has created new thermal constraints in the 60kV corridor between Newburg-Bridgeville.

The identified overloads will be addressed by the following proposed solutions:

- Complete the approved transmission solution of building a new Bridgeville-Garberville 115 kV transmission line. This transmission solution will address the overload on the various 60 kV line sections in the Bridgeville-Mendocino 60 kV corridor that is expected under multiple contingencies categories as well as solve voltage concerns in the Bridgeville area. This new 115 kV transmission line project was approved in the 2011-2012 transmission plan.
- The voltage concerns in the Arcata load pocket were seen in the 5-10 year time frame, which can be mitigated either by installing additional reactive power resources or by reconfiguring the 60 kV lines serving the Arcata area.

- Employ PG&E's action plans that include operator actions such as generation adjustments and load dropping to address the various Category C related thermal violations found in the Humboldt area.
- On an interim basis, use PG&E action plans to address low voltages and voltage deviation concerns in the most northern part of Humboldt County.

No capital project proposals were received from PG&E in this planning cycle for the Humboldt planning area.

2.5.2 North Coast and North Bay Areas

2.5.2.1 *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 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 747 MW in 2020 and 760 MW in 2025 time frames was assumed. For the winter peak assessment, a simultaneous area load of 615 MW and 610 MW in the 2020 and 2025 time frames was 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 Bridgeville-Garberville-Laytonville 60 kV lines. It is connected 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.

North Bay encompasses the area just north of San Francisco. This transmission system serves Napa and portions of Marin, Solano and Sonoma counties.

The larger cities served in this area include Novato, San Rafael, Vallejo and Benicia. North Bay's electric transmission system is composed of 60 kV, 115 kV and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento and the Bay Area. For the summer peak assessment, a simultaneous area load of 757 MW and 778 MW in the 2020 and 2025 time frames was assumed. For the winter peak assessment, a simultaneous area load of 539 MW and 542 MW in the 2020 and 2025 time frames was assumed. Like the North Coast, the 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.

2.5.2.2 *Area-Specific Assumptions and System Conditions*

The North Coast and North Bay area studies were performed consistent with the general study assumptions and methodology described in section 2.3. The ISO secured website lists the contingencies that were performed as part of this assessment. Specific assumptions and methodology that were applied to the North Coast and North Bay area studies are provided below. Summer peak and winter peak assessments were done for North Coast and North Bay areas for the study years 2016, 2019 and 2024. Additionally a 2016 summer light Load condition and a 2019 summer off-peak condition were studied for the North Coast and North Bay areas.

Generation

Generation resources in the North Coast and North Bay area consist of market, qualifying facilities and self-generating units. Table 2.5-4 lists a summary of the generation in the North Coast and North Bay area, with detailed generation listed in Appendix A.

Table 2.5-4: North Coast and North Bay area generation summary

Generation	**Capacity (MW)**
Thermal	54
Hydro	26
Geo Thermal	1,533
Biomass	6
Total	**1,619**

Load Forecast

Loads within the North Coast and North Bay area reflect a coincident peak load for 1-in-10-year forecast conditions for each study year.

Table 2.5-5 and table 2.5-6 summarize the substation loads assumed in the studies for North Coast and North Bay areas under summer and winter peak conditions.

Table 2.5-4: Load forecasts modeled in North Coast and North Bay area assessments, Summer Peak

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	**Summer Peak (MW)**		
	2017	**2020**	**2025**
North Coast	733	747	760
North Bay	738	757	778

Table 2.5-5: Load forecasts modeled in North Coast and North Bay area assessments, Winter Peak

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	Winter Peak (MW)		
	2017	2020	2025
North Coast	611	615	610
North Bay	530	539	542

2.5.2.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standards requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The ISO assessment of the PG&E North Coast and North Bay revealed the following reliability concerns:

- No Category P1 thermal violations were found in this year's analysis.
- Overall there were 8 Category P1 and 32 Category P2, P6 or P7 overloads identified in this year's assessment.
- Low voltage violations have been found in four local pockets for Category P1 conditions and in four local pockets for Category P2, P6 or P7 conditions.
- Voltage deviation concerns were identified in two local pockets for Category P1 conditions.

The identified violations will be addressed as follows:

- One Category P1 overload may require reconductoring a transmission line by the summer of 2023. No mitigation is recommended at this time but will be monitored in future cycles.
- Certain severe local low voltage and voltage deviation violations under Category P6 conditions, which resulted in a voltage collapse in the Mendocino-Garberville 60 kV corridor, will need additional reactive support installed. No mitigation is recommended at this time but will be monitored in future planning cycles. The ISO will continue to work with PG&E on various mitigation alternatives as a part of the conceptual Mendocino long-term study.
- All other Category P1 and Category P2, P6 or P7 issues either already have a project approved or have a PG&E operating procedure in place as mitigation. In cases where the approved projects have not yet come into service, interim operating solutions or action plans may need to be put in place as mitigation. The ISO will continue to work with PG&E in developing the interim plans as required.

The ISO is recommending for approval the following project to address high voltage issues in the North Coast and North Bay area.

The ISO received the capital project proposal through the request window to install a new 150 Mvar 230kV reactor to mitigate high voltages on the PG&E system at Ignacio. The project scope includes installing a 2 step 150 Mvar reactor by sectionalizing the 230kV bus with two (2) circuit breakers. Two other circuit breakers are also included in the design to switch the reactor in and out of service. The project is estimated to be in service in 2020 and is expected to cost between $23.4 Million - $35.1 Million. The ISO has found the project to be needed given the real-time high voltage concerns system operators were experiencing in this area as validated from real-time SCADA values. As the high voltage concerns are being seen in real-time operations, the ISO is working with PG&E to potentially expedite the implementation of this project.

This year’s analysis shows that the previously approved projects in the North Coast and North Bay area are still needed to mitigate the identified reliability concerns. These projects include the following:

- Ignacio-Alto 60 kV Line Voltage Conversion Project;
- Clear Lake 60kV system reinforcement project;
- Napa-Tulucay No. 1 60 kV Line Upgrade;
- Tulucay No. 1 230-60 kV Transformer Capacity Increase;
- Geyser #3-Cloverdale 115 kV Line Switch Upgrade; and,
- Big River SVC.

2.5.3 North Valley Area

2.5.3.1 *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 as well as 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 adjacent figure depicts the approximate geographical location of the North Valley area.

North Valley's electric transmission system is composed 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 local electricity demand. In addition to the Pacific Intertie, one other external interconnection exists connecting to the PacifiCorp system. The internal transmission system connections to the Humboldt and Sierra areas are via the Cottonwood, Table Mountain, Palermo and Rio Oso substations.

Historically, North Valley experiences its highest demand during the summer season; however, a few small areas in the mountains experience highest demand during the winter season. Load forecasts indicate North Valley should reach a summer peak demand of 988 MW by 2025.

Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions. Table 2.5.3–2 includes load forecast data.

2.5.3.2 *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 Market Participant Portal lists the 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, qualifying facilities and self-generating units. More than 2,000 MW of hydroelectric generation is located in this area. These facilities are fed from the following river systems: Pit River, Battle Creek, Cow Creek, North Feather River, South Feather River, West Feather River and Black Butt. Some of the large powerhouses on the Pit River and the Feather River watersheds are the following: Pit, James Black, Caribou, Rock Creek, Cresta, Butt Valley, Belden, Poe and Bucks Creek. The largest generation facility in the area is the natural gas-fired Colusa County generation plant, which has a total capacity of 717 MW and it is interconnected to the four Cottonwood-Vaca Dixon 230 kV lines. Table 2.5-6 lists a summary of the generation in the North Valley area with detailed generation listed in Appendix A.

Table 2.5-6: North Valley area generation summary

Generation	Capacity (MW)
Thermal	1,070
Hydro	1,670
Wind	103
Total	**2,843**

Load Forecast

Loads within the North Valley area reflect a coincident peak load for 1-in-10-year forecast conditions for each peak study scenario. Table 2.5-7 shows loads modeled for the North Valley area assessment.

Table 2.5-7: Load forecasts modeled in the North Valley area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	Summer Peak (MW)		
	2017	2020	2025
North Valley	939	961	988

2.5.3.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B.

The 2015 reliability assessment of the PG&E North Valley area revealed several reliability concerns. These concerns consist of thermal overloads and low voltages under Categories P0, P1, P2, P3, P6 and P7 contingencies.

- Three facilities were identified with thermal overloads for Category P0 performance requirements.
- Two facilities were identified with thermal overloads for Category P1 performance requirements. Four facilities were identified with low voltage concerns and 15 facilities were identified with high voltage deviations.

- Eight facilities were identified with thermal overloads for Category P2 performance requirements. Eight facilities were identified with low voltage concerns and 21 facilities were identified with high voltage deviations.
- One facility was identified with thermal overloads for Category P3 performance requirements.
- Eighteen facilities were identified with thermal overloads for Category P6 performance requirements.
- Seven facilities were identified with thermal overloads for Category P7 performance requirements.

This year's reliability assessment of the PG&E North Valley area identified several reliability concerns that consist of thermal overloads and low voltages under normal or Category P0 operating conditions and Category P1, P2, P3, P6 and P7 contingency conditions. The ISO's previously approved solutions will address these reliability concerns in the long term. Until the approved solutions are completed, operating action plans will be relied upon to address the thermal overloads and low voltage issues.

The ISO is recommending for approval the following project to address high voltage issues in the North Valley area.

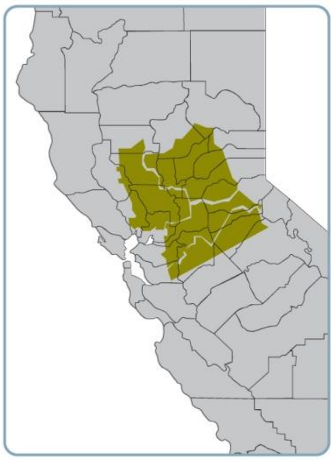
Cottonwood 115 kV Substation Shunt Reactor

The project is to install a new 100 Mvar 115kV reactor to mitigate high voltages on the PG&E system at Cottonwood. The project scope includes installing a 100 Mvar reactor and associated bus and line work to interconnect the reactors. The project is estimated to be in service in 2019 and is expected to cost between $13 Million - $19 Million. The ISO has found the project to be needed given the real-time high voltage concerns system operators were experiencing in this area as validated from real-time SCADA values. As the high voltage concerns are being seen in real-time operations, the ISO is working with PG&E to potentially expedite the implementation of this project.

2.5.4 Central Valley Area

2.5.4.1 *Area Description*

The 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 composed of the Sacramento, Sierra, Stockton and Stanislaus divisions as shown in the figure below.



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

The Sierra division 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 composed of 60 kV, 115 kV and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 kV and 230 kV facilities transmit generation resources from north-to-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 division 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 composed of 60 kV, 115 kV and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. Lodi is a member of the Northern California Power Agency (NCPA), and it is the largest city that is served by the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus division 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 composed of 230 kV, 115 kV and 60 kV facilities. The 230 kV facilities connect Bellota to the Wilson and Borden substations. The 115 kV transmission network is located in the northern portion of the area and it has connections to qualifying facilities 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, the Central Valley experiences its highest demand during the summer season. Load forecasts indicate the Central Valley should reach its summer peak demand of 4335 MW by 2025 assuming load is increasing by approximately 50 MW per year.

Accordingly, system assessments in these areas included technical studies using load assumptions for these summer peak conditions. Table 2.5-9 includes load forecast data.

2.5.4.2 *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. The total installed capacity is approximately 3459 MW with another 530 MW of North Valley generation being connected directly to the Sierra division. Table 2.5-8 lists a summary of the generation in the Central Valley area with detailed generation listed in Appendix A.

Table 2.5-8: Central Valley area generation summary

Generation	Capacity (MW)
Thermal	1,359
Hydro	1,545
Wind	894
Biomass	162
Total	**3,960**

- Sacramento division — there are approximately 970 MW of internal generating capacity within the Sacramento division. More than 800 MW of the capacity (Lambie, Creed, Goosehaven, EnXco, Solano, High Winds and Shiloh) are connected to the new Birds Landing Switching Station and primarily serves the Bay Area loads.
- Sierra division — there is approximately 1250 MW of internal generating capacity within the Sierra division, and more than 530 MW of hydro generation listed under North Valley that flows directly into the Sierra electric system. More than 75 percent of this generating capacity is from hydro resources. The remaining 25 percent of the capacity is from QFs, and co-generation plants. The Colgate Powerhouse (294 MW) is the largest generating facility in the Sierra division.
- Stockton division — there is approximately 1370 MW of internal generating capacity in the Stockton division.
- Stanislaus division — there is approximately 590 MW of internal generating capacity in the Stanislaus division. More than 90 percent of this generating capacity is from hydro resources. The remaining capacity consists of QFs and co-generation plants. The 333 MW Melones power plant is the largest generating facility in the area.

Load Forecast

Loads within the Central Valley area reflect a coincident peak load for 1-in-10-year forecast conditions of each peak study scenario. Table 2.5-9 shows loads modeled for the Central Valley area assessment.

Table 2.5-9: Load forecasts modeled in the Central Valley area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area	**Summer Peak (MW)**		
	2017	**2020**	**2025**
Sacramento	1159	1205	1259
Sierra	1231	1259	1286
Stockton	1414	1463	1523
Stanislaus	267	268	267
TOTAL	**4070**	**4195**	**4335**

2.5.4.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2015-2016 reliability assessment of the PG&E Central Valley Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies. The ISO previously approved solutions will address these reliability concerns in the long term. Until the approved solutions are completed, operating action plans will be relied upon to address the thermal overloads and low voltage issues.

The ISO is recommending for approval the following projects to address high voltage issues in the Central Valley area.

Bellota 230 kV Substation Shunt Reactor

ISO received one capital project proposal through the request window to install a new 100 Mvar 230kV reactor to mitigate high voltages on the PG&E system at Bellota. The project scope includes installing a 100 Mvar reactor and associated bus and line work to interconnect the reactors. The project is estimated to be in service in 2020 and is expected to cost between $13 Million - $19 Million. The ISO has found the project to be needed given the real-time high voltage concerns system operators were experiencing in this area as validated from real-time SCADA values. As the high voltage concerns are being seen in real-time operations, the ISO is working with PG&E to potentially expedite the implementation of this project.

Delevan 230 kV Substation Shunt Reactor

ISO received one capital project proposal through the request window to install a new 200 Mvar 230kV reactor to mitigate high voltages on the PG&E system at Delevan. The project scope includes installing a 200 Mvar reactor and associated bus and line work to interconnect the reactors. The project is estimated to be in service in 2020 and is expected to cost between $19 Million - $28 Million. The ISO has found the project to be needed given the real-time high voltage concerns system operators were experiencing in this area as validated from real-time SCADA values. In light of the fact that the high voltage concerns are being seen in real-time operations, the ISO is working with PG&E to potentially expedite the implementation of this project.

2.5.5 Greater Bay Area

2.5.5.1 *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. To better conduct the performance evaluation, the area is divided into three sub-areas: East Bay, South Bay and San Francisco-Peninsula.

The East Bay sub-area includes cities in Alameda and Contra Costa counties. Some major cities are 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 Santa Clara County. Some major cities are 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 Calpine's Metcalf Energy Center, Los Esteros Energy Center, Calpine Gilroy Power 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.

Last, the San Francisco-Peninsula sub-area encompasses San Francisco and San Mateo counties, which include 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 that include the 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 became operational in 2011. It is a unidirectional, controllable, 400 MW HVDC land and submarine-based electric transmission system. The line employs voltage source converter technology, which will transmit 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.

The ISO Planning Standards were enhanced in 2014 to recognize that the unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages for extreme events that are beyond the level that is applied to the rest of the ISO controlled grid. Further, the ISO shall consider the overall impact of the mitigation on the identified risk and the associated benefits that the mitigation provides to the San Francisco Peninsula area. The ISO Planning Standards were approved by the Board on September 18, 2014.

2.5.5.2 *Area-Specific Assumptions and System Conditions*

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

Generation

Table 2.5-10 lists a summary of the generation in the Greater Bay area, with detailed generation listed in Appendix A.

Table 2.5-10: Greater Bay area generation summary

Generation	Capacity (MW)
Thermal	7938
Wind	335
Biomass	13
Total	**8286**

Load Forecast

Loads within the Greater Bay Area reflect a coincident peak load for 1-in-10-year forecast conditions. Table 2.5-12 and table 2.5-13 show the area load levels modeled for each of the PG&E local area studies, including the Greater Bay Area.

Table 2.5-11: Summer Peak load forecasts for Greater Bay Area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area	Summer Peak (MW)		
	2017	2020	2025
East Bay	920	925	927
Diablo	1664	1688	1715
San Francisco	957	953	943
Peninsula	896	887	864
Mission	1301	1331	1350
De Anza	985	996	986
San Jose	1902	1915	1942
TOTAL	8625	8695	8727

Table 2.5-12: Winter Peak load forecasts for San Francisco and Peninsula Area assessments

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area	Winter Peak (MW)		
	2017	2020	2025
San Francisco	938	928	904
Peninsula	925	901	845

2.5.5.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2015-2016 reliability assessment of the PG&E Greater Bay Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies. In addition to previously approved projects, the ISO recommends the following transmission development project as a part of the mitigation plan, to address the identified thermal overloads and low voltage concerns.

Los Esteros 230 kV Substation Shunt Reactor

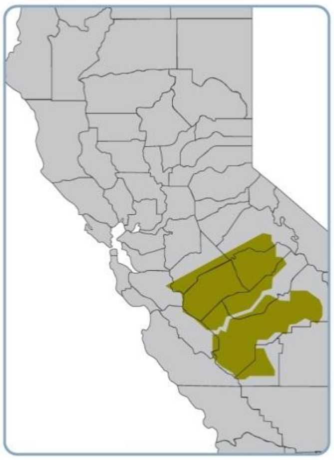
The ISO assessment has determined high voltages in Greater Bay Area transmission system during light load conditions. To mitigate these high voltages, PG&E submitted this project through the 2015 Request Window to install 250 Mvar Shunt Reactor at Los Esteros 230 kV Substation. The ISO determined that the project is needed to mitigate high voltages identified in the San Jose area. The project is expected to cost between $24 million and $36 million and has an in-service date of December 2020.

The ISO conducted a sensitivity study in the East Bay area to identify the order of magnitude long-term reliability needs and to assess reliance on existing SPSs in East Bay area without the local generation being available. With the reliance on aging generation in the area, the ISO continues to assess the transmission needs in the East Bay area without the generation being available. The ISO will continue to assess transmission, generation or non-transmission solutions in the 2016-2017 transmission planning cycle as we assess the needs of the area. In the near-term the area relies on SPS with a relatively small amount of load shedding as per the ISO Planning Standards; however the ISO will consider other alternatives for the long-term horizon.

2.5.6 Greater Fresno Area

2.5.6.1 *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, which are located within the San Joaquin Valley Region. The adjacent figure depicts the geographical location of the Fresno area.



The Greater Fresno area electric transmission system is composed of 70 kV, 115 kV and 230 kV transmission facilities. Electric supply to the Greater Fresno area is provided primarily by area hydro generation (the largest of which is Helms Pump Storage Plant), several market facilities and a few qualifying facilities. It is supplemented by transmission imports from the North Valley and the 500 kV lines along the west and south parts of the Valley. The Greater Fresno area is composed of two primary load pockets including the Yosemite area in the northwest portion of the shaded region in the adjacent figure. The rest of the shaded region represents the Fresno area.

The Greater Fresno area interconnects to the bulk PG&E transmission system by 12 transmission circuits. These consist of nine 230 kV lines; three 500/230 kV banks; and one 70 kV line, which are 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 it also experiences high loading because of the potential of 900 MW of pump load at Helms Pump Storage Power Plant during off-peak conditions. Load forecasts indicate the Greater Fresno area should reach its summer peak demand of approximately 3715 MW in 2025, which includes losses and pump load. This area has a maximum capacity of about 5124 MW of local generation in the 2025 case. The largest generation facility within the area is the Helms plant, with 1212 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 Helms.

Significant transmission upgrades have been approved in the Fresno area in past transmission plans, which are set out in chapter 7.

2.5.6.2 *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 that applied to the Fresno area study are provided below.

Generation

Generation resources in the Greater Fresno area consist of market, QFs and self-generating units. Table 2.5-14 lists a summary of the generation in the Greater Fresno area with detailed generation listed in Appendix A.

Table 2.5-14: Greater Fresno area generation summary

Generation	**Capacity (MW)**
Thermal	1108
Hydro	2106
Solar	1547
Biomass	70
Distributed Generation (DG)	292
Total	**5124**

Load Forecast

Loads within the Fresno and Yosemite area reflect a coincident peak load for 1-in-10-year forecast conditions for each peak study scenario. Table 2.5-15 shows the substation loads assumed in these studies under summer peak conditions.

Table 2.5-15: Load forecasts modeled in Fresno and Yosemite area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	**Summer Peak (MW)**		
	2017	**2020**	**2025**
Yosemite	955	997	1052
Fresno	2423	2535	2662

2.5.6.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.3. Details of the planning assessment results are presented in Appendix B. The 2015-2016 reliability assessment of the PG&E Greater Bay Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies. In addition to previously approved projects, the ISO recommends the following transmission development projects as a part of the mitigation plan, to address the identified thermal overloads and voltage concerns.

Panoche-Oro Loma 115 kV Line Project

Reconductoring the Panoche-Oro Loma 115 kV Line will improve reliability, increase capacity, and address the thermal concerns in the area under an outage condition. In addition, the proposed project will mitigate the need to curtail roughly 500 MW of generation south of Panoche Substation and re-dispatching roughly 500 MW of generation north of Oro Loma Substation following the same outage condition. The expected in-service date of the project as proposed in PGE's request window submission is summer 2021 with an estimated cost of $20 million.

Wilson 115 kV SVC Project

High Voltage has been observed in the Northern Fresno Area on Several 115kV and 70kV buses. The purpose of this project is to help mitigate the high voltages in PG&E's Yosemite area.

The recommended project is to replace the existing capacitor at Wilson 115kV with a 100 Mvar SVC at Wilson 115kV, instead of adding a reactor at Wilson 230kV as initially proposed in PG&E's submission in the request window. Results from power flow analysis show that having the SVC at Wilson 115kV better addresses the voltage concerns in the Northern Fresno Area. Having an SVC to replace the existing capacitor rather than installing a reactor at Wilson 230kV would avoid having to operate separate reactive devices in the same station, which could become very challenging to coordinate in real-time operations, as there are also reactive devices at Borden, Gregg and McCall.

The proposed in service date is 2020, or earlier to address the existing conditions, with an approximate cost of $35-45 million. To expedite the installation the reactive component of the SVC could be installed initially with the removal of the existing capacitor bank or incorporation of the capacitive component staged later.

2.5.7 Kern Area

2.5.7.1 *Area Description*

The Kern area is located south of the Yosemite-Fresno area and north of the southern California Edison's (SCE) service territory. Midway substation, one of the largest substations in the PG&E system, is located in the Kern area and has 500 kV transmission connections to PG&E's Diablo Canyon, Gates and Los Banos substations as well as SCE's Vincent substation. The figure on the left depicts the geographical location of the Kern area.

The bulk of the power that interconnects at Midway substation transfers onto the 500 kV transmission system. A substantial amount also reaches neighboring transmission systems through Midway 230 kV and 115 kV transmission interconnections. These interconnections include 230 kV lines to Yosemite-Fresno in the north as well as 115 and 230 kV lines to Los Padres in the west. Electric customers in the Kern area are served primarily through the 230/115 kV transformer banks at Midway, Kern Power Plant (Kern PP) substations and 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 2367 MW in 2025. Accordingly, system assessments in this area included technical studies using load assumptions for summer peak conditions.

2.5.7.2 *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 addition, specific assumptions and methodology that applied to the Kern area study are provided in this section.

Generation

Generation resources in the Kern area consist of market, qualifying facilities and self-generating units. Table 2.5-16 lists a summary of the generation in the Kern area with detailed generation listed in Appendix A.

Table 2.5-16: Kern area generation summary

Generation	Capacity (MW)
Thermal	3,176
Hydro	22
Solar	189
Biomass	56
Total	**3,443**

Load Forecast

Loads within the Kern area reflect a coincident peak load for 1-in-10-year forecast conditions for each peak study scenario. Table 2.5-17 shows loads in the Kern area assessment.

Table 2.5-17: Load forecasts modeled in the Central Valley area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	**Summer Peak (MW)**		
	2017	**2020**	**2025**
Kern	2200	2285	2367

2.5.7.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results, if any, are presented in Appendix B. In this planning cycle, ISO performed studies for the Kern area. The Kern area study yielded the following conclusions:

- No thermal overloads and no voltage concerns would occur under normal (i.e., NERC Category P0) conditions.

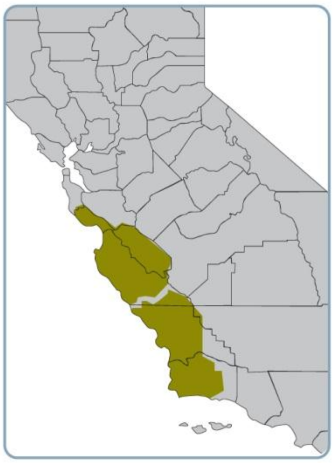
The summer reliability assessment for the PG&E Kern area performed in 2015 confirmed the previously identified reliability concerns and their associated mitigation plans. The concerns were thermal overloads, low voltages, and voltage deviations, which were under NERC Category P6 contingency conditions. Similar to the previous year’s studies, no NERC Category P0 reliability concerns were identified.

The previously approved projects, which include the North East Kern Voltage Conversion (70 kV to 115 kV), Wheeler Ridge Junction Station, Kern PP 115 kV Area Reinforcement, Midway-Kern PP#1, #3 & #4 230 kV Line Capacity Increase, replacement of limiting equipment on Kern PWR 115/230 kV #3 transformer bank as well as the installation of a special protection scheme (SPS) as part of the already approved Kern PP 230 kV Area Reinforcement Project to mitigate overload of the Kern PP 230/115 kV #3 transformer bank following Kern PP 230/115 kV #4 & #5 bank outage (double transformer outage) address the observed concerns. Consequently, there were no recommendations for new projects to be considered for approval in the PG&E's Kern division in this planning cycle as there were no new concerns identified that merit new system upgrades. A detailed list of the facilities that did not meet the required NERC planning performance criteria including their corresponding loading levels is provided in Appendix C.

In the interim, all the previously identified action plans and operating procedures including the Semitropic and Famoso summer operating procedures will continue to be in effect until the corresponding approved projects are in-service. PG&E will be reviewing these existing operating procedures, monitoring the area conditions and coming up with appropriate action plans if needed.

2.5.8 Central Coast and Los Padres Areas

2.5.8.1 *Area Description*



The PG&E Central Coast division is located south of the Greater Bay Area and extends along the Central Coast from Santa Cruz to King City. The green shaded portion in the figure on the left depicts the geographic location of the Central Coast and Los Padres areas.

The Central Coast transmission system serves Santa Cruz, Monterey and San Benito counties. It consists of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Most of the customers in the Central Coast division are supplied via a local transmission system out of the Moss Landing Substation. Some of the key substations are Moss Landing, Green Valley, Paul Sweet, Salinas, Watsonville, Monterey, Soledad and Hollister. The local transmission systems are the following: Santa Cruz-Watsonville, Monterey-Carmel and Salinas-Soledad-Hollister sub-areas, which are supplied via 115 kV double circuit tower lines. King City, also in this area, is supplied by 230 kV lines from the Moss Landing and Panoche substations, and the Burns-Point Moretti sub-area is supplied by a 60 kV line from the Monta Vista Substation in Cupertino. Besides the 60 kV transmission system interconnections between Salinas and Watsonville substations, the only other interconnection 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 total installed generation capacity is 2,900 MW, which includes the 2,600 MW Moss Landing Power Plant, which is scheduled for compliance with the SWRCB Policy on OTC plants by the end of 2020.

The PG&E Los Padres division is located in the southwestern portion of PG&E's service territory (south of the Central Coast division). Divide, Santa Maria, Mesa, San Luis Obispo, Templeton, Paso Robles and Atascadero are among the cities in this division. The city of Lompoc, a member of the Northern California Power Authority, is also located in this area. Counties in the area include San Luis Obispo and Santa Barbara. The 2400 MW Diablo Canyon Nuclear Power Plant (DCPP) is also located in Los Padres. Most of the electric power generated from DCPP is exported to the north and east of the division through 500 kV bulk transmission lines; in terms of generation contribution, it has very little impact on the Los Padres division operations. 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. With the retirement of the Morro Bay Power Plants, the present total installed generation capacity for this area is approximately 950 MW. This includes the recently installed photovoltaic solar generation resources in the Carrizo Plains, which includes the 550 MW Topaz and 250 MW California Valley Solar Ranch facilities on the Morro Bay-Midway 230 kV line corridor. The total installed capacity does not include the 2400 MW DCPP output as it does not serve the load in the PG&E's Los Padres division.

Load forecasts indicate that the Central Coast and Los Padres areas summer peak demand will be 730 MW and 574 MW, respectively, by 2020. By 2025, the summer peak loading for Central

Coast and Los Padres is forecasted to rise to 709 MW and 587 MW, respectively. Winter peak demand forecasts in Central Coast are approximately 655 MW in 2020 and 652 MW in 2025. The area along the coast has a dominant winter peak load profile in certain pockets (such as the Monterey-Carmel sub-area). The winter peak demands in these pockets could be as high as 10 percent more than their corresponding summer peaks. Accordingly, system assessments in these areas included technical studies using load assumptions for summer and winter peak conditions.

2.5.8.2 *Area-Specific Assumptions and System Conditions*

The study of the Central Coast and Los Padres areas 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 study of the Central Coast and Los Padres areas are provided below.

Generation

Generation resources in the Central Coast and Los Padres areas consist of market, qualifying facilities and self-generating units. Table 2.5-18 lists a summary of the generation in the Central Coast and Los Padres area at present with a detailed generation list provided in Appendix A.

Table 2.5-18: Central Coast and Los Padres area generation summary

Generation	**Capacity (MW)**
Solar	800
Thermal	2,916
Nuclear	2,400
Total	**6,116**

Load Forecast

Loads within the Central Coast and Los Padres areas reflect a coincident peak load for 1-in-10-year forecast conditions for each peak study scenario. Tables 2.5.19 and 2.5.20 show loads modeled for the Central Coast and Los Padres areas assessment.

Table 2.5-19: Load forecasts modeled in the Central Coast and Los Padres area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area	Summer Peak (MW)		
	2017	2020	2025
Central Coast	712	730	709
Los Padres	562	574	587
Total	**1364**	**1401**	**1443**

Table 2.5-20: Load forecasts modeled in the Central Coast and Los Padres area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area	Winter Peak (MW)		
	2017	2020	2025
Central Coast	655	660	652
Los Padres	423	428	429
Total	**1135**	**1159**	**1168**

2.5.8.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results, if any, are documented in Appendix B. The summer and winter peak reliability assessment for the PG&E Central Coast area and the summer reliability assessment for the Los Padres area performed in 2015 confirmed the previously identified reliability concerns and their associated mitigation plans. The concerns are thermal overloads, low voltages, and voltage deviations, which are mostly under NERC Category P6 contingency conditions. Similar to the previous year's studies, no NERC Category P0 reliability concerns were identified.

The previously approved projects, which include the Estrella Substation, Midway-Andrew 230 kV, Mesa and Santa Maria SPS in the Los Padres division, and Watsonville 115 kV Voltage Conversion, Crazy Horse Substation, Natividad Substation, and Moss Landing 230/115 kV Transformer Replacement in the Central Coast division mitigate a number of thermal overloads and voltage concerns under the identified Category P6 contingencies. The Watsonville 115 kV

Voltage Conversion Project adds a new 115 kV interconnection source to the Santa Cruz area from Crazy Horse. The Midway-Andrew 230 kV Project adds an additional source from Midway 230 kV Substation to the Mesa and Divide 115 kV system via the Andrew Substation. The Estrella Substation Project provides Paso Robles Substation with more reinforced 70 kV sources from the Templeton and Estrella 230 kV system. It addresses the thermal overloads and voltage concerns in the Templeton 230 kV and 70 kV systems following Category P1 contingency due to loss of either the Templeton 230/70 kV #1 Bank or the Paso Robles-Templeton 70 kV Line as well as Category P6 contingency condition involving loss of Morro Bay-Templeton and Templeton-Gates 230 kV lines. There were no new concerns identified that merit new system upgrades. Consequently, there were no recommendations for new projects to be considered for approval for the PG&E’s Central Coast and Los Padres divisions in this planning cycle.

2.5.9 Review of previously approved projects

As a part of the 2015-2016 transmission planning process, the ISO conducted a separate and standalone review of a large number of local area low voltage transmission projects in the PG&E service territory that were predominantly load forecast driven and whose approvals dated back a number of years. In reviewing the potential to cancel those projects, the results set out in sections 2.5.1 through 2.5.8 were reviewed to ensure that cancelling those projects did not affect sections 2.5.1 through 2.5.8 results and recommendations. The review was due to changes of assumptions, predominantly current load forecast projects that differed considerably from the load forecasts that were in place when the projects were originally approved, that primarily affected localized areas within the planning area. The ISO reviewed the need based upon:

- Transmission planning process and applicable reliability standards (NERC standards, WECC regional criteria and ISO Planning Standards)
- Local Capacity Requirements
- Deliverability requirements for generators with executed interconnection agreements

The analysis was conducted on the topology of the system the in 2017 base case (with only projects already moving forward in-service) and with load levels escalated to the 2025 forecast. The assessment done with and without AAEE (similar to the sensitivity studies conducted in this planning cycle.) While this approach does not emulate all of the resource and bulk system changes expected to occur by 2025, it does provide a reasonable basis for assessing local area issues. Further, the results of this analysis were then reviewed with the results of the analysis set out in sections 2.5.1 through 2.5.8 for consistency.

There were 13 projects that were found to be no longer required based on reliability, local capacity requirements and deliverability assessments and that are recommended to be cancelled:

- Bay Meadows 115 kV Reconductoring (Greater Bay Area)
- Cooley Landing - Los Altos 60 kV Line Reconductor (Greater Bay Area)
- Del Monte - Fort Ord 60 kV Reinforcement Project (Central Coast & Los Padre)
- Kerckhoff PH #2 - Oakhurst 115 kV Line (Fresno)
- Mare Island - Ignacio 115 kV Reconductoring Project (North Coast & North Bay)
- Monta Vista - Los Altos 60 kV Reconductoring (Greater Bay Area)
- Monta Vista - Wolfe 115 kV Substation Equipment Upgrade (Greater Bay Area)
- Newark - Applied Materials 115 kV Substation Equipment Upgrade (Greater Bay Area)
- Potrero 115 kV Bus Upgrade (Greater Bay Area)
- Taft 115/70 kV Transformer #2 Replacement (Kern)
- Tulucay 230/60 kV Transformer No. 1 Capacity Increase (North Coast & North Bay)
- West Point - Valley Springs 60 kV Line Project (Second Line) (Central Valley)
- Woodward 115 kV Reinforcement (Fresno)

The remaining previously approved transmission projects were found to continue to be required to meet the applicable reliability, local capacity requirements and deliverability needs.

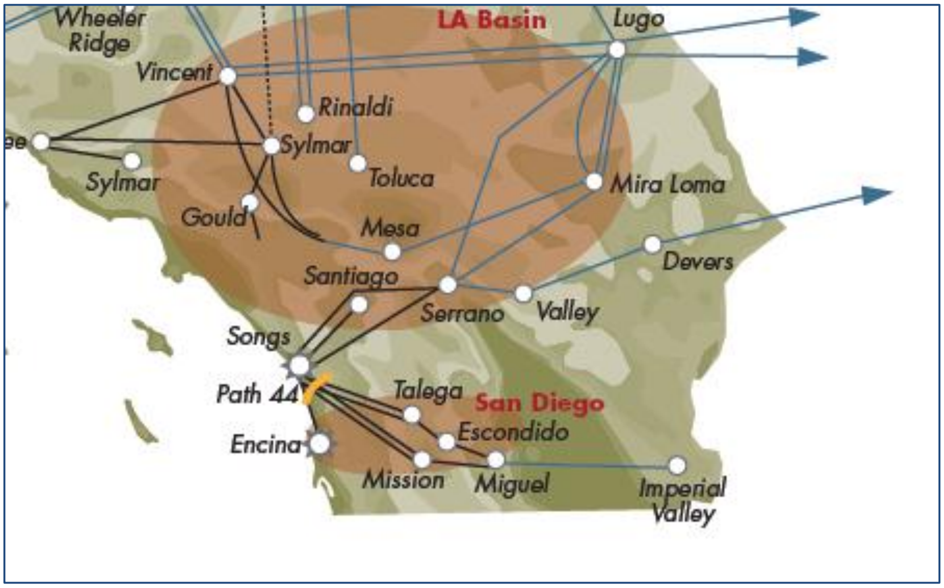
The ISO will continue to assess in future planning cycles the need to reassess previously approved transmission projects if there are material changes in the assumptions associated with the need for previously approved projects.

2.6 Southern California Bulk Transmission System Assessment

2.6.1 Area Description

The southern California bulk transmission system primarily includes the 500 kV transmission systems of Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) companies and the major interconnections with Pacific Gas and Electric (PG&E), LA Department of Water and Power (LADWP) and Arizona Public Service (APS). Figure 2.6–1 provides an illustration of the southern California's bulk transmission system.

Figure 2.6–1: Map of ISO Southern California Bulk Transmission System



SCE serves over 14 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. Most of the SCE load is located within the Los Angeles Basin. The CEC's load growth forecast for the entire SCE area is about 150 MW[40] per year. The CEC's 1-in-10 load forecast includes the SCE service area, and the Anaheim Public Utilities, City of Vernon Light & Power Department, Pasadena Water and Power Department, Riverside Public Utilities, California Department of Water Resources and Metropolitan Water District of southern California loads. The 2025 summer peak forecast load, including system losses, is 27,381 MW. SCE area load is served by generation that includes a diverse mix of renewables, qualifying facilities, hydro and gas-fired power plants, as wells as by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and Desert Southwest.

SDG&E provides service to 3.4 million consumers via 1.4 million electric meters in San Diego and southern Orange counties. Its service area encompasses 4,100 square miles from southern

[40] Based on the CEC-adopted California Energy Demand Forecast 2015-2025 (Updated Forecast) – Mid Demand Baseline Case, Low-Mid AAEE Savings, January 2015 version

Orange County to the U.S. and Mexico border. The existing points of imports are the South of SONGS[41] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2025 summer peak forecast load for the SDG&E area including system losses is 5,393 MW. Most of the SDG&E area load is served by generation that includes a diverse mix of renewables, qualifying facilities, small pumped storage, and gas-fired power plants. The remaining demand is served by power transfers into San Diego via points of imports discussed above.

Electric grid reliability in southern California has been challenged by the retirement of the San Onofre Nuclear Generating Station and the expected retirement of power plants using ocean or estuarine water for cooling due to OTC regulations. In total, approximately 9,291 MW of generation (7,045 MW gas-fired generation and 2,246 MW San Onofre) in the region is affected. Further, consistent with the CPUC's assigned commissioner's ruling (ACR) addressing assumptions for the 2014 LTPP and 2015-2016 transmission plan[42] (the 2015-2016 LTPP/TPP ACR), the ISO has also taken into account the potential retirement of over 1,100 MW of older non-OTC generation in the area.[43]

To offset the retirement of SONGS and OTC generation, the CPUC in the 2012 LTPP Track 1 and Track 4 decisions authorized SCE to procure between 1900 and 2500 MW of local capacity in the LA Basin area and up to 290 MW in the Moor Park area, and SDG&E to procure between 800 and 1100 MW in the San Diego area.[44] In May 2015, the CPUC issued Decision D.15-05-051 that conditionally approved SDG&E's application for entering into a purchase power and tolling agreement (PPTA) with Carlsbad Energy Center, LLC, for 500 MW. The Decision also required the residual 100 MW of requested capacity to consist of preferred resources or energy storage. In November 2015, the CPUC issued Decision D.15-11-041 to approve, in part, results of SCE's Local Capacity Requirements Request for Offers for the Western LA Basin. The Decision permitted SCE to enter into a PPTA for a total of 1812.6 MW of local capacity that includes 124.04 MW of energy efficiency, 70 MW of demand response, 37.92 MW of renewable (solar) distributed generation, 263.64 MW of energy storage, and 1382 MW of conventional (gas-fired) generation. In this analysis, the ISO considered the authorized levels of procurement and then focused on the results thus far in the utility procurement process – which, in certain cases, is less than the authorized procurement levels.

As set out below, preferred resources and storage are expected to play an important role in addressing the area's needs. As the term "preferred resources" encompasses a range of measures with different characteristics, they have been considered differently. Demand side resources such as energy efficiency programs are accounted for as adjustments to loads, and supply side resources such as demand response are considered as separate mitigations. Further, there is a higher degree of uncertainty as to the quantity, location and characteristics of these preferred resources, given the unprecedented levels being sought and the expectation that

[41] The SONGS was officially retired on June 7, 2013.

[42] Rulemaking 13-12-010 "Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long-Term Procurement Plan and 2015-2016 CAISO TPP" on March 4, 2015, with minor updates issued in October, 2015.

[43] Includes Etiwanda, Long Beach, and Cabrillo II generating facilities.

[44] The CPUC Decisions D.13-02-015 (Track 1 for SCE), D.14-03-004 (Track 4 for SCE), D.13-03-029/D.14-02-016 (Track 1 for SDG&E), and D.14-03-004 (Track 4 for SDG&E)

increased funding over time will result in somewhat diminishing returns. While the ISO's analysis focused primarily on the basic assumptions set out below in section 2.6.2, the ISO has conducted and will continue to conduct additional studies as needed on different resources mixes submitted by the utilities in the course of their procurement processes.

In summary, the focus of the 2015-2016 transmission plan studies for this area was to assess the adequacy of approved transmission and resource procurement authorizations with updated forecast assumptions, and to assess the effectiveness of the procurement in meeting the identified reliability needs in the area and potential alternatives in the event that the approved procurement is determined to be insufficient.

2.6.2 Area-Specific Assumptions and System Conditions

The analysis of the southern California bulk transmission system was performed consistent with the general study methodology and assumptions described in section 2.3.

The starting base cases and contingencies that were studied as part of this assessment are available on the ISO-secured website. In addition, specific assumptions and methodology that were applied to the southern California bulk transmission system study area are provided below. Two types of assessments were evaluated: (a) the regional bulk transmission reliability, which covers all of the bulk transmission facilities in southern California, including but not restricted to the local capacity requirement (LCR) areas; and (b) the long-term LCR studies for the three identified LCR areas in southern California (i.e., Big Creek/Ventura, LA Basin, and San Diego-Imperial Valley). The regional bulk reliability assessment's objective was to evaluate reliability of the entire bulk transmission system under the ISO operational control in a region that has a larger area footprint than the LCR areas. Due to load diversity of a larger footprint study area, a 1-in-5 load forecast was modeled for the studies. For the LCR area and sub-area assessment, a 1-in-10 load forecast was modeled because the study area has similar climate characteristics and is more likely to have peak demand at the same time. In an LCR assessment, local resource adequacy was evaluated to determine if the resources within the study area are adequate to meet applicable NERC, WECC and ISO planning criteria. A brief summary of the long-term LCR assessment is provided in section 2.6.3, and section 3.1.2 and Appendix D provide further discussion and detailed results.

Generation

The bulk transmission system studies use the same set of generation plants that are modeled in the local area studies. A summary of generation is provided in each of the local planning area sections within the SCE and SDG&E local areas.

Load Forecast

The regional bulk transmission summer peak base cases assume the CEC 1-in-5 year load forecast while the LCR assessment included 1-in-10 year load forecast for the LCR areas only. These forecast demand include system losses. Table 2.6-1 provides a summary of the SCE and SDG&E area load used in the regional bulk transmission summer peak assessment. Table 2.6-2 provides a summary for the 1-in-10 year load forecast for the LCR areas studied (i.e., Big Creek/Ventura, LA Basin and San Diego-Imperial Valley).

The summer light, summer off-peak and fall peak base cases assume approximately 50 percent, 65 percent and 84 percent of the coincident 1-in-2 year load forecast, respectively.

Table 2.6-1: Summer Peak load forecasts (1-in-5)[45] used in the regional Southern California bulk transmission system assessment

	2017 (MW)	2020 (MW)	2025 (MW)
SCE Area	25,134	25,688	26,333
SDG&E Area	5,136	5,235	5,236
Total	30,270	30,923	31,569

Table 2.6-2: Summer Peak load forecasts (1-in-10)[46] used in the long-term LCR assessments for the southern California LCR areas

LCR Areas	2025 (MW)
Big Creek/Ventura	3,890
LA Basin	22,382
San Diego	5,393

In addition to the long-term LCR studies, the ISO also performed a sensitivity LCR assessment for the LA Basin and San Diego LCR areas without the Mesa Loop-In Project in 2021 time frame. This is to analyze the potential reliability impacts with the project delayed, and the OTC generating units in the LA Basin retired to comply with the State Water Resources Control Board policy on OTC plants. In addition to identifying potential reliability concerns, the ISO also evaluated potential interim mitigation which includes extension of the use of some of the OTC generating units until the Mesa Loop-In Project is completed and placed online. The results of this sensitivity assessment are included in section 3.1. Table 2.6-3 below includes the 1-in-10 summer peak demand forecast from the CEC for the intermediate 2021 timeframe.

[45] California Energy Demand Forecast 2015-2025 (Updated Forecast) – Mid Demand Baseline Case, Low-Mid AAEE Savings, January 2015 version

[46] California Energy Demand Forecast 2015-2025 (Updated Forecast) – Mid Demand Baseline Case, Low-Mid AAEE Savings, January 2015 version

Table 2.6-3: Summer Peak load forecasts (1-in-10)[47] used in the intermediate-term LCR assessments for the LA Basin and San Diego LCR areas

LCR Areas	2021 (MW)
LA Basin	21,933
San Diego	5,418

2012 LTPP Tracks 1 and Track 4 Resource Assumptions

In the 2012 LTPP Tracks 1 and Track 4 decisions, the CPUC authorized the respective utilities to procure between 1900 and 2500 MW of local capacity in the LA Basin area, up to 290 MW in the Moor Park sub-area and between 800 and 1100 MW in the San Diego area to offset the retirement of SONGS and OTC generation. The actual amount, mix and location of the local capacity additions are from the utilities' request for offers (RFOs) and ultimately the CPUC decisions approving purchase power and tolling agreements. Table 2.6-4 summarizes the assumptions used in the current studies, based on the CPUC-approved procurement for SDG&E and SCE for the San Diego and Western LA Basin, respectively. The procurement for the Moorpark sub-area was selected by SCE for the CPUC review process and is ongoing at this time. For SDG&E, the CPUC approved 800 MW of conventional (gas-fired) resources, but the procurement for preferred resources is ongoing and will be submitted to the CPUC for consideration and decisions at a future timeframe.

Table 2.6-4: Summary of 2012 LTPP Tracks 1 & 4 Procurement (1)

Area Name	Total (MW)	Gas-fired generation (MW)	Preferred Resources and Energy Storage (MW)	Assumed In-Service Date
SCE Western LA Basin Area	1882.6	1382	500.6(1)	2021
SCE Moorpark Area	274.16	262	12.16	2021
SDG&E Area	1100	800	300(1)	2017
Total	**3256.76**	**2444**	**812.76**	

1. The long-term LCR study presented in this transmission plan used the latest updated assumptions for Track 1 and Track 4 local capacity additions based on utility procurement approvals and activities to date. See section 3.1.2 for details.

[47] California Energy Demand Forecast 2015-2025 (Updated Forecast) – Mid Demand Baseline Case, Low-Mid AAEE Savings, January 2015 version

In 2015, the CPUC issued two important decisions regarding procurement selection submissions SDG&E and SCE made to meet the 2012 LTPP Tracks 1 and 2 decisions. In May 2015, the CPUC issued Decision D.15-05-051 allowing SDG&E to enter into a purchase power and tolling agreement with NRG for the 500 MW Carlsbad Energy facility. In addition, the Decision also converted the requested 100 MW residual capacity from gas-fired resources to preferred resources or energy storage. In November 2015, the CPUC issued Decision D.15-11-041 allowing SCE to enter PPTAs with various parties for 124.04 MW of energy efficiency, 5 MW of DR[48], 37.92 MW of solar distributed generation (DG), 263.64 MW of energy storage, and 1382 MW of gas-fired generation. SDG&E will submit its procurement selection to satisfy the preferred resources authorizations to the CPUC for decisions at a future date. In late 2014, SCE submitted Application 14-11-016 for 274.16 MW in the Moorpark sub-area from the LCR RFO, which includes 6 MW for energy efficiency, 5.66 MW for solar DG, 0.5 MW for energy storage and 262 MW for gas-fired generation. The ISO analyzed the authorized amounts and the approved procurements of local resources in the LA Basin and San Diego areas, as well as submitted procurement (for the CPUC decisions) for the Moorpark sub-area in the long-term LCR analysis described in chapter 3 and Appendix D.

Energy Efficiency

The CEC load forecast includes the impact of committed energy efficiency programs. In addition, incremental energy efficiency (also known as Additional Achievable Energy Efficiency or AAEE) was also assumed and modeled for the local reliability studies based on the CEC low-mid projection adjusted to include distribution loss avoidance. Table 2.6-5 summarizes the total AAEE modeled in the local reliability study cases.

Table 2.6-5: Summary of AAEE Assumptions

	2017 (MW)	**2020 (MW)**	**2025 (MW)**
SCE Area	499	877	1,568
SDG&E Area	118	213	401
Total	617	1,090	1,969

There have been several positive steps to increase energy efficiency objectives. In Rulemaking 13-11-005 (Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues) the CPUC began to shift utility energy efficiency programs to a rolling three year funding cycle, thus promoting greater program durability. Further, the CPUC's decision[49] of October 16, 2014 in that proceeding established funding for 2015 and more importantly also established funding at the same (*i.e.,* 2015) level

[48] The original requested amount was 75 MW DR, but 70 MW was denied due to its characteristic being related to behind-the-meter gas-fired distributed generation.

[49] CPUC Decision 14-10-046: DECISION ESTABLISHING ENERGY EFFICIENCY SAVINGS GOALS AND APPROVING 2015 ENERGY EFFICIENCY PROGRAMS AND BUDGETS (CONCLUDES PHASE I OF R.13-11-005)

through 2025, unless subsequently changed through future proceedings. Additionally, annual goals through 2025 will be included in post-processing by the Energy Commission to establish locational benefits going forward.

The CPUC rolling portfolio process for energy efficiency lends itself to continual review of each year's results, and modification to funding levels to ensure overall forecast objectives for energy efficiency are met. However, current measures do not provide the same level of tracking and more definitive forecasting of achieving these goals as other types of projects like transmission lines or generating stations. The high reliance on significant volumes of additional achievable energy efficiency in managing reliability in southern California (and in the LA Basin and San Diego areas in particular) necessitates monitoring the development of this resource to be assured that it is developing and performing according to the forecast assumptions that the ISO is relying upon for long term planning purposes. The ISO looks forward to continued dialog with the CEC and CPUC in this regard.

Given the inherent forecast uncertainty absent more definitive tracking and the general concern that increased funding is generally expected to be progressively less effective as higher levels of funding are employed, the ISO took prudent and necessary steps in the previous 2014-2015 Transmission Plan to explore transmission alternatives (and their associated timelines) so that feasible options may be considered (together with other conventional or alternative resources, as appropriate) if forecasted resources fail to meet their planning targets. This was discussed in more detail in section 2.6.4.2 in last year's transmission plan.

Demand Response (DR)

The ISO understands the CEC load forecast includes the impact of non-event-based demand response programs, such as real-time or time-of-use pricing, and event-based programs, such as critical peak pricing and peak time rebates.

The ISO has assumed in the study base case that approximately 200 MW of these resources, located in the Orange County and San Diego area, will be locally dispatchable and will have the necessary characteristics to be applicable as transmission mitigation resources – in particular, a fast enough response to dispatch instructions from the ISO (not exceeding 20 minutes). The ISO understands this entails repurposing existing demand programs that were designed to address system resource issues but lacked the required performance attributes.

This baseline study assumption is consistent with the CPUC scoping ruling and memo for the LTPP Track 4 proceeding (R.12-03-014) in which modest amounts of repurposed DR programs were assumed as a reasonable study basis. These include fast responding DR assumptions for the post first contingency as listed in the Summary Table of the SONGS Study Area Input Assumptions of the CPUC scoping ruling for the LTPP track 4 process. These are "fast" DR programs located in the most effective locations in the southwestern LA Basin and San Diego areas and can respond within 30 minutes or less, including notification time.

The ISO has also included the utility-provided demand response in the power flow study models as the ceiling amount identified in the CPUC's 2014 LTPP and 2015-2016 TPP ACR, which is the total of all of the existing programs that could be reasonably considered for repurposing. The ACR identified for potential repurposing up to 1,141 MW of existing DR in the SCE and SDG&E areas.

Excluding resources in SCE's service area that are outside of the LA Basin, this results in about 911 MW for the combined LA Basin and San Diego area.

The baseline amount continues to reflect the reasonable basis for long term planning at this time as the ISO is not aware of clear direction to the utilities to initiate the repurposing of these resources, or results of the utilities' efforts to repurpose the existing DR programs for transmission-related use.

Demand response that is procured by the utilities in response to the 2012 LTPP Tracks 1 and Track 4 decisions is assumed to be incremental to this baseline amount.

Table 2.6-6 provides the amount of existing demand response that were modeled in the study cases. The DR amounts were modeled offline in the initial study cases under normal conditions and were considered as mitigation once reliability issues were identified. The ISO understands the amounts reflect average rather than more dependable load impact estimates of the DR programs. Actual location is not available for some of the DR resources in which case the amounts were modeled at assumed locations, which were provided by the utilities.

Table 2.6-6: Summary of Existing DR Assumptions

Service Area	2017 (MW)	2020 (MW)	2025 (MW)
SCE Area	Same amount as 2025		1125
SDG&E Area			17
Total			1142

Distributed Generation

The CEC load forecast accounts for all major programs designed to promote behind-the-meter solar and other types of self-generation. The ISO understands the forecast also includes power plants that were explicitly reported to the CEC by the owners as operating under cogeneration or self-generation mode. In addition, the ISO has modeled incremental grid-connected DG as provided by the CPUC for the Commercial-Interest RPS Portfolio (i.e., trajectory scenario). Table 2.6-7 summarizes the grid-connected RPS DG that was modeled in the study cases. The DG amounts were modeled offline in the initial study cases under normal conditions and were considered as mitigation once reliability issues were identified. For the long-term LCR studies, the RPS DG are dispatched using the 0.47 (or 47 percent) peak impact factor per the Small Solar PV Operational Attributes from the CPUC ACR document on planning assumptions for the 2014 LTPP and ISO 2015-2016 TPP power flow studies.

Table 2.6-7: Summary of RPS DG Assumptions (Installed Nameplate Capacity)

Service Area	2017 (MW)	2020 (MW)	2025 (MW)
SCE Area	393	421	565
SDG&E Area	92	108	143
Total	**485**	**529**	**708**

Previously Approved Transmission Projects

A number of complementing transmission projects have been approved by the ISO in past transmission planning cycles to address the reliability in this area. All of those projects are modeled in this analysis, assuming those projects are completed on their current schedules. The ISO is not aware of any material change in circumstances that questions the continued need for those projects, and none have been identified by stakeholders through the numerous stakeholder consultation efforts conducted as part of this planning cycle.

Path Flow Assumptions

Table 2.6-8 lists the transfers modeled on major paths in the southern California assessment.

Table 2.6-8: Path Flow Assumptions

Path	SOL/Transfer Capability (MW)	17SP (MW)	20SP (MW)	25SP (MW)	17OP (MW)	20LL (MW)
Path 26	4000 (N-S)	3952	3987	3997	19	2804
PDCI	3100	3100	3100	3100	600	2702
SCIT	17,870	16,427	18,597	20,209	6835	10,007
Path 45	800 (S-N) 408 (N-S)	250 (N-S)	250 (N-S)	250 (N-S)	300 (S-N)	0
Path 46 (WOR)	11,200	7742	9716	8805	4263	3421
Path 49 (EOR)	9600	4856	6163	5076	2502	692

2.6.3 Assessment and Recommendations

2.6.3.1 *Conclusions and Assessments*

The ISO conducted a detailed planning assessment of the southern California Bulk Transmission System based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The assessment and recommendations also draw upon the findings of the long term local capacity reliability study found in chapter 3 and Appendix D.

The ISO has relied on the resource assumptions noted earlier for this assessment. As described above, there is currently some uncertainty associated with those assumptions, particularly the final amount and locations of the residual preferred resources procurement selection that SDG&E is to file with the CPUC for decisions, and the tracking of the amount and locations of AAEE that would materialize in the future. Nevertheless, the study results will be updated in the next planning cycle based on the latest available information available at the time.

The ISO assessment of the southern area bulk transmission system yielded the following conclusions.

Potential Deficiency in Local Capacity Requirements under Base Case Assumptions

The long term local capacity requirements analysis set out in chapter 3 and Appendix D indicates that the currently-authorized resource procurement and previously approved transmission may not be adequate without driving further local resource needs or minor transmission upgrades at this time. The reason for potential need for additional resources, either local capacity additions or transmission upgrades, is due to contingency loading concerns on the south of Mesa 230 kV lines (i.e., Mesa-Laguna Bell No. 1 230kV line and Mesa-Redondo 230 kV line) under overlapping P6 (i.e., N-1-1) contingencies. The most limiting constraint is the Mesa-Laguna Bell No. 1 230 kV line loading. Both capacity additions and transmission upgrades were evaluated as potential mitigations. In Appendix D, in the Western LA Basin discussion, 13 options were evaluated for mitigating this overloading concern. In this planning cycle, the ISO modeled the RPS renewable resources located outside of the LA Basin LCR area. This modeling approach results in an additional 2000 MW of renewable generation dispatch impacting flow into the LCR area compared to the previous long term LCR studies that modeled RPS resources outside of the LCR area at lower output values. Both the previous and current power flow models for the long-term LCR assessment model RPS renewable resources located internally in the LCR area with net qualifying capacity (NQC) values. The vast majority of these are solar DG.

Potential mitigation options that appear to be feasible to implement and mitigate identified overloading concerns are to (1) procure more resources or (2) to install minor transmission upgrades along with a reduced amount of additional resource procurement:

1. Local capacity resource procurement option – with this option the mitigation is entirely composed of adding new resources without new transmission upgrades. It consists of an additional 692 MW of preferred resources or energy storage at effective location(s) is to be procured beyond the recent CPUC approved procurement for the Western LA Basin sub-area. In addition, an additional 286 MW of existing demand response beyond

the baseline amount of 189 MW needs to be repurposed. This option would mitigate identified loading concern but does not have margin for future load growth.

2. Transmission upgrade options – with these options transmission upgrades are identified that would reduce the amount of additional resources needed. A number of small-scale transmission upgrades were evaluated. These are summarized in table D7 in the Appendix D. The following are the more effective and potentially lower cost transmission alternatives that were evaluated:
    - opening Mesa 500/230kV Bank #2 under contingency conditions;
    - re-arranging Mesa-Laguna Bell 230kV Lines and Opening Laguna Bell-La Fresa 230 kV line under contingency; and
    - installing 10-Ohm series reactors[50] on the Mesa-Laguna Bell #1 230 kV line and potentially the Mesa-Redondo 230kV line in the future (beyond 10-year horizon for this line).

Both options 1 and 2 require the development of 250 MW of preferred resources in the San Diego area, which are within the authorized ranges already approved by the CPUC as part of the track 1 and track 4 decisions.[51]

Of the above three transmission options, installing 10-Ohm series reactors[52] on the Mesa-Laguna Bell #1 230 kV line and potentially the Mesa-Redondo 230kV line, the third transmission option listed above, appears to have the least risk of unintended consequences and potentially has the lowest cost. This transmission upgrade option also would be less costly and more effective in mitigating the potential loading concern than the option for additional local capacity resource procurement. More details are provided in Appendix D.

Thermal Overload and Voltage Stability Concerns Associated with Single and Overlapping Outages in Sunrise Powerlink and Southwest Powerlink

The reliability assessment identified various thermal overloads and transient voltage stability concerns associated with the Southwest Powerlink (SWPL) and Sunrise Powerlink (SPL) systems under various Category P1, P2, P3, P4, P6, and P7 contingencies. These concerns are generally similar to what are described in the section 2.9 San Diego Gas & Electric Local Area Assessment. With the Imperial Valley phase shifting transformers in-service and the SWPL and SPL series capacitor banks bypassed as per previous planning cycles, however, all the reliability concerns can be managed and mitigated by relying on operational mitigations or modified SPS. For more details on these concerns and the recommended mitigations please refer to section 2.9.

Various transmission upgrade projects and back-up alternatives were submitted to reinforce the SWPL and SPL systems through the 2015 Request Window. These projects are not found to be needed in this planning cycle, and the ISO will continue to monitor reliability needs in the San

[50] Variation of this option includes thyristor-controlled series reactor to be inserted upon occurrence of the second N-1 contingency under peak load conditions. This option would have higher cost than the permanently installed series reactor, but its advantage is to preserve the original line impedance for lower losses in the pre-contingency condition.
[51] CPUC Decisions D.14-03-004 (issued March 14, 2014) and D.15-05-051 (issued May 29, 2015)
[52] Variation of this option includes thyristor-controlled series reactor to be inserted upon occurrence of the second N-1 contingency under peak load conditions. This option would have higher cost than the permanently installed series reactor, but its advantage is to preserve the original line impedance for lower losses in the pre-contingency condition.

Diego bulk system and consider exploring the proposals' potential economic or policy-driven benefits in future planning cycles.

The synchronous condensers already approved and proceeding in the Orange County and northern San Diego areas for the long term provide sufficient long-term dynamic reactive supports for the area, particularly when the OTC generating units are retired in the LA Basin and San Diego areas, Coupled with lower demand forecast, the post-transient voltage instability concern is no longer a primary concern as long as the AAEE projection materializes as forecast.

Thermal Overload and Voltage Stability Concerns Associated with Overlapping Outage of Sunrise Powerlink and Southwest Powerlink without System Re-Adjustment

For all study years, overlapping outages of the East County-Miguel (TL 50001) or East County-Imperial Valley (TL 50004) and Ocotillo-Suncrest (TL 50003) or Ocotillo-Imperial Valley (TL 50005) 500 kV lines without system re-adjustment after the initial contingency resulted in thermal overloads on the SDG&E-CFE tie lines as well as CFE transmission lines within the La Rosita-Tijuana 230 corridor, and potential voltage instability unless mitigated. The voltage instability occurred when the Otay Mesa-Tijuana 230 kV line was tripped by the existing CFE SPS due to the thermal overloads on the La Rosita-Tijuana 230 kV corridor. The existing South of SONGS Safety Net, which is enabled when all of the 500 kV lines are in service, will ensure voltage stability if the overlapping outages occur before system adjustments could be performed (Extreme Event condition). The ISO Operating Procedure 7820 provides the system adjustments (i.e., unit commitments) currently needed to maintain voltage stability following the N-1/N-1 condition.

For outages occurring with sufficient time to adjust the system after the first contingency and before the second – a P6 (N-1-1) condition – the following mitigations will be relied upon:

- In the short term (i.e., until the Imperial Valley phase shifting transformer is in-service), enabling the existing SDG&E 230 kV TL 23040 Otay Mesa-Tijuana SPS was recommended in the previous ISO 2014-2015 Transmission Plan[53] to address the thermal overload on the SDG&E-CFE tie lines following the overlapping SDG&E 500 kV line outages because the CFE's Valle-Costa path cross-tripping SPS is not designed to activate for overloads of the tie lines and the tie lines can overload even when loading on the La Rosita-Tijuana 230 kV corridor is within limits. The voltage stability issue associated with the cross-tripping of the Otay Mesa-Tijuana or Imperial Valley-La Rosita 230 kV lines following the overlapping SDG&E 500 kV line outages is addressed by dispatching available generation in the San Diego and LA Basin areas after the initial contingency in accordance with existing operating procedures.
- In the longer term, the approved Imperial Valley phase shifting transformer will be used in conjunction with available resources in the San Diego and LA Basin areas to mitigate the thermal overloads that trigger the CFE cross tripping scheme following the overlapping SDG&E 500 kV line outages. Mitigating the thermal overloads that trigger the CFE cross tripping scheme addressed the voltage stability concern. In the 2025 summer peak case in which OTC generators were removed from service, available preferred resources and

[53] Section 2.9 (San Diego area assessment)

energy storage were used in addition to available conventional generation to address the overloading and voltage stability concern.

Lugo-Victorville 500 kV Line Thermal Overload

The Lugo-Victorville 500 kV line is overloaded under P6 (L-1/L-1) contingency conditions in all summer peak cases. While the overloads in the 2017 and 2020 base cases could be mitigated by increasing generation and preferred resources in southern California and decreasing transfers (i.e., congestion management) on Path 46 (West of River path), the results indicate that local resources procured thus far may not be sufficient to mitigate the overload after the retirement of OTC generation. However, it is important to note that this overloading issue is not related to local area reliability issue but rather system reliability concern because the overloaded line (i.e., Lugo-Victorville 500 kV line) is a defined WECC path (Path 61) or an interface that is jointly connected with another balancing authority area (i.e., LADWP). Currently, the potential overloading on this path is being managed by congestion management. In the future (i.e., post 2020 time frame), with the retirement of the bulk of OTC generating units in the western LA Basin, as well as potential retirement of generating units in the eastern LA Basin due to its age (i.e., more than 40 years old), congestion management on this path will become much more challenging. Based on the recommendations that are discussed in sections 2.7.3 and 2.7.5, transmission upgrades, which include line terminal equipment upgrades and removal of line's ground clearance limitations, are needed. In order to implement this upgrade, coordination that includes cost allocation considerations will need to take place with LADWP. SCE submitted the joint Lugo-Victorville 500kV line upgrade project, which has an estimated in-service date of 12/31/2018, and the project is discussed in more detail below.

Request Window Proposals

The ISO received a number of specific high-voltage transmission solution proposals to the 2015 Request Window for the southern California bulk transmission system. The following table 2.6-9 provides a summary of these submittals and ISO comments as to whether the proposals were found to be needed and recommended in this planning cycle. Comments have also been provided as potential changes in circumstances that could call for these projects to be needed in future planning cycles. Further ISO comments and descriptions of the Request Window submittals are provided in the following summary table.

Table 2.6-9 – Summary of Proposed Projects Submitted into the 2015 Request Window

Transmission Solutions	**Type of Project**	**Submitted By**	**Is the Request Window Submittal Found Needed in the 2015-2016 Transmission Planning Cycle?**
Strategic Transmission Expansion Project or STEP (Hoober-SONGS HVDC Inter-tie)	Reliability	Regenerate Power	No
IID Midway-Devers 500 kV Inter-tie	Reliability	Regenerate Power	No
Lugo-Victorville 500 kV Line Upgrade	Reliability	SCE/LADWP	Yes
Lugo-Adelanto 500 kV Transmission Line	Reliability	NEET West	No
Mead-Adelanto Project (MAP) Upgrade	Reliability	StarTrans, LLC	No
Valley-Inland Powerlink	Reliability	SDG&E	No
Southern California Clean Energy Transmission Project (SoCal-CETP)	Reliability	Starwood Energy	No

Strategic Transmission Expansion Project or STEP (Hoober-SONGS HVDC Inter-tie)

The STEP Hoober-SONGS HVDC was submitted by Regenerate Power Company and involves the construction of 180-mile 1,100 MW 500kV HVDC line connecting IID's Hoober substation to joint SCE-SDG&E SONGS substation. The proposed project has an anticipated in-service date of June 1, 2021. The estimated cost is about $2 billion.

The ISO did not identify a reliability need nor generation deliverability need out of Imperial County for the STEP Hoober-SONGS HVDC Intertie in the current planning cycle and therefore this project was found to be not needed. However, the ISO may consider the concept in future planning cycles if the need for additional local capacity in the LA Basin / San Diego beyond the CPUC authorized Tracks 1 and 4 procurement or additional generation deliverability from the Imperial County beyond the 1,700-1,800 MW incremental to the existing generation is identified.

Midway-Devers 500kV Transmission Line

The Midway-Devers 500 kV Transmission line was submitted by Regenerate Power Company and involves the construction of a 90-mile 500 kV Transmission line connecting IID's Midway substation and SCE's Devers substation. The proposed project has an estimated cost of $386 million and a June 2021 in-service date.

The ISO did not identify a reliability need nor generation deliverability need out of Imperial County for the Devers-Midway 500 kV Transmission line in the current planning cycle and therefore this project was found to be not needed. However, the ISO may consider the concept in future planning cycles if the need for additional local capacity in the LA Basin and San Diego area beyond the CPUC authorized Tracks 1 and 4 procurement or additional generation deliverability from the Imperial County beyond the 1700-1800 MW incremental to the existing generation is identified.

Lugo-Victorville 500 kV Line Upgrade

The project includes SCE's portion of the upgrades for four (4) transmission towers and replacing terminal equipment at Lugo Substation. The estimated cost of SCE's portion is $18 million. The estimated cost of LADWP's portion is $16 million, including the terminal equipment upgrades at Victorville Substation. This is a joint project for both SCE and LADWP. The proposed project has an estimated in-service date of December 31, 2018.

The Lugo-Victorville 500 kV line is overloaded under P6 (L-1/L-1) contingency conditions in all summer peak cases. While the overloads in the 2017 and 2020 base cases could be mitigated by increasing generation and preferred resources in southern California and decreasing transfers (i.e., congestion management) on Path 46 (West of River path), the results indicated that local resources procured thus far may not be sufficient to mitigate the overload after the retirement of OTC generation. The overloading issue, identified in the system reliability assessment, is not related to local area reliability issue but rather system reliability concern because the overloaded line (i.e., Lugo-Victorville 500kV line) is a defined WECC path (Path 61) or an interface that is jointly connected with other balancing authority area (i.e., LADWP). Currently, the potential overloading on this path is being managed by congestion management. Post 2020 time frame, with the retirement of the bulk of OTC generating units in the western LA Basin, as well as potential retirement due to its age of 40-year old or more generating units in the eastern LA Basin, it would be much more challenging to perform congestion management on this path. The historical congestion cost since January 2013 is $43 million. Consistent with the recommendations that are discussed in sections 2.7.3 and 2.7.5, this project has been identified as needed. SCE submitted the joint Lugo-Victorville 500 kV line upgrade project, which has an estimated in-service date of 12/31/2018. As the project requires coordination with a neighboring balancing authority area and potential cost allocation issues, the ISO intends to commence that process with LADWP and SCE, and seek approval once the coordination has taken place.

Lugo-Adelanto 500 kV Transmission Line

NextEra Energy Transmission West, LLC (NEET West) proposed a new 17 mile 500 kV transmission line between Lugo 500 kV substation and Adelanto 500 kV substation. This project creates a new 500 kV interconnection between SCE-owned Lugo Substation and LADWP-owned Adelanto substation. This project has an estimated cost of $65 million and has an estimated in-service date of June 1, 2022. This is an alternative transmission solution to the joint SCE-LADWP's Lugo-Victorville 500 kV Line Upgrade Project.

The proposed project provides thermal overloading relief to the Lugo-Victorville 500kV line under contingency conditions. However, the proposed project includes construction of a new 500 kV line, which needs to go through an environmental review permit process, and has a higher cost, and a later proposed in-service date, than the recommended Lugo-Victorville 500 kV Upgrade Project. For these reasons, the project was not found to be needed.

Mead-Adelanto Project (MAP) Upgrade

The MAP Upgrade was submitted by Startrans IO LLC and involves the conversion of the MAP transmission line from its existing high-voltage alternating current (HVAC) to high-voltage direct current (HVDC), which increases its capacity from 1291 MW AC to 3500 MW DC. The project requires the construction of two HVDC converter terminals: one near the Marketplace Substation in Southern Nevada and the second near the Adelanto Substation in southern California. The project also includes AC system upgrades around the converter terminals to reliability integrate the new transmission capacity into the transmission system. The estimated cost of the project is $1.11 billion. The proposed in-service date is January 2022.

The ISO did not identify a reliability need for the Mead-Adelanto Project (MAP) upgrade in the current planning cycle. However, the ISO may consider the concept in future planning cycles if the need for increased transmission capacity across the Eldorado-Lugo corridor is identified. Please refer to chapter 5 regarding economic study request for this project.

Southern California Clean Energy Transmission Project (SoCal-CETP)

The SoCal-CETP was submitted by SoCal-CETP Holdings, LLC, and involves building a transmission superhighway of 500 kV high-voltage alternating current (HVAC) overhead, underground and subsea +/- 500 kV high-voltage direct current (HVDC) transmission lines, and HVDC converter stations that would connect the Miguel substation to the Encina Huntington Beach substations. Total transmission mileage is about 148 miles. The proposed project has an estimated cost of $2.4-$2.85 billion, with an estimated in-service date of December 2022.

The ISO did not identify a reliability need for the SoCal-CETP in the current planning cycle and therefore this project was found to be not needed. However, the ISO may consider the concept in future planning cycles if the need for additional local capacity in the LA Basin and San Diego area beyond the CPUC authorized Tracks 1 and 4 procurement is identified.

2.6.3.2 *Preferred Resources Assessment (Non-Conventional Transmission Alternative Assessment)*

As indicated earlier, available preferred resources and storage including additional energy efficiency (AAEE), distributed generation, demand response and the preferred resources assumed to fill the LTPP 2012 local capacity authorization were used to mitigate reliability issues in the southern California bulk transmission system. The ISO did not receive proposals for additional preferred resources other than the preferred resources selected by SCE for the western LA Basin and under consideration by SDG&E for the San Diego local area as part of the CPUC's long-term local capacity procurement process through the 2015-2016 Request Window. Also, the reliability assessment results did not indicate the need for additional resources beyond previously authorized amounts for LTPP Tracks 1 and 4 for the combined LA Basin and San Diego area to meet reliability requirements.

2.6.3.3 *Summary of Recommendations*

The ISO conducted a detailed planning assessment for the southern California bulk transmission system to comply with the reliability standard requirements of section 2.2, as well as long-term local capacity analyses of section 3.1 and Appendix D and found the following:

1. In the short-term (i.e., until the Imperial Valley phase shifting transformer is in-service), enabling the existing SDG&E 230 kV TL 23040 Otay Mesa-Tijuana SPS was recommended in the 2014-2015 Transmission Plan and found to continue to be effective in this planning cycle to address the thermal overload on the Otay Mesa-Tijuana 230 kV line following the overlapping SDG&E 500 kV line outages. The voltage stability issue associated with the cross-tripping of the Otay Mesa-Tijuana 230 kV line or Imperial Valley-La Rosita 230 kV line following the overlapping outages is addressed by dispatching available resources in the San Diego and LA Basin areas after the initial contingency in accordance with existing operating procedures.
2. In the longer term (post June 2017), the Imperial Valley phase shifting transformer and other transmission projects that were approved as part of the ISO 2013-14 transmission plan are expected to go into service. In addition, resources assumed to fill the CPUC-authorized local capacity additions are expected to go into service by 2018[54] and 2020-2021 timeframe[55]. System adjustments using all available resources, after the initial contingency, are needed to mitigate the overloading and voltage stability issue associated with the overlapping outages of SDG&E 500 kV transmission lines. The approved Imperial Valley phase shifting transformer will be incorporated into the area operating procedures when it becomes operational.
3. There are a number of uncertainties that could impact the above results for the long-term planning horizon including uncertainties associated with the amount of authorized local capacity additions, AAEE, distributed generation, and the amount of existing demand response that would be repurposed for use in meeting local reliability needs. The assessment will be revisited in the next planning cycle with the latest available information.
4. The Lugo-Victorville 500 kV Upgrade Project is needed to mitigate existing congestion and identified reliability concerns. As the project requires coordination with a neighboring balancing authority area and potential cost allocation issues, the ISO intends to commence that process with LADWP and SCE, and seek approval once the coordination has taken place.
5. The cost and feasibility of small transmission upgrades (i.e., installing 10-ohm series reactors or special protection system as described further in section 3.1.2 and Appendix D as part of the western LA Basin LCR analysis discussion) warrant further investigation as effective solutions to further mitigate south of Mesa 230 kV line loading concerns concurrent with the Mesa Loop-In Project.

[54] Anticipated in-service date for gas-fired generation in San Diego

[55] Anticipated in-service dates for preferred resources and gas-fired generation in the western LA Basin and preferred resources in San Diego area

2.7 SCE Local Areas Assessment

2.7.1 Tehachapi and Big Creek Corridor

2.7.1.1 *Area Description*

The Tehachapi and Big Creek Corridor consists of the SCE transmission system north of Vincent substation. The area includes the following:

- WECC Path 26 — three 500 kV transmission lines between PG&E's Midway substation and SCE's Vincent substation with Whirlwind 500 kV loop-in to the third line;
- Tehachapi area — Windhub-Whirlwind 500 kV, Windhub – Antelope 500 kV, and two Antelope-Vincent 500 kV lines;
- 230 kV transmission system between Vincent and Big Creek Hydroelectric project that serves customers in Tulare county; and
- Antelope-Bailey 230 kV system which serves the Antelope Valley, Gorman, and Tehachapi Pass areas.

There are three major transmission projects that have been approved in prior cycles by the ISO in this area, which are as follows:

- San Joaquin Cross Valley Loop Transmission Project (completed);
- Tehachapi Renewable Transmission Project (in-service date: 2016); and
- East Kern Wind Resource Area 66 kV Reconfiguration Project (completed).

2.7.1.2 *Area-Specific Assumptions and System Conditions*

The Tehachapi and Big Creek Corridor study was performed consistent with the general study methodology and assumptions described section 2.3.

The ISO-secured participant portal lists the base cases and contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the study area are provided below.

Table 2.7-1 lists a summary of the generation in the Tehachapi and Big Creek Corridor, with detailed generation listed in Appendix A.

Table 2.7-1: Tehachapi and Big Creek Corridor generation summary

Generation	Capacity (MW)
Thermal	1720.1
Hydro	1201.3
Wind	2968.1
Solar	2521.4
Total	**8410.9**

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year load forecast and includes system losses. Table 2.7-2 shows the Tehachapi and Big Creek Corridor load in the summer peak assessment cases excluding losses.

The ISO spring light load and spring off-peak base cases assume 50 percent and 65 percent of the 1-in-2 year load forecast, respectively.

Table 2.7-2: Summer Peak load forecasts modeled in the SCE's Tehachapi and Big Creek Corridor assessment

Tehachapi and Big Creek Corridor Coincident A-Bank Load Forecast (MW) Substation Load and Large Customer Load (1-in-10 Year)			
Substation	**2017**	**2020**	**2025**
Antelope-Bailey 220/66 kV	748	740	749
Rector 220/66 kV	810	819	850
Springville 220/66 kV	278	289	309
Vestal 220/66 kV	188	192	198
Big Creek 220/33 kV	9	9	9

Study Scenarios

The Tehachapi and Big Creek Corridor study included five baseline and one sensitivity scenarios as described in table 2.7-3.

Table 2.7-3: Scenarios studied in the Tehachapi and Big Creek Corridor assessment

Baseline scenarios					Sensitivity scenario
2017 Summer Peak	2017 Spring Off-Peak	2020 Summer Peak	2020 Spring Light Load	2025 Summer Peak	2020 Summer Peak with Low Hydro

2.7.1.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B.

The Tehachapi and Big Creek Corridor Sensitivity Scenario reliability assessment identified the following system performance concerns listed below under various contingency conditions.

- One facility was identified with thermal overload under one Category P1 condition.
- Two facilities were identified with thermal overloads under two Category P3 conditions.
- Two facilities were identified with thermal overloads under 12 Category P6 conditions.

The ISO will work with SCE to develop the operational action plan to address the thermal overload concerns.

The Tehachapi and Big Creek Corridor Baseline and Sensitivity Scenario reliability assessment identified transient stability concerns under Big Creek 1-Big Creek 2 230 kV line (P5) outage.

SCE will be installing second (dual) high speed protection for this line with an in-service date of December 2017. In the interim, for faults at the remote terminal ends of Big Creek 1-Big Creek 2 and upon loss of the high speed protection, the total output of the Eastwood unit should be maintained below 160 MW.

2.7.2 North of Lugo Area

2.7.2.1 *Area Description*

The North of Lugo transmission system serves San Bernardino, Kern, Inyo and Mono counties. The figure below depicts the geographic location of the North of Lugo area, which extends more than 270 miles.

The North of Lugo electric transmission system comprises 55 kV, 115 kV and 230 kV transmission facilities. In the north, it has inter-ties with Los Angeles Department of Water and Power (LADWP) and Sierra Pacific Power. In the south, it connects to the Eldorado substation through the Ivanpah-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line. It also connects to the Pisgah substation through the Lugo-Pisgah #1 and #2 230 kV lines. Two 500/230 kV transformer banks at the Lugo substation provide access to SCE's main system. The North of Lugo area can be divided into the following sub-areas: North of Control; South of Control to Inyokern; South of Inyokern to Kramer; South of Kramer; and Victor.

2.7.2.2 *Area-Specific Assumptions and System Conditions*

The North of Lugo area study was performed consistent with the general study methodology and assumptions described in section 2.3. As described in section 2.3, some potentially planned renewable generation projects were modeled.

The ISO-secured website lists the base cases and contingencies that were studied as part of this assessment. Additionally, specific methodology and assumptions that were applicable to the study area are provided below.

Generation

Table 2.7-4 lists a summary of the generation in the North of Lugo area, with detailed generation listed in Appendix A.

Table 2.7-4: North of Lugo area generation summary

Generation	Capacity (MW)
Thermal	892
Hydro	55
Solar	648
Geothermal	302
Total	**1897**

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year load forecast. This forecast load includes system losses. Table 2.7-5 shows the North of Lugo area load in the summer peak assessment cases excluding losses.

The ISO spring light-load base case assumes 25-30 percent of the 1-in-10 year load forecast. The off-peak base case assumes approximately 60 percent of the 1-in-10 year load forecast.

Table 2.7-5: Load forecasts modeled in the North of Lugo area

North of Lugo Area Coincident A-Bank Load Forecast (MW) Substation Load and Large Customer Load (1-in-10 Year)			
Substation	**2017**	**2020**	**2025**
Kramer / Inyokern / Coolwater 220/115	248	260	303
Victor 220/115	695	701	724
Control 115kV	79	87	95

2.7.2.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. The summer peak and off-peak reliability assessment of the North of Lugo area revealed the following reliability concerns.

- Inyo 115 kV phase shifting transformer overload was observed under N-1 and N-1-1 contingency conditions. The recommended solution for this issue is congestion management for the N-1 contingency and generation redispatch after the first contingency to mitigate the N-1-1 concerns.

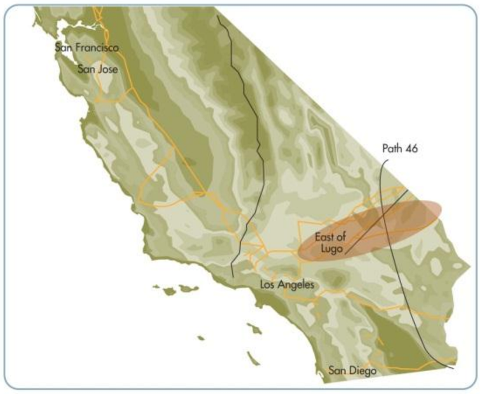
- High voltage concerns were observed at Inyo 115 kV and Inyo 230 kV buses under several N-1 contingency scenarios. The recommended mitigation for this reliability concern is to adjust voltage schedule of generators in this local area, reactive devices and transformer taps.
- Victor 230/115 kV transformer bank overload was observed under N-1-1 contingency conditions. The recommended mitigation is to bring the hot spare bank at Victor substation in service after the first N-1 contingency.
- Case divergence was observed under T-1-1 contingency of Lugo 500/230 kV banks under existing generation drop SPS. The recommendation is to review and limit the total generation drop caused by this T-1-1 contingency.
- Ivanpah-Mountain Pass 115 kV line overload was observed under T-1-1 contingency of Lugo 500/230 kV banks under a variation of generation drop SPS associated with the contingency. The recommendation is to review the total generation drop armed for this T-1-1 contingency.

Details of the planning assessment results for North of Lugo area are presented in Appendix B.

2.7.3 East of Lugo

2.7.3.1 *Area Description*

The East of Lugo area consists of the transmission system between the Lugo and Eldorado substations. The East of Lugo area is a major transmission corridor connecting California with Nevada and Arizona; a part of Path 46 (West of River), and is heavily integrated with LADWP and other neighboring transmission systems. The SDG&E owned Merchant 230 kV switchyard became part of the ISO controlled grid and now radially connects to the jointly owned Eldorado 230 kV substation. Merchant substation was formerly in the NV Energy balancing authority, but after a system reconfiguration in 2012, it became part of the ISO system. The East of Lugo bulk system consists of the following:



- 500 kV transmission lines from Lugo to Eldorado and Mohave;
- 230 kV transmission lines from Lugo to Pisgah to Eldorado;
- 115 kV transmission line from Cool Water to Ivanpah; and
- 500 kV and 230 kV tie lines with neighboring systems.

2.7.3.2 *Study 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. The ISO-secured website lists the base cases and contingencies that were studied as part of this assessment. As described in section 2.3.2.5, some potentially planned renewable generation projects were modeled. In addition, specific assumptions and methodology that applied to the East of Lugo area study are provided below.

Transmission

Transmission upgrades consisting of the Lugo-Eldorado 500 kV series capacitor and terminal equipment upgrade, Lugo-Mohave 500 kV series capacitor and terminal equipment upgrade and the re-route of Eldorado-Lugo 500 kV line, which were approved as policy-driven upgrades in 2012-2013 and 2013-2014 Transmission Plan, are modeled in the 2019 and 2024 study cases.

In light of the FERC-approved transition agreement between ISO and Valley Electric Association, the planned interconnection tie between VEA's newly proposed 230 kV Bob Switchyard and SCE's new 220 kV Eldorado substation is assumed to be in-service during the year 2018.

Generation

There is approximately 720 MW of existing generation connected to the SDG&E owned Merchant substation and 400 MW of renewable generation connected to Ivanpah substation. Table 2.7-6 lists the generation in the East of Lugo area with detailed generation listed in Appendix A.

Table 2.7-6: Generation in the East of Lugo area

Generation	Capacity (MW)
Thermal	506
Solar (including solar thermal)	605
Total	**1111**

Load Forecast

The ISO summer peak base case assumes the CEC's 1-in-10 year load forecast. This forecast load includes system losses but excludes power plant auxiliary loads in the area. The SCE spring light load base cases assume 50 percent of the 1-in-2 year load forecast.

Table 2.7-7 provides a summary of the Eldorado area load in the summer peak assessment.

Table 2.7-7: Summer Peak load forecasts modeled in the East of Lugo area assessment

Area	2017	2020	2025
East of Lugo and Ivanpah 500/230 kV Area (MW)	65	62	60

2.7.3.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2016-2025 reliability assessment for the SCE East of Lugo Area identified the following reliability concern that requires mitigation.

- Mead-Bob 230 kV line overload was observed for the T-1 contingency of Eldorado 500/230 kV 5AA transformer bank.
- Ivanpah – Mountain Pass 115 kV line overload was observed for the N-1 contingency of Eldorado-Primm 230 kV line.
- Ivanpah 230/115 kV transformer overload was observed for several N-1-1 contingencies.
- Lugo-Victorville 500 kV line overload was observed for several N-1-1 contingencies involving 500 kV lines bringing power into Lugo 500 kV and into Devers 500 kV substations.
- Voltage deviation concerns were noticed at Laughlin 500kV, Mohave 500 kV and Primm 230 kV substations.
- High voltage issues were observed at Cima, Pisgah, Eldorado and Ivanpah 230 kV buses and at Mohave and Laughlin 500 kV buses.

Request Window Proposals

The ISO has received the following project proposal in the East of Lugo area through the 2015 Request Window in connection with the reliability issue identified above.

Lugo-Victorville 500 kV Upgrade (SCE portion)

The project was submitted by Southern California Edison. The Lugo-Victorville 500 kV transmission line is jointly owned by SCE and the Los Angeles Department of Water and Power (LADWP). The upgrade will be performed for facilities owned by each respective party. This project increases the rating of the 500 kV line by upgrading terminal equipment at both substations and removing ground clearance limitations. SCE's portion include upgrading four transmission towers and replacing terminal equipment at the Lugo substation. The estimated cost of SCE's portion is $18 million. The estimated cost of LADWP's portion is $16 million. This is a joint project requiring the participation of both SCE and LADWP to complete.

Mead-Adelanto Project Upgrade (MAP Upgrade Project)

The project was submitted by Starwood Energy Group Global, LLC. This project involves the conversion of the MAP transmission line from its existing high-voltage alternating current (HVAC) to high-voltage direct current (HVDC) Operations, which increases the capacity from 1291 MW AC to approximately 3500 MW DC. The estimated cost of this project is $1.11 billion.

ISO Assessment of Request Window Proposals

Lugo-Victorville 500 kV Upgrade (SCE portion)

The reliability assessment in East of Lugo, SE bulk and SCE Metro areas demonstrated overloads of this facility under a number of category P6 contingencies in all summer peak cases. While the overloads in the 2017 and 2020 base cases could be mitigated by increasing generation and preferred resources in southern California and decreasing transfers (i.e., congestion management) on Path 46 (West of River path), the results indicated that local resources procured thus far may not be sufficient to mitigate the overload after the retirement of OTC generation. The overloading issue, identified in the system reliability assessment, is not related to local area reliability issue but rather system reliability concern because the overloaded line (i.e., Lugo-Victorville 500kV line) is a defined WECC path (Path 61) or an interface that is jointly connected with other balancing authority area (i.e., LADWP).

The 33 percent RPS policy-driven studies also identified this facility as a limiting constraint for delivering resources from multiple renewable zones.

Currently, the potential overloading on this path is being managed by congestion management. In addition to the reliability and RPS policy-driven concerns, the accrued congestion cost of this constraint since January 2013 was found to be $43 million. In the post 2020 time frame, with the retirement of the bulk of OTC generating units in the western LA Basin, as well as potential retirement due to its age of 40-year old or more generating units in the eastern LA Basin, it would be much more challenging to perform congestion management on this path.

Taking these factors into consideration, the ISO recognizes that increasing the rating of Lugo-Victorville 500 kV line is needed. Consistent with the recommendations that are discussed in sections 2.6.3 and 2.7.5, this project has been identified as needed. SCE submitted the joint Lugo-

Victorville 500 kV line upgrade project, which has an estimated in-service date of 12/31/2018. As a portion of this line is owned by LADWP, the ISO will work with SCE and LADWP to finalize the scope of the project and coordinate the next steps. As the project requires coordination with a neighboring balancing authority area and potential cost allocation issues, the ISO intends to commence that process with LADWP and SCE, and seek approval once the coordination has taken place as discussed in section 2.6.3.

Mead- Adelanto Project Upgrade (MAP Upgrade Project)

The reliability assessment did not establish a need for this project.

2.7.3.1 *Recommendations*

The ISO conducted a detailed planning assessment for the SCE Eastern area to comply with the reliability standard requirements of section 2.2 and makes the following recommendations to address the reliability concerns identified:

- Modify the existing Ivanpah Area SPS to trip generation for Eldorado 500/230 kV 5AA transformer bank contingency;
- Rely on congestion management mechanism in the ISO market;
- Commence discussions with LADWP and SCE to coordinate upgrading the Lugo-Victorville 500 kV line as discussed in section 2.6.3;
- Confirm an exception for the specified voltage deviations; and adjust voltage schedules for local generators, to adjust transformer taps and to rely on reactive support.

2.7.4 Eastern Area

2.7.4.1 *Area Description*

The ISO controlled grid in the Eastern Area serves the portion of Riverside County around and to the west of the Devers Substation. The figure below depicts the geographic location of the area. The system is composed of 500 kV, 230 kV and 161 kV transmission facilities from Devers Substation to Palo Verde Substation in Arizona. The area has ties to Salt River Project (SRP), the Imperial Irrigation District (IID), the Metropolitan Water District (MWD), and the Western Area Lower Colorado control area (WALC).

The ISO has approved the following major transmission projects in this area in prior planning cycles:

- Path 42 Upgrade Project (2015);
- West of Devers Upgrade Project (2020), and
- Delaney-Colorado River 500 kV line Project (2020).

2.7.4.2 *Area-Specific Assumptions and System Conditions*

The Eastern Area reliability assessment was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO secured participant portal lists the base cases and contingencies that were studied.

Additionally, specific assumptions and methodology that were applied to the Eastern Area study are provided below.

Generation

Table 2.7-8 lists a summary of generation in the Eastern area. A detailed list of generation in the area is provided in Appendix A.

Table 2.7-8: Eastern area generation summary

Generation	Capacity (MW)
Thermal	1,506
Wind	814
Solar	800*
Total	**3,120**

*The capacity value shown includes generation currently under construction.

Load Forecast

The ISO summer peak base cases are based on the CEC 1-in-10 load forecast. The forecast load includes system losses. Table 2.7-9 provides a summary of the Eastern Area coincident substation load used in the summer peak assessment.

The summer light load and spring off-peak base cases assume 50 percent and 65 percent of the 1-in-2 peak load forecast, respectively.

Table 2.7-9: Summer Peak load forecasts modeled in the Eastern Area assessment

Eastern Area Coincident Load Forecast (MW) Substation Load (1-in-10 Year)			
Substation	**2017**	**2020**	**2025**
Blythe	57	58	61
Camino	1	1	1
Devers	526	536	569
Eagle Mountain	2	2	2
Mirage	475	496	529
Total	**1060**	**1092**	**1161**

Base Case Scenarios

Table 2.7-10 provides additional details regarding the system conditions modeled in the Eastern Area assessment.

Table 2.7-10: Additional Eastern Area Study Assumptions

Study Case	**MWD Pumps Online**	**Blythe Unit Status**
2017 Summer Peak	8 pumps/station	All units on
2020 Summer Peak	8 pumps/station	All units off
2025 Summer Peak	8 pumps/station	All units on
2017 Summer Off-Peak	0 pumps/station	All units on
2020 Light Load	0 pumps/station	All units off

2.7.4.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2016-2025 reliability assessment for the SCE Eastern Area identified the following reliability concern that requires mitigation.

Overlapping outages of the Julian Hinds-Mirage 230 kV line and the Julian Hinds 230 kV shunt reactor were found to cause high voltages at Buck Boulevard, Julian Hinds and Eagle Mountain substations when area pumps and generators are offline. Opening the Buck Boulevard gen-tie mitigated the high voltage problem. SCE is developing operating procedures for maintaining voltages in the area within limits under these conditions. The procedures will include opening the Buck Boulevard gen-tie as needed when Blythe is not available. Two shunt reactors are proposed to be installed at Eagle Mountain substation to mitigate the high voltage issues in long term.

Request Window Proposals

The ISO has received the following project proposal in the Eastern area through the 2015 Request Window in connection with the reliability issue identified above.

Buck-Colorado River-Julian Hinds Loop-in Project

The project was submitted by Blythe Energy Inc. and consists of looping the existing private Buck Boulevard-Julian Hinds 230 kV generation tie line into the Colorado River substation. The project creates a new 230 kV networked facility between Colorado River and Julian Hinds and moves the point of connection of the Blythe generation facility to Colorado River. The project has an estimated cost of $81-125 million including the cost of the networked portion of the existing line. The proposed in-service date is December, 2017.

ISO Assessment of Request Window Proposals

Buck-Colorado River-Julian Hinds Loop-in Project

The need for this project was assessed as part of the 2014-2015 ISO transmission planning cycle, and it has not been found to be needed at this time. Activities are continuing, as an extension of the 2014-2015 planning cycle, to explore the issues raised by the project proposal.

2.7.4.4 *Recommendations*

The ISO conducted a detailed planning assessment for the SCE Eastern area to comply with the reliability standard requirements of section 2.2 and makes the following recommendations to address the reliability concerns identified:

For an interim period, continued use of an operating solution is recommended to mitigate the Category P1 (N-1) and P6 (N-1/N-1) high voltage concern identified in the Julian Hinds area when area pumps and generators are offline. SCE has developed an operating procedure that will include opening the Buck Boulevard generation tie-line as needed to maintain voltages in the area within acceptable limits when the Blythe generation facility is out-of-service. Two reactors are proposed to be installed at Eagle Mountain substation to mitigate the issue in long term.

2.7.5 Los Angeles Metro Area

2.7.5.1 *Area Description*

The Los Angeles Metro area consists of SCE owned 500 kV and 230 kV facilities that serve major metropolitan areas in the Orange, Riverside, San Bernardino, Los Angeles, Ventura and Santa Barbara counties. The boundary of LA Metro area is marked by the Vincent, Lugo and Valley 500 kV substations and the San Onofre 230 kV substation. The bulk of SCE load as well as most southern California coastal generation is located in the LA Metro area.

The ISO has approved the following major transmission projects in this area in prior planning cycles:

- Mesa 500 kV Loop-In Project (2020);
- West of Devers Upgrade Project (2020);
- Orange Country Dynamic Reactive Support (2018);
- Method of Service for Alberhill 500/115 kV Substation (2018); and
- Method of Service for Wildlife 230/66 kV Substation (2020).

The San Onofre Nuclear Generating Station (SONGS), which had an installed capacity of 2,246 MW, was retired in 2013. Also, a total of about 6100 MW of generation in the Metro Area is expected to retire by the end of 2020 to comply with the State Water Resources Control Board (SWRCB) once-through cooling (OTC) regulations.

In the 2012 LTPP Track 1 and Track 4 decisions, the CPUC authorized SCE to procure between 1900 and 2500 MW of local capacity in the LA Basin area and up to 290 MW in the Moorpark area to offset the retirements of SONGS and OTC generation. The Metro area study assumed local capacity addition of 1882 MW in the LA Basin area and 260 MW in the Moorpark area based on the procurement plan SCE submitted to the CPUC for approval.

2.7.5.2 *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. The ISO-secure participant portal provides the base cases and contingencies that were studied as part of this assessment. In addition, specific assumptions and methodology that were applied to the Metro area study are provided below.

Generation

Table 2.7-11 lists a summary of the existing generation in the Metro area, with detailed generation listed in Appendix A.

Table 2.7-11: LA Metro area existing generation summary

Generation	**Capacity (MW)**
Thermal	12,036(1)
Hydro	319
Solar	61
Biomass	140
Total	**12,556**

Note (1): Amount includes 6100 MW of OTC generation capacity that is scheduled to retire by 2021

OTC generators were assumed to retire per their respective compliance dates. In the 2025 base cases, 2012 LTTP Track 1 and Track 4 local capacity resources were modeled based on SCE's procurement plan. The detailed modeling assumptions for the authorized local capacity additions are summarized in section 2.6.

Load Forecast

The summer peak base cases assume the CEC 1-in-10 year load forecast, which includes system losses. Table 2.7-12 provides a summary of the Metro area substation load used in the summer peak assessment.

The summer light load and spring off-peak base cases assume 50 percent and 65 percent of the coincident 1-in-2 year load forecast, respectively.

Table 2.7-12: Summer Peak load forecasts modeled in the LA Metro area assessment

LA Metro Area Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year) (1)			
Substation	**2017**	**2020**	**2025**
Alamitos	195	200	209
Alberhill	--	380	422
Barre	723	720	730
Center	456	463	468
Chevmain	169	169	169
Chino	789	792	854
Del Amo	570	584	615
Eagle Rock	271	280	296
El Casco	171	188	215
El Nido	400	415	415
Ellis	700	724	772
Etiwanda	737	754	854
Etiwanda Ameron	59	59	59
Goleta	337	348	343
Goodrich	327	332	339
Gould	150	154	164
Hinson	360	361	371
Johanna	461	483	498
La Cienega	522	533	554
La Fresa	698	712	746
Laguna Bell	644	659	687
Lewis	657	682	716
Lighthipe	504	525	549
Mesa	678	694	724
Mira Loma	707	735	723

LA Metro Area Coincident A-Bank Load Forecast (MW) Substation Load (1-in-10 Year) [(1)]			
Substation	**2017**	**2020**	**2025**
Moorpark	796	818	860
Olinda	417	423	433
Padua	678	687	694
Rio Hondo	810	830	871
San Bernardino	607	634	673
Santa Clara	484	634	672
Santiago	879	942	1012
Saugus	855	957	1014
Valley AB	801	844	939
Valley D	1038	737	811
Viejo	381	386	400
Villa Park	737	754	769
Vista	968	653	675
Walnut	705	710	739
Wilderness	--	354	390

Note (1): Load forecast values do not include the impact of AAEE.

Preferred Resources

Preferred resources were modeled in the study cases consistent with the study plan. These include the following:

- Additional Achievable Energy Efficiency (AAEE) based on the CEC Low-Mid AAEE projection;
- distributed generation based on the CPUC Commercial-Interest RPS Portfolio;
- two levels of repurposed existing emergency demand response (DR) programs based on the average load impact estimates in the study plan as allocated to substations by SCE; and
- CPUC 2012 LTPP Track 1 and Track 4 energy storage (ES), solar PV, DR, and EE resources.

With the exception of energy efficiency, which was modeled and used in the initial study cases, preferred resources were modeled but not used in the initial study cases and were considered as potential mitigation once reliability issues were identified. See section 2.6 for details of preferred resource assumptions.

Study Scenarios

The Metro area study included five baseline and two sensitivity scenarios as described in table 2.7-13.

Table 2.7-13: Scenarios studied in the LA Metro area assessment

Baseline scenarios					Sensitivity scenarios	
2017 Summer Peak	2017 Spring Off-Peak	2020 Summer Peak	2020 Spring Light Load	2025 Summer Peak	2020 Summer Peak with 1350 MW of Western LA OTC generation assumed unavailable	2025 Summer Peak with CEC High Load Scenario

2.7.5.3 *Assessment and Recommendations*

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B.

The Metro area reliability assessment identified several system performance concerns under various contingency conditions. The majority of the issues identified can be mitigated without the loss of load by such operational measures as reconfiguring the system or utilizing available conventional and preferred resources as discussed in Appendix B. Those issues that require or could in the future require additional mitigation are further discussed below.

Lugo-Victorville 500 kV line thermal overload

The Lugo-Victorville 500 kV line overloaded under P7 (L-1/L-1) conditions in all summer peak scenarios and under P1 (L-1) conditions in the 2025 summer peak scenarios. While the overloads in the 2017 and 2020 scenarios could be mitigated by utilizing available generation and preferred resources in southern California and reducing transfers on Path 46, the results indicate adequate resources may not be available to mitigate the overload after the retirement of OTC generation. Table 2.7-14 shows the loading on Lugo-Victorville line in the 2025 summer peak baseline and high CEC load scenarios with all available conventional and preferred resources dispatched and transfers on Path 26 and PDCI into southern California maximized

.

Table 2.7-14: Lugo–Victorville 500 kV line loading

Worst Contingency	**Category**	**Loading (%)** (1)							
		2025 Summer Peak (baseline scenario)				2025 Summer Peak (high CEC load scenario)			
		W/o PR&ES other than AAEE	With PR&ES, no DR	With PR&ES incl. 200 MW re-purposed DR	With PR&ES incl. 1140 MW re-purposed DR	W/o PR&ES other than AAEE	With PR&ES, no DR	With PR&ES incl. 200 MW re-purposed DR	With PR&ES incl. 1140 MW re-purposed DR
Eldorado–Lugo 500 kV line	P1 (L-1)	100%	91%	N/A (2)	N/A (2)	115%	107%	N/A (2)	N/A (2)
Eldorado–Lugo & Eldorado–Mohave or Mohave–Lugo 500 kV lines	P6 (L-1/L-1)	127%	N/A (2)	115%	105%	149%	N/A (2)	135%	124%

Notes (1) Total PR&ES modeled in SoCal (other than AAEE) is 2586 MW including 1140 MW of existing DR
(2) DR used for N-1/N-1 conditions only due to use limitation.

The above table also provides information regarding the effectiveness of preferred resources in mitigating the overloads on the Lugo-Victorville line. For example, a total of 2586 MW of preferred resources and energy storage was used to bring the N-1/N-1 loading from 127 percent to 105 percent in the 2025 summer peak baseline scenario and from 149 percent to 124 percent in the high CEC load scenario. A simple extrapolation of these results suggests roughly 600 MW and 2500 MW of additional resources or an equivalent amount of load drop is needed to bring the N-1/N-1 loading within the line rating in the baseline and high load sensitivity scenarios, respectively. The additional resource or load drop amounts in both cases are in addition to 1140 MW of repurposed existing DR becoming available.

Therefore, transmission upgrade is needed to address the loading concern associated with the Lugo-Victorville 500 kV line. Two request window projects were submitted by stakeholders to address the loading issue. The projects involve upgrading the existing line or building a new parallel line. The ISO's evaluation of these projects is presented in section 2.7.3.

Mesa-Laguna Bell No. 1 230 kV Overload

The Mesa-Laguna Bell No. 1 230 kV line overloaded under P7 (L-2) and P6 (L-1/L-1) conditions in the 2025 summer peak cases. Table 2.7-15 shows the loading on the line in the 2025 summer peak baseline and high CEC load scenarios with all available conventional and preferred resources dispatched. The loading on the line was below the line rating in the baseline 2025 summer peak case when preferred resources and storage were used. However, available resources were not adequate to fully address the loading concern in the 2025 high CEC load scenario. As a result, additional mitigation may be required in the future if high load growth materializes.

Table 2.7-15: Mesa–Laguna Bell #1 230 kV line loading

Worst Contingency	Category	Loading (%) (1)							
		2025 Summer Peak (baseline scenario)				2025 Summer Peak (high CEC load scenario)			
		W/o PR&ES other than AAEE	With PR&ES, no DR	With PR&ES incl. 200 MW re-purposed DR	With PR&ES incl. 1140 MW re-purposed DR	W/o PR&ES other than AAEE	With PR&ES, no DR	With PR&ES incl. 200 MW re-purposed DR	With PR&ES incl. 1140 MW re-purposed DR
Mesa–Lighthipe & Mesa–Laguna Bell #2 230 kV lines	P7 (L-21)	102%	95%	N/A (2)	N/A (2)	110%	102%	N/A (2)	N/A (2)
Mesa–Lighthipe & Mesa–Redondo 230 kV lines	P6 (L-1/L-1)	108%	N/A (2)	98%	94%	116%	N/A	105%	102%

Notes (1) Total PR&ES modeled in SoCal (other than AAEE) is 2586 MW including 1140 MW of existing DR)
(2) DR used for N-1/N-1 conditions only due to use limitation.

Recommendations

The ISO conducted a detailed planning assessment for the LA Metro area to comply with the reliability standard requirements of section 2.2 and makes the recommendations below to address the reliability concerns identified.

- Operational measures, such as system reconfiguration or use of conventional and preferred resources, are available to mitigate the majority of the system performance issues identified in the Metro area without impacting service to load.
- Transmission upgrade is needed to address thermal overloading of the Lugo-Victorville 500 kV line. The line overloaded in both the 2025 summer peak baseline and sensitivity cases under L-1/L-1 conditions despite all available conventional and preferred resources being

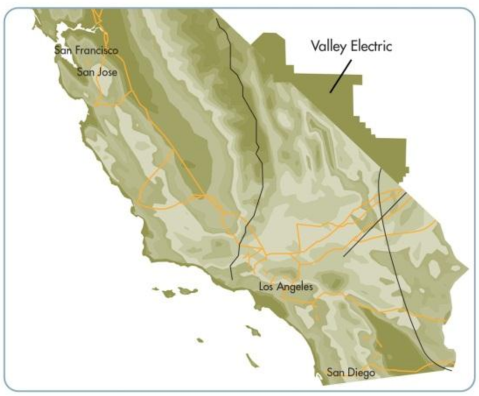
used and transfers on Path 26 and PDCI maximized. The line is also overloaded under L-1 conditions in the high CEC load sensitivity case. Transmission projects were submitted through the request window to address the Lugo-Victorville thermal overload. The ISO's evaluation of the project along with the recommendation is presented in section 2.7.3.

- The Mesa-Laguna Bell No. 1 230 kV line overloaded under L-2 and L-1/L-1 conditions in the 2025 summer peak baseline and sensitivity cases. The assessment did not find additional mitigation to be needed since utilizing available preferred resources mitigated the overload in the baseline scenario. However, additional mitigation may be needed in the future if high load growth materializes.

2.8 Valley Electric Association Local Area Assessment

2.8.1 Area Description

The existing Valley Electric Association (VEA) system consists of a 138 kV system that originates at the Amargosa Substation and extends to the Pahrump Substation and then continues into the VEA service area, the Pahrump-Mead 230 kV line, and a 230 kV transmission line from NV Energy's Northwest 230 kV substation to Desert View to Pahrump. This line provides a second 230 kV source into VEA's major system substation at Pahrump and forms a looped 230 kV supply source. With this new 230 kV line in service, the VEA system now has four transmission tie lines with its neighboring systems, which are as follows:



- Amargosa-Sandy 138 kV tie line with WAPA;
- Jackass Flats-Lathrop Switch 138 kV tie line with NV Energy (NVE);
- Mead-Pahrump 230 kV tie with WAPA; and
- Northwest-Desert View 230 kV tie-line with NV Energy.

2.8.2 Area-Specific Assumptions and System Conditions

The VEA area study was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO-secured participant portal lists the base cases and contingencies that were studied as part of this assessment. In addition, specific assumptions and methodology that were applied to the VEA area study are described below.

Transmission

In light of the FERC-approved Transition Agreement between the ISO and VEA, the following major transmission projects were modeled in this planning cycle.

- VEA is planning a new 138 kV line from Charleston to Vista. This line will provide a looped supply source to the Charleston and Thousandaire substations, which is approximately one third of VEA's load and are currently radially supplied from Gamebird 138 kV substation. This line is expected to be in service in 2017.
- A new transmission interconnection tie between the VEA newly proposed 230 kV Bob Switchyard and the SCE new 220 kV Eldorado substation is planned by VEA and SCE and is assumed to be in service in 2018.
- A new Innovation-Mercury 138 kV transmission line and the Innovation 230/138 kV substation (formerly referred to as Sterling Mountain), which has been interconnected with the Desert View-Pahrump 230 kV line.

Generation

There is no existing generation in the Valley Electric Association system.

Load Forecast

The VEA summer peak base case assumes the CEC's 1-in-10 year load forecast. This forecast load includes system losses in the area. The VEA summer light load and off-peak base cases assume 35 percent and 50 percent of the 1-in-10 year load forecast, respectively.

Table 2.8-1 provides a summary of the VEA area loads modeled in the Valley Electric Association area assessment.

Table 2.8-1: Summer Peak load forecasts

Substation	2017	2020	2025
Valley Electric Association area (MW)	146	147	147.4

2.8.3 Assessment and Recommendations

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. The 2015-2025 reliability assessment of the SCE East of Lugo area resulted in the following reliability concerns:

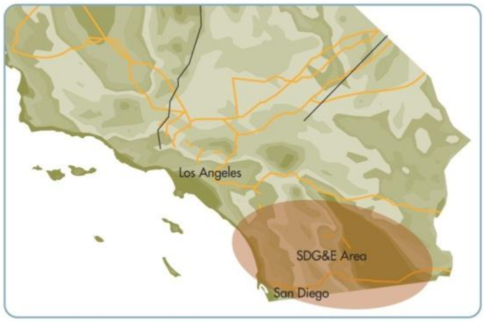
- Mead-Bob 230 kV line overload was observed for the T-1 contingency of Eldorado 500/230 kV 5AA transformer bank. The recommended mitigation is to modify the existing Ivanpah Area SPS to trip generation for this T-1 contingency.
- Pahrump 230/115 kV bank overload was observed for a breaker failure at Pahrump. Since the overload is seen only in 2025, the recommended mitigation includes exploring short-term emergency rating or relying on automatic load transfer or future generation development.
- Several overloads were observed on VEA's 138 kV system and the transformers at Amargosa and Pahrump under various combinations of N-1-1 contingencies that take out at least one 230 kV source into this area. The same combinations of contingencies also caused widespread low voltages on the 138 kV system. Several of these issues are mitigated by the existing UVLS (under voltage load shedding) scheme in VEA area. In addition to relying on this UVLS scheme, the recommended mitigation is to operate VEA 138 kV system radially after the first N-1 for certain category P6 issues.
- Voltage deviation issues were observed at Charleston, Gamebird, Sandy and Thousandaire 138 kV substations and at Pahrump and Gamebird 230 kV substations under N-1 contingencies. The recommended mitigation is to achieve a voltage deviation exception for these buses.

Details of the planning assessment results for VEA area are presented in Appendix B.

2.9 San Diego Gas & Electric Local Area Assessment

2.9.1 Area Description

SDG&E is an investor-owned utility that provides energy service to 3.4 million consumers through 1.4 million electric meters and more than 840,000 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 US-Mexico border,[56] covering two counties and 27 cities.



The SDG&E system, including its main 525/230 kV system and 138/69 kV sub-transmission system, uses imports and internal generation to serve the area load. The geographical location of the SDG&E system is shown in the adjacent illustration. The existing points of San Diego Import Transmission (SDIT) are the South of San Onofre (SONGS) transmission path, the Southwest Powerlink (SWPL) and Sunrise Powerlink (SPL) systems via Imperial Valley 525/230 kV substation, and the Otay Mesa-Tijuana 230 kV transmission line.

The existing SDG&E 525 kV system consists of the 525 kV Southwest Power Link (North Gila-Imperial Valley- Miguel) and the 525 kV Sunrise Power Link (Imperial Valley-Ocotillo-Suncrest). Its 230 kV system extends from the Talega substation in Orange County and SONGS substation in the north to the Otay Mesa substation in the south near the US-Mexico border, and to the Suncrest and Imperial Valley substations in the east. 230 kV transmission lines form an outer loop located along the Pacific coast and around downtown San Diego. The SDG&E sub-transmission system consists of 138 kV and 69 kV transmission systems underlies the SDG&E 230 kV system from the San Luis Rey 230/138/69 kV substation in the north to the South Bay (Bay Blvd) and Miguel substations in the south. There is also a 138 kV arrangement with seven substations interconnected to the Talega 230/138/69 kV substation in southern Orange County. Rural customers in the eastern part of San Diego County are served exclusively by a 69 kV system and often by long lines with low ratings.

There are several previously approved transmission projects planned for the SDG&E system which are listed in Chapter 7. Two of the more significant changes to the SDG&E transmission system are the addition of the Imperial Valley phase shifting transformers, along with implementation of an operational mitigation of by-passing the series capacitor banks on SWPL, and SPL 525 kV lines under normal system conditions that was approved by the ISO in the 2014-2015 transmission planning process. These two projects substantially improve the reliability to southern California load and the deliverability of Imperial area generation.

[56] These numbers are provided by SDG&E in the 2011 Transmission Reliability Assessment

2.9.2 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-secured website provides the study base cases and the contingencies that were evaluated as a part of this assessment. In addition, the specific assumptions and methodology that applied to the SDG&E area study are provided below.

Transmission

The transmission system modeled in these studies include the existing system and all future transmission projects that received ISO approval in the 2014-2015 or earlier ISO transmission plans. This includes the South Orange County Reliability Enhancement Project, the Sycamore Canyon-Penasquitos 230 kV line, the phase shifting transformers at the Imperial Valley 230 kV substation, and new reactive power support facilities at Suncrest, San Luis Rey, and SONGS. The existing series capacitors on the Southwest PowerLink and the Sunrise PowerLink 525 kV lines were bypassed to increase generation deliverability in the Imperial zone and mitigate the various overload concerns as set out in the 2014-2015 transmission plan. The 230 kV tie systems between the ISO controlled grid and the Imperial Irrigation District (IID) system were modelled based on the ISO 2015-2016 TPP base cases provided by IID in the spring of 2016. Models for vicinity systems of IID and CENACE, formerly known as CFE, were updated and refined by IID and CENACE in coordination with the ISO at that time. However, in October, 2015, IID provided new base cases modifying its future transmission plans as comments into the ISO's planning process. As IID surmised in its comments, the ISO's study timelines do not permit restarting the process within a given cycle. IID's input will be taken into account in preparing the study plan for the future 2016-2017 transmission planning cycle, and the ISO will coordinate with IID to ensure use of the best possible and current information at that time.

Generation

The studies performed for the heavy summer conditions assumed all available internal generation was being dispatched with targeted San Diego import level in a range of 2400 to 3500 MW. Category P3 contingency studies were also performed for one generation plant being out-of-service. The single generator contingencies were assumed to be the whole Otay Mesa Energy Center, Termoeléctrica de Mexicali (TDM) power plant, or Palomar Energy Center. These three power plants are combined-cycle plants and as such there is a significant probability an outage would include the entire plant. In addition to these generators, other generator outages were also studied.

Table 2.9-1 lists a summary of the generation resources under the California ISO operational control in the San Diego study area by location and technology, respectively, which includes existing and planned resources modeled in the study years and retirement assumptions as well. All five Encina steam units and one gas turbine were assumed to be available in the 2017 base cases, but retired by the end of 2017 based on the OTC compliance schedule. Palomar Energy Center and Otay Mesa power plant were modeled up to their maximum output of 565 MW and 603 MW, respectively. Combustion turbines totaling 1290 MW are assumed to be retired in the base cases by the year of 2025 in the San Diego study area, which includes Cabrillo Power's units at Encina, Kearny, Miramar GT, El Cajon, Division, Naval Station Metering as well as Applied Energy's units at Point Loma, and Goal Line's units at Escondido.

Renewable generation resources totaling 2230 MW are modeled by the year of 2025, including photovoltaic (PV), wind, biofuel, and hydro pumped-storage resources in the San Diego, Imperial Valley, ECO, Ocotillo, Liebert, Hoodoo Wash, and Hassayampa sub-areas. Renewable generation included in the model for all the study years are the 50 MW Kumeyaay Wind Farm, the 26 MW Borrego Solar that started commercial operation in January 2013, the 265 MW Ocotillo Express wind farm that became operational in December 2012, the 155 MW ECO wind facility that is planned to become operational by 2020, a total of 985 MW PV solar generation that expected in service by the summer of 2017 with power injected into Imperial Valley 230 kV substation, and 582 MW PV solar generation that will become operational by the summer of 2017. The Lake Hodges pump-storage plant is composed of two 20 MW units. Both units became operational in summer 2012. An additional 100 MW of wind generation was modeled based on the CPUC's Commercial Interest Portfolio after considering the 33 percent renewables portfolio standard requirements and generation interconnection agreements status.

In addition to the generation plants internal to San Diego, 1080 MW (NQC) of existing thermal power plants is connected to the 230 kV bus of the Imperial Valley 525/230 kV substation.

SONGS has been permanently retired and was not modeled in the base cases.

Table 2.9-2 shows additional preferred resources and energy storage by the year of 2025 that are used to mitigate reliability concerns in the San Diego studies, which is consistent with the CPUC Long Term Procurement Plan Track 1 and Track 4 decisions. This includes the 800 MW of gas-fired resources that the CPUC authorized SDG&E to procure and 279 MW (NQC) of preferred resource and energy storage in the San Diego area to partially address identified reliability needs caused by the retirement of SONGS and OTC generation. Pio Pico (300 MW) and Carlsbad Energy Center (500 MW) power purchase agreements have been approved by the CPUC as part of the LTPP.

Table 2.9-1: SDG&E-Imperial Valley Area Generation Resource Assumption

Generation Resources (MW)		Unit	2017	2020	2025
by location	San Diego Metro	MW	3210	2645	2607
	ECO	MW	155	255	255
	Ocotillo	MW	265	265	265
	Imperial Valley-SDGE	MW	1915	1915	1915
	Imperial Valley-IID	MW	150	150	150
	HDWSH-APS	MW	290	290	290
	Hassayampa-APS	MW	292	292	292
by technology	Gas	MW	4147	3582	3544
	PV	MW	1593	1593	1593
	Wind	MW	470	570	570
	Biomass	MW	27	27	27
	Storage	MW	40	40	40
Total		MW	6276	5811	5773
Retirement included		MW	-187	-1252	-1290

Table 2.9-2: Additional Preferred Resources and Energy Storage by 2025

Track 1 and 4 Conventional Gas Fired		Unit	LA Basin	SDGE
		MW (in NQC)	1382	800
Preferred Resources and Energy Storage	CPUC Authorized Preferred Resource & Energy storage	MW	501	182
	Existing repurposed Demand Response	MW	1124	16.8
	RPS Portfolio Distributed Generation	MW	203	65
	Additional Energy Storage based on CPUC D13-10-040	MW	0	15
	Subtotal of MW in NQC	MW	1828	279

Load Forecast and Energy Efficiency

Loads within the SDG&E system reflect a coincident peak load based on the load forecast provided by the CEC for 1-in-10-year forecast conditions with Low-Mid AAEE projected. The load demand for 2017 was assumed at 5453 MW, and AAEE was 118 MW. The load demand for 2020 was assumed at 5654 MW, and AAEE was 213 MW. The load demand for 2025 was assumed at 5850 MW, and AAEE was 401 MW. SDG&E substation loads were assumed according to the data provided by SDG&E and scaled to represent the load forecast. The total loads in other areas in the power flow cases were modeled based on the load forecast provided by the CEC. Table 2.9-3 summarizes load and AAEE in SDG&E for the study horizon.

Table 2.9-3: Load Forecast and Energy Efficiency modeled in the SDG&E studies

		2017	2020	2025
Load Demand	MW	5453	5654	5850
Energy Efficiency (AAEE)	MW	-118	-213	-401
Net Peak Load	MW	5335	5441	5449

Power flow cases for the study modeled a load power factor of 0.992 lagging at nearly all load buses in 2020 and 2025. Power factors for the year 2017 were modeled based on the actual peak load data recorded in the supervisory control and data acquisition (SCADA) system at peak hours. One exception listed is the Naval Station Metering (bus 22556), which was modeled at 0.707 lagging power factor based on typical historical values. This substation has a 24 Mvar shunt capacitor.

Area Interchange

Major area interchanges, also known as net area imports/exports, were assumed and modeled for the studies. Table 2.9-4 summarizes area interchanges for the SDG&E and its major vicinity areas.

Table 2.9-4: Area Interchange Assumption

Area		2017	2020	2025
		Summer Peak	Summer Peak	Summer Peak
SCE	MW	-11,260	-12,757	-12,025
SDG&E	MW	-1,239	-1,355	-1,410
LADWP	MW	-2,005	-1,746	-1,539
IID	MW	313	722	1061
CFE	MW	0	0	0
APS	MW	5,664	6,300	6,081

2.9.3 Assessments and Recommendations

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B.

In response to the ISO study results and proposed alternative mitigations, 15 reliability project submissions were received through the 2015 Request Window. These projects included alternatives for solving SDG&E transmission system problems and alternatives that targeted the Southern California Bulk Transmission System.

The ISO investigated various transmission upgrade mitigation alternatives, and recommends three transmission network upgrade projects to address identified local reliability concerns in the SDGE transmission system, which are summarized below and described in greater detail in Appendix B.

The ISO reliability assessment for the SDG&E area identified various thermal overload concerns on the Southwest Powerlink (SWPL), Sunrise Powerlink (SPL) systems under various Category P1, P2, P3, P4, P6, and P7 contingencies. The thermal overload concerns on the SWPL and SPL systems are primarily attributed to the renewable generation development in the greater Imperial Valley area, and the power plant retirements in the San Diego area and LA Basin as part of the OTC plan. However, all the concerns, except for the Imperial Valley 525/230 kV transformer thermal overload that is described below, can be managed by relying on operational mitigations or modified SPS that are described in the 2014-2015 Transmission Plan. The ISO, SDG&E, and CENACE (former CFE) have agreed in general on operation guidelines for the phase shifting transformers to achieve its reliability goal by optimizing system operation in both the ISO controlled grid and the CENACE areas, and will continue work together to develop a new operation procedure for the phase shifting transformers.

Below are the fifteen transmission upgrade projects that were received through the 2015 Request Window to address the local SDG&E reliability concerns. The ISO found the need for six of them in the 2015-2016 transmission planning process, and will continue to monitor system needs for the rest of submittals. In addition, the ISO concurs with one load service interconnection project requested by SDG&E to accommodate load growth in its distribution system, but needs to revisit its plan of service in the next planning cycle.

Install a New 3rd SA-ME 69 kV Line

The third San Luis Rey-Melrose 69 kV Project was received through the 2015 Request Window as a transmission solution to eliminate the overload of TL680B (Melrose Tap-Melrose) 69 kV line under a P7 outage of TL6966 and TL693 (San Luis Rey-Melrose) lines. A new 69 kV line from San Luis Rey to Melrose with a minimum rating of 102 MVA is proposed. Estimated cost is $50 million-$60 million, and the expected in-service date is June 2017.

The ISO also evaluated an operating procedure or SPS as alternatives to the 3rd SA-ME 69 kV line.

The ISO recommends an operating procedure or SPS as the most cost effective mitigation for this P7 outage at this time.

Basilone Substation 15 Mvar Capacitor

Substations along the Oceanside corridor have low voltage issues for a Category P1 or P2 contingency of a loss of TL695 or TL690c. The low power factor at the substations involved exacerbates the problem. The ISO recommends installing a 15 Mvar capacitor at Basilone substation to provide voltage support as soon as possible. The estimated cost of the project is $1.5 million-$2 million. The estimated in-service date is June 2016.

Pendleton Substation 30 Mvar Capacitor

There is a voltage deviation problem greater than 5 percent at Pendleton substation for a Category P1 contingency of a loss of TL6912. The ISO recommends installing a 30 Mvar capacitor at Pendleton substation to provide voltage support as soon as possible. The estimated cost of the project is $2 million-$3 million. The estimated in-service date is June 2017.

Reconductor TL 605 Silvergate-Urban 69 kV Circuit

The Silvergate-Urban 69 kV Project was received through the 2015 Request Window as a transmission solution to eliminate the overload of TL605 (Silvergate-Urban) 69 kV line under a P6 outage of TL602 and TL699 (Silvergate-Station B) lines. TL605 is to be re-conductored to a minimum continuous rating of 137 MVA. The estimated cost is $5 million-$6 million, and the expected in-service date is June 2018. Since there is no generation available to re-dispatch in the area and it is not feasible to add a 2nd Urban-Silvergate 69 kV line, the ISO recommends this project to relieve the potential overload of the TL 605 line.

Mesa Heights Loop-in and Reconductor Project

The Mesa Heights Loop-in 69 kV Project was received through the 2015 Request Window as a transmission solution to eliminate the overload of TL600B (Clairemont Tap-Clairemont) and TL600C (Clairemont Tap-Mesa Heights) 69 kV line under a P6 outage of TL676 (Mission-Mesa Heights) and TL663 (Mission-Kearny) lines. TL600B and TL600C are re-conductored to a minimum of 102 MVA and 150 MVA respectively. TL600C is also looped into the Mesa Heights substation. The estimated cost of the project is $15 million-$20 million. The estimated in-service date is June, 2018.

The need for this project is triggered by the retirement of the Kearny generation which results in severe 69 kV system overloading during the contingency conditions described above. Mesa Heights substation is located adjacent to the TL 600 right-of-way, so looping this line into Mesa Heights and reconductoring is a simple and low cost construction project to maintain the reliability of the 69 kV system after the retirement of the Kearny generation. Therefore, the ISO recommends this project to maintain the reliability of the 69 kV after the retirement of the Kearny generation.

Second Miguel – Bay Boulevard 230 kV Transmission Circuit

A package of several transmission upgrades and re-configurations was submitted through the 2015 Request Window to reinforce the 230/138/69 kV System in the Southern San Diego area. Total of estimated cost of these 230 kV network upgrades and 138/69 kV system re-configuration is $140 million - $151 million, which involves following work scope:

- adding 2nd 230kV line from Miguel to Bay Blvd rated in 1175 MVA rating
- adding 2nd Silvergate-Bay Blvd 230 kV line rated in 912/1176 MVA by taking advantage of the existing TL13815 underground section between Bay Boulevard and Silvergate
- re-conductoring about 8 miles 230 kV lines from Mission to Fanita Junction
- reconfiguring the 138/69 kV system

The second Miguel – Bay Boulevard 230 kV transmission line project submitted as part of the package was found to be needed to address the Category P2, P4, P6, and P7 thermal overload concerns on the Mission – Old Town, Mission – Old Town Tap, and Miguel – Bay Boulevard 230 kV transmission circuits. This project would also eliminate the worst Category P6 contingency that results in the thermal overload concern on Sycamore – Scripps 69 kV line (TL6916) without generation support from Miramar Energy Facility at Miramar GT and which would otherwise establish local capacity need for some of Miramar Energy Facility as minimum generation capacity necessary for reliable load serving capability in the Miramar sub-area. The project scope is to add a 230 kV line position at both Miguel and Bay Boulevard 230 kV substations and to string a new 10-mile 230 kV overhead circuit in the vacant position on the existing double circuit 230kV structures between Miguel and Bay Boulevard 230 kV substations. The estimated cost of the project is $20 million-$45 million. The expected in-service date is June 1, 2019.

The ISO recommends adding the Second Miguel–Bay Boulevard 230 kV transmission circuit project, and will continue to monitor system needs in the southern San Diego 230/138/69 kV system.

Draft Transmission Plan Editorial Note:

The ISO has been made aware of potential additional reliability concerns that could impact the need for the 2nd Silvergate-Bay Blvd 230 kV line. These additional concerns are being researched, and the ISO expects to address them – as well as any changes to the draft recommendations that may be necessary depending on the outcome of the further review – at the February stakeholder session reviewing the draft transmission plan.

Bay Boulevard Third 230/69 kV Transformer Bank

The ISO identified the need to address the Category P2, P4, and P6 thermal overload concerns on the two transformer banks in the planned Bay Boulevard 230/69 kV Substation. Although the Category P2 and P4 thermal concerns could be eliminated by re-arranging the 230 kV lines and the banks' positions in the substation, a third transformer is still needed to mitigate the residual Category P6 thermal overload concern to comply with the ISO's High Density Urban Load Area Standard. The estimated cost of the project is $13 million-$18 million. The proposed in-service date is the same as the Bay Boulevard 230/69 kV substation, which is June 1, 2018.

The ISO recommends the Bay Boulevard Third 230/69 kV transformer bank project.

Suncrest Reinforcement

The Suncrest Reinforcement Project was received through the 2015 Request Window as a transmission solution to increase system operation flexibility by boosting SDG&E import transmission capability and minimize curtailment on generation resources in the greater Imperial Valley area under various contingencies. In addition, the project could reduce exposure to the potential risk of unacceptable outcome of triggering the Path 44 South of SONGS Safety Net that is designed to prevent voltage instability, uncontrolled separation, or cascading outages in the SDG&E area. Estimated cost of the project is $216 million-$235 million, which involves the following major transmission additions:

- adding a third 500/230 kV bank at the Suncrest Substation;
- adding three bay positons, 1½ breaker design, at the Suncrest 230 kV substation; and
- sectionalizing TL23041 and convert it to Suncrest–Miguel and Suncrest–Sycamore 230 kV lines.

The project is not found to be needed at this time and the ISO will continue to monitor its reliability need in the Sunrise PowerLink system and explore its economic or policy-driven benefit in future planning cycles.

Miguel Third 525/230 kV Transformer Bank

The Miguel Third 525/230 kV Transformer Bank Project was received through the 2015 Request Window as a transmission solution to eliminate the Miguel 525/230 bank overload concerns for the other Miguel bank outage (Category P1 event). The project would also reduce exposure to the potential risk of triggering the Path 44 South of SONGS Safety Net that is designed to prevent voltage instability, uncontrolled separation, or cascading outages in the SDG&E area and LA Basin. The project scope is to expand the 525 kV gas insulated switchgear at Miguel and add a third 525/230 kV transformer bank. Estimated cost of the project is $65 million - $75 million. The project was not found to be needed, and the ISO will continue to monitor its reliability need in the Southwest PowerLink system and explore its economic or policy-driven benefit in future planning cycles.

Imperial Valley fourth 525/230 kV Transformer Bank

A potential need to add the fourth 525/230 kV transformer bank at Imperial Valley was identified to eliminate the Imperial Valley 525/230 banks overload concerns that could result in cascading event for various Contingencies P2. P4, and P6 outages. The ISO also evaluated other alternatives, such as SPS either shedding generation injected into the Imperial Valley 230 kV bus or opening 525 or 230 kV transmission branches in the area, and re-configuring the layout of the Imperial Valley substation. The alternatives were deemed infeasible as they could potentially lead to voltage instability in the San Diego area and LA Basin, or the Path 44 safety net taking action shedding significant amount of loads is the San Diego area. However, as noted discussed earlier, the ISO has been made aware of potential material change in IID's transmission plan that may have impact on the project adding the fourth 525/230 kV transformer bank. The ISO will continue to coordinate with IID and evaluate the need and potential other alternatives in the next planning cycle.

New Miramar 230/69 kV Substation

The New Miramar 230/69 kV Substation Project was received through the 2015 Request Window as a transmission solution. This project was proposed to mitigate the thermal overload concern on Sycamore – Scripps 69 kV line (TL6916) for the Contingency P6 event of the Miguel – Bay Boulevard 230 kV transmission circuit followed by the new Sycamore Canyon – Penasquitos 230 kV line outage, without generation support from Miramar Energy Facility (2 units: Miramar I & Miramar II) and the Cabrillo Power II (2 CT units) at the Miramar GT switchyard. In previous studies, the TL6916 overload concern established local capacity needs in the Miramar sub-area. The estimated cost of the project is $ 23.6 million - 28.3 million, and involves:

- modifying the new Mission to Penasquitos 230 kV line with in-service date of 2019 by adding a new Miramar 230 kV tap that feeds into nearby Miramar GT switchyard; and
- retiring the Cabrillo II CT units at Miramar GT switchyard and converting it to a 230/69 kV substation

The reliability study results do not identify Cabrillo Power II CT units as generation necessary for reliable load serving capability since they are already assumed to be retired in the base cases. In addition, as discussed above, the recommended Second Miguel–Bay Boulevard 230 kV transmission circuit project would significantly reduce the local capacity need in the Miramar sub-area. Therefore a new Miramar 230/69 kV Substation is not needed.

San Diego 500 kV Transmission Backup Solutions

Two San Diego area 500 kV backup transmission alternatives were received through the 2015 Request Window as back-up transmission solutions to address the SONGS retirement and the retirement of gas-fired generation in the San Diego and LA Basin areas. Both alternatives were designed to address the potential local capacity need for the San Diego and LA Basin area, and to provide additional generation deliverability for the greater Imperial Valley area. They are almost identical to submittals in the 2013 Request Window. A preliminary evaluation on the potential backup transmission solutions was presented in section 2.6.4.2 of the 2014-2015 Transmission Plan. The projects were not found to be needed in this planning cycle.

Ocean Ranch 69 kV load substation driven by SDG&E distribution load interconnection

The Ocean Ranch Loop-in 69 kV Project was received through the 2015 Request Window as a load interconnection to support the growing demand in the Vista load pocket. A 120 MVA substation with up to four 30 MVA 69/12 kV transformer banks would be constructed. SDG&E proposed to loop both of the existing transmission lines from San Luis Rey to Melrose (TL693 and TL6966) into the new substation, and to reconductor the transmission line section between San Luis Rey and Ocean Ranch. The ISO concurs with the plan to interconnect the Ocean Ranch 69 kV load substation with one line looped-in. The ISO did not find a need at this time to loop-in the second transmission line into the new substation, and reconductor the transmission line section between San Luis Rey and Ocean Ranch.

Border Unit 1 Synchronous Condenser Retrofit

Enterprise Unit 1 Synchronous Condenser Retrofit

Similar to submissions in the 2014 Request Window, the above two projects were re-submitted in the 2015 Request Window that would upgrade existing generation facilities so they could be operated as synchronous condensers when they are not operating in the generation mode. As indicated in the 2014-2015 ISO Transmission Plan, the ISO relied on these facilities to operate as generators to meet existing reliability needs and operating them as synchronous condensers under the same study conditions would result in these facilities providing less reliability benefit, so the ISO did not identify a reliability benefit from these projects.

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Chapter 3

3 Special Reliability Studies and Results

The special studies discussed in this chapter have not been addressed elsewhere in the transmission plan. The studies include the reliability requirements for resource adequacy studies, both short term and long term, studies furthering the assessment of frequency response with increased levels of renewable generation, an assessment of the planned transmission system's capacity to deliver renewable generation on an energy-only basis, a preliminary consideration of gas system impacts on electricity reliability, and a preliminary assessment of the future impacts of large energy storage on flexibility requirements.

3.1 Reliability Requirement for Resource Adequacy

Sections 3.1.1 - 3.1.5 summarize the technical studies conducted by the ISO to comply with the reliability requirements initiative in the resource adequacy provisions under section 40 of the ISO tariff as well as additional analysis supporting long term planning processes. The local capacity technical analysis addressed the minimum local capacity requirements (LCR) on the ISO grid. The resource adequacy import allocation study established the maximum resource adequacy import capability to be used in 2016.

3.1.1 Local Capacity Requirements

The ISO conducted short- and long-term local capacity technical (LCT) analysis studies in 2015. A short-term analysis was conducted for the 2016 system configuration to determine the minimum local capacity requirements for the 2016 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the ISO tariff section 40.3. This study was conducted January-April through a transparent stakeholder process with a final report published on April 30, 2015. One long-term analysis was also performed identifying the local capacity needs in the 2020 period; the 2020 report was published on April 30, 2015. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years. This section summarizes study results from these studies.

As shown in the LCT reports and indicated in the LCT manual, 11 load pockets are located throughout the ISO-controlled grid as shown in and illustrated in table 3.1-1 and figure 3.1-1 below.

Table 3.1-1: List of LCR areas and the corresponding PTO service territories within the ISO Balancing Authority Area

No	LCR Area	PTO Service Territory
1	Humboldt	PG&E
2	North Coast/North Bay	
3	Sierra	
4	Stockton	
5	Greater Bay Area	
6	Greater Fresno	
7	Kern	
8	Los Angeles Basin	SCE
9	Big Creek/Ventura	
10	Greater San Diego/Imperial Valley	SDG&E
11	Valley Electric	VEA

Figure 3.1-1: Approximate geographical locations of LCR areas

Each load pocket is unique and varies in its capacity requirements because of different system configuration. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 200 MW. In contrast, the requirements of the Los Angeles Basin are approximately 10,000 MW. The short- and long-term LCR needs from this year's studies are shown in the table below.

Table 3.1-2: Local capacity areas and requirements for 2016 and 2020

LCR Area	LCR Capacity Need (MW)	
	2016	2020
Humboldt	167	170
North Coast/North Bay	611	509
Sierra	2,018	1,703
Stockton	808	403
Greater Bay Area	4,349	4,191
Greater Fresno	2,519	1,888
Kern	400	135
Los Angeles Basin	8,887	9,229
Big Creek/Ventura	2,398	2,598
Greater San Diego/Imperial Valley	3,184	2,878
Valley Electric	0	0
Total	**25,341**	**23,704**

For more information about the LCR criteria, methodology and assumptions please refer to the ISO LCR manual.

For more information about the 2016 LCT study results, please refer to the report posted on the ISO website.

For more information about the 2020 LCT study results, please refer to the report posted on the ISO website.

The ten-year LCR studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide indication whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding and per agreement between agencies they are done on every other year cycle. For detailed information about the 2024 long-term LCT study results, please refer to the stand-alone report in the Appendix E of the 2014-2015 Transmission Plan.

The ten-year LCR study is particularly important for the LA Basin / San Diego areas as the majority of the once-through cooled (OTC) generating facilities are scheduled to comply with the State Water Resources Control Board (SWRCB) Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling by the end of 2020 timeframe in addition to the retirement of the San Onofre Nuclear Generating Station (SONGS) that was announced by SCE on June 7, 2013. Because of the importance of the LA Basin / San Diego areas and there are several transmission and resource developments needed for these areas in various stages of regulatory approval and development, the ten-year LCR study for these two areas was updated in this 2015-2016 transmission planning cycle, based on the latest available information.

The following section 3.1.2 updates the study results for the ten-year out long-term LCR evaluation for the combined LA Basin / San Diego areas as the retirement of SONGS and OTC generating facilities affect the reliability of these two areas. The objectives of the annual assessments of the long-term LCR needs for these two areas are to evaluate if additional local capacity resource needs are required given the latest information regarding approved long-term procurement contracts for local capacity from the CPUC, adopted demand forecast from the CEC, and approved transmission projects from the Board. In addition to the long-term ten-year LCR needs for the LA Basin and San Diego areas, the ISO also evaluates other sensitivity scenarios requested by the state energy agencies and for special circumstances related to potential permitting delay of major approved transmission projects located in these two areas. In this planning cycle, the ISO evaluated a mid-term 2021 LCR needs per the CEC request. In addition, the ISO evaluated the mid-term 2021 LCR needs for the scenario where the Mesa Loop-In Project may experience potential delay in in-service date related to the permitting process. These sensitivity assessments are discussed further in sections 3.1.3 and 3.1.4.

3.1.2 Summary of Study Results for the 2025 Long-term LCR Assessment of the combined LA Basin/San Diego LCR areas

As mentioned above, the primary purpose of performing the 2025 long-term LCR assessment is to determine whether the combined LA Basin / San Diego area will have sufficient resources to meet local reliability standards with SCE and SDG&E procured resources that have been approved by the CPUC for long-term contracts via power purchase and tolling agreements (PPTA) through the 2012 LTPP Track 1 and 4 proceeding processes and transmission projects that were approved by the Board in the previous transmission planning cycles.

In assessing the adequacy of the resource procurement authorized thus far, the ISO tested the amounts approved by the CPUC on the selected procurement submitted by the utilities through their procurement activities, as well as anticipated procurement considerations to date. In addition, the ISO evaluated potential amounts for further procurement, up to the ceiling of the authorized amounts and transmission upgrades as alternatives to meet identified local needs.

The authorized procurement amount ceilings are set out in table 3.1-3 below:

Table 3.1-3: Summary of 2012 LTPP Track 1 & 4 Authorized Procurement Ceilings (1)

Area Name	**Total**	**Gas-fired generation**	**Preferred Resources and Storage**	**Assumed In Service Date**
SCE LA Basin Area	2500	1500	1000	2020
SCE Moorpark Area	290	194	96	2020
SDG&E Area	1100	900	200	2017
Total	**3890**	**2594**	**1296**	

The ISO monitored the local capacity procurement process at the CPUC to obtain the latest approval decisions for modeling inputs for the 2025 long-term LCR studies. In addition, the ISO worked closely with SDG&E to obtain the latest procurement considerations, particularly for the residual preferred resources and energy storage. The following table 3.1-4 provides a summary of the resource procurement assumptions for both LA Basin and San Diego areas based on the CPUC-approved procurement contracts for SCE and SDG&E, as well as procurement considerations by SDG&E for the residual preferred resources and energy storage.

Table 3.1-4 — LTPP Tracks 1 and 4 procurement assumptions for 2025 long-term LCR studies (based on procurement activities to date)

SCE LTPP Procurement Assumptions[57]						**San Diego LTPP Procurement Assumptions**				
Conventional (MW)	BTM[58] Solar PV (MW) (NQC value)	Energy Storage (MW) (Minimum 4-hr product)	EE (MW)	DR (MW)	Total portfolio (MW)	Conventional (MW)[59]	EE (MW)[60]	Energy Storage (MW)[61]	Demand Response (MW)[62]	Total portfolio (MW)
1,382	37.92	263.64	124.04	5	1,812.6	800	40	150	60	1,050

[57] The CPUC approved SCE procurement selection, with exception, for the Western LA Basin local capacity needs per Decision D.15-11-041 at the November 19, 2015 CPUC Voting Meeting.
[58] Behind-the-meter solar distributed generation
[59] The CPUC approved Pio Pico and Carlsbad Energy Centers per Decisions D.14-02-016 and D.15-05-051, respectively at the CPUC voting meetings.
[60] Power flow modeling proxy considerations at this time per SDG&E suggested inputs
[61] Ibid.
[62] Ibid.

The demand assumptions modeled for the studies are summarized in the following table 3.1-5. The CEC provided demand forecast (1-in-10 mid-demand) as part of the California Energy Demand 2014-2024 Final Forecast. The AAEE projection (low-mid for local area assessment) was also provided on a bus-by-bus basis by the CEC. SCE and SDG&E used the CEC demand forecast for the planning areas and provided projections on individual transmission substation basis.

Table 3.1-5 —Summary of demand assumptions for the 2025 long-term LCR studies

(based on procurement activities to date)

Area	**CEC 1-in-10 Mid Demand Forecast for 2025[63] (MW)**	**Low-Mid[64] AAEE Forecast (MW)**	**Total Net Load (MW)**
San Diego	5,850	-401	5,449
LA Basin	23,717	-1,288	22,429
Total	**29,567**	**-1,689**	**27,878**

The following table 3.1-6 lists the critical transmission upgrades planned for the LA Basin/San Diego LCR areas and assumed in this analysis. These transmission upgrades were approved by the Board in previous transmission plans and there have been no material changes in circumstances identified that would cause the ISO to reassess the need for these projects.

[63] Based on the adopted California Energy Demand Updated (CEDU) 2014 forecast for 2025 (posted January 2015)

[64] Low-mid AAEE forecast is provided by the CEC and utilized for local reliability assessments per the CPUC Assigned Commissioner's Ruling on Updates to Planning Assumptions and Scenarios for Use in the 2014 Long-Term Procurement Plan and the ISO's 2015-2016 Transmission Planning Process (Rulemaking 13-12-010, filed 3/4/2015)

Table 3.1-6 — Summary of critical transmission upgrades modeled in the 2025 long-term LCR studies[65]

No	Transmission Projects	PTO	BAA
1	Mesa Loop-in Project and South of Mesa 230 kV Line Upgrades	SCE	ISO
2	Imperial Valley Phase Shifting Transformers (2x400 MVA)	SDG&E	ISO
3	Sycamore – Penasquitos 230 kV Line	SDG&E	ISO
4	Talega Synchronous Condensers (2x225 Mvar)	SDG&E	ISO
5	San Luis Rey Synchronous Condensers (2x225 Mvar)	SDG&E	ISO
6	San Onofre Synchronous Condenser (1x225 Mvar)	SDG&E	ISO
7	Santiago Synchronous Condenser (1x225 Mvar)	SCE	ISO
8	Miguel Synchronous Condensers (450 / -242 Mvar)	SDG&E	ISO

Overall, the 2025 LCR need for the overall LA Basin remains fairly constant compared to the 2024 LCR need (8,319 MW vs. 8,350 MW). However, the Eastern LA Basin sub-area LCR need, due to the same critical contingency, decreases by about 650 MW due to lower net peak demand in the LA Basin (320 MW). For the Western LA Basin sub-area, however, the LCR need increases by about 620 MW, which can be met by either additional local capacity procurement[66] of preferred resources or energy storage, or by implementing a small-scale transmission solution as discussed further in the Western LA Basin sub-area in chapter 2 and Appendix D. For the procurement option, the ISO modeled energy storage at the substations located on the load side of Laguna Bell. For the small-scale transmission option, the ISO evaluated various mitigations that are summarized in the Western LA Basin Sub-area discussion in the Appendix D. The ISO has found that the small-scale transmission upgrades, such as a series reactor for controlling power flow, or interrupting flow through the Mesa 500/230kV transformer banks under contingencies via a special protection system, is more effective in mitigating the identified 230 kV loading concerns while still maintaining the CPUC's current level of approved long-term local capacity procurement contracts in the Western LA Basin.

The increase in the Western LA Basin sub-area LCR need for the 2025 time frame is due to a higher dispatch of renewable resources. Renewable resource dispatch was based on the CPUC-provided technology factors (for Net Qualifying Capacity), for renewable generation north and east of the LA Basin LCR area. This higher level of renewable generation dispatch (about 2,000

[65] List includes only transmission projects considered critical to assessing the local capacity requirements in the specific area; other major projects are also modeled but not listed.

[66] This additional amount of procurement of preferred resources would fill up the authorized level of local capacity for the Western LA Basin from the LTPP Tracks 1 and 4.

MW higher) reflects updated modeling for centralized photovoltaic solar farms located outside north and east of the LA Basin LCR area. In addition, the updated modeling also includes wind generation resources located north of the LA Basin LCR area. The increase in renewable generation dispatch level to reflect net qualifying capacity (NQC)-level outputs contributes to further thermal loading concerns for the 230kV lines south of newly upgraded Mesa Substation under contingency conditions. This reflects the benefit of the upgraded Mesa Substation to facilitate delivering more renewable generation into the LA Basin load centers when it's upgraded to 500 kV voltage level and having additional 230 kV lines in the Western LA Basin looped into it. In the Western LA Basin Sub-area discussion section in the Appendix D, the ISO evaluated 13 different options, which include either additional resource procurement or small-scale transmission upgrades[67], for mitigating the identified overloading concerns.

The overall San Diego-Imperial Valley LCR need increases by about 720 MW, mainly due to the need to dispatch resources to mitigate thermal loading concerns on the 230 kV lines south of the new upgraded Mesa Substation as discussed above. Although it would be more effective to procure additional resources in the Western LA Basin to mitigate this thermal loading concern, the additional procurement, as identified in the Western LA Basin, would have been exhausted as it would have reached the maximum authorized level of 2,500 MW for local capacity. As discussed below, there are small-scale transmission upgrades that would be the most cost-effective in addressing identified loading concerns while staying within the procurement assumptions shown in table 3.1-4.

The following table 3.1.7 provides a summary of the long-term 2025 LCR studies for the LA Basin and San Diego local reliability areas. Further details are available in the Appendix D. Following this table, a brief discussion is provided regarding various options for mitigating identified overloading concerns on the 230kV lines south of Mesa Substations under various overlapping and simultaneous contingencies.

[67] Small-scale transmission upgrades include upgrades that are anticipated to be confined within the substation boundaries and do not require new Rights-of-Way for implementation.

Table 3.1.7 – Comparison of the 2024 vs. 2025 Long-Term LCR Studies for the LA Basin and San Diego Local Reliability Areas

	Projected Available Qualifying Capacity (MW)			2025 LCR Need Based on Single-Element Contingency (MW)			2025 LCR Need Based on Multiple-Element Contingency (MW)		
Local Area Name	**Available Existing Resources**	**Recent CPUC-approved procurement contracts**	**Total**	**Available Capacity Needed**	**Deficiency**	**Total**	**Available Capacity Needed**	**Deficiency**	**Total**
Western LA Basin	2,728	1,813	4,541	4,541	(695)	5,236	4,541	(973)[68]	5,514
Eastern LA Basin	3,531	N/A	3,531	2,132	0	2,132	3,531	0	2,805
San Diego Sub-Area	2,078	800[69]	2,878	2,316	0	2,316	2,878	(250)[70]	3,128
San Diego/ Imperial Valley	3,818	800	4,618[71]	3,151	0	3,151	4,618	(250)[72]	4,868

[68] This can be met with: 687 MW of potential further procurement; and 286 MW of additional repurposing for existing demand response (beyond the baseline 173 MW assumptions for the Western LA Basin sub-area and 17 MW for San Diego sub-area), or by minor transmission upgrades in the area.
[69] The 800 MW of local capacity approved by the CPUC is referred to 300 MW Pio Pico and 500 MW Carlsbad Energy Center PPTA contracts.
[70] To be met by further procurement of preferred resources in San Diego sub-area
[71] This also includes 133 MW of wind resources, 67 MW (NQC value) of new RPS distributed generation (PV), 17 MW of existing demand response and 800 MW of conventional resources that were approved by the CPUC as part of the long-term procurement plan for Tracks 1 and 4.
[72] This can be met with additional procurement (250 MW) of preferred resources and energy storage as previously authorized by the CPUC for long-term procurement plan Tracks 1 and 4 for San Diego area.

The more detailed discussions for each Local Capacity Area in Southern California are included in Appendix D, and include the Big Creek/Ventura area.

Transmission upgrade options

A number of small-scale transmission upgrades were evaluated for mitigating contingency overloading concerns on the South of Mesa 230kV lines. These are summarized in table D7 in the Appendix D. The following are the more effective and potentially lower cost alternatives that were evaluated:

- opening Mesa 500/230kV Bank #2 under contingency conditions;
- re-arranging Mesa-Laguna Bell 230kV Lines and Opening Laguna Bell – La Fresa 230kV line under contingency; and
- Installing 10-Ohm series reactors[73] on the Mesa-Laguna Bell #1 230kV Line and potentially the Mesa-Redondo 230kV line in the future (beyond ten-year horizon for this line)

Of the above three options, installing 10-Ohm series reactors[74] on the Mesa-Laguna Bell #1 230kV Line and potentially the Mesa-Redondo 230kV line in the future, the third option listed above, appears to have the least impact to the system under contingency condition and potentially have the lowest cost. This transmission upgrade option also would appear to be less costly and more effective in mitigating the potential loading concern than the option that calls for additional local capacity preferred resource procurement in the Western LA Basin.

Conclusions

The following table 3.1-8 summarizes the range of alternatives that were studied to address the 2025 LCR need under various resource procurement scenarios, including the above options and other alternatives that were found not to be sufficient and would leave a resource deficiency in the area. More details are provided in Appendix D of this transmission plan report.

[73] A variation of this option includes a thyristor-controlled series reactor to be inserted upon occurrence of the second N-1 contingency under peak load conditions. This option would have a higher cost than the permanently installed series reactor, but its advantage is to preserve the original line impedance for lower losses in the pre-contingency condition.

[74] See footnote 74.

Table 3.1-8 — High-level summary assessment of 2025 long-term LCR study results for the combined LA Basin / San Diego Area

No	Scenarios	Results
	Alternatives that do meet the identified need	
1	• This is the same as option 1 described above • Fully procure LTPP Tracks 1 and 4 resources up to maximum authorizations for SCE (i.e., 2500 MW) and SDG&E (i.e., 1100 MW); and • Repurpose a total of 476 MW of existing demand response (i.e., this amount is approximately 286 MW beyond the baseline assumption of 189 MW in the LTPP Track 4 scoping ruling) with adequate operational characteristics[75], ***OR***	Then there is no resource deficiency
2	Alternatively to the above additional resource procurement scenario, • implement the CPUC recent decisions for SCE's procurement (i.e., 1813 MW) for the western LA Basin sub-area, and • procure additional 250 MW[76] of preferred resources for local capacity in the San Diego sub-area (part of the CPUC maximum authorizations of 300 MW of preferred resources for San Diego), and • implement small transmission upgrades[77] in the western LA Basin	Then there is no resource deficiency; system is more robust than Scenario 1
	Alternatives that do NOT meet the identified need	
3A	• LTPP Tracks 1 and 4 are not fully procured up to maximum authorizations (i.e., 687 MW less than maximum authorized amount of 2500 MW) for the western LA Basin; • however, fully procure 300 MW preferred resources in San Diego to complete the San Diego local capacity procurement;	Then there would be resource deficiency

[75] Implementable within 20 minutes time frame
[76] Potential preferred resources for procurement under consideration by SDG&E
[77] For further information on potential small-scale transmission upgrades in the western LA Basin, please see discussion and summary table under the "Western LA Basin Sub-area" in this report.

No	Scenarios	Results
	• utilize LTPP Track 4 baseline assumptions for existing demand response (i.e., 190 MW for both western LA Basin and San Diego sub-areas) • but there are no further transmission upgrades in the western LA Basin, ***OR***	
3B	Alternately • same Scenario as 2 but if AAEE does not materialize as forecast (i.e., 962 MW in the western LA Basin and 401 MW in San Diego sub-area) , ***OR***	Then there would be resource deficiency
3C	• same as Option 3B, but the existing demand response is fully repurposed and used (i.e., 894 MW in the western LA Basin and 17 MW in the San Diego sub-area)	Then there would still be resource deficiency

In addition to the above high-level summary assessment of the long-term LCR study results for the combined LA Basin / San Diego area, the following are highlights of other important conclusions:

- Quick start resources such as gas fired combustion turbines, storage resources, and repurposed demand response need to have a response time of within 20 minutes following notification in order to be effective in positioning a system post-contingency to be prepared for the next contingency; NERC standards call for the system to be repositioned within 30 minutes of the initial event, and time must also be allowed for transmission operator decisions and communication.
- With higher level of renewable resource dispatch from the Tehachapi and east of LA Basin, the most critical contingency is the overlapping 230kV lines south of Mesa Substation, which cause loading concerns on the 230kV lines south of Mesa Substation.
- The ISO identified small-scale transmission upgrades that would be effective in mitigating identified loading concerns while staying within the procurement assumptions shown in table 3.1-4.
- Post-transient voltage instability, caused by overlapping outage of the 500kV lines in southern San Diego sub-area, is the next reliability constraint behind the thermal loading constraints in the Western LA Basin.

- The series capacitors on the southern 500 kV lines (i.e., ECO–Miguel, Ocotillo–Suncrest and Imperial Valley–North Gila) are normally bypassed under summer peak load conditions in the studies[78].
- Loading concerns on the Miguel transformers and Sycamore–Suncrest 230 kV lines under overlapping contingency conditions would require special protection system (SPS) refinements as identified in the last planning cycle (i.e., 2014-2015).

3.1.3 Sensitivity 2021 LCR Assessments for the LA Basin/San Diego Area with the Mesa Loop-in Project In-Service by Fourth Quarter 2020 or Prior to Summer 2021

Western LA Basin LCR Sub-Area

The LCR need for the Western LA Basin is based on the need to mitigate thermal overloading concern on the Mesa – Laguna Bell No. 1 230kV line due to the overlapping N-1-1 (P6) contingency of the Mesa – Redondo #1 230kV line, system readjusted, then followed by the contingency of the Mesa – Lighthipe # 1 230kV line. The LCR need to mitigate this overloading concern is determined to be approximately 5,013 MW, of which to be met mostly by projected local capacity resources of 4,541 MW in 2021. That will leave a deficiency of 576 MW, which can be met by either having an additional procurement of 576 MW of preferred resources or energy storage at the substations located on the load side of Laguna Bell, or implementing small-scale transmission upgrades as discussed under section 3.X.X. for the year 2025 scenario. The ISO has found that the small-scale transmission upgrades, such as series reactor for controlling power flow, or interrupting flow through the Mesa 500/230kV transformer banks via Special Protection System under contingencies, is more effective in mitigating identified 230kV loading concerns while still maintaining the CPUC's current level of approved long-term local capacity procurement contracts in the Western LA Basin. Of the 4,541 MW total local resources available in 2021, 1,813 MW are from the CPUC decisions on long-term local capacity procurement for SCE's Western LA Basin sub-area (Decision D.15-11-041). The following tables provide summary of the projected available resources by 2021 and the LCR need for the Western LA Basin sub-area for the scenario with the Mesa Loop-In Project.

[78] This is continued from the last planning cycle studies, which identified this action to mitigate potential loading concerns on the 500kV transmission facilities located south of San Diego area.

Table 3.1-9: Summary of LTPP Local Capacity Procurement for the Western LA Basin Sub-Area

2021 LTPP Tracks 1 & 4 Assumptions	LTPP EE (MW)	Behind the Meter Solar PV (MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
CPUC Final Decisions on SCE-submitted procurement selection[79]	124	37.9	263.6	5	1,382	1,813

Table 3.1-10: Existing Available Resources[80] for the 2021 Planning Horizon

2021	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG[81] (MW)	DR[82] (MW)	Max. Qualifying Capacity (MW)
Existing Available Resources	517	8	588	1,285	157	173	2,728

Table 3.1-11: Summary of LCR Needs for the Western LA Basin Sub-Area for the 2021 Planning Horizon

2021	Total Local Capacity Requirements (MW)	Potential Resource Deficiency (MW)[83]	Break-downs of Projected 2021 Western LA Basin Sub-Area Resources		
			Available Existing Resources (MW)	CPUC-Approved Local Capacity Procurement for Western LA Basin (MW)	Projected Total 2021 Local Resources (MW) (Sum of Two Columns at Left`)
Most Critical Contingency (Multiple)[84]	5,117	(576)[85]	2,728	1,813	4,541

79 The CPUC issued Final Decision (D.15-11-041) on November 24, 2015, regarding SCE-submitted procurement selection for the Western LA Basin.

80 Existing resources minus planned OTC generation retirement and aging generation (i.e., more than 40-year old facilities)

81 Grid-connected RPS DG is expressed in Net Qualifying Capacity (NQC) values

82 Based on the CPUC LTPP Track 4 baseline assumptions for "fast" response DR. This includes 173 MW for the western LB Basin (at most effective locations) and 17 MW of DR in SDG&E system. There is approximately 90 MW currently is eligible to be characterized as being ready for contingency response in 20 minutes or less. The rest will need to be repurposed for response to the second contingency condition.

83 To mitigate this potential resource deficiency concern, potential options include: (a) additional procurement of LTPP preferred resources (at effective locations) and repurposing of additional existing DR; or (b) implement cost effective and environmentally friendly transmission upgrade options. Please see Table 3.1-8 for more details.

84 Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

85 The identified deficiency can be mitigated either by further procurement of preferred resources in the western LA Basin or by implementing small-scale transmission upgrades as discussed under Section 3.1.2. and Table D7 (of Appendix D) for the 2025 long-term LCR scenario.

Eastern LA Basin LCR Sub-Area

The LCR need for the Eastern LA Basin sub-area is based on the need to mitigate post-transient voltage instability that is caused by the loss of the Alberhill - Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines. The LCR need to mitigate this post-transient voltage instability concern is determined to be approximately 2,408 MW, which can be met by available resources in the Eastern LA Basin sub-area. There is no anticipated deficiency for this sub-area.

Table 3.1-12: Available Existing Resources for the Eastern LA Basin Sub-Area for the 2021 Planning Horizon

2021	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	Max. Qualifying Capacity (MW)
Available resources	220	60	581	2,648	22	3,531

Table 3.1-13: Summary of LCR Needs for the Eastern LA Basin Sub-Area for the 2021 Planning Horizon

2021	Local Capacity Requirements (MW)	Deficiency (MW)	Total MW Requirement
Category C (Multiple)[86]	2,408	0	2,408

Total Overall LA Basin LCR Need

The total overall LA Basin LCR need is the sum of the Western and Eastern LA Basin sub-area LCR needs. The LCR needs are based on the most critical contingencies.

Table 3.1-14: Available Existing Resources for the 2021 Planning Horizon

2021	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available resources	737	68	1,169	3,933	179	173[87]	6,259*

Notes:
*Due to large geographic area of the LA Basin (i.e. Western and Eastern Sub-Areas) , not all resources located in the larger LA Basin Area are effective at mitigating identified reliability concerns in the Western LA Basin sub-area.

[86] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[87] Baseline demand response in the LA Basin that was used in the LTPP Track 4 Scoping Ruling and studies

Table 3.1-15: Summary of Total LCR Needs for the LA Basin Area for the 2021 Planning Horizon

2021	Total LCR Requirements (MW)	Existing Resources Needed (MW)	CPUC Final Decisions for SCE Long-Term Local Capacity Procurement (MW)	Deficiency (MW)
Western LA Basin	5,117	2,728	1,813	(576)
Eastern LA Basin	2,408	2,408	0	0
Total LA Basin	7,525	5,136	1,813	(576)[88]

San Diego-Imperial Valley LCR Area

The LCR need for the San Diego-Imperial Valley LCR Area, as well as the San Diego sub-area, is based on the need to help in mitigating thermal overloading concern on the Mesa-Laguna Bell 230kV line No. 1 as a result of the overlapping N-1-1 (P6) contingency of the Mesa - Redondo No. 1 230kV line, system readjusted, then followed by the contingency of the Mesa - Lighthipe No. 1 230kV line. Resources located downstream of the overloaded line help mitigating identified loading concerns. In this study, the ISO dispatched dispatchable resources with 5 percent effectiveness factors to help mitigate this overloading concern. As mentioned in the Western LA Basin sub-area results discussion, the overloading concern was identified with higher level of renewable resource dispatch, based on NQC values for solar and wind resources that are located north of and east of the Los Angeles County (i.e., outside of the LA Basin LCR area). The LCR need to mitigate this overloading concern is determined to be approximately 4,778 MW, which are met mostly by available local capacity resources of 4,618 MW in 2021. That will leave a deficiency of 160 MW, which can be met by procurement of preferred resources and energy storage as part of the authorized long-term procurement for San Diego sub-area. Of the 4,618 MW total local resources available in 2021, 800 MW are from the CPUC decisions on long-term local capacity procurement for San Diego area (i.e., Pio Pico[89] and Carlsbad Energy Center[90]). The following tables provide summary of the projected available resources by 2021 and the LCR need for the San Diego – Imperial Valley LCR area for the scenario with the Mesa Loop-In Project achieving commercial operation by summer of 2021.

[88] Deficiency is only for the Western LA Basin sub-area, which can be addressed by either having additional procurement, or implementing small-scale non-environmental impact transmission upgrades (i.e., line series reactors or interrupting flow through Mesa transformer banks under contingencies).
[89] The CPUC Decisions D.14-02-016, approved on February 5, 2014 and issued on February 12, 2014.
[90] The CPUC Decisions D.15-05-051, approved on May 21, 2015 and issued on May 29, 2015.

Table 3.1-16: Total Projected Available Resources for the San Diego-Imperial Valley Area for the 2021 Planning Horizon

2021	QF (MW)	Wind (MW)	Market (MW)	New RPS DG[91] (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available resources[92]	164	133	4,237	67	17	4,618

Table 3.1-17: Summary of Total LCR Needs for the San Diego-Imperial Valley Area for the 2021 Planning Horizon

2021	Total Local Capacity Requirement (MW)	Available Resources (MW)	Deficiency (MW)	Incremental Resource Needs
				SDG&E Preferred Resources from LTPP Track 4 (MW)
Category C (Multiple)[93]	4,778	4,618	160	160 - 250[94]

3.1.4 Sensitivity 2021 LCR Assessments for the LA Basin/San Diego Area with the Mesa Loop-in Project In-Service Date Delayed (i.e., Not In-Service by Summer 2021)

For this sensitivity analysis, only for the most critical contingency and the corresponding LCR need for the subject sub-area or LCR area is discussed.

Western LA Basin LCR Sub-Area

The LCR need for the Western LA Basin is based on the need to mitigate thermal overloading concern on the Serrano – Villa Park No. 1 230kV line as a result of the overlapping N-1-1 (P6) contingency of the Serrano – Villa Park No. 2 230kV line, system readjusted, then followed by the contingency of the Serrano – Lewis No. 1 (or No. 2) 230kV line. The LCR need to mitigate this overloading concern is determined to be approximately 5,223 MW, most of which is to be met by projected local capacity resources of 4,541 MW in 2021. That will leave a deficiency of 682 MW, which can be met by an extension of the OTC compliance schedule of the Redondo Beach generating facility (for units 1 and 7, or units 1 and 8) until the Mesa Loop-In Project is completed. Of the 4,541 MW total local resources available in 2021, 1,813 MW are from the CPUC decisions on long-term local capacity procurement for SCE's Western LA Basin sub-area (Decision D.15-11-041). The following tables provide summary of the projected available resources by 2021 and the LCR need for the Western LA Basin sub-area for the scenario without Mesa Loop-In Project (i.e., project is delayed until the end of 2021 timeframe).

[91] NQC values based on the CPUC assumptions of 47% of installed capacity for solar DG
[92] This includes 300 MW (Pio Pico) and 500 MW (Carlsbad Energy Center)
[93] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[94] While the needs are 160 MW for 2021, the 2025 incremental needs are 250 MW, which are within the 300 MW authorized amount for preferred resources and energy storage for San Diego.

Table 3.1-18: Summary of LTPP Procurement Assumptions for the Western LA Basin Sub-Area

2021 LTPP Tracks 1 & 4 Assumptions	LTPP EE (MW)	Behind the Meter Solar PV (MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
CPUC Final Decisions on SCE-submitted procurement selection[95]	124	37.9	263.6	5	1,382	1,813

Table 3.1-19: Summary of Existing Available Resources[96]

2021	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG[97] (MW)	DR[98] (MW)	Max. Qualifying Capacity (MW)
Existing Available Resources	517	8	588	1,285	157	173	2,728

Table 3.1-20: Summary of LCR Needs for the Western LA Basin for the 2021 Planning Horizon

2021	Total Local Capacity Requirements (MW)	Potential Resource Deficiency (MW)[99]	Break-downs of Projected 2021 Western LA Basin Sub-Area Resources		
			Available Existing Resources (MW)	CPUC-Approved Local Capacity Procurement for Western LA Basin (MW)	Projected Total 2021 Local Resources (MW) (Sum of Two Columns at Left`)
Most Critical Contingency (Category C-Multiple)[100]	5,223	(682)*	2,728	1,813	4,541

[95] The CPUC issued Final Decision (D.15-11-041) on November 24, 2015, regarding SCE-submitted procurement selection for the Western LA Basin.

[96] Existing available resources are existing resources minus planned OTC generation retirement and aging generation (i.e., more than 40-year old units)

[97] Grid-connected RPS DG is expressed in net qualifying capacity (NQC) values

[98] Based on the CPUC LTPP Track 4 baseline assumptions for "fast" response DR. This includes 173 MW for the western LB Basin (at most effective locations) and 17 MW of DR in SDG&E system. There is approximately 90 MW currently is eligible to be characterized as being ready for contingency response in 20 minutes or less. The rest will need to be repurposed for response to the second contingency condition.

[99] To mitigate this potential resource deficiency concern, potential options include: (a) additional procurement of LTPP preferred resources (at effective locations) and repurposing of additional existing DR; or (b) implement cost effective and environmentally friendly transmission upgrade options. Please see Table 3.1-8 for more details.

[100] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

Notes: *This deficiency can be mitigated by temporary extension of the Redondo Beach generating facility OTC compliance date until the Mesa Loop-In Project is completed with estimated in-service date by the end of 2021 timeframe.

Eastern LA Basin LCR Sub-Area

The LCR need for the Eastern LA Basin sub-area is based on the need to mitigate post-transient voltage instability that is caused by the loss of the Alberhill – Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines. The LCR need to mitigate this post-transient voltage instability concern is determined to be approximately 2,230 MW, which is to be met by available resources in the Eastern LA Basin sub-area. There is no anticipated deficiency for this sub-area.

Table 3.1-21: Available Resources for the Eastern LA Basin Sub-Area for the 2021 Planning Horizon

2021	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	Max. Qualifying Capacity (MW)
Available resources	220	60	581	2,648	22	3,531

Table 3.1-22: Summary of the LCR Needs for the Eastern LA Basin Based on Most Critical Contingency for the 2021 Planning Horizon

2021	Local Capacity Requirements (MW)	Deficiency (MW)	Total MW Requirement
Category C (Multiple)[101]	2,230	0	2,230

Total Overall LA Basin LCR Need

The total overall LA Basin LCE need is the sum of the LCR needs of the Western and Eastern LA Basin sub-areas.

Table 3.1-23: Summary of Available Resources[102] for the Overall LA Basin for 2021 Planning Horizon

2021	QF (MW)	Wind (MW)	Muni (MW)	Market (MW)	RPS DG (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available resources	737	68	1,169	3,933	179	173[103]	6,259*

Notes:
*Due to the large geographic area of the LA Basin, not all resources are effective at mitigating identified reliability concerns in the western LA Basin sub-area.

[101] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[102] Available resources include 1,813 MW of local capacity recently approved by the CPUC for the Western LA Basin sub-area.
[103] Baseline demand response in the LA Basin that was used in the LTPP Track 4 scoping ruling and studies

Table 3.1-24: Summary of LCR Needs for the Overall LA Basin for the 2021 Planning Horizon

2021	Total LCR Requirements (MW)	Existing Resources Needed (MW)	CPUC Final Decisions for SCE Long-Term Local Capacity Procurement (MW)	Deficiency (MW)
Western LA Basin	5,223	2,728	1,813	(682)
Eastern LA Basin	2,230	2,230	0	0
Total LA Basin	7,453	4,958	1,813	(682)[104]

<u>San Diego-Imperial Valley LCR Area</u>

The LCR need for the San Diego-Imperial Valley LCR Area, as well as the San Diego sub-area, is based on the need to help in mitigating thermal overloading concern on the Serrano – Villa Park No. 1 230kV line as a result of the overlapping N-1-1 (P6) contingency of the Serrano – Villa Park No. 2 230kV line, system readjusted, then followed by the contingency of the Serrano – Lewis No. 1 (or No. 2) 230kV line. Resources located downstream of the overloaded line help mitigating identified loading concerns. The LCR need to mitigate this overloading concern is determined to be approximately 4,778 MW, which is met mostly by available local capacity resources of 4,618 MW in 2021. That will leave a deficiency of 160 MW, which can be met by procurement of preferred resources and energy storage as part of the authorized long-term procurement for San Diego area. Of the 4,618 MW total local resources available in 2021, 800 MW are from the CPUC decisions on long-term local capacity procurement for San Diego area (i.e., Pio Pico[105] and Carlsbad Energy Center[106]). The following tables provide summary of the projected available resources by 2021 and the LCR need for the San Diego – Imperial Valley LCR area for the scenario without the Mesa Loop-In Project in 2021 (i.e., scenario where project is delayed until the end of 2021 or before start of summer 2022 timeframe).

[104] Deficiency is only for the Western LA Basin sub-area, under a scenario where the Mesa Loop-In Project in-service is delayed to 4Q 2021 or prior to summer 2022. This can be addressed by potential extension of compliance schedule for the Redondo Beach generating facility for the interim until the Mesa Loop-In Project is completed.
[105] CPUC Decision D.14-02-016, approved on February 5, 2014 and issued on February 12, 2014.
[106] CPUC Decision D.15-05-051, approved on May 21, 2015 and issued on May 29, 2015.

Table 3.1-25: Available Resources[107] for the San Diego-Imperial Valley Area for the 2021 Planning Horizon

2021	QF (MW)	Wind (MW)	Market (MW)	New RPS DG[108] (MW)	DR (MW)	Max. Qualifying Capacity (MW)
Available resources[109]	164	133	4,237	67	17	4,618

Table 3.1-26: Summary of LCR Needs for the San Diego-Imperial Valley Area Based on the Most Critical Contingency

2021	Total Local Capacity Requirement (MW)	Available Resources (MW)	Deficiency (MW)	Incremental Resource Needs SDG&E Preferred Resources from LTPP Track 4 (MW)
Category C (Multiple)[110]	4,778	4,618	160	160 - 250[111]

3.1.5 Resource adequacy import capability

The ISO has established the maximum RA import capability to be used in year 2016 in accordance with ISO tariff section 40.4.6.2.1. These data can be found on the ISO website. (A link is provided here). The entire import allocation process is posted on the ISO website.

The ISO also confirms that all import branch groups or sum of branch groups have enough MIC to achieve deliverability for all external renewable resources in the base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2024.

The future outlook for all remaining branch groups can be accessed at the following link:

http://www.caiso.com/Documents/AdvisoryEstimates-FutureResourceAdequacyImportCapability_Years2016-2025.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2020 to accommodate renewable resources development in this area that ISO has established in accordance with Reliability Requirements BPM section 5.1.3.5. The import capability from IID to the ISO is the combined amount from the IID-SCE_BG and the IID-SDGE_BG.

[107] Includes approved total 800 MW of local capacity resources for San Diego sub-area (i.e., 300 MW from Pio Pico and 500 MW from Carlsbad Energy Center).
[108] NQC values based on the CPUC assumptions of 47% of installed capacity for solar DG
[109] This includes 300 MW (Pio Pico) and 500 MW (Carlsbad Energy Center)
[110] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.
[111] While the needs are 160 MW for 2021, the 2025 incremental needs are 250 MW which are within the 300 MW authorized amount for preferred resources and energy storage for San Diego.

The 10-year increase in MIC from current levels out of the IID area is dependent on transmission upgrades in both the ISO and IID areas as well as new resource development within the IID and ISO systems, and, for the ISO system, on the West of Devers upgrades in particular. The increase to the target level is expected to take place when the West of Devers upgrades are completed and depends on all necessary upgrades being completed in both the ISO and IID areas.

Past studies have indicated that that approximately 500 MW to 750 MW of additional deliverability may be available for new generation that does not have a current PPA and may not already be moving forward. Subject to that deliverability remaining available, future deliverability is to be shared between future resources connected to the ISO grid and those connected to the IID system in the Imperial zone.

3.2 Frequency Response Study

3.2.1. Frequency Response and Over generation issues

As penetration of renewable resources increases, conventional generators are being displaced with renewable resources. Given the materially different operating characteristics of renewable generation, this necessitates broader consideration of a range of issues in managing system dispatch and maintaining reliable service across the range of operating conditions. Many of these concerns relate directly or indirectly to the “duck curve”, highlighting the need for flexible ramping generation but also for adequate frequency response to maintain the capability to respond to unplanned contingencies as the percentage of renewable generation online at any time climbs and the percentage of conventional generation drops. This study focused on the frequency response issue, building on the analysis commenced in the 2014-2015 transmission planning cycle. As a reliability issue, mandatory standards are applicable. However, standards have not been put in place that apply specifically to planning the system – planners instead turn to the conditions that need to be met and performance that must be achieved in real time operations for guidance.

On January 16, 2014 FERC approved Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting), as submitted by North American Reliability Corporation (NERC). This standard created a new obligation for balancing authorities, including the ISO, to demonstrate sufficient frequency response to disturbances that result in decline of the system frequency by measuring actual performance against a predetermined obligation. Compliance with BAL-003-1 will begin December 1, 2016.

NERC has established a methodology for calculating frequency response obligations (FRO). A balancing authority’s FRO is determined by first defining the FRO of the interconnection as a whole, which is referred to as the Interconnection Frequency Response Obligation (IFRO). The methodology then assigns a share of the total IFRO to each balancing authority based on its share of the total generation and load of the interconnection. The IFRO of the WECC Interconnection is determined annually based on the largest potential generation loss, which is the loss of two units of the Palo Verde Nuclear Generation Station (2,626 MW). This is a credible outage that results in the most severe frequency excursion post-contingency.

To assess each balancing authority’s frequency performance, NERC selects at least 20 actual disturbances involving drop in frequency each year, and measures frequency response of each balancing authority to each of these disturbances. Frequency response is measured in MW per 0.1 Hz of deviation in frequency. The median of these responses is the balancing authority’s Frequency Response Measure (FRM) for the year. It is compared with the balancing authority’s FRO to determine if the balancing authority is compliant with the standard. Thus, the BAL-003-1 standard requires the ISO to demonstrate that its system provides sufficient frequency response during disturbances that affected the system frequency. To provide the required frequency response, the ISO needs to have sufficient amount of frequency-responsive units online, and these units need to have enough headroom to provide such a response. Even though the operating standard measures the median performance, at this time planners assume that the performance should be targeted at meeting the standard at all times, and that unforeseen circumstances will inevitably lead to a range of outcomes in real time distributed around the simulated performance.

The transition to increased penetration of renewable resources and more conventional generators being displaced with renewable resources does affect the consideration of frequency response issues. Most of the renewable resources coming online are wind and solar photovoltaic (PV) units that are inverter-based and do not have the same inherent capability to provide inertia response or frequency response to frequency changes as conventional rotating generators. Unlike conventional generation, inverter-based renewable resources must be specifically designed to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their output in response to a decline in frequency. While a frequency response characteristic can be incorporated into many inverter-based generator designs, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has upward ramping headroom remaining. To provide this inertia-like frequency response, wind and solar resources would have to have the necessary controls incorporated into their designs, and also have to operate below their maximum capability for a certain wind speed or irradiance level, respectively, to provide frequency response following the loss of a large generator. As more wind and solar resources displace conventional synchronous generation, the mix of the remaining synchronous generators may not be able to adequately meet the ISO's FRO under BAL-003-1 for all operating conditions.

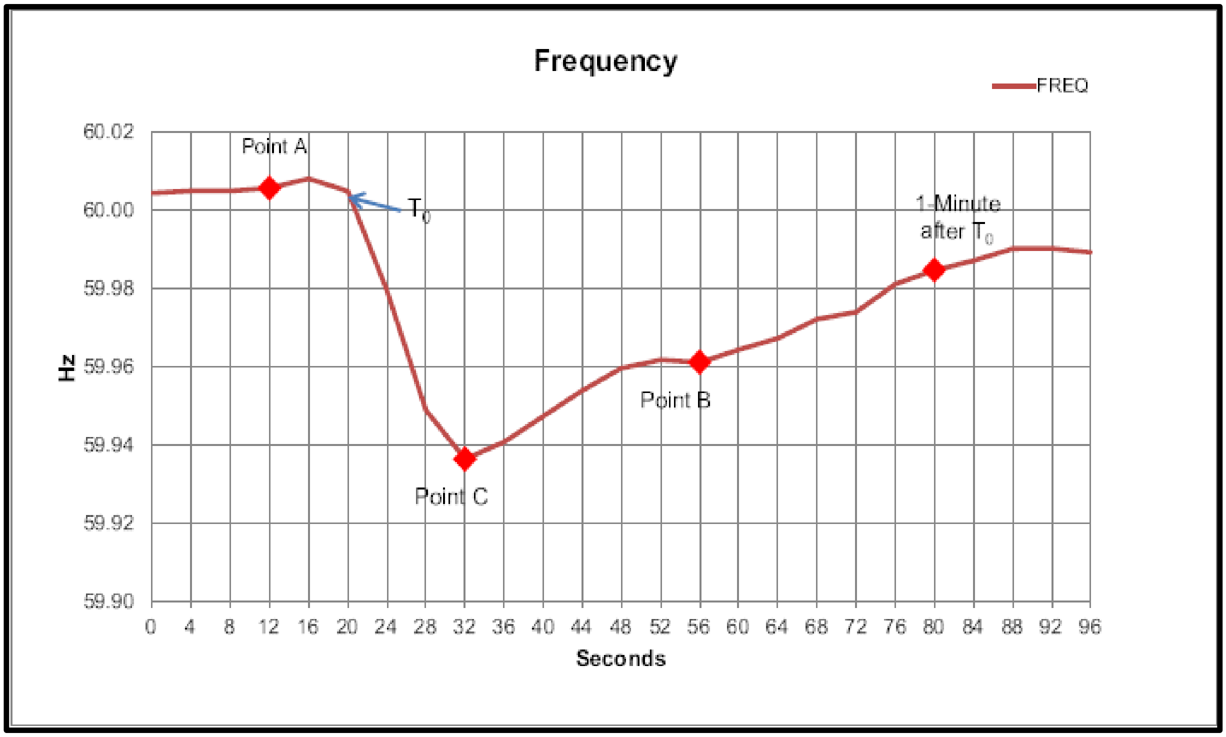
The most critical conditions when frequency response may not be sufficient is when a large amount of renewable resources is online with high output and the load is relatively low, therefore many of conventional resources that otherwise would provide frequency response are not committed. Curtailment of renewable resources either to create headroom for their own governor response, or to allow conventional resources to be committed at a minimum output level is a potential solution but undesirable from an emissions and cost perspective.

The ISO assessed in the 2014-2015 transmission planning process the potential risk of oversupply conditions – a surplus of renewable generation that needs to be managed - in the 2020 timeframe under the 33 percent renewables portfolio standard (RPS) and evaluated frequency response during light load conditions and high renewable production. That study also assessed factors affecting frequency response and evaluated mitigation measures for operating conditions during which the FRO couldn't be met. The ISO continued analysis in the 2015-2016 planning process this study using updated system and equipment models. In this study, the ISO evaluated frequency response and studied such measures to provide the required response as having sufficient headroom on the frequency responsive units.

The ISO 2014-2015 Transmission Plan in section 3.3 (http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf) discusses reliability issues that can occur during oversupply conditions and also describes frequency performance metrics.

As in the 2014-2015 transmission study, this study concentrated on the primary frequency response. Figure 3.3-1 illustrates a generic system disturbance that results in frequency decline, such as a loss of a large generating facility. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 3.3-1. Illustration of Primary Frequency Response.



The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

Frequency response of the Interconnection's Frequency Response Measure or FRM) is calculated as

$$FR = \frac{\Delta P}{\Delta f}\left[\frac{MW}{0.1Hz}\right]$$

Where ΔP is the difference in the generation output before and after the contingency, and Δf is the difference between the system frequency just prior to the contingency and the settling frequency. For each balancing authority within an interconnection to meet the BAL-003-1 standard, the actual Frequency Response Measure should exceed the FRO of the balancing authority. FRO is allocated to each balancing authority and is calculated using the formula below.

$$FRO_{BA} = FRO_{Int} \frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

The Interconnection Frequency Response Obligation changes from year to year primarily as the result of the changes in the statistical frequency variability during actual disturbances, and statistical values of the frequency nadir and settling frequency observed in the actual system events. Allocation of the Interconnection FRO to each balancing authority also changes from year to year depending on the balancing authority's portion of the interconnection's annual generation and load. This study used the WECC FRO for 2016 that was determined as 858 MW/0.1 Hz and being on a conservative side, assumed that the ISO's share is approximately 30 percent of WECC, which is 258 MW/0.1 Hz.

Another metric that was evaluated was the headroom of the units with responsive governors. The headroom is defined as a difference between the maximum capacity of the unit and the unit's output. For a system to react most effectively to changes in frequency, enough total headroom must be available. Block loaded units and units that don't respond to changes in frequency (for example, inverter-based or asynchronous renewable units) have no headroom.

The ratio of generation that provides governor response to all generation running on the system is used to quantify overall system readiness to provide frequency response. This ratio is introduced as the metric Kt; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt is not standardized. For this study, it is defined as the ratio of power generation capability of units with governors to the MW capability of all generation units. For units that don't respond to frequency changes, power capability is defined as equal to the MW dispatch rather than the nameplate rating because these units will not contribute beyond their initial dispatch.

3.2.2. Study assumptions and methodology

The study focused on light spring conditions, because the relatively low level of conventional generation may present a challenge in meeting the FRO. The starting base case selected for the study was 2025 Spring Off-Peak case that was used in the studies of the Pacific Gas & Electric (PG&E) bulk system. The selected case was for the year 2025 because this case had more renewable resources than the cases for the earlier years. A sensitivity study was also performed for one of the cases used for the Policy Studies with 50 percent of renewable generation.

Dynamic stability data used the latest WECC Master Dynamic File. Missing dynamic stability models for the new renewable projects were added to the dynamic file by using typical models according to the type and capacity of the projects. The latest models for inverter-based generation recently approved by WECC were utilized. For the new wind projects, the models for type 3 (double-fed induction generator) or type 4 (full converter) were used depending on the type and size of the project. For the solar PV projects, three types of models were used: large PV plant, small PV plant and distributed PV generation. All the load in the WECC system was modeled with the composite load dynamic model.

The goal of the study was to determine if the ISO can meet its FRO with the most severe credible contingency under the conditions studied. Other goals were to determine under which conditions the FRO may not be met, and what headroom on responsive units the ISO needs to have to meet its FRO.

Several power flow cases were used in the study. As was mentioned earlier, the starting case was the 2025 Spring Off-Peak case that was used for the PG&E bulk system studies. If the FRO is met for this case for the worst credible contingency, other cases with reduced headroom are studied. If the FRO for this case were not met, then the cases with increased headroom would be studied.

It should be noted that for the 2015-2016 transmission planning process (TPP) studies, the WECC IFRO (Interconnection Frequency Response Obligation), and thus the ISO FRO, was assumed to be lower than for the studies of the 2014-2015 transmission planning process. This was because the latest actual IFRO for the WECC Interconnection mandated by NERC was lower than the WECC IFRO for the previous year. Compared with the 949 MW/0.1Hz for WECC and 285 MW/0.1 Hz for the ISO assumed as its FROs in the 2014-2015 Transmission Plan, the latest IFRO mandated by NERC (for the year 2016) was 858 MW/0.1 Hz, and the FRO estimated for the ISO was assumed at 258 MW/0.1 Hz. The document on the latest IFRO determined by NERC can be found by following this link:

http://www.nerc.com/comm/oc/rs%20landing%20page%20dl/frequency%20response%20standard%20resources/ba_fro_allocation_20151204_revised.pdf

The simultaneous loss of two Palo Verde generation units was studied because it results in the lowest post contingency frequency nadir. The transient stability simulation was run for 60 seconds.

In addition to evaluating the system frequency performance and the WECC and ISO governor response, the study evaluated the impact of unit commitment and the impact of generator output level on governor response. For this evaluation, such metrics as headroom or unloaded synchronized capacity, speed of governor response, and number of generators with governors were estimated.

The studies showed that for the starting base case, the ISO FRO was met for the contingency studied. Therefore, other base cases with reduced headroom on the responsive governors were developed. However, the first of these cases did not have reduced headroom. This case had high dispatch of the renewable units that was compensated by reduction of generation on the units with blocked governors. The same contingency of an outage of two Palo Verde units was simulated with this case. This was done to investigate impact of renewable generation on the system frequency versus impact on the frequency of conventional generation that doesn't have frequency response. It appeared that the system frequency performance was essentially the same with renewable units, compared with the conventional units with blocked governors. Thus, the technology of the generation resources appeared not to have impact on frequency performance. What had impact was whether the units respond to changes in frequency.

Other cases studied were the following:

- Case with reduced headroom in the ISO with dispatch in the rest of WECC remaining the same. This was achieved by turning off some units with responsive governors and re-dispatching their output to other frequency-responsive units in the same vicinity (or the same river for the hydro plants). This case was needed to determine at which headroom frequency response from the ISO will not meet the standard.
- Case with reduced headroom in both WECC and the ISO. This was also achieved by turning off some units with responsive governors in WECC and re-dispatching their output to other frequency-responsive units in the same vicinity. This case was needed to determine at which headroom WECC frequency response may become below what is required by the BAL-003 standard, and thus to determine the total required headroom in WECC.
- Case with reduced headroom in WECC but not in the ISO. This case was needed to determine at which headroom ISO frequency performance will be within its Frequency Response Obligation, when at the same time WECC frequency response will be low.
- Case with headroom in WECC reduced even more, to determine what headroom should be in the ISO when total WECC frequency response is at its limit

The headroom in the ISO, as well as the ratio of responsive units to the total, in the latest extreme case when both WECC and ISO frequency response measures are close to those mandated by NERC, can be considered to be the minimum required headroom and the minimum required ratio of responsive units that the ISO should have. In this case, the ISO will contribute its fair share to the WECC frequency response.

The study also investigated the ISO required headroom with different generation dispatch. Results of the study were compared with the results of the similar study from the 2014-2015 Transmission Plan.

Table 3.2-1 shows the load, capacity and dispatch levels of different types of generation technology modeled in the study cases.

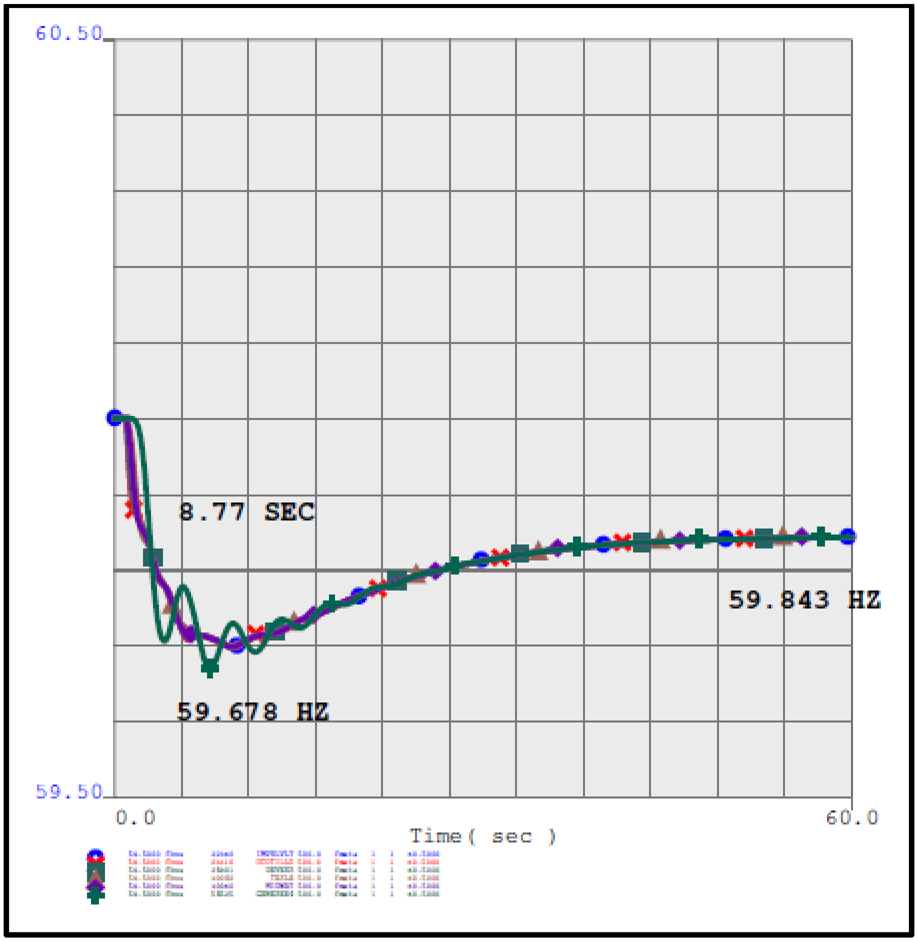
Table 3.2-1. Generation and Load in the cases studied and metrics of responsive generation

		2025 Spring Off-Peak Base	Renewables, Replacing Base Loaded	Reduced Headroom in ISO	Reduced Headroom ISO and WECC	Reduced Headroom WECC only	Extreme Low Headroom WECC only
Load, including pumps and motors	ISO (incl. Muni)	28,559	28,559	28,559	28,559	28,559	28,559
	Total WECC	96,382	96,382	96,382	96,382	96,382	96,382
Generation, Total	ISO (incl. Muni)	29,134	29,183	29,171	29,182	29,183	29,183
	Total WECC	99,406	99,451	99,445	99,457	99,454	99,472
Generation, Responsive Governors	ISO (incl. Muni Dispatch	6,570	6,570	6,197	6,205	6,570	6,570
	ISO (Incl. Muni) Capacity	9,196	9,196	7,333	7,333	9,196	9,196
	Total WECC, Dispatch	31,499	31,471	31,127	31,359	31,555	30,974
	Total WECC, Capacity	47,018	46,986	45,157	40,572	42,144	39,131
Renewable, Non Responsive	ISO (Incl. Muni)	4,752	7,318	7,318	7,318	7,318	7,318
	Total WECC	9,172	11,738	11,738	11,738	11,738	11,738
Conventional, non-responsive	ISO (Incl. Muni)	17,812	15,295	15,656	15,659	15,295	15,295
	Total WECC	58,735	56,242	56,580	56,450	56,161	56,760
Dispatch of Responsive Generation, % of Capacity	ISO (Incl. Muni)	71.4%	71.4%	84.6%	84.6%	71.4%	71.4%
	Total WECC	67.0%	67.0%	68.9%	77.3%	74.9%	79.2%
Kt – ratio of responsive generation to total	ISO (Incl. Muni)	28.9%	28.9%	24.2%	24.2%	28.9%	28.9%
	Total WECC	40.9%	40.9%	39.8%	37.3%	38.3%	36.4%

3.2.3 Study results

The dynamic simulation results for an outage of two Palo Verde generation units for the 2025 Spring Off-Peak base case shows the frequency nadir of 59.678 Hz at 8.8 seconds (7.8 seconds after the disturbance) and the settling frequency after 60 seconds at 59.843 Hz. The frequency plot for the six 500 kV buses with the largest frequency deviations is shown in figure 3.3.2.

Figure 3.2-2: Frequency on 500 kV buses with an outage of two Palo Verde units in the 2025 Spring Off-Peak case



As can be seen from the plot, the frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz. For this contingency, voltages on all the buses were within the required limits.

The study evaluated governor response of the units that had responsive governors. The highest response in MW was from large hydro units in Washington State, with the highest from Grand Coulee unit #22 at 56 MW. This is a large unit (825 MW) that was loaded only to one-third of its capacity in the base case. Other generation units that showed high governor response are Intermountain coal-fired power plant in Utah operated by LADWP; Dry Fork, which is a coal plant in Wyoming; and unit #4 of the San Juan coal plant in New Mexico, as well as hydro power plants in Alberta. If measured in percentage from the generator's capacity, an average response was

5.2 percent, but it varied from 0.2 percent for the units that were loaded up to their capacity to 15 percent for the small lightly loaded units.

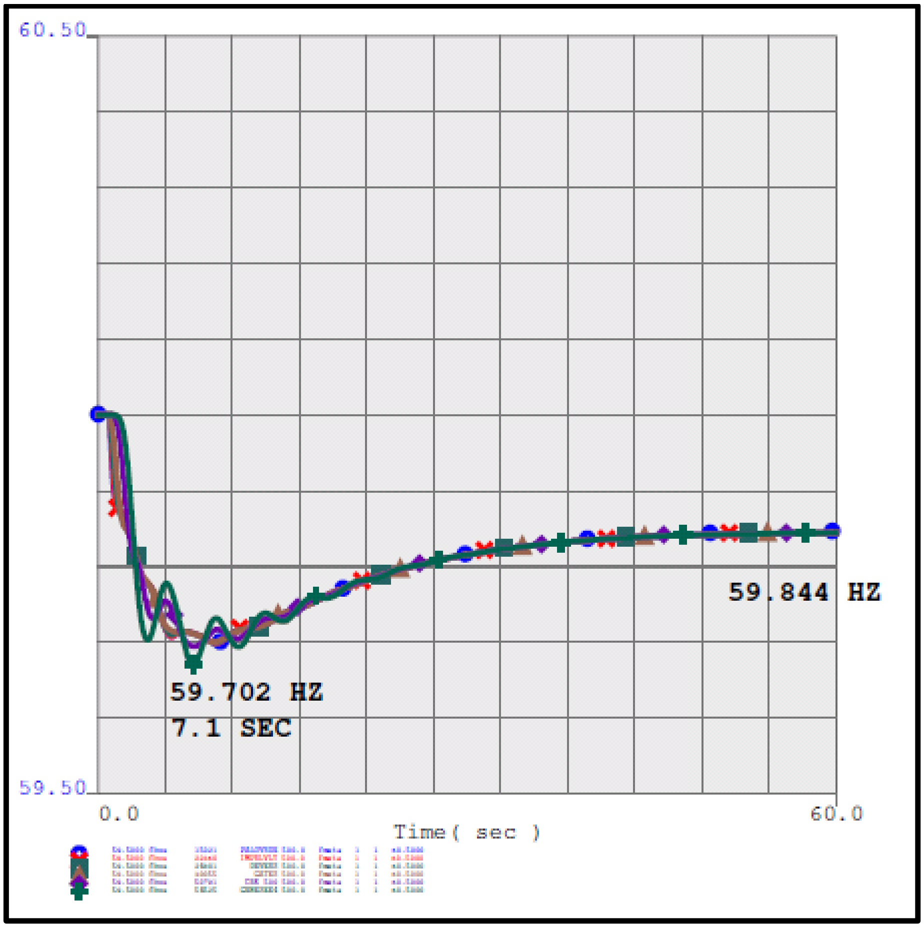
For the base case, total frequency response from WECC was 2,392 MW, or 1,527 MW/0.1Hz, which is well above the WECC Frequency Response Obligation. For the ISO - not including the Sacramento Municipal Utility District (SMUD) - the response was 445 MW, or 284 MW/0.1 Hz, which is also above the ISO FRO of 258 MW/0.1Hz. The calculated headroom in WECC was 15,514 MW with 722 frequency-responsive units, and in the ISO the headroom was 2,416 MW with 146 responsive units. The metric Kt (percentage of responsive generation capacity versus total generation capacity) for this case was 41 percent for WECC and 29 percent for the ISO. Due to the large amount of inverter-based generation within the ISO balancing authority area, which is not responsive to changes in frequency, the Kt metrics for the ISO was significantly lower than for the WECC as a whole.

The next case had increased output from the renewable generation units within the ISO. This increase in generation was compensated by lowering generation from the conventional units that did not have frequency response (base loaded units). The same simulation of an outage of two Palo Verde units was performed. This study was undertaken to determine if the technology has an impact on frequency response for the units that do not respond to changes in frequency. The study result showed that as long as the unit is not responsive to frequency, its technology doesn’t have an impact on the system frequency performance.

The frequency response from WECC in this case was 2,369 MW, or 1,512 MW/0.1Hz, which was almost the same as in the base case. For the ISO (not including SMUD), the response was 446 MW, or 284 MW/0.1 Hz which is the same as in the base case. The headroom on the responsive units and the metric Kt also were the same as in the base case.

The frequency plot for the six 500 kV buses with the largest frequency deviations is shown for this case in figure 3.2.3.

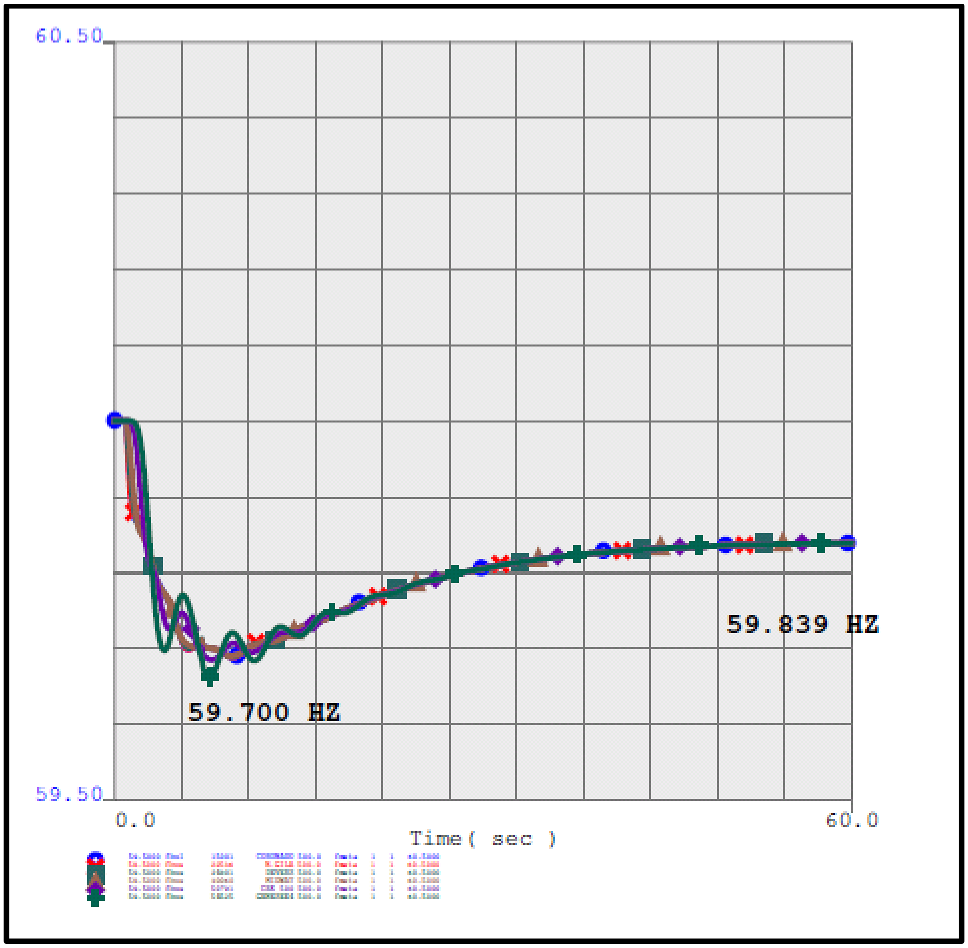
Figure 3.2.3. Frequency on 500 kV buses with an outage of two Palo Verde units in the 2025 Spring Off-Peak case with some base-loaded generation replaced by renewable generation.



Because the base case showed that frequency response from the ISO was above its FRO, the study was performed to determine at which headroom this response will become insufficient. The study case was created by turning off some units that had lower dispatch and re-dispatching their output to other online units. The ISO generation headroom was reduced in this case from 2,416 MW to 1,001 MW. No changes were made to the generation dispatch in the rest of WECC. The same contingency of an outage of two Palo Verde units was studied. Frequency on 500 kV buses in this sensitivity case is shown in figure 3.2-4.

As can be seen from the plot, even if headroom was reduced only in the ISO, both frequency nadir and settling frequency went down compared to the base case. Frequency response from WECC in this case was 2,314 MW, or 1433 MW/0.1Hz, which is still well above WECC Frequency Response Obligation. For the ISO (not including SMUD), the response was 317 MW, or 196 MW/0.1 Hz, which is below the ISO FRO of 258 MW/0.1Hz. The calculated headroom in WECC was 14,056 MW with 688 frequency-responsive units, and in the ISO the headroom was 1,001 MW with 114 responsive units. The metric Kt (percentage of responsive generation capacity versus total generation capacity) for this case was 40 percent for WECC and 24 percent for the ISO.

Figure 3.2-4: Frequency on 500 kV buses with an outage of two Palo Verde units in the case with the reduced headroom in the ISO

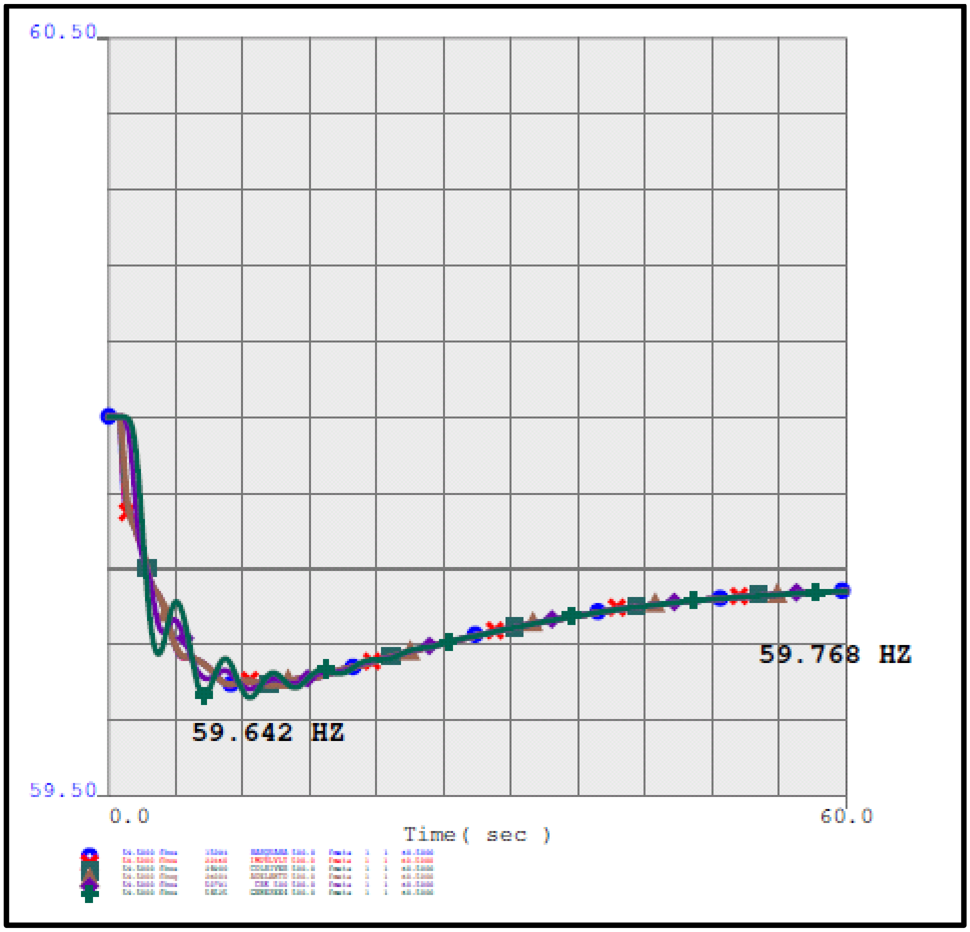


The next case studied was a case with reduced headroom in both WECC and the ISO. This was also achieved by turning off some units with responsive governors in WECC and re-dispatching their output to other frequency-responsive units in the same vicinity. The ISO dispatch remained the same as in the previous case. This case was needed to determine at which headroom WECC frequency response may become below what is required by the BAL-003 standard, and thus to determine the total required headroom in WECC.

The study results showed that the frequency nadir was still above the point of the load shedding (it was at 59.642 Hz). Frequency response from WECC was still above its FRO, 2,290 MW or 989 MW/0.1 Hz. However, frequency response from the ISO was extremely low, 385 MW, or 166 MW/0.1 Hz. Even if the total increase in generation within the ISO in response to the frequency drop was higher than in the previous case, but the response in MW/0.1 Hz was lower because the settling frequency was lower.

Frequency on 500 kV buses in this sensitivity case is shown in figure 3.2-5.

Figure 3.2-5: Frequency on 500 kV buses with an outage of two Palo Verde units in the case with the reduced headroom in the ISO and in WECC



The calculated headroom in WECC was 9,206 MW with 610 frequency-responsive units, and in the ISO the headroom was 1,001 MW with 114 responsive units, same as in the previous case since the dispatch in the ISO hasn't been changed. The metric Kt (percentage of responsive generation capacity versus total generation capacity) for this case was 37 percent for WECC and 24 percent for the ISO.

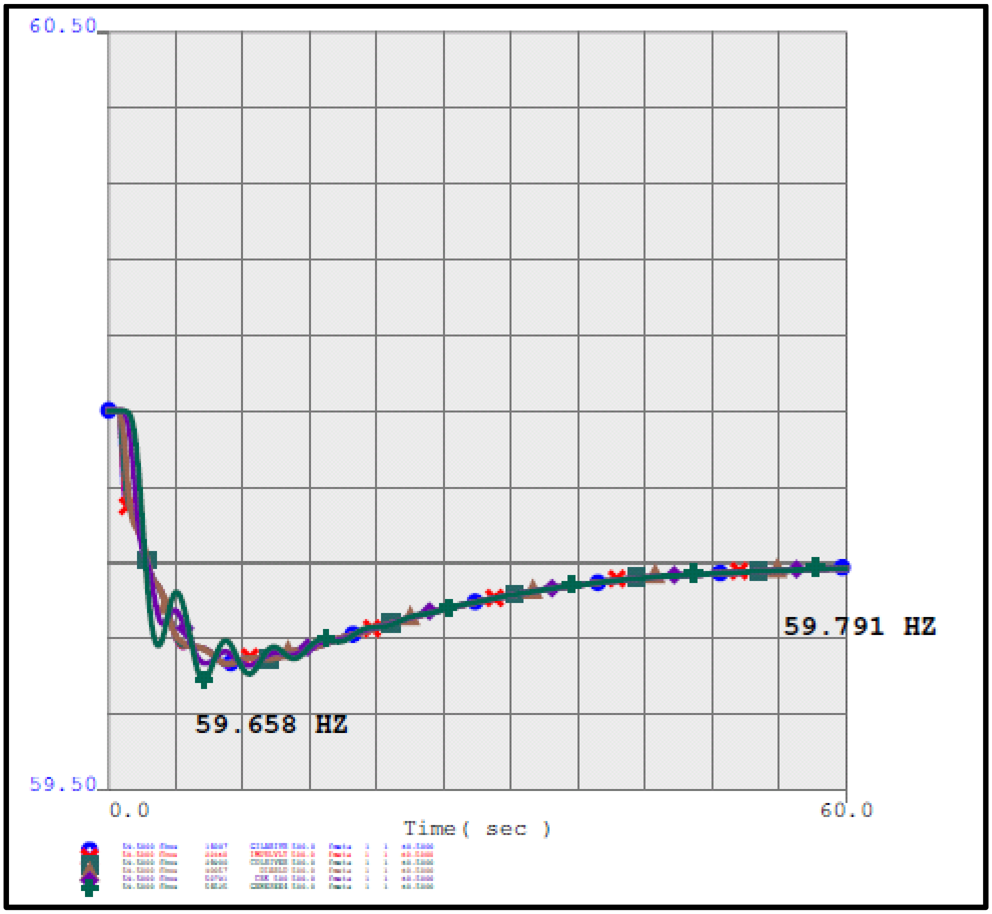
The next case was developed in consideration that the ISO frequency response in MW/0.1 Hz substantially depends on the system settling frequency, and the value of the settling frequency is defined due to the response from the whole WECC and not only from the ISO. The goal of this study was to determine at which headroom the ISO frequency performance will be within its Frequency Response Obligation when at the same time WECC frequency response will be low. This case had reduced headroom in WECC but not in the ISO.

The dispatch in the ISO was the same as in the base case with increased output from the renewable resources and the headroom was reduced only in the rest of WECC by turning off some frequency responsive units and re-dispatching their output to other units in the same vicinity, or on the same river for large hydro plants. This case had 2,416 MW of headroom in the

ISO with 146 frequency-responsive units and 10,619 MW of headroom in the total of WECC with 640 frequency-responsive units.

Frequency on 500 kV buses in this sensitivity case is shown in figure 3.2-6.

Figure 3.2-6: Frequency on 500 kV buses with an outage of two Palo Verde units in the case with the reduced headroom in WECC, but not in the ISO



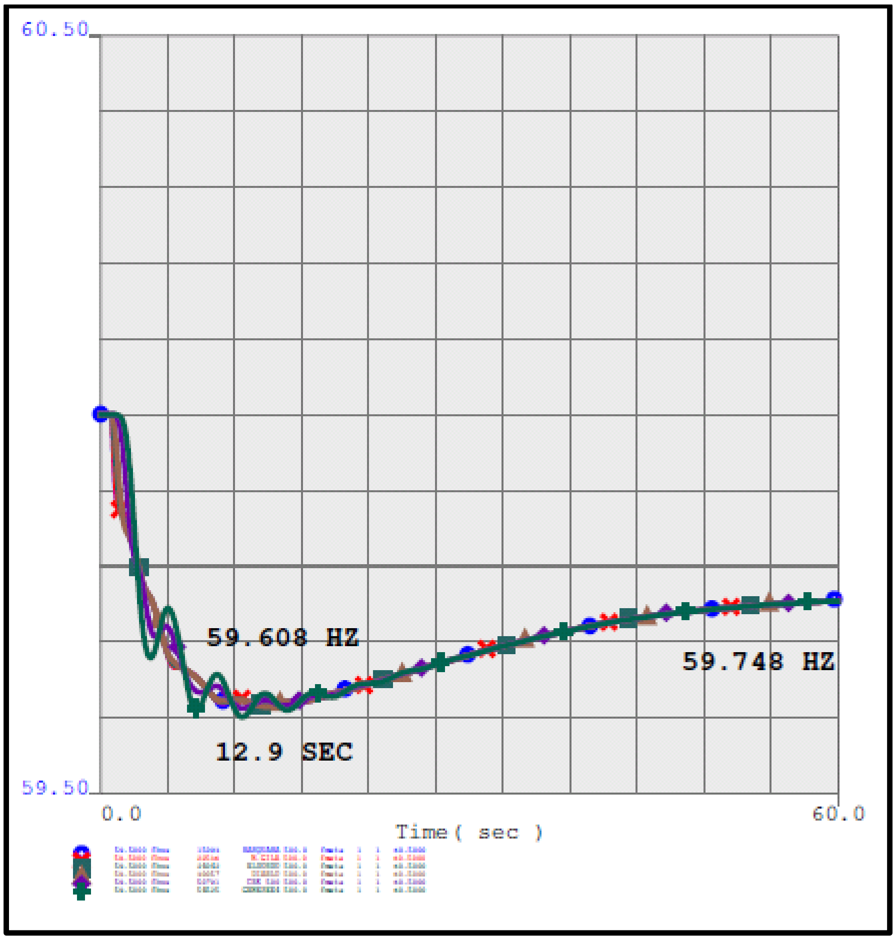
In this case, frequency response from WECC was 2,306 MW, or 1,104 MW/0.1 Hz, and response from the ISO was 576 MW, or 276 MW/0.1 Hz. Both responses from WECC and the ISO were above the Frequency Response Obligations. The metric Kt (percentage of responsive generation capacity versus total generation capacity) for this case was 38 percent for WECC and 29 percent for the ISO.

Because this case had the response from WECC still well above the Frequency Response Obligation, the more extreme case was developed where the headroom in WECC was reduced even more. The dispatch and the headroom in the ISO remained the same. This purpose of this study was to determine what headroom should be in the ISO and in WECC when the total WECC frequency response is close to its limit. If in this case the ISO response is at or above its FRO, the ISO would fulfill its share of the Frequency Response Obligation without relying on the frequency response from other balancing authorities.

The headroom in the ISO remained at 2,416 MW as in the previous cases when the ISO response was acceptable, and the headroom in WECC was reduced in steps to find out the minimum headroom to meet the criteria. Reduction in the headroom was achieved by turning off some frequency responsive units that had low output and high headroom and re-dispatching their generation to adjacent units. The final case had total headroom in WECC at 8,175 MW with 610 frequency-responsive units.

Frequency on 500 kV buses in this sensitivity case is shown in figure 3.2-7.

Figure 3.2-7: Frequency on 500 kV buses with an outage of two Palo Verde units in the case with the extreme low headroom in WECC, but not in the ISO



The results of this study identified frequency response in WECC at 2,227 MW, or 883 MW/0.1 Hz and response from the ISO at 662 MW, or 263 MW/0.1 Hz. The frequency response values for WECC and for the ISO are above, but close to the WECC and the ISO Frequency Response Obligations, which are 858 MW for WECC and 258 MW for the ISO. The metric Kt (percentage of responsive generation capacity versus total generation capacity) for this case was 36 percent for WECC and 29 percent for the ISO.

Thus, the values of approximately 2,500 MW of the headroom and approximately 30 percent of the responsive generation capacity may be considered to be the minimum values to provide the sufficient frequency response from the ISO to meet the BAL-003 standard. However, it should be noted that these values were determined only for this particular case. In the case when the starting generation dispatch on the responsive units is lower, the minimum required headroom will appear to be higher. In the 2025 Spring Off-Peak case that was studied, the dispatch on the responsive units was on average approximately at 71 percent of the unit's capacity. If, for example, the units are dispatched at 30 percent of their capacity, the response from these units will still be the same, because the response generally depends on the unit's capacity and not on its output, unless the output is so high that the remaining headroom is not sufficient. However, the headroom, if the units are dispatched at 30 percent will constitute the remaining 70 percent of the capacity, versus 29 percent of the capacity when the units are dispatched at 71 percent as in the case studied. Therefore, if the average dispatch of the responsive units were 30 percent of their capacity, and the remainder would be dispatched on non-responsive units, the required headroom would be around 6,000 MW, instead of the 2,500 MW when the units are dispatched at 71 percent. Thus, the metric Kt, which is the percentage of the frequency responsive capacity versus total generation capacity appears to be a more universal measure than just the headroom.

In the 2014-2015 Transmission Plan study, the headroom on the responsive units in the ISO was estimated as 4,420 MW, when the response was approximately the same as in the case of the 2015-2016 Transmission Plan (269 MW/0.1 Hz in the 2014-2015 transmission planning process versus 263 MW/0.1 Hz of the final study case with low WECC headroom). However, the dispatch of the frequency-responsive units was on average only at 48 percent of the units' capacity versus 71 percent in the case of the 2015-2016 Transmission Plan. The metric Kt, in this case of the 2014-2015 TPP for the ISO was at 31 percent, which is very close to the same metric for the 2025 Spring Off-Peak case used in this study (29 percent). This also proves that the percentage of the frequency responsive capacity is a more universal measure that the headroom.

The following table summarizes the study results of the 2025 Spring Off-Peak case.

Table 3.2-2. Frequency Response study results for the 2025 Spring Off-Peak Conditions

Case	Name	Settling Frequency	Response WECC (FRO 858 MW/0.1HZ)		Response ISO (w/out SMUD) (FRO 258 MW/0.1 HZ)		Headroom, MW		Responsive Units (with increased output)	
		HZ	MW	MW/0.1 HZ	MW	MW/0.1 HZ	WECC	ISO (w/out SMUD)	WECC	ISO (w/out SMUD)
1	2025 Spring-off- peak base	59,843	2,393	1,527	445	284	15,514	2,416	722	148
2	High renewable, replacing base loaded	59,844	2,369	1,512	446	284	15,514	2,416	722	148
3	Reduced Headroom in ISO	59,839	2,314	1,433	317	196	14,056	1,001	688	114
4	Reduced Headroom ISO and WECC	59,768	2,290	989	385	166	9,206	1,001	610	114
5	Reduced Headroom WECC only	59,791	2,306	1,104	576	276	10,619	2,416	640	146
6	Extreme Low Headroom WECC only	59,748	2,227	883	662	263	8,175	2,416	610	146

3.3.4. Sensitivity Case with 50% of generation from renewable resources.

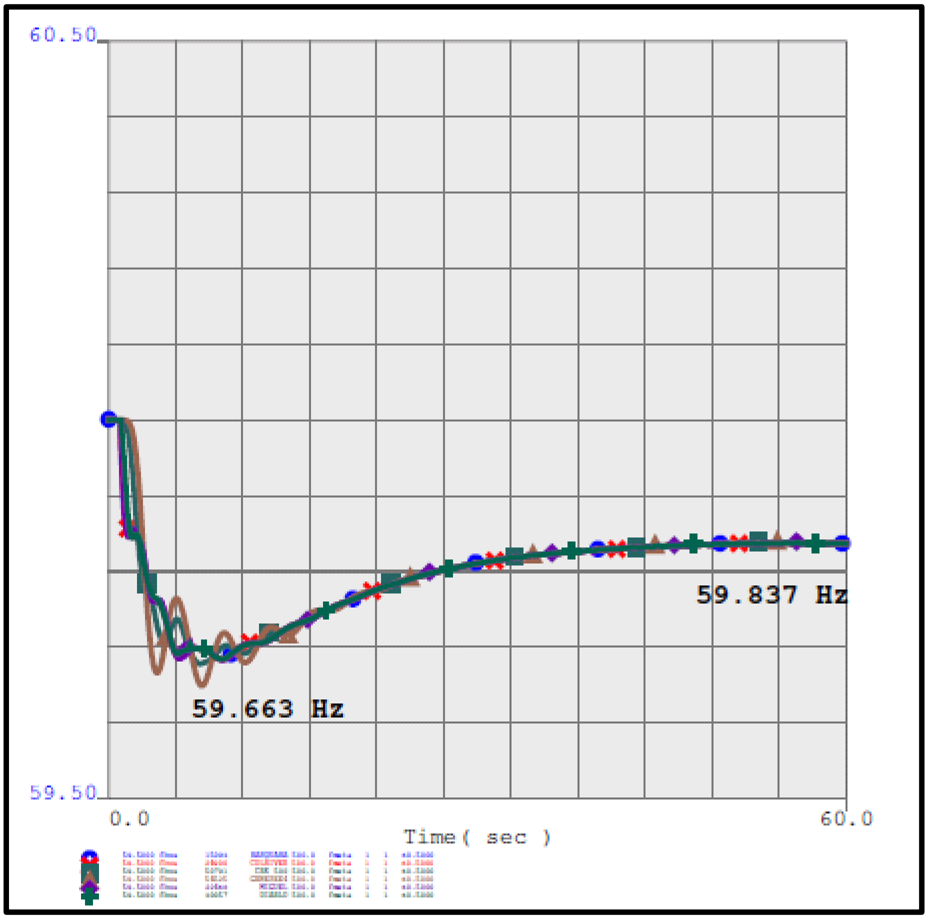
A sensitivity screening study was performed for one of the cases for the policy-driven studies — northern California with 50 percent of generation provided by renewable resources coming from out-of-state.

This case had 13,258 MW of headroom on frequency-responsive units in WECC and 1,053 MW of headroom in the ISO. There were 661 frequency-responsive units dispatched in the whole WECC and 78 frequency-responsive units dispatched in the ISO.

The same contingency of an outage of two Palo Verde units was studied. Transient stability simulation was run for 60 seconds. The study results showed that frequency response from WECC was 2,341 MW, or 1,436 MW/0.1 Hz, which is above WECC FRO. The response from the ISO was 190 MW, or 116 MW/0.1 Hz, which is significantly below ISO FRO. The frequency nadir and the settling frequency were within the acceptable limits, subsequently at 59.663 Hz and 59.837 Hz.

Frequency on 500 kV buses in this sensitivity case is shown in figure 3.3-8.

Figure 3.2-8: Frequency on 500 kV buses with an outage of two Palo Verde units in the Northern California case with 50 percent of generation from renewable resources



It can be concluded that with 50 percent of generation coming from renewable sources, frequency response from the ISO may become deficient.

3.2.5. Study Conclusions

- The initial study results indicated acceptable frequency performance both within WECC and the ISO for the base case studied (Spring Off-Peak of 2025). Both WECC and the ISO frequency response was above the obligation specified in BAL-003-1. However, with lower commitment of the frequency-responsive units, frequency response from the ISO may fall below the Frequency Response Obligation specified by NERC.
- In the future when more inverter-based renewable generation will come online, frequency response from the ISO will most likely become insufficient.
- Compared to the ISO's actual system performance during disturbances, the study results seem optimistic because actual frequency responses for some contingencies were lower than the dynamic model indicated. Therefore, a thorough validation of the models needs to be performed to ensure that governor response in the simulations matches their response in the real life.
- The main factor in insufficient frequency response is insufficient amount of generating resources that respond to frequency deviations. The studies showed that technology of

the resources not responding to frequency deviations did not have any impact on frequency response. The study results were the same when base-loaded units were replaced by wind and solar PV generation.

- The study to determine minimum required headroom on frequency responsive generation showed that the value for this headroom substantially depends on the initial generation dispatch. With the frequency-responsive ISO generation dispatched on average at 71 percent of capacity, minimum required headroom was calculated as about 2,500 MW. With lower dispatch of the frequency-responsive units, the minimum required headroom will be higher. Because frequency response of each unit depends more on the unit capacity than on the output, and the headroom is directly tied to the unit's output, the headroom may not be a good indicator of the frequency response metric. The exception is when a unit is dispatched close to its capacity, then it will not have sufficient room to respond to frequency dips.
- The requirement for the ISO to have a certain headroom on frequency-responsive units appears not to be universal as the required headroom substantially depends on the generation dispatch. Depending on the generation dispatch, the minimum headroom requirement will be different.
- Determining the headroom of each unit appears to be challenging because maximum generation output may not match the unit's nominal capacity. Some units may supply more power than their capacity due to additional gain of their turbines, and some units cannot get to their maximum capacity due to limitations in gate openings and lower gain of the turbines.
- A more universal indicator of the frequency response than the headroom is the percentage of the frequency responsive capacity versus total generation capacity (metric Kt). The study results showed that this metric has to be above 30 percent in the ISO and approximately above 35 percent in total of WECC for both ISO and WECC to respond above its Frequency Response Obligations. This is in addition to frequency-responsive units not to be dispatched above 90-95 percent of their capacity to have sufficient room to increase their output in response to frequency decline.
- Exploration of other sources of governor response is needed. These sources may include the following: load response, response from storage and frequency response from inverter-based generation.
- Exploration of procurement of the frequency-responsive reserve from other balancing authorities is also needed. To determine the amount of frequency-responsive reserve to be procured by the ISO from other balancing authorities, additional studies are required.

Further work will investigate measures to improve the ISO frequency response post contingency. Other contingencies may also need to be studied, as well as other cases with reduced headroom. Future work will also include validation of models based on real-time contingencies and studies with modeling of behind the meter generation.

3.3 Gas-Electric Coordination Transmission Planning Studies for Southern California

Section 6.3 of the California ISO 2015-2016 Transmission Planning Process Unified Planning Assumptions and Study Plan[112] included the following discussion regarding the need to examine the potential impact of gas supply on the operation of gas-fired electric generating facilities:

“The potential impacts of the changing role of gas-fired generation in providing local capacity support and flexible generation needs has been raised as a concern regarding both physical capacity and gas contracting requirements that should be examined in the planning framework. This issue will be explored, and to the extent viable, studied in this planning cycle. The scope of work itself will be defined through the preliminary analysis carried out in this cycle; as such, it may be necessary to execute much of the scope of work over several planning cycles.”

In this planning cycle, because of known gas supply events that affected the operation of electric generating facilities in southern California in recent years, the discussion of potential gas-electric coordination issues and transmission planning reliability assessment studies focus on the southern California system, primarily the Los Angeles Basin and the San Diego metropolitan areas, and gas supply disruption scenarios were developed from events over the last number of years.

However, this study was scoped and much of the analysis completed before the circumstances and the potential impacts became apparent regarding the leak detected in October 2015 at one of the natural gas storage wells at the Aliso Canyon storage field in the Santa Susana Mountains. The storage field is the largest of SoCalGas’s four storage facilities and the most strategically located for serving the LA Basin and San Diego generation. The potential loss of the use of the field across a season was far beyond the outage scenarios contemplated for this preliminary analysis. Current efforts are focusing on the more immediate operational situation, and as the implications are better understood, they will be incorporated into an expanded scope of long term planning analysis in the 2016-2017 planning cycle.

As well, the analysis undertaken this year indicates that more analysis is necessary to assess flexible generation needs and local ramping needs to necessary to address transmission contingencies during adverse gas supply conditions is necessary. This in turn needs to take into account a more granular view of the gas supply system, and the role critically-located gas storage fields can play.

Overview of Southern California’s Gas Transmission System

Most of the natural gas used in California comes from out-of-state natural gas basins. As of 2012, California customers received 35 percent of their natural gas supply from basins located in the Southwest, 16 percent from Canada, 40 percent from the Rocky Mountains, and 9 percent from basins located within California.

112 http://www.caiso.com/Documents/2015-2016FinalStudyPlan.pdf

Natural gas from out-of-state production basins is delivered into California via the interstate natural gas pipeline system. The major interstate pipelines that deliver out-of-state natural gas to southern California consumers are the following:

- El Paso Natural Gas Company;
- North Baja – Baja Norte Pipeline, which takes gas off the El Paso Pipeline at the California/Arizona border, and delivers that gas through California into Mexico;
- Kern River Transmission Company;
- Mojave Pipeline Company;
- Questar's Southern Trails Pipeline Company, and
- Transwestern Pipeline Company.

The FERC regulates the transportation of natural gas on the interstate pipelines, and the CPUC regulates the intra-state pipeline, local transmission and distribution pipeline system within California. The CPUC has regulatory jurisdiction over 150,000 miles of utility-owned natural gas pipelines, which transported 82 percent of the total amount of natural gas delivered to California's gas consumers in 2012.

Most of the natural gas transported via the interstate pipelines, as well as some of the California-produced natural gas, is delivered into the PG&E and southern California Gas Company intrastate natural gas transmission pipeline systems (also known as California's "backbone" natural gas pipeline system). Natural gas on the utilities' backbone pipeline systems is then delivered into the local transmission and distribution pipeline systems, or onto natural gas storage fields. Some large noncore customers take natural gas directly off the high-pressure backbone pipeline systems, while core customers and other noncore customers take natural gas off the utilities' distribution pipeline systems.

In the northernmost of the SoCalGas system in the Wheeler Ridge Zone at Kern River Station in the San Joaquin Valley, SoCalGas maintains a major interconnection with the PG&E intrastate pipeline system, and receives PG&E/Gas Transmission Northwest deliveries at that location.

The SoCalGas Northern System interconnects with the Transwestern Pipeline Company and the Southern Trails Pipeline Company at North Needles, California and with El Paso Natural Gas Company at Topock, California. In addition, it also includes connection with Kern River Transmission Company and Mojave Pipeline Company at Kramer Junction in the high desert. figure 3.3-1 depicts the Sempra-owned gas transmission system.

The SoCalGas Southern System consists primarily of: three high-pressure pipelines extending westward from the Colorado River near Blythe to Moreno Station in the City of Moreno Valley; two high-pressure pipelines extending westward from Moreno Station to the LA Basin; and three high-pressure pipelines extending southward from Moreno Station to San Diego Gas & Electric's (SDG&E) gas transmission system. The three high-pressure pipelines extending southward to the SDG&E gas transmission system are also known as the Rainbow Corridor gas system.

According to SoCalGas[113], the Southern System was designed primarily to receive gas from El Paso system at the Colorado River near Blythe and deliver it to load centers at these communities:

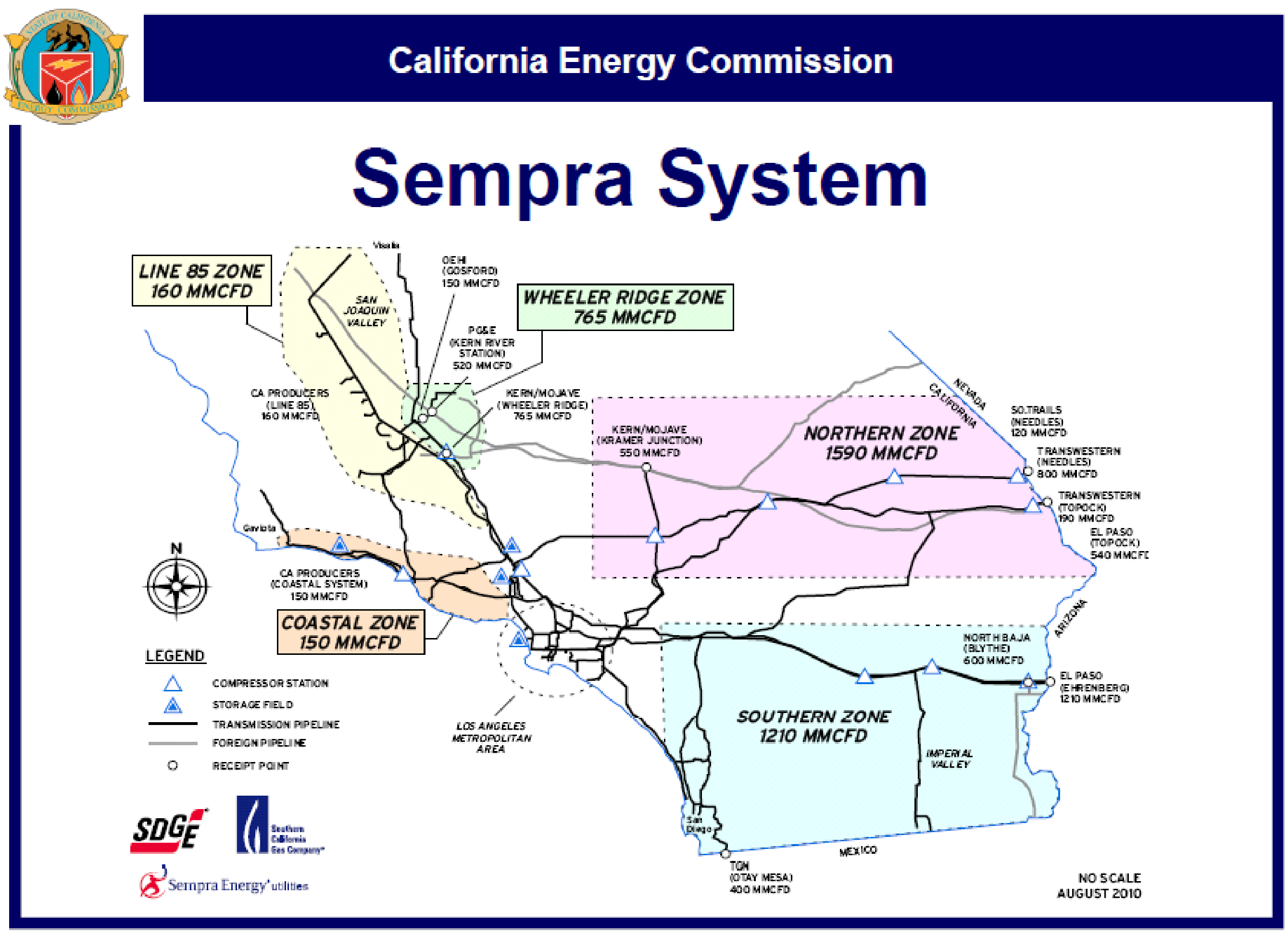
[113] SoCalGas and SDG&E's Application (A.13-12-013) to the CPUC for the North-South Project Revenue Requirements (http://www.socalgas.com/regulatory/A1312013.shtml)

Inland Empire, Imperial Valley, San Diego and the LA Basin. Additional supplies can be received from other pipelines within the SoCalGas system using the two valve stations located on the high-pressure pipelines extending westward from the Moreno Station,and from the Otay Mesa receipt point; however, the volume of supplies at Otay Mesa has been minimal due to growing demand of natural gas that is exported to Mexico.

SoCalGas can also transport up to 80 million cubic feet per day (MMcfd) of supply from its Northern System to Southern System via gas Transmission Line No. 6916 (aka: Questar Southern Trail Pipeline).

The figure below (courtesy of the CEC, SoCalGas and SDG&E) shows Sempra's SoCalGas and SDG&E gas transmission systems. The SoCalGas Southern System and SDG&E gas system are shown in light blue color area.

Figure 3.3-1 SoCalGas and SDG&E gas system



Southern System's Minimum Flow Requirements

The Southern System requires minimum flows at the Blythe or Otay Mesa receipt points to maintain service to customers in the Imperial Valley and San Diego load centers, as well as to customers in the communities in the San Bernardino and Riverside Counties. Supplies to the Southern System can also be provided by the Chino and Prado Stations. However, supplies that are not met by these two stations establish the minimum flow requirements that would need to be delivered at Blythe or Otay Mesa.

According to SoCalGas, the Southern System minimum flow rose from an annual average level of 366 Mdth/d[114] in 2008 to the current 541 Mdth/d, in large part due to the retirement of the San Onofre Nuclear Generating Station and increased in gas demand from the Southern System electric generating facilities. At the same time, gas deliveries into the Southern System dropped from an annual average level exceeding 800 Mdth/d in 2008 to 593 Mdth/d in 2013 as the El Paso supplies are diverted to the higher-value Mexican markets.

Gas Supply Impact Concerns on Gas-Fired Generating Facilities

Generally, natural gas demand is typically highest in the winter months because natural gas is used to heat homes and businesses in the winter and is also used in many industrial processes. Natural gas-fired generation, however, is highest in the summer months because the demand for electricity is higher, with the increase largely driven by air conditioning loads. The gas distribution companies categorize residential, small commercial and business customers as core customers. Electric generation facilities, as well as hospitals, refineries, food processing facilities and other large-scale operation customers are categorized as non-core customers. In an event of a gas-related emergency, natural gas-fired generation and other non-core customers are often curtailed first. Thus, natural gas reliability issues can become electric reliability issues and would need to be coordinated carefully in a gas-related emergency condition to maintain both natural gas and electric system reliability.

The following are recent gas related issues that occurred in the last few years which impacted electric generating facilities in southern California:

Winter gas curtailment that affected non-core customers such as electric generating facilities in the Southern Zone;

Recent summer gas curtailment in the summer 2015 due to major gas transmission line outage in the SoCalGas' Northern Zone (Line 4000) that affected various generating facilities in the Western LA Basin.

Winter Gas Curtailment Concerns

There have been two major gas curtailments[115] in the last four years due to a combination of high demand and inadequate supplies to the SoCalGas' Southern System:

[114] 1 MDth = 1 thousand dekatherms ~ equivalent to 1 million cubic feet (MMCF) of natural gas
[115] http://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx and https://www.sdge.com/sites/default/files/regulatory/ORA-06.doc

- In February 2011 cold weather in Texas led to natural gas supply shortages from wellhead “freeze-offs.” Reduced production from the Permian and San Juan basins contributed to the loss of firm electric load in Texas, portions of the Desert Southwest and also resulted in a substantial reduction in the volume of gas flowing to California. On February 3, 2011, the SoCalGas Southern System curtailment was initiated because of a lack of supply from upstream pipelines. It was estimated that gas curtailment of about 200 MMcfd of gas was implemented, which affected non-core customers, including electric generation, in the San Diego area. SoCalGas curtailed 19 interruptible retail non-core and electric generator customers, and 40 firm non-core and electric generator customers. SDG&E curtailed all its interruptible load and all its firm service to three electric generator customers. Approximately 59 MW to 476 MW of electric generation outputs were curtailed in the SCE service area (non-local reliability area) for a period of 13 hours on February 3, 2011. Within SDG&E service area, approximately generation curtailments in the amount of 117 MW to 440 MW were implemented in a 13-hour period. Additional generation curtailments of 57 MW to 379 MW were implemented in a 14-hour period.[116]

- On February 6, 2014, many states experienced severe cold weather conditions and natural gas supplies were limited in some parts of the country as a result. This created competition for natural gas supplies delivered to California. In some cases, natural gas was being pulled out of storage in California to offset natural gas demand needs outside of California. The SoCalGas Company contacted the ISO before 7 a.m. on the gas supply constraint day with concerns about the generating units’ gas usage rates. The company informed the ISO that they were experiencing triple the gas burn rate compared to the day before and was declaring a gas emergency; it asked that Encina units 1, 2, 4 and 5, with a total of about 700 MW, to be off line. The company soon later directed that all generating units located in the southern portion of its system not increase their current natural gas usage rates as it called a system-wide emergency. By mid-day, the company asked that about 1,000 MW of generation be reduced in SCE service area to make it through gas peak period. In response to the gas curtailments, the ISO issued exceptional dispatches to generators to ensure they did not increase their gas usage rate, consistent with SoCalGas’ directive. The ISO real-time operators then dispatched other generating units outside of SoCalGas’ southern system, and intertie resources, to make up for the loss of the power plants. The ISO also called for demand response with about 602 MW expected for the southern California area. About 548 MW of firm load was curtailed in SCE service area, and 2 MW was curtailed in SDG&E service area. Overall, it was estimated that approximately 300 MMcfd of natural gas was curtailed.

[116] http://www.caiso.com/Documents/April18_2011CorrectedFebruary2011ExceptionalDispatchReport_Chart1data_inDocketNos_ER08-1178-000_EL08-88-000.pdf

Summer Gas Curtailment Concerns Due to Major Gas Transmission Maintenance Outage

On June 30, 2015, the SoCalGas Company had an outage online 4000, a large transmission gas pipeline that impacts delivery of gas to the LA Basin. The ISO was requested to reduce generation output up to 1,700 MW to reduce gas usage on a select set of units in the north and south LA Basin of SoCalGas transmission zones. The company informed the ISO that the gas pipeline maintenance outage was scheduled to last until August 28, 2015. On June 30, 2015, the ISO curtailed approximately 1,600 MW using exceptional dispatch to the following generating facilities in the LA Basin in response to SoCalGas' request for gas curtailments at various hours on June 30, 2015:

- Malberg Generating Station
- Glen Arm Unit 1-4
- Center peaker
- Carson Cogeneration
- Canyon Power Plant Unit 1-4
- Anaheim Combustion Turbine
- El Sungundo Energy Center Unit 5 - 8
- El Segundo Generating Station Unit 4
- Harbor Cogen Combined Cycle
- Hinson Long Beach Unit 1-2
- Alamitos Generating Station Unit 1-4
- Alamitos Generating Station Unit 5-6
- Barre Peaker
- Huntington Beach Unit 1-2
- Redondo Generating Station Unit 5-8
- Watson Cogeneration Company.

In addition to the generation curtailments mentioned above, approximately 400 MW of demand response was implemented in SCE service area in tandem with an ISO issued Flex Alert that urged voluntary conservation. SCE triggered its demand response program, which consisted primarily of its AC cycling program.

The following table provides a summary of the aggregated MW output and estimated total gas volume usage (in MMCFH) for generating facilities in each of the proposed gas transmission zones in the LA Basin and San Diego areas.

Table 3.3-1 Summary of Existing Generating Facilities Maximum Output and Estimated Total Gas Volume Usage in the LA Basin and San Diego Areas

	Gas Transmission Zone	Aggregated Generation Output (MW)	Estimated Total Gas Volume Usage (MMCFH)[117]
1	South of Moreno/SDG&E	2,997	27.35
2	South of Moreno / SCE	742	6.75
3	West of Moreno	748	6.8
4	East of Moreno	1,425	12.95
5	North of LA Basin	384	3.49
6	South of LA Basin	5,798	52.71
7	Northern Gas Transmission Zone	1,937	17.61

Based on the above information, it is observed that the total gas volume usage trends linearly with the aggregated generation output. It is also noted that the gas transmission zones are not the same geographically as the electric local capacity requirement (LCR) areas or sub-areas (see Fig. 1), except for the South of Moreno / SDG&E zone, which mirrors the San Diego sub-area.

Gas-Electric Coordinated Transmission Planning Studies

To address the gas-electric coordination concerns, the ISO proposed the following reliability assessments. During the course of evaluation, some of the earlier proposed studies were determined no longer needed due to projected retirement of once-through-cooled generating facilities in the LA Basin and San Diego areas. More detailed discussion is provided in the following sections. The studies that were performed have the assumptions of existing gas transmission infrastructure.

Summer Reliability Assessment

The ISO originally proposed this study to assess whether a major gas transmission pipeline outage (i.e., Line No. 4000), due to maintenance need, would have any electric transmission reliability impact to the LA Basin and San Diego areas under summer peak load conditions for the long-term horizon. As discussed in the above sections, up to 1,600 MW of generation was curtailed in various amounts at fourteen power plants in the western LA Basin as a result of the extended outage on gas pipeline Line No. 4000. After further evaluation, the ISO determined that the total net generation reduction, due to retirement of OTC generating units and potential

[117] Million cubic feet per hour

retirement of aging generating facilities (i.e., units that are forty years and older), exceeds the total amount of generation curtailment that occurred in June 2015. The following table illustrates this point. To determine the future amount of net generation reduction as a sum of future retirements and repowering and/or additions in the LA Basin, the ISO included the units that have retirement dates and in-service dates after summer 2015.[118]

[118] Summer 2015 was when the gas curtailment to various gas-fired generation occurred. Therefore, to determine the future net gas-fired generation reduction in the LA Basin, the retirement and in-service dates need to occur after summer 2015.

Table 3.3-2: Future Net Generation Reduction in the Western LA Basin

Generating Facility (Total Plant MW)	Owner	Unit	State Water Resources Control Board (SWRCB) Compliance Date	Net Qualifying Capacity (NQC) (MW)	Repowering Projects that Are Completed or Have Obtained CPUC Approval for PPTAs (MW)
El Segundo		4	12/31/2015	-335	
Alamitos (2,011 MW)	AES	1	12/31/2020	-175	
		2	12/31/2020	-175	
		3	12/31/2020	-332	
		4	12/31/2020	-336	
		5	12/31/2020	-498	
		6	12/31/2020	-495	
		New 2x1 CCGT			+640 (estimated in-service Summer 2020)
Huntington Beach (452 MW)	AES	1	12/31/2020	-226	
		2	12/31/2020	-226	
		New 2x1 CCGT			+644 (estimated in-service Summer 2020)
Redondo Beach (1,343 MW)	AES	5	12/31/2020	-179	
		6	12/31/2020	-175	
		7	12/31/2020	-493	
		8	12/31/2020	-496	
		5	12/31/2017	-329	
Stanton Energy Reliability Peakers					+98 (estimated in-service date of Summer 2020)
Total Retirement after Summer 2015				-4,470	
Total Addition & Repowering after Summer 2015					+1,382
Total Net Gas-Fired Generation Reduction after Summer 2015					-3,088

Based on the table above, it is estimated that a total net gas-fired generation reduction in the western LA Basin is 3,088 MW, well exceeds the 1,600 MW of generation curtailment due to major gas transmission line outage that occurred in June 2015. The impact of this net gas-fired generation reduction is already captured in the long-term (2025) as well as mid-term (2021) LCR studies in this planning cycle. The results for these LCR studies are included in sections 3.1.2 – 3.1.4 in this chapter.

Winter Gas Curtailment Reliability Assessment

The ISO proposed to perform this study to evaluate the scenario where an external gas supply shortage, due to high demand in winter time, that cause gas curtailments to generating facilities in the LA Basin and/or San Diego areas could cause electric transmission reliability concerns. To perform this study, the ISO utilized the 2020/2021[119] winter study case available from the posted 2015-2016 Transmission Planning Process reliability study cases and created a 2021-2022 winter case by adding the Mesa Loop-In Project in the LA Basin. The winter peak loads were modeled at about 62 percent of SCE 2021 summer peak load and 66 percent of San Diego summer peak loads. OTC generating facilities were retired per the State Water Board's compliance dates. Aging generating units (more than 40 years old) were modeled off-line per the Final 2015-2016 Transmission Planning Process Study Plan. A total of 2,200 MW of gas-fired generation was curtailed, with about 900 MW in the San Diego area and the remaining is in the LA Basin. This was an effort to simulate the generation curtailment that occurred on February 6, 2014 where external gas supply was constraint for delivery to southern California due to out-of-state heavy demand caused by severe cold weather condition.

Contrary to the summer peak load conditions where most gas-fired generation is expected to be online to meet peak load demand, the winter peak load conditions assume less gas-fired generation is dispatched, but the gas demand is expected to be high due to heating demand.

The ISO performed steady-state contingency, post-transient and transient stability analyses on this winter case. Noteworthy reliability concerns, with potential mitigations are provided in the following table. The most critical reliability concern was the potential overloading on the Lugo – Victorville 500kV line due to overlapping outages of the Lugo – Mohave 500kV line, system readjusted, followed by the Lugo – Eldorado 500kV line. All the existing demand response in the LA Basin was utilized, with the caveat that those would need to be repurposed with 20-minute response time for contingency mitigation purpose.

The second most critical reliability concern was the potential post-transient voltage instability concern due to overlapping outage of the ECO-Miguel 500 kV line, system readjusted, followed by the Ocotillo – Suncrest 500 kV line. The post-transient voltage instability concern is mitigated with re-scheduling of voltage control of the synchronous condensers that are being installed in northern San Diego and southern Orange County. Upon rescheduling of voltage control to enable VAR injection support, the post-transient voltage instability is mitigated. Another reliability concern associated with this overlapping contingency is the potential overloading on the La Rosita

[119] Since the 2025 winter study case is not available, but the 2020/21 winter case is, the ISO utilized this case for the winter gas curtailment studies.

– Rumorosa 230 kV and the Otay Mesa – Tijuana 230 kV line, which can be mitigated by bypassing the series capacitors under pre-contingency basis on the ECO-Miguel 500 kV or Ocotillo – Suncrest 500 kV line (depending on which line had the outage first) and reducing imports via Path 45 to ISO balancing authority area from 300 to 200 MW. The series capacitors on these two lines are normally bypassed for the summer peak conditions[120], but could be bypassed for winter peak conditions as part of system readjustment before the next contingency.

The third critical reliability concern was the transient voltage dips at Lewis and Valley Substations under the same overlapping contingencies on the Southwest Powerlink and the Sunrise Powerlink lines as noted above. To mitigate transient voltage dip concerns at these two substations, it is important that the preferred resources from the long-term procurement for SCE Western LA Basin and San Diego areas are utilized during system readjustment in preparation for the next contingency. These resources proved to be effective in mitigating the transient voltage dip concerns, reducing the voltage dip to within acceptable limit (i.e., 14 – 15 percent) and within acceptable time duration (i.e., less than 30 cycles).

[120] Per recommendations from the previous 2014-2015 Transmission Plan

Table 3.3-3: Reliability Assessment Results

	Reliability Concerns	Contingencies	Type of Analyses	Pre-Mitigated Reliability Concerns	Post-Mitigation Results	Potential Mitigation
1	Vincent-Victorville Loading Concerns	P6: Lugo-Mohave, Lugo-Eldorado	Steady-state contingency	125% loading	100% loading	-Utilize LTPP preferred resources and existing DR for system readjustment, and -Reschedule 250 MW less on IPPDC lines, or -Upgrade terminal equipment on the line
2	Miguel 500/230kV Bank	P1: Parallel Miguel 500/230kV Bank	Steady-state contingency	106% - 108%	0%	-Opening the circuit breakers for the overloaded bank
3	Imperial Valley 500/230kV Bk#80	P6: T-1-1 Bk# 81 and 82	Steady-state contingency	158% loading	98%	-Curtail about 800 MW generation connecting to Imperial Valley, and
4	Post-transient voltage instability in San Diego and LA Basin	P6: ECO-Miguel 500kV, system readjustment, followed by Ocotillo-Suncrest 500kV line	Post-transient	Post-transient voltage instability	Mitigated post-transient voltage instability concerns	-Reschedule voltage regulation at terminal voltage with 1.05 – 1.1 p.u. for synchronous condensers located in northern San Diego and southern Orange County.
5	Transient voltage dips beyond acceptable limits at Valley 115kV bus (39%) and Lewis 69kV bus (38%) beyond 30 cycles (i.e., 32 and 33 cycles)	Same as above	Transient stability	Transient voltage dip	Mitigated transient voltage dip concerns	-Utilize LTPP preferred resources and energy storage and baseline DR (190 MW) for system readjustment before the next contingency
6	La Rosita-Rumorosa 230kV and Otay Mesa – Tijuana 230kV line loading concerns	Same as above	Post-transient	101% - 103% loading	92% - 93%	- Bypass series capacitors on the ECO-Miguel 500kV line and Ocotillo-Suncrest 500kV line pre-contingency - Reduce imports via Path 45 from 300 to 200 MW (to ISO BAA)

Generation Ramping Impact Assessment

The preceding discussions focused on the adequacy natural gas supply to electric generating facilities over some number of days or weeks - either under major transmission gas pipeline outage condition or external supply shortage.[121]

Another consideration is the ability of the existing gas transmission system to provide large amounts of natural gas in a short period of time (i.e., less than 30 minutes) to generation peaking facilities due to generation ramping needs or to sustain ramping over the run-up to a daily peak load. Generation ramping need may occur due to either generation re-dispatch need following an electric transmission contingency event in preparation for the next contingency, or due to future flexible capacity needs[122] to integrate and meet California's 50 percent renewables portfolio standard (RPS).

At face value, for unconstrained gas availability condition, re-dispatch of gas-fired peaking generation to prepare for the next contingency can be utilized as an option among other options which could include the use of demand response and energy storage and assessing the adequacy of the gas supply during unconstrained gas availability conditions appeared straightforward. In the long-term 2025 LCR studies, the estimated amount of generation re-dispatch involving gas-fired peaking generators can be calculated as the net difference in the LCR requirements between single-element contingency (P1) and multiple-element (i.e., P6, P3) after subtracting potential preferred resources and energy storage dispatch, if those have not been utilized at peak loads already. The following table provides estimates for peaking generation re-dispatch based on the results from table 3.1.7.

[121] External supply shortage includes reduced delivery of natural gas to California from out-of-state basins due to extreme cold weather that triggers higher need of natural gas for out of state market.
[122] http://www.caiso.com/Documents/2020_Flexible_Capacity_Needs.pdf

Table 3.3-4: Potential Estimated Peaking Generation Ramping for Re-dispatch To Meet Second Contingency Reliability Need

Local Area	2025 LCR Need Based on Single-Element Contingency (MW)	2025 LCR Need Based on Multiple-Element Contingency (MW)	Re-dispatch Capacity Need (MW)	Preferred Resources/Energy Storage Use for Re-dispatch (MW)	Potential Peaking Generator Re-dispatch Need (MW)
Western LA Basin	5,236	5,514	278	278[123]	0 / 278[124]
Eastern LA Basin	2,132	2,805	673	0[125]	673 (see footnotes for the column at left)
San Diego/Imperial Valley	3,151	4,868	1,717	267[126]	1,450[127]

Under normal circumstances these unplanned localized ramping events may take advantage of gas storage in the pipelines themselves (line packing) as well as local gas storage facilities and are unlikely to generate gas supply concerns.

In considering the impacts on gas-fired generation ramping need for dispatching resources prior to the next contingency (in an N-1-1 contingency condition) during the gas constraint conditions or gas curtailment conditions, the situation also appeared straight forward. Under gas constraint or curtailment conditions, gas curtailment would be enforced on non-core customers, which include electric generation facilities. System readjustment, in this case, would need to be rely on other non-gas generation alternatives, such as the use of demand response[128] (i.e., preferred resources) and energy storage.

[123] Due to limited operational availability (i.e., 4-hours), preferred resources and energy storage typically are reserved for use after the first contingency occurs to allow for time available for mitigating the second contingency.

[124] If preferred resources are sufficiently dispatched to prepare for the next contingency, then the gas-fired peaking generation need is 0 MW. However, if preferred resources and/or energy storage are dispatched first in the base case to meet peak load conditions, then the peaking generation can be dispatched to meet second contingency need.

[125] Long-term procurement plan focus on procurement of preferred resources and energy storage procurement in the Western LA Basin area (due to deficiency identified previously for the area). The Eastern LA Basin does not require additional procurement and has available capacity to meet its local reliability need.

[126] This includes 250 MW of preferred resources and energy storage under consideration (by SDG&E) and 17 MW of existing demand response assumptions.

[127] The peaking generators (CTs) in the San Diego-Imperial Valley LCR area are projected to have a total of about 1,344 MW by 2018 time frame. This amount includes 300 MW for Pio Pico generating facility and 500 MW for Carlsbad Energy Center.

[128] Demand response that has operational characteristics of 20-minute response time for contingency purposes

However, the current situation at the Aliso Canyon storage field highlights the complex interplay between pipe and storage capacity, and the dependence on specific more localized gas storage facilities in managing more rapidly varying withdrawals from the gas network. Building on the operational analysis the ISO is participating in to identify potential impacts of the current gas storage conditions on summer 2016 reliability, the ISO intends to more fully explore these issues in the 2016-2017 and subsequent transmission plans.

This work can also benefit from further advancement of a number of issues associated with flexible ramping requirements, that may in turn impact the supply-side fleet that play a role in meeting flexible ramping needs both locally and system-wide. These include among others the ISO's Flexible Resource Adequacy Criteria and Must Offer Obligation (FRACMOO) stakeholder initiative[129] and the CPUC's Resource Adequacy proceedings.

129 http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx

3.4 50 Percent Renewable Energy Special Study

The idea of the 2015 special study was generated from a mutual desire on part of the CPUC and the ISO to investigate impacts and implications of higher RPS targets on the transmission grid recognizing that the trajectory to achieving the 33 percent RPS goal by 2020 was largely set and that higher targets were likely. Additional knowledge about the capabilities of the system as it exists today and taking into account transmission plans already being implemented would support increased optionality in considering future resource choices and alternative procurement frameworks.

3.4.1 Objective

The 50 percent special study focused on supporting broader investigation into the feasibility and implications of moving beyond 33 percent RPS using energy-only procurement, recognizing there were indicators that the need for future renewable generation – beyond 33 percent - to provide system resource adequacy capacity was diminishing. While past transmission planning analysis and generator interconnection studies provide some insights into the likely requirements for system reinforcement if future generation was deliverable, e.g. achieving full capacity delivery status for provision of system resource adequacy capacity, less was known about the ability of the system to move beyond 33% on an energy-only basis.

The primary approach taken was for the ISO to estimate the reasonable amount of energy-only renewable generation the transmission system could accommodate with modest curtailment, the CPUC to provide 50 percent renewable generation portfolios relying on those estimates and utilizing the CPUC's RPS Calculator v6, and then in this study for the ISO test the validity of those assumptions through detailed modeling and system analysis.

The ISO's initial estimates were developed based on experience modeling and studying the system, as well as considering past generator interconnection study results and production simulation modeling. It was anticipated that the results would lead to refining those capabilities, but that an iterative approach would be a reasonable means to home in on valid results by making adjustments around reasonable starting estimates.

This was strictly an informational effort; the results, recommendation and conclusions of this study will not provide a basis for procurement or transmission upgrade decisions in 2015-2016 TPP cycle. The recommendations will be used to develop portfolios for consideration by the ISO in future TPP cycles.

3.4.2 Portfolios

In order to generate preliminary 50 percent portfolios, the ISO provided a transmission capability estimate for each renewable zone to accommodate possible Energy Only resource procurement beyond 33 percent RPS resources to the CPUC, who then produced test portfolios using the RPS Calculator v6. Two portfolios were selected for the 50 percent special studies; an in-state portfolio with new generation limited to California and an out-of-state portfolio that selected a material but reasonable amount of out-of-state resources. Note that these portfolios built upon the 33% renewable energy portfolios and represent the additional resources necessary to achieve a 50 percent energy objective. The out-of-state portfolio was used to test the ability of the California system to deliver the renewable energy from intertie injection points bordering the system to California load centers.

In-state portfolio

Renewable Net Short (RNS) is filled only by resources located within California. Figure 3.4-1 shows the resource selection for the top 20 zones in in-state portfolio. Table 3.4-1 shows a detailed breakdown of renewable zones and renewable resources selected in these zones by technology.

Figure 3.4-1: In-state 50% portfolio

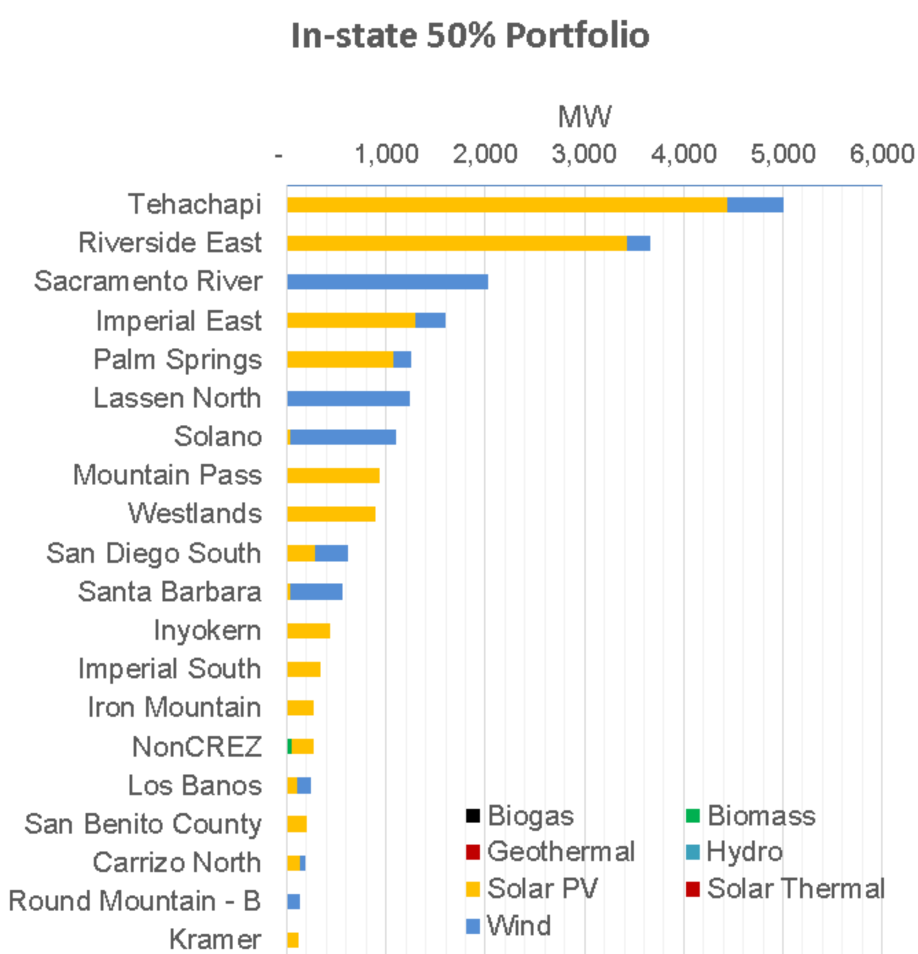


Table 3.4-1: 50% In-state portfolio – Top 20 zones

No.	Renewable Zone	Biogas	Biomass	Geothermal	Hydro	Solar PV	Solar Thermal	Wind	Total
1	Tehachapi	0	0	0	0	4,440	0	560	**5,000**
2	Riverside East	0	0	0	0	3,433	0	228	**3,661**
3	Sacramento River	0	0	0	0	0	0	2,027	**2,027**
4	Imperial East	0	0	0	0	1,292	0	303	**1,595**
5	Palm Springs	0	0	0	1	1,072	0	184	**1,256**
6	Lassen North	0	0	0	0	0	0	1,244	**1,244**
7	Solano	7	0	0	0	30	0	1,064	**1,101**
8	Mountain Pass	0	0	0	0	933	0	0	**933**
9	Westlands	0	0	0	3	891	0	0	**894**
10	San Diego South	0	0	0	0	286	0	335	**622**
11	Santa Barbara	0	0	0	0	34	0	525	**558**
12	Inyokern	0	0	0	0	432	0	0	**432**
13	Imperial South	0	0	0	0	341	0	0	**341**
14	Iron Mountain	0	0	0	0	276	0	0	**276**
15	NonCREZ	0	49	0	5	219	0	0	**272**
16	Los Banos	0	0	0	0	97	0	143	**240**
17	San Benito County	0	0	0	0	207	0	0	**207**
18	Carrizo North	0	0	0	0	126	0	56	**182**
19	Round Mountain - B	0	0	0	0	0	0	133	**133**
20	Kramer	0	0	0	0	120	0	0	**120**
	Other	0	0	0	3	263	0	208	**474**
	Total	**7**	**49**	**0**	**11**	**14,490**	**0**	**7,010**	**21,567**

Out-of-state portfolio

RNS is filled by resources throughout the Western Interconnection. Figure 3.4-2 shows the resource selection for the top 20 zones in in-state portfolio. Table 3.4-2 shows a detailed breakdown of renewable zones and renewable resources selected in these zones by technology.

Figure 3.4-2: Out-of-state 50% portfolio

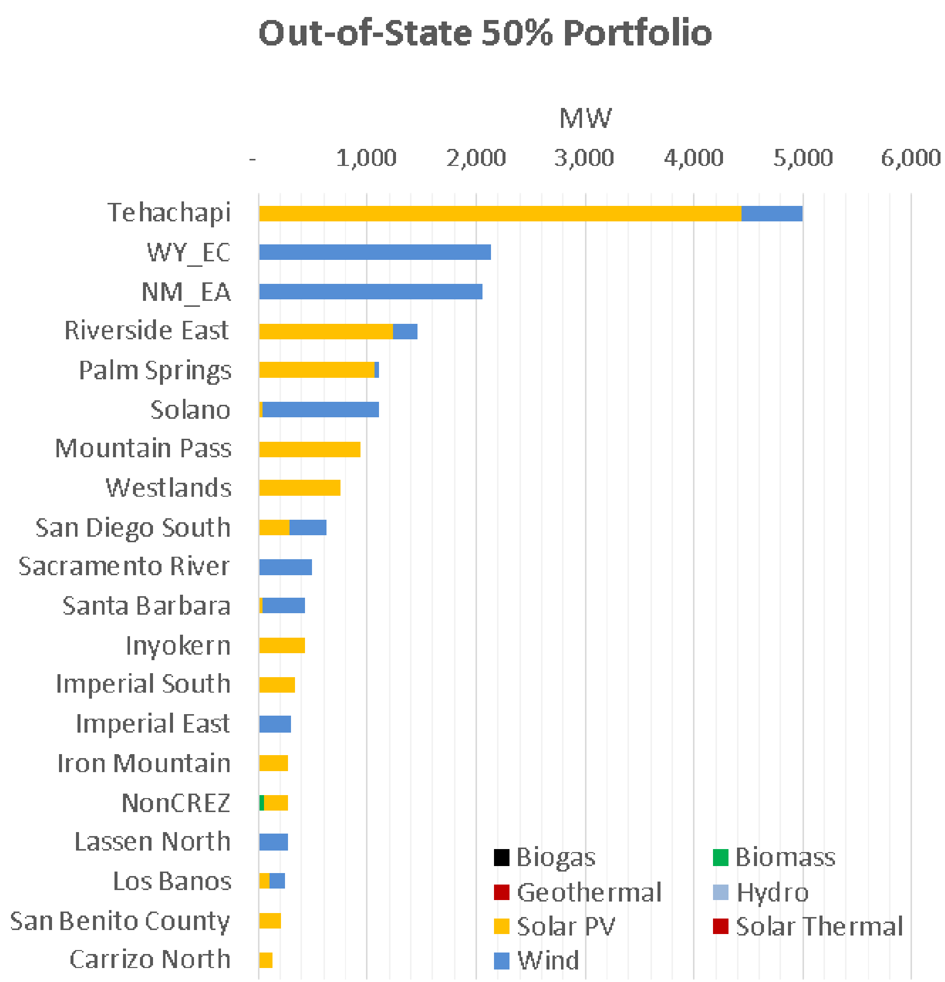


Table 3.4-2: 50% Out-of-state portfolio – Top 20 zones

No.	CREZ	Biogas	Biomass	Geothermal	Hydro	Solar PV	Solar Thermal	Wind	Total
1	Tehachapi	0	0	0	0	4,440	0	560	**5,000**
2	WY_EC	0	0	0	0	0	0	2,141	**2,141**
3	NM_EA	0	0	0	0	0	0	2,063	**2,063**
4	Riverside East	0	0	0	0	1,238	0	228	**1,465**
5	Palm Springs	0	0	0	1	1,072	0	33	**1,106**
6	Solano	7	0	0	0	30	0	1,064	**1,101**
7	Mountain Pass	0	0	0	0	933	0	0	**933**
8	Westlands	0	0	0	3	746	0	0	**749**
9	San Diego South	0	0	0	0	286	0	335	**622**
10	Sacramento River	0	0	0	0	0	0	493	**493**
11	Santa Barbara	0	0	0	0	34	0	399	**433**
12	Inyokern	0	0	0	0	432	0	0	**432**
13	Imperial South	0	0	0	0	341	0	0	**341**
14	Imperial East	0	0	0	0	0	0	303	**303**
15	Iron Mountain	0	0	0	0	276	0	0	**276**
16	NonCREZ	0	49	0	5	219	0	0	**272**
17	Lassen North	0	0	0	0	0	0	268	**268**
18	Los Banos	0	0	0	0	97	0	143	**240**
19	San Benito County	0	0	0	0	207	0	0	**207**
20	Carrizo North	0	0	0	0	126	0	0	**126**
	Other	0	0	0	3	383	0	217	**604**
	Total	**7**	**49**	**0**	**11**	**10,859**	**0**	**8,248**	**19,174**

The estimates for the transmission capability numbers were used as a starting input to the RPS calculator v.6 in order to generate the two portfolios being used in the 50 percent special study. Table 3.4-3 presents a summary of the initial transmission capability estimates and the CREZ-wise utilization of these capability numbers in the in-state and out-of-state portfolios.

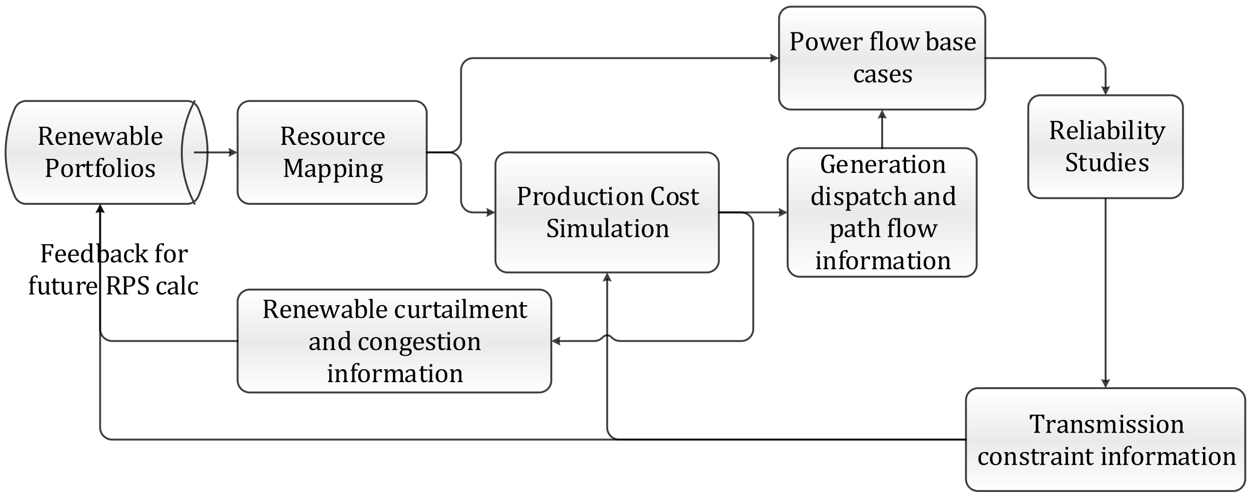
Table 3.4-3: Summary of transmission capability estimates and portfolio utilization

Zones	Transmission Capability Estimate (MW)	New renewable resources modeled (MW)	
		In-State	Out-of-State
Greater Carrizo	1,140	798	559
Central Valley North & Los Banos	2,000	240	240
Greater Imperial	2,633	2,633	1,341
Kramer & Inyokern	750	750	750
Mountain Pass & El Dorado	2,982	1,226	1,226 + 2,141 (WY wind)
Northern California	3,404	3,404	869
Riverside East & Palm Springs	4,917	4,917	2,571 + 2,063 (NM wind)
Solano	1,101	1,101	1,101
Tehachapi	5,000	5,000	5,000
Westlands	2,900	894	749

3.4.3 Study Methodology

A combination of production cost simulation results and reliability assessment results was used to test the initial the transmission capability estimates provided to the CPUC by the ISO and to arrive at recommendations for revising the transmission capability estimates for future renewable generation portfolio modeling. Figure 3.4-3 shows a simplified study process of the 50 percent special study.

Figure 3.4-3: 50% special study process



The resources in the 50 percent portfolios received from the CPUC – based on the initial estimates for transmission capability provided by the ISO - were mapped to transmission system nodes for modeling purpose. This mapping was used to build power flow models and production cost simulation models. Production cost simulations were used to create 8,760 hourly snapshots of the system with 50 percent RPS resources. These snapshots were used to identify high transmission system usage patterns to be tested using the power flow models for reliability assessment.

Production cost simulations were used to identify renewable curtailment and transmission congestion in several zones. Reliability assessment was relied upon for identification of transmission system limitations above and beyond the constraints monitored in the production cost simulations. This was an iterative process as these new constraints identified in the reliability assessment were modeled in the production cost simulations for a re-run that resulted in more accurate numbers for renewable curtailment and transmission congestion.

Power flow contingency analysis, post transient voltage stability analysis, and transient stability analysis were performed as part of reliability assessment.

3.4.4 Base Case Assumptions

3.4.4.1 *Production cost simulation base case*

The ISO economic planning database for 2025 (Chapter 5) was used to develop the 50 percent renewables portfolio production cost simulation model. The 50 percent portfolio resources mapped to specific transmission substations were added to the ISO economic planning database. Regulation and load following requirements were updated based on the 50 percent renewables portfolio and incorporated into the model. The 2025 load level used in the TEPPC model was used for the 50 percent special study. Because of the reduced expected load growth due to several factors such as energy efficiency and development of new behind-the-meter resources, this load level was expected to be a reasonable approximation for the 2025 to 2030 time frame.

3.4.4.2 *Power flow and stability base case*

Starting base cases

Base cases developed for 33 percent policy-driven study were used as a starting point for building the 50 percent portfolio models.

Load Assumptions

The study snapshots were identified based on high transmission system usage under high renewable dispatch in respective study areas, and the corresponding load levels were modeled.

Transmission assumptions

Similar to the ISO Annual Reliability Assessments for NERC Compliance, the 50 percent special study modeled all transmission projects approved by the ISO. Details can be found in chapter 2.

3.4.5 Power Flow and Stability Base Case Development

3.4.5.1 *Power flow modeling and reactive power capability*

50 percent renewables portfolios provided by the CPUC have assigned renewable resources geographically by technology to CREZ and non-CREZ areas. Using the geographical locations provided, the ISO represented renewable resources in the power flow model based on substation location information and the information from generator interconnection studies performed by the ISO and utilities. The objective of modeling generation projects this way is not to endorse any particular generation project, but to streamline and focus the transmission analysis on the impact of certain MWs of generation modeled at the respective location. In other words, transmission constraints observed for a specific generation build-out within a renewable resource area would be independent of specific projects that get built. Equivalent generic models were used to model resources with the same capacity as that indicated in the portfolios. Large scale wind turbine or solar PV generation was assumed to regulate bus voltage at the point of interconnection utilizing a power factor range of 0.95 lagging to leading. Unity power factor was assumed for solar PV distributed generation. For all other new generation modeled, typical data was used in the equivalent model with a power factor range of 0.90 lagging and 0.95 leading.

3.4.5.2 *Dynamic modeling of renewable generators*

WECC approved models from the GE PSLF library were used to represent the resources in the 50 percent portfolios. For geothermal, biomass, biogas and solar thermal projects, dynamic models of similar existing units in the system were used, which included generator, exciter, power system stabilizer and governor models. For wind turbine and PV solar generators, GE Positive Sequence Load Flow Software models from the GE PSLF library were used. In this study, a Type 3 wind turbine generator model for doubly fed induction generators was used for wind generators if the generator type was not specified. For any future wind projects that were specified by interconnection customers as units with full converters, Type 4 inverter models were used.

The models for the wind Type 3 projects (doubly fed induction generator) included models for the generator/converter (regc_a), inverter electrical control models applicable to wind plants (reec_a), wind generator torque controller models (wtgq_a), drive train models (wtgt_a), simplified aerodynamic models (wtga_a), and pitch controller models (wtgp_a). In addition to these models, large plants (capacity 20 MW and higher) were assumed to have centralized plant control, which was modeled with a separate model (repc_a). The wind plants' models also included low and high voltage and low and high frequency protection models (lhvrt, lhfrt).

The models for the wind Type 4 projects (full converter) included generator/converter models, electrical controls for inverters and centralized plant control model for the large wind farms. In addition, the same protection that was modeled for the Type 3 projects was modeled for the Type 4. Depending on the design of the turbines, drive train models were also included in some Type 4 wind plants.

For both Type 3 and Type 4 dynamic models of the new plants, the control parameters were set such that the generators have adequate low voltage ride through and low frequency ride through capability.

The dynamic data set used for transient stability simulations had also models for Type 1 (induction generator) and Type 2 (induction generator with variable rotor resistance) wind power plants, but these were existing projects built rather significant time ago. These generators are not used in new installations.

Dynamic stability models for the solar PV plants distinguished between large solar plants, small plants and distributed solar PV generation. If no data from the interconnection customers was available, it was assumed that the solar PV plants 20 MW and higher connected to the transmission or sub-transmission systems will operate under centralized plant control. For these projects, dynamic stability models included models for the generator/converter (regc_a), inverter electrical control models applicable to solar PV plants (reec_b) and centralized plant control model (repc_a). The solar PV plants models also included low and high voltage and low and high frequency protection models (lhvrt, lhfrt). For the large plants, it was assumed that the centralized plant controller can regulate voltage at the point of interconnection and the power factor can be maintained between 0.95 leading and 0.95 lagging.

Smaller solar PV projects (less than 20 MW) were assumed as not having centralized plant control; therefore datasets for these projects did not include the centralized plant control model.

Both large and small solar PV plants were assumed to have adequate low voltage ride through and low frequency ride through capability.

Distributed solar PV generation was modeled with the simplified model (pvd1). It was assumed that these units have unity power factor and don't have voltage regulation.

Load in the whole WECC system, including the ISO was modeled with composite load model for the selected conditions (Off-peak).

3.4.5.3 *Power flow and stability snapshot in base cases*

Production cost simulation software was used to predict unit commitment and economic dispatch on an hourly basis for the study year with the results used as reference data to predict future dispatch and flow patterns.

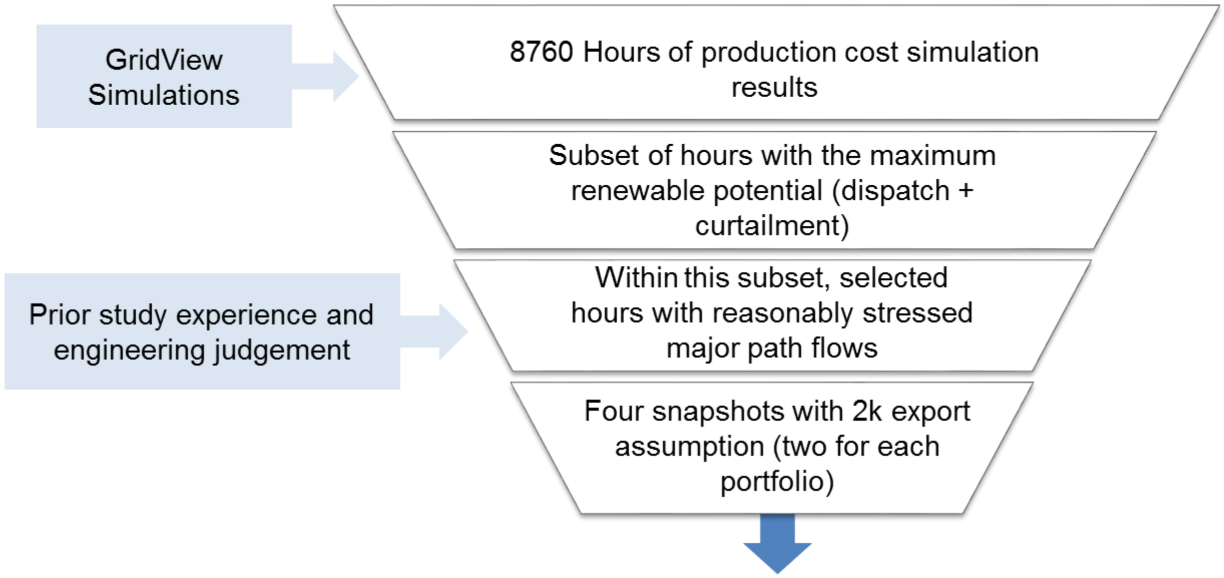
Certain hours that represent stressed patterns of path flows in the 2025 study year were selected from the production cost simulation results with the objective of studying a reasonable upper bound on stressed system conditions. The following two critical factors were considered in selecting the stressed patterns:

- renewable generation potential system wide and within renewable study areas
- power flow on the major transfer paths in California and especially in the study area

For example, hours that were selected for reference purposes were during times of near maximum renewable generation potential within key study areas (Riverside, Imperial and Kramer) and reasonably high transfers across transmission paths in Southern CA during these hours with high renewable potential.

The reliability assessment was performed based on a dispatch that modeled the renewable potential (dispatch + curtailment) instead of renewable dispatch from the production simulation snapshot. The renewable curtailment in production cost simulation could be due to ISO system-wide over-supply or transmission congestion. The objective of the reliability assessment was to examine the transmission system constraints for certain snapshots. In order to identify such constraints, the renewable dispatch in power flow cases was based on the available renewable production before curtailment resulting from the security constrained economic dispatch model. This snapshot selection based on renewable potential allowed for identification of new transmission constraints that were not modeled in production cost simulations. Figure 3.4-4 shows the process followed for identification of snapshots and specific snapshots identified for the in-state and out-of-state portfolios to be studied for potential reliability issues.

Figure 3.4-4: Snapshot selection for reliability assessment



Scenario	Northern CA	Southern CA
In-state portfolio	March 18 – Hr 19	March 18 – Hr 13
Out-of-state portfolio	February 02 – Hr 13	November 29 – Hr 12

The approach described above recognizes that production cost simulation does not model all contingencies and branches in the simulation because of computational limitations. Given this gap between the production cost simulation and the power flow and stability assessments, as well as the fact that the production cost simulation is based on the DC power flow model, the renewable dispatch selected for reliability assessment was based on the renewable potential in the selected hour instead of dispatch for that hour.

3.4.6 Study Results

The study results comprise of production simulation results and reliability assessment results. These two studies resulted in information about the expected renewable curtailment, transmission congestion and reliability concerns under the assumptions in the production cost simulation model and the snapshots identified for power flow cases.

3.4.6.1 *Production cost simulation results*

Four scenarios with different assumptions on the ISO export limitation were simulated for both in-state and out-of-state portfolios:

1) Maximum zero MW net export from the ISO controlled grid
2) Maximum 2000 MW net export from the ISO controlled grid
3) Maximum 8000 MW net export from the ISO controlled grid
4) Unconstrained net export from the ISO controlled grid

Curtailments on wind and solar generation within the ISO controlled grid and the transmission congestions were analyzed for the above four scenarios. It was expected that the unconstrained net export scenario would have less curtailment than other scenarios since it minimized the impact of over-supply on the renewable curtailment.

Results for In-State Portfolio

Figure 3.4-5 shows the total wind and solar curtailments in four export scenarios for the in-state portfolio. As expected the zero MW net export scenario has the most curtailment, and the unconstrained net export scenario has the least curtailment. The percentage values on the plot are calculated as the curtailment of wind and solar divided by the total potential wind and solar energy within the ISO controlled grid.

Figure 3.4-5: Total wind and solar curtailment Vs Export assumption – In-state portfolio

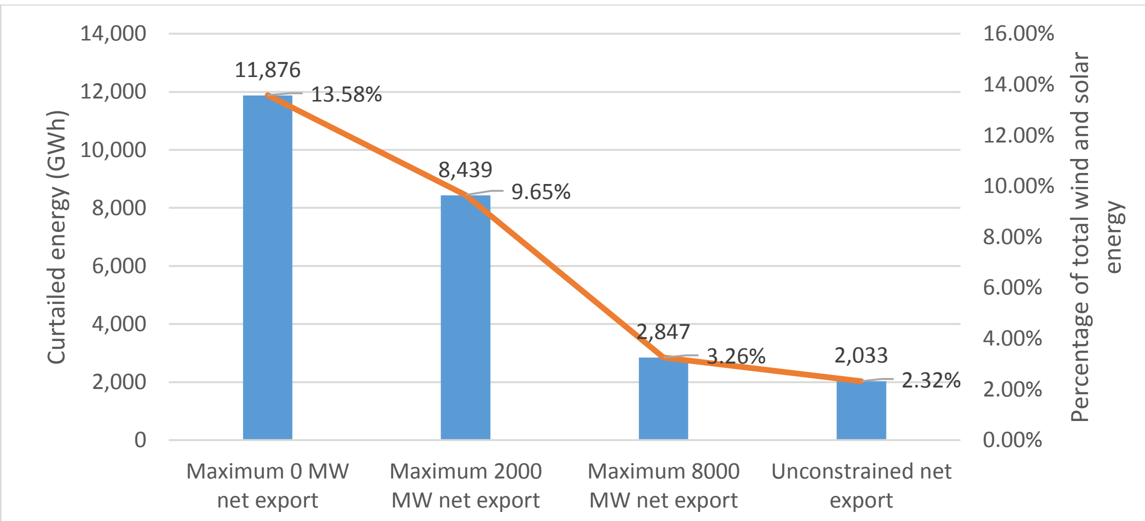


Figure 3.4-6 shows the congestions observed in four scenarios. Please note that the congestions were originally reported in the production cost simulation results for each of the transmission lines or interfaces. In figure 3.4-6, the congestions were aggregated based on both geographic locations and electrical connections. For example Lassen North/Round MT. congestion, which has the most congestion hours in the figure, includes several congestions on the transmission lines that are located in Lassen North CREZ and Round Mountain CREZ. The renewables in these two CREZs contribute to the flows on those congested lines.

Figure 3.4-6: Congestion Hours – In-state portfolio

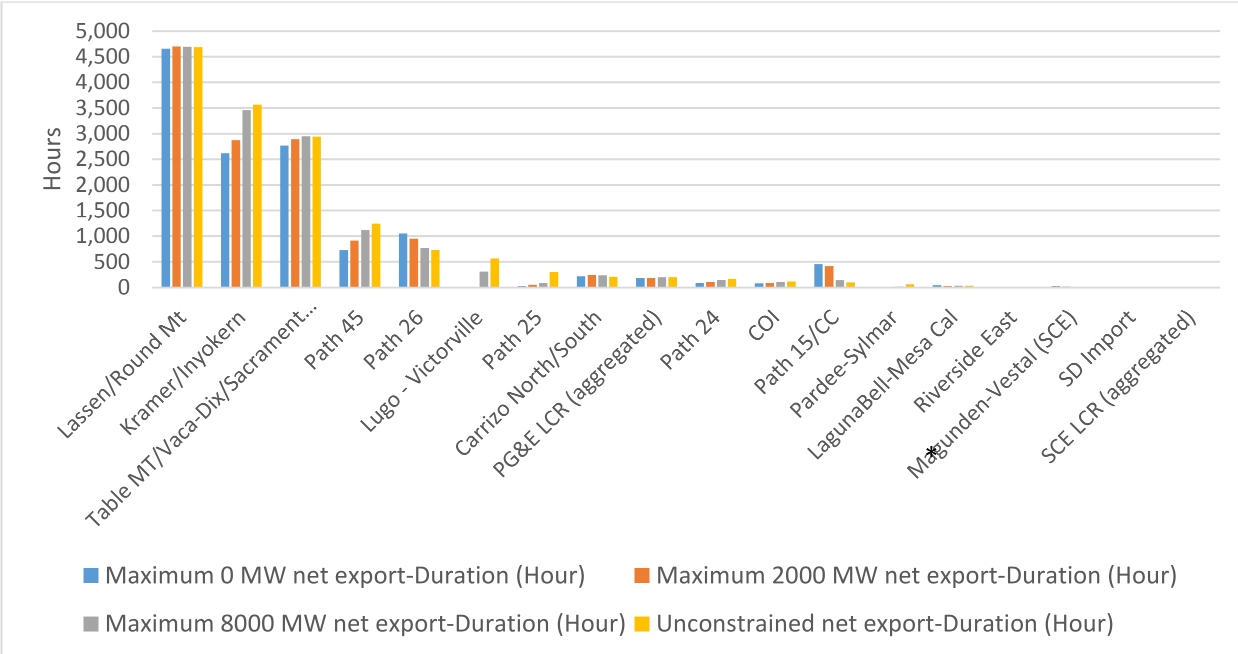


Figure 3.4-7 shows the curtailment in MWh for each CREZ and figure 3.4-8 shows curtailment in percentage of available energy in a CREZ, under all four export scenarios. Figure 3.4-8 shows only the CREZs with the most significant percentage curtailment.

Figure 3.4-7: Wind and solar curtailment by CREZ (MWh) – In-state portfolio

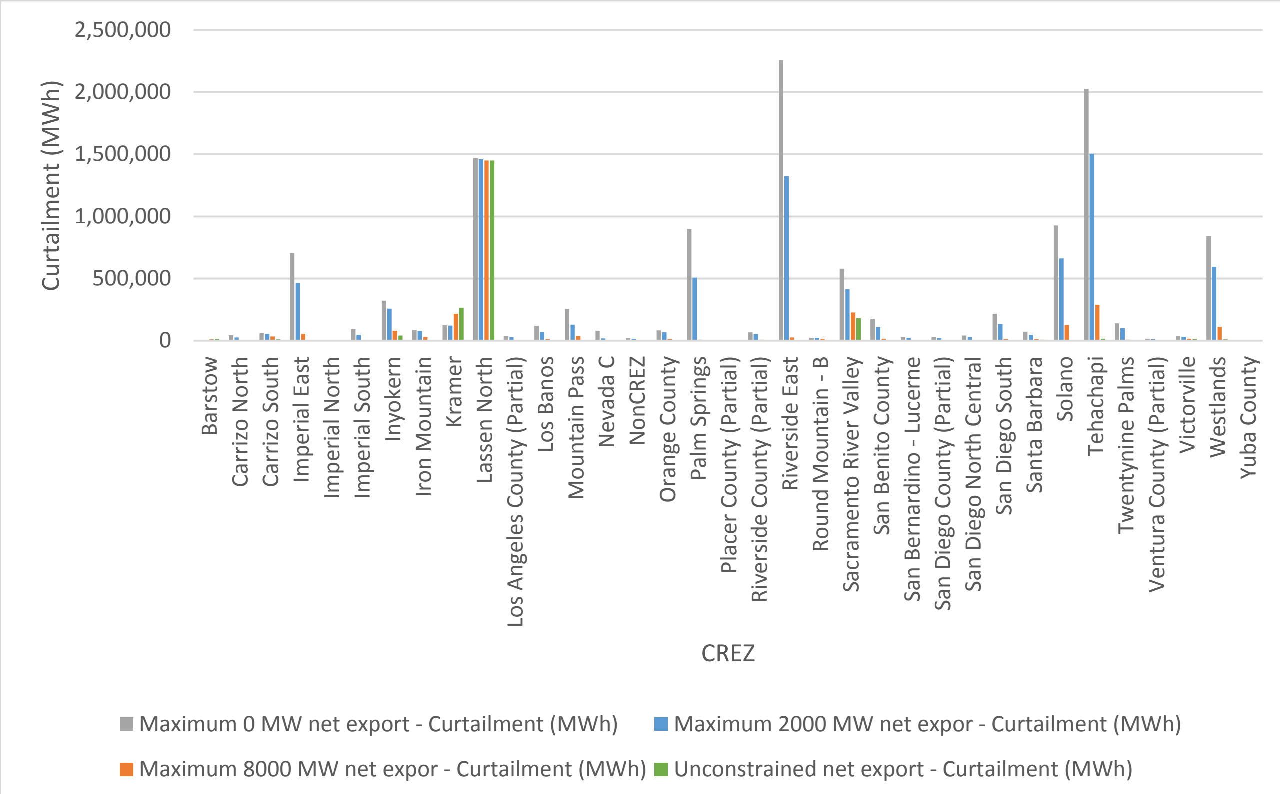
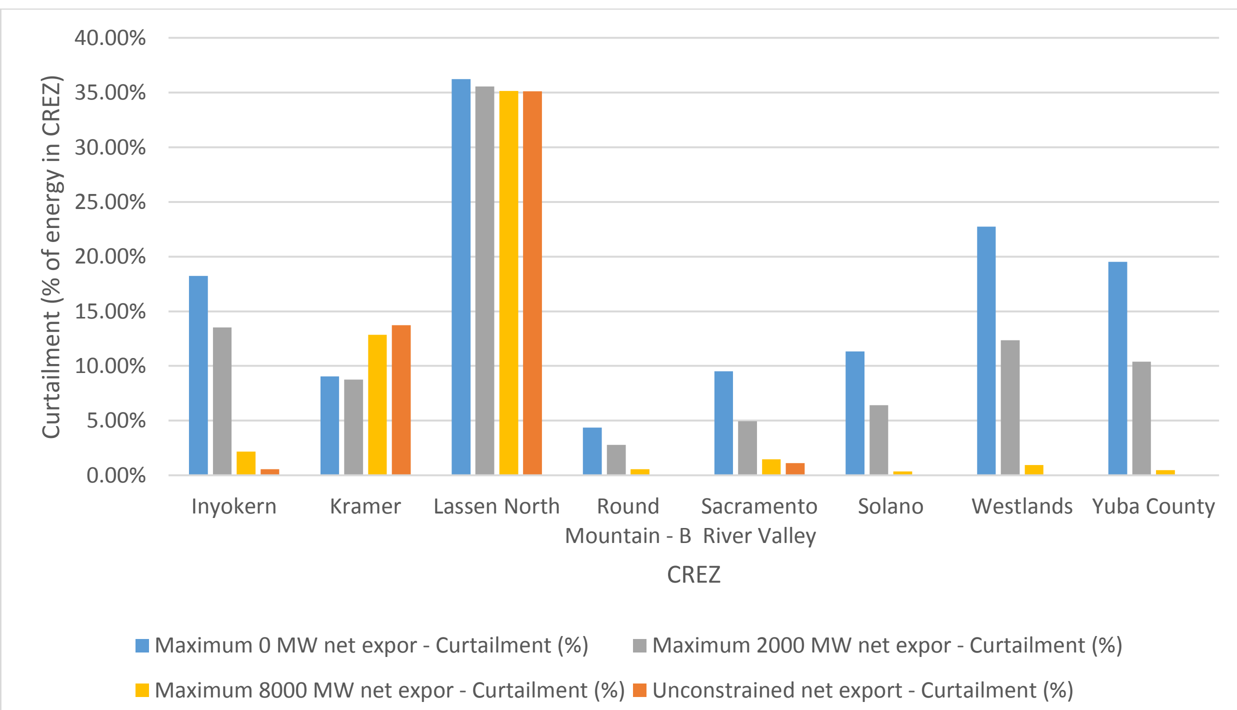


Figure 3.4-8: Wind and solar curtailment by CREZ (% of energy curtailed) – In-state portfolio



Out-of-State Portfolio Results

Similar to the in-state portfolio results, figure 3.4-9 and figure 3.4-10 below show the total curtailments and the congestions observed in four export scenarios. The figure 3.4-11 shows the curtailment in MWh for each CREZ and figure 3.4-12 shows curtailment in percentage of available energy in a CREZ under all four export scenarios. Figure 3.4-12 shows only the CREZs with the most significant percentage curtailment.

Figure 3.4-9: Total wind and solar curtailment Vs Export assumption – Out-of-state portfolio

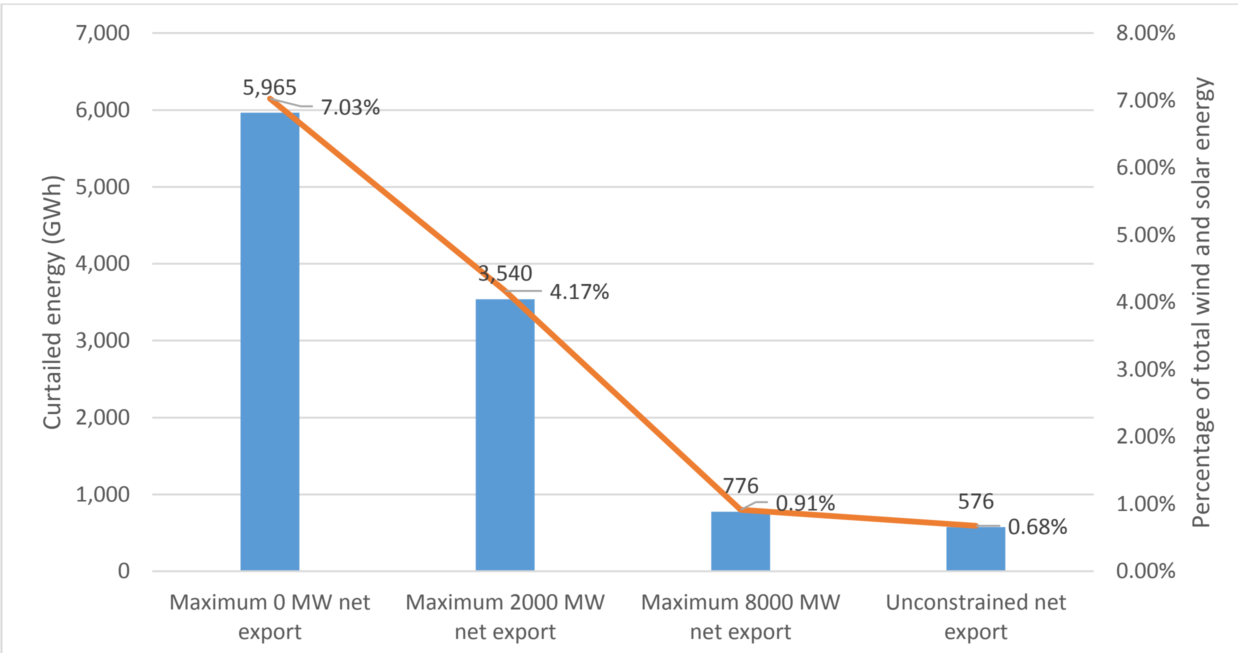


Figure 3.4-10: Congestion Hours – Out-of-state portfolio

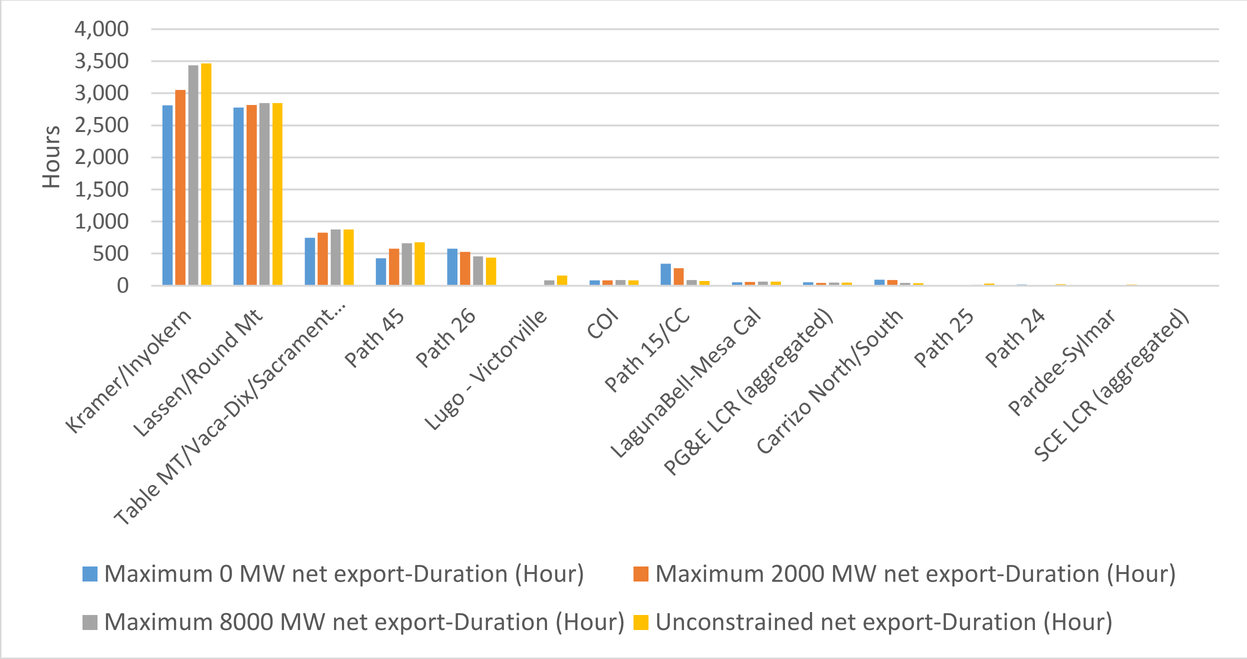


Figure 3.4-11: Wind and solar curtailment by CREZ (MWh) – Out-of-state portfolio

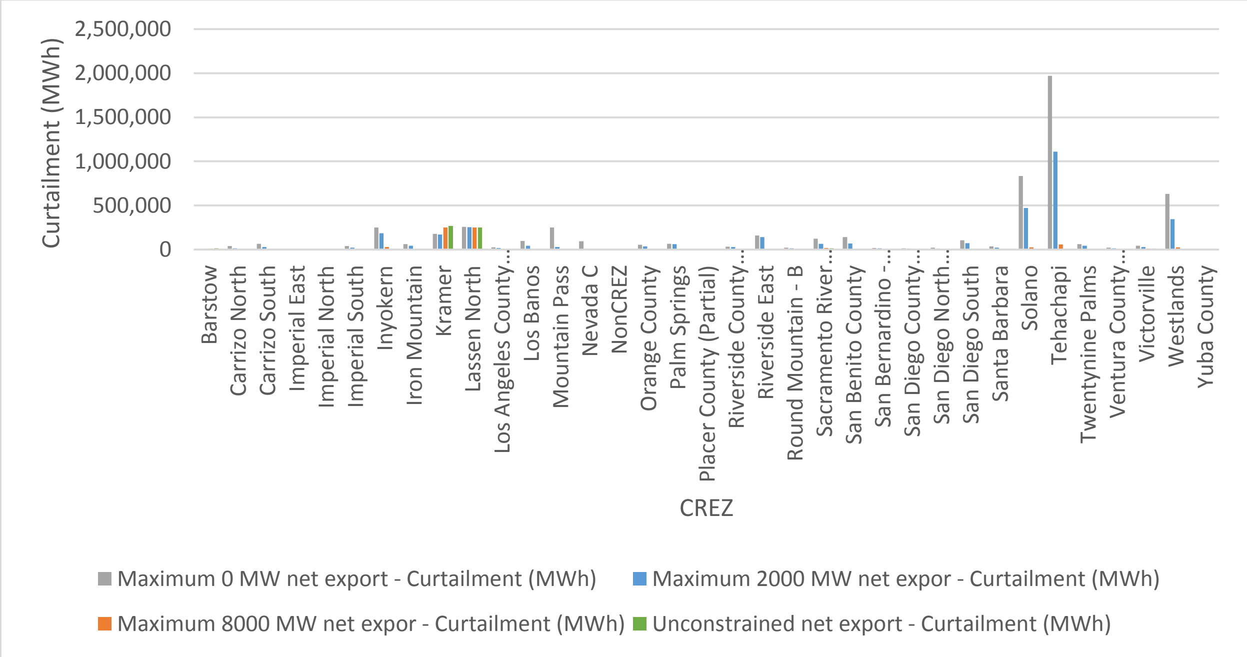
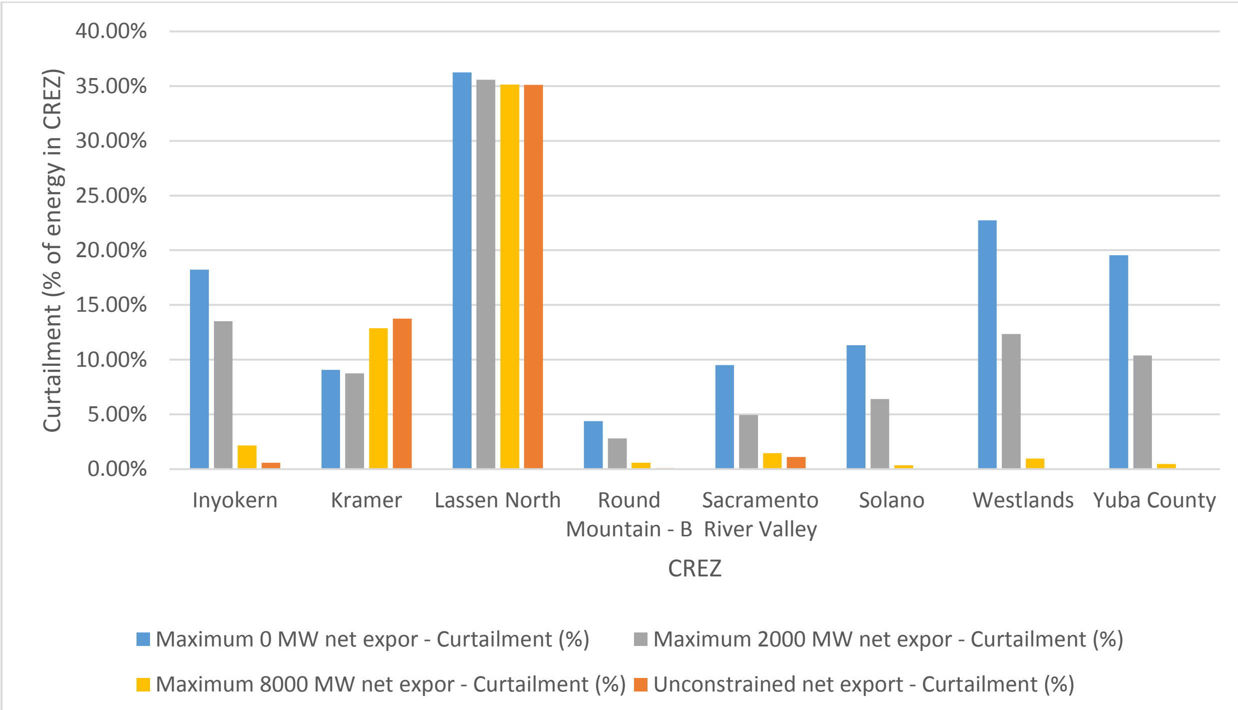
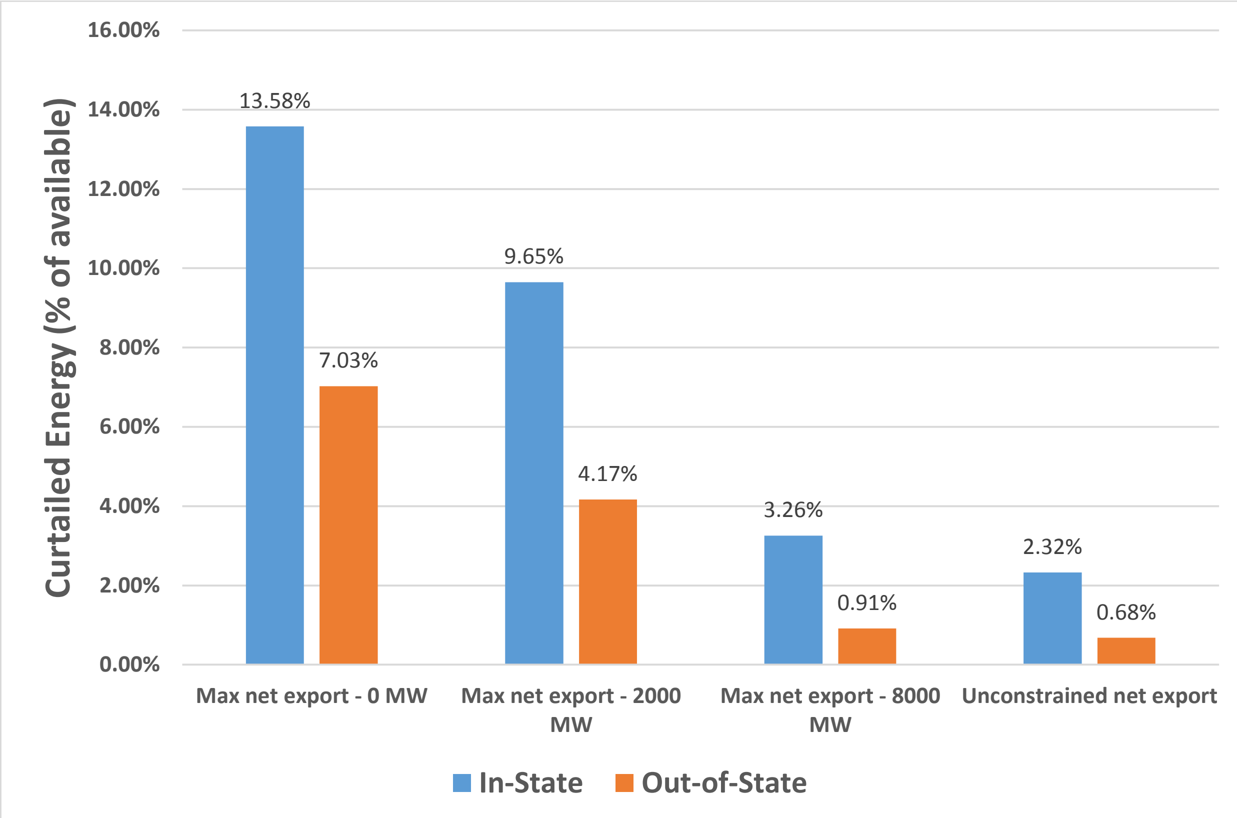


Figure 3.4-12: Wind and solar curtailment by CREZ (% of energy curtailed) – Out-of-state portfolio



In summary, Lassen North, Round Mountain – B, Sacramento River Valley, Kramer and Inyokern are the CREZs that experience the highest amount of transmission congestion in In-state as well as Out-of-state portfolios. The study results demonstrated a significant variation in total renewable curtailment between In-state and out-of-state portfolios. Figure 3.4-13 shows that the renewable curtailment observed with the out-of-state portfolio is approximately half of the renewable curtailment observed with the in-state portfolio.

Figure 3.4-13: Wind and solar curtailment (% of available renewable energy) – In-state vs. Out-of-state portfolio



3.4.6.2 *Power flow snapshot reliability assessment results*

In addition to production cost simulations, power flow reliability assessment was performed using the snapshots identified as described in section 3.4.5.3. Following is a CREZ-wise discussion of the reliability assessment results.

Northern California

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-4.

Table 3.4-4: Transmission capability estimates and portfolio utilization – Northern California

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Lassen North, Round Mountain A, Round Mountain B and Sacramento River	3,404	868	3,404

Reliability Concerns

The following overloads which would result in renewable curtailment were observed in northern California zone under the snapshots selected for in-state and out-of-state portfolios. Only the contingency that resulted in the highest loading is shown for each contingency category. These results are based on the power flow studies for the local areas, as well as on the post-transient studies for the PG&E Bulk transmission system.

Table 3.4-5: Reliability issues in Northern California zone

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
Lassen North Zone				
In-state/ OOS	Cottonwood-Burney Forest 230 kV line	Base Case	P0	166 / 71
In-state/ OOS	Pit No.1-Cottonwood(F) 230 kV Line (Cottonwood-Burney Forest Power)	Base Case	P0	164 / 68
In-state/ OOS	Carberry-Round Mountain 230 kV Line	Base Case	P0	240 / 117
In-state/ OOS	Pit No.1-Cottonwood 230 kV Line (Pit No.1-Burney Forest Power)	Base Case	P0	182 / 55
In-state/ OOS	Carberry-PIT 3 230 kV Line	Base Case	P0	203 / 76
In-state/ OOS	Caribou-Table Mountain 230 kV Line	Base Case	P0	164 / 23
In-state/ OOS	Olinda 500/230 kV x-former	Base Case	P0	97/ <100
In-state/ OOS	Olinda 500/230 kV x-former	Round Mountain 500/230 kV x-former	P1	146/ <100
In-state/ OOS	Cottonwood-Burney Forest 230 kV line	Carbery-Round Mountain 230 kV	P1	383 / 164
In-state/ OOS	Pit No.1-Cottonwood 230 kV Line (Pit No.1-Burney Forest Power)	Carbery-Round Mountain 230 kV	P1	442 / 186
In-state/ OOS	Carberry-Round Mountain 230 kV Line	Olinda 500/230 kV x-former	P1	224/102
In-state/ OOS	Carberry-PIT 3 230 kV Line	Olinda 500/230 kV x-former	P1	191/ <100
In-state/ OOS	Table Mountain-Rio Oso 230 kV line	Table Mountain 500/230 kV x-former	P1	115/ <100

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Cottonwood 230 kV breaker E-F	Round Mountain 500/230 kV x-former	P1	129/ <100
In-state/ OOS	Cottonwood 230 kV breaker F2-WAPA	Round Mountain 500/230 kV x-former	P1	109/ <100
In-state/ OOS	Olinda-Cottonwood 230 kV # 1 line	Round Mountain 500/230 kV x-former	P1	132/ <100
In-state/ OOS	Olinda-Cottonwood 230 kV # 2 line	Round Mountain 500/230 kV x-former	P1	122/ <100
In-state/ OOS	Carberry-Round Mountain 230 kV Line	Cottonwood 230 kV Bus Section 2F w/o Hatchet Ridge SPS	P2	352 / 162
In-state/ OOS	Pit No.1-Cottonwood 230 kV Line (Pit No.1-Burney Forest Power)	Cottonwood 230 kV Bus Section 2F w/ Hatchet Ridge SPS	P2	303 / 108
In-state/ OOS	Carberry-PIT 3 230 kV Line	Cottonwood 230 kV Bus Section 2F w/ Hatchet Ridge SPS	P2	322 / 127
In-state/ OOS	Cottonwood-Burney Forest 230 kV	Round Mountain 500 kV stuck breaker	P4	151/ <100
In-state/ OOS	Pit No.1-Cottonwood(F) 230 kV Line (Cottonwood-Burney Forest Power)	Round Mountain 500 kV stuck breaker	P4	171/ <100
In-state/ OOS	Carberry-Round Mountain 230 kV Line	Vaca Dixon 500 kV stuck breaker # 732	P4	210/ <100
In-state/ OOS	Pit No.1-Cottonwood 230 kV Line (Pit No.1-Burney Forest Power)	Vaca Dixon 500 kV stuck breaker # 732	P4	160/ <100
In-state/ OOS	Carberry-PIT 3 230 kV Line	Vaca Dixon 500 kV stuck breaker # 732	P4	178/ <100
In-state/ OOS	Carberry-Round Mountain 230 kV Line	Brighton - Grand Island 115 kV Line No. 2 & Brighton - Grand Island 115 kV Line No. 1	P6	211 / <100
In-state/ OOS	Caribou-Table Mountain 230 kV Line	Rio Oso - Woodland 115 kV No. 2 & Caribou No.11 230/115/60 kV Transformer	P6	154 / <100
In-state/ OOS	Table Mountain-Rio Oso 230 kV line	Table Mountain 500/230 kV bank #1 & Table Mountain-Palermo 230 kV	P6	162 / <100
In-state/ OOS	Caribou-Grizly 115 kV line	Table Mountain 500/230 kV bank #1 & Table Mountain-Palermo 230 kV	P6	111 / <100
In-state/ OOS	Olinda 500/230 kV x-former	Table Mountain -Tesla & Tesla-Vaca Dix 500 kV lines	P7	102/ <100

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Carberry-Round Mountain 230 kV Line	Pit No.1-Cottonwood(F) 230 kV Line and Round Mountain-Cottonwood(E) No.2 230 kV Line	P7	348 / 158
In-state/ OOS	Pit No.1-Cottonwood 230 kV Line (Pit No.1-Burney Forest Power)	Pit No.1-Cottonwood(F) 230 kV Line and Round Mountain-Cottonwood(E) No.2 230 kV Line	P7	297 / 104
In-state/ OOS	Carberry-PIT 3 230 kV Line	Pit No.1-Cottonwood(F) 230 kV Line and Round Mountain-Cottonwood(E) No.2 230 kV Line	P7	316 / 123
In-state/ OOS	Cottonwood-Burney Forest 230 kV	Table Mtn-Tesla & Table Mtn-Vaca Dix 500 kV lines	P7	164/ <100
In-state/ OOS	Pit No.1-Cottonwood 230 kV Line (Pit No.1-Burney Forest Power)	Table Mtn-Tesla & Table Mtn-Vaca Dix 500 kV lines	P7	187/ <100
In-state/ OOS	Carberry-Round Mountain 230 kV Line	Tracy-Tesla & Tracy-Los Banos 500 kV lines	P7	211/ <100
In-state/ OOS	Pit No.1-Cottonwood 230 kV Line (Pit No.1-Burney Forest Power)	Tracy-Tesla & Tracy-Los Banos 500 kV lines	P7	160/ <100
In-state/ OOS	Carberry-PIT 3 230 kV Line	Tracy-Tesla & Tracy-Los Banos 500 kV lines	P7	178/ <100
In-state/ OOS	Caribou-Table Mountain 230 kV Line	Round Mountain-Table Mountain 500 kV lines #1&#2	P7	144/ <100
In-state/ OOS	Cottonwood 230 kV breaker E-F	Table Mountain-Tesla & Tesla-Vaca Dix 500 kV lines	P7	101/ <100
Lassen North, Round Mountain – B Zone				
In-state/ OOS	Round Mountain 500/230 kV Bank	Base Case	P0	111/ <100
In-state/ OOS	Round Mountain 500/230 kV Bank	Olinda 500/230 Bank #1	P1	152 / <100
In-state/ OOS	Cottonwood-Round Mountain #2	Round Mountain 500/230 Bank 1	P1	113 / <100
In-state/ OOS	Cottonwood-Round Mountain #3	Round Mountain 500/230 Bank 1	P1	125 / <100
In-state/ OOS	Round Mountain 500/230 kV Bank	P2-4:A3:1_COTTONWOOD CB 462 OR 482 STUCK	P2	127 / 57
In-state/ OOS	Round Mountain 500/230 kV Bank	Vaca Dixon 500 kV stuck breaker # 732	P4	105/ <100

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Round Mountain 500/230 kV Bank	Rio Oso - Woodland 115 kV No. 2 & Ignacio - Mare Island 115 kV No. 2	P6	115 / <100
In-state/ OOS	Round Mountain 500/230 kV Bank	Olinda 500/230 Bank #1 and Table Mountain bank w/ SPS	P6	162 / <100
In-state/ OOS	Cottonwood-Round Mountain #2	Round Mountain 500/230 Bank 1 & Cottonwood-BFRST 230 kV	P6	166 / <100
In-state/ OOS	Cottonwood-Round Mountain #3	Round Mountain 500/230 Bank 1 & Cottonwood-Round Mountain #1	P6	183 / <100
In-state/ OOS	Round Mountain 500/230 kV Bank	Pit No.1-Cottonwood(F) 230 kV Line and Round Mountain-Cottonwood(E) No.2 230 kV Line	P7	127 / 56
Lassen North, Sacramento River Zone				
In-state/ OOS	Table Mountain 500/230 kV Bank	Base Case	P0	102/ <100
In-state/ OOS	Table Mountain 500/230 kV Bank	Round Mountain 500/230 kV Transformer	P1	109/ <100
In-state/ OOS	Rio Oso-Lockford 230 kV	Table Mountain 500/230 kV Transformer	P1	116/ <100
In-state/ OOS	Rio Oso-Lockford 230 kV	Table Mountain 500/230 kV Transformer & Brighton-Bellota 230 kV	P6	157 / <100
In-state/ OOS	Table Mountain 500/230 kV Bank	30624 Tesla 230 kV Bus CB202 Internal Breaker Fault (1E and 2E)	P2	115 / 18
In-state/ OOS	Table Mountain 500/230 kV Bank	Vaca Dixon 500 kV stuck breaker # 732	P4	105/ <100
In-state/ OOS	Table Mountain 500/230 kV Bank	UC Davis - Dixon Canning 115 kV & Davis - Dixon 115 kV Line	P6	108 / <100
In-state/ OOS	Table Mountain 500/230 kV Bank	Brighton-Bellota 230 kV Line & Rio Oso-Lockeford 230 kV Line	P7	114 / 18
Lassen North, Sacramento River, Solano Zone (at Brighton)				
In-state/ OOS	Atlantic-Gold Hill 230 kV	Table Mountain 500/230 kV x-former	P1	111/ <100
In-state/ OOS	Eight Mile-Tesla 230 kV	Table Mountain 500/230 kV x-former	P1	114/ <100
In-state/ OOS	Woodland BM-Woodland 115 kV	Table Mountain 500/230 kV x-former	P1	104/ <100
In-state/ OOS	Woodland BM- Plain Field 115 kV	Table Mountain 500/230 kV x-former	P1	118/ <100
In-state/ OOS	Davis-Plain Field 115 kV	Table Mountain 500/230 kV x-former	P1	113/ <100
In-state/ OOS	Brighton-Bellota 230 kV	Table Mountain 500/230 kV x-former	P1	136/ <100

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Lockford-Bellota 230 kV	Table Mountain 500/230 kV Transformer & Brighton-Bellota 230 kV	P6	135 / <100
In-state/ OOS	Rio Oso - Gold Hill 230 kV	Table Mountain 500/230 kV bank #1 & Atlantic-Gold Hill 230 kV	P6	130 / <100
In-state/ OOS	Rio Oso-Brighton 230 kV	Table Mountain 500/230 kV bank #1 & Rio Oso-Lockford 230 kV	P6	116 / <100
In-state/ OOS	Atlantic-Gold Hill 230 kV	Table Mountain 500/230 kV bank #1 & Rio Oso-Gold Hill 230 kV	P6	172 / <100
In-state/ OOS	Gold Hill-Eight Mile 230 kV	Table Mountain 500/230 kV bank #1 & Gold Hill-Lodi 230 kV	P6	143 / <100
In-state/ OOS	Gold Hill-Lodi 230 kV	Table Mountain 500/230 kV bank #1 & Gold Hill-Eight Mile 230 kV	P6	144 / <100
In-state/ OOS	Eight Mile-Tesla 230 kV	Table Mountain 500/230 kV bank #1 & Eight Mile-Stagg 230 kV	P6	164 / <100
In-state/ OOS	Eight Mile-Stagg 230 kV	Table Mountain 500/230 kV bank #1 & Eight Mile-Tesla 230 kV	P6	143 / <100
Sacramento River Zone				
In-state/ OOS	Cortina - Vaca Dixon 230 kV Line	Base Case	P0	100/ <100
In-state/ OOS	Madison - Vaca 115 kV Line	Base Case	P0	106 / 16
In-state/ OOS	Palermo-Bogue 115 kV Line	Base Case	P0	120 / 5
In-state/ OOS	Cottonwood No.2 60 kV Line	Base Case	P0	100 / 102
In-state/ OOS	Butte No.1 115/60 kV Transformer	Base Case	P0	115 / 14
In-state/ OOS	Butte-Esquon 60 kV Line	Base Case	P0	273 / 10
In-state/ OOS	Glenn No.1 60 kV Line	Base Case	P0	102 / 4
In-state/ OOS	Fulton Jct - Vaca 115 kV Line (Putak Creek-Vaca)	Base Case	P0	281 / 152
In-state/ OOS	Rio Oso - Woodland 115 kV No. 2	Base Case	P0	244 / 209
In-state/ OOS	Fulton Jct - Vaca 115 kV Line (Putak Creek-Vaca)	Base Case	P0	275 / 147
In-state/ OOS	Bogue - Rio Oso 115 kV Line	Base Case	P0	124 / 1

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Cortina - Vaca Dixon 230 kV Line	Round Mountain 500/230 kV x-former	P1	115/ <100
In-state/ OOS	Madison - Vaca 115 kV Lin	Fulton Jct - Vaca 115 kV Line (Putak Creek-Vaca)	P1	326 / 174
In-state/ OOS	Delevan-Cortina 230 kV Line	Cortina-Vaca #1 230 kV	P1	123 / <100
In-state/ OOS	Delevan-Cortina 230 kV Line	NON-BUS-TIE BREAKER CB242 FAILURE AT CORTINA 230kV	P2	122 / 52
In-state/ OOS	Madison - Vaca 115 kV Lin	NON-BUS-TIE BREAKER CB1822 FAILURE AT VACA-DIXON 115kV	P2	327 / 175
In-state/ OOS	Cottonwood-Benton No.1 60 kV Line	COTTONWOOD BUS PARALLEL BKR STUCK 115KV	P2	104 / <100
In-state/ OOS	Cortina - Vaca Dixon 230 kV Line	Table Mountain 500 kV stuck breaker	P4	101/ <100
In-state/ OOS	Palermo-Bogue 115 kV Line	Palermo No.2 230/115 kV Transformer & Woodleaf-Palermo 115 kV Line	P6	101 / <100
In-state/ OOS	Cottonwood-Benton No.1 60 kV Line	Cottonwood #4 230/115 kV Transformer & Cottonwood #1 230/115 kV Transformer	P6	114 / <100
In-state/ OOS	Butte-Esquon 60 kV Line	Table Mountain-Butte No.1 115 kV Line & Table Mountain No.3 230/115 kV Transformer	P6	235 / <100
In-state/ OOS	Madison - Vaca 115 kV Lin	Fulton Jct - Vaca 115 kV Line (Putak Creek-Vaca) & Vaca Dixon 230/115 kV Transformer No. 2	P6	330 / 176
In-state/ OOS	Bogue - Rio Oso 115 kV Line	Woodleaf-Palermo 115 kV Line & Rio Oso - Woodland 115 kV No. 2	P6	126 / <100
In-state/ OOS	Warnerville - Wilson 230 kV Line	Los Banos-Tesla & Los Banos-Tracy 500 kV lines	P7	105/ <100
In-state/ OOS	Bogue - Rio Oso 115 kV Line	Rio Oso-Woodland #1 115 kV Line & Rio Oso-Woodland #2 115 kV Line	P7	126 / 1
In-state/ OOS	Cortina - Vaca Dixon 230 kV Line	Logan Creek-Delevan 230 kV Line & Delevan-Cortina 230 kV Line	P7	145 / 57

The constraints observed in Lassen North and Round Mountain B CREZ are of an area-wide nature due to the amount of generation that may be limited due to these concerns under certain operating conditions. As such, congestion due to most of these constraints were also captured in the production cost simulation. Constraints observed in the Sacramento River CREZ are mostly of local nature. Additional curtailment is expected in Sacramento River CREZ from these local constraints unless resources are connected to the 230 kV system. SPS is not feasible to mitigate the overloads identified in this zone.

Solano

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-6.

Table 3.4-6: Transmission capability estimates and portfolio utilization - Solano

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Solano	1,101	1,101	1,101

Reliability Concerns

The following overloads which would result in renewable curtailment were observed in Solano zone under the snapshots selected for in-state and out-of-state portfolios.

Table 3.4-7: Reliability issues in Solano zone

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Martinez-Sobrante 115kV Line	Sobrante-North Tower 115kV Line	P1	116 / 106
In-state/ OOS	Martinez-Sobrante 115kV Line	BUS-TIE BREAKER FAULT AT 30526 PITSBG D 230.00	P2	106 / 127
In-state/ OOS	Martinez-Sobrante 115kV Line	Pittsburg - Tesla 115 kV Line No. 2 & Sobrante-North Tower 115kV Line	P6	118 / 115
In-state/ OOS	Brighton - Grand Island 115 kV Line No. 1	Base Case	P0	253 / 223
In-state/ OOS	Brighton - Grand Island 115 kV Line No. 2	Base Case	P0	250 / 220
In-state/ OOS	Brighton - Grand Island 115 kV Line No. 1	P1-2:A4:38:_Brighton - Grand Island 115 kV Line No. 2	P1	417 / 365
In-state/ OOS	Brighton - Grand Island 115 kV Line No. 2	P1-2:A4:37:_Brighton - Grand Island 115 kV Line No. 1	P1	417 / 365
In-state/ OOS	Brighton-Bellota 230 kV	Table Mountain 500/230 kV x-former	P1	136/ <100
In-state/ OOS	Brighton - Bellota 230 kV Line	Table Mountain 500/230 kV Transformer w/ SPS	P1	132 / <100
In-state/ OOS	Brighton - Bellota 230 kV Line	Davis - Dixon 115 kV Line & UC Davis - Dixon Canning 115 kV	P6	101 / <100
In-state/ OOS	Brighton 230/115 kV Transformer No. 9	Brighton 230/115 kV Transformer No. 10 & Brighton - Davis 115 kV Line	P6	119 / 102

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Brighton - Davis 115 kV Line	Brighton 230/115 kV Transformer No. 10 & Brighton 230/115 kV Transformer No. 9	P6	109 / 90
In-state/ OOS	Brighton - Grand Island 115 kV Line No. 1	Brighton - Grand Island 115 kV Line No. 2 & Rio Oso - Woodland 115 kV No. 2	P6	442 / 368
In-state/ OOS	Brighton - Grand Island 115 kV Line No. 2	Brighton - Grand Island 115 kV Line No. 1 & Rio Oso - Woodland 115 kV No. 2	P6	443 / 368
In-state/ OOS	Brighton - Bellota 230 kV Line	Table Mountain 500/230 kV Transformer w/ SPS & Rio Oso-Lockford 230 kV	P6	174 / <100
In-state/ OOS	Brighton-Bellota 230 kV	Table Mountain-Tesla & Tesla-Vaca Dix 500 kV lines	P7	111/ <100
In-state/ OOS	Brighton - Bellota 230 kV Line	Gold Hill-Eight Mile Road 230 kV Line & Eight Mile Road-Lodi Stig 230 kV Line	P7	103 / 39

The constraints observed in the Solano CREZ are mostly of local nature. Additional curtailment is expected in Solano CREZ from these local constraints unless resources are connected to the 230 kV system. SPS is not feasible to mitigate the overloads identified in this zone.

Greater Carrizo

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-8.

Table 3.4-8: Transmission capability estimates and portfolio utilization – Greater Carrizo

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Carrizo North, Carrizo South and Santa Barbara	798	559	1,140

Reliability Concerns

The following overloads which would result in renewable curtailment were observed in Greater Carrizo zone under the snapshots selected for in-state and out-of-state portfolios.

Table 3.4-9: Reliability issues in Greater Carrizo zone

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Sisquoc-Santa Ynez Sw.Sta. 115 kV Line	Base Case	P0	242 / 118
In-state/ OOS	Buellton 115 kV Tap	Base Case	P0	185 / 9
In-state/ OOS	Sisquoc-Santa Ynez Sw.Sta. 115 kV Line	Base Case	P0	303 / 156
In-state/ OOS	Divide-Cabrillo 115 kV Line No. 1	Base Case	P0	217 / 156
In-state/ OOS	Sisquoc-Santa Ynez 115 kV	Base Case	P0	248 / 124
In-state/ OOS	AECCEORTP-ZACA 115 kV	Base Case	P0	257 / 131
In-state/ OOS	Sisquoc-Santa Ynez Sw.Sta. 115 kV Line	Brighton - Grand Island 115 kV Line No. 2 & Brighton - Grand Island 115 kV Line No. 1	P6	270 / <100
In-state/ OOS	Divide-Cabrillo 115 kV Line No. 1	Brighton - Grand Island 115 kV Line No. 2 & Brighton - Grand Island 115 kV Line No. 1	P6	192 / <100
In-state/ OOS	Sisquoc-Santa Ynez 115 kV	Brighton - Grand Island 115 kV Line No. 2 & Brighton - Grand Island 115 kV Line No. 1	P6	222 / <100
In-state/ OOS	AECCEORTP-ZACA 115 kV	Brighton - Grand Island 115 kV Line No. 2 & Brighton - Grand Island 115 kV Line No. 1	P6	229 / <100
In-state/ OOS	Estrella 230/70 kV Bank #1	Estrella- Moro Bay 230 & Gates - Cal Flat 230 kV	P6	110 / <100

The constraints observed in the Greater Carrizo zone are mostly of local nature. Additional curtailment is expected in Santa Barbara CREZ from these local constraints unless resources are connected to the 230 kV system. SPS is not feasible to mitigate the overloads identified in this zone

Westlands

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4.10.

Table 3.4-10: Transmission capability estimates and portfolio utilization – Westlands

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Westlands	894	749	2,900

Reliability Concerns

The following overloads which would result in renewable curtailment were observed in Westlands zone under the snapshots selected for in-state and out-of-state portfolios.

Table 3.4-11: Reliability issues in Westlands zone

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Gates-Kettlemen tap 70kV	Base Case	P0	<100 / 108
In-state/ OOS	Avenal-Kettlemen tap 70kV	Base Case	P0	99 / 138
In-state/ OOS	Helms-E1 230kV line #1	Helms-Gregg 230kV #2 Line	P1	110 / 110
In-state /OOS	Helms-E1 230kV line #2	Helms-Gregg 230kV #1 Line	P1	110 / 110
In-state/ OOS	Avenal-Kettlemen tap 70kV	Avenal Generator	P1	<100 / 102
In-state/ OOS	Exchequer-Merced 70kV line	Merced 115/70kV TB #2	P1	95.8 / 104
In-state/ OOS	Moss Landing-Las Aguillas 230kV line	Moss Landing-Los Banos 500 kV	P1	<100 / 117
In-state/ OOS	Helms-E1 230kV line #1	CB 442 Fault at Gregg 230kV	P2	112 / 112
In-state/ OOS	Helms-E1 230kV line #2	CB 442 Fault at Gregg 230kV	P2	112 / 112
In-state/ OOS	Los Banos-Livignston-Canal 70kV line	Bus 2 Fault at Losbanos 230kV	P2	102 / <100
In-state/ OOS	Schindler-Q526T 70kV	Bus Tie Breaker at Gates 230kV	P2	<100 / 105
In-state/ OOS	Schindler-Q526T 70kV	Bus Tie Breaker at Gates 230kV	P2	<100/117.8
In-state/ OOS	Exchequer-Merced 70kV line	Bus Fault at Merced 115kV	P2	95 / 105
In-state/ OOS	Warnerville-Wilson 230kV line	Gates-Gregg 230kV & North Merced-El Capitan 115kV	P6	100.3 / <100
In-state/ OOS	MossLanding-Las Aguillas 230kV line	Los Banos-Westley 230kV & Los Banos 500/230kV TB	P6	<100 / 103.5
In-state/ OOS	Wilson-Lyons 230kV line	Gates-Gregg 230kV & Wilson-Borden #2 230kV line	P6	106.6 / <100
In-state/ OOS	Helms-E1 230kV line #1	Helms-Gregg 230kV #2 (Helms-Northern Fresno) Line& Helms-Gregg 230kV #2 (Gregg-Northern Fresno)	P6	111.6 / 112
In-state/ OOS	Helms-E1 230kV line #2	Helms-Gregg 230kV #1 (Helms-Northern Fresno) Line& Helms-Gregg 230kV #1 (Gregg-Northern Fresno)	P6	111.6 / 112

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Kearney-Herndon 230kV line	Gates-Gregg 230kV & Gregg-Henrietta 230kV line	P6	106 / 112
In-state/ OOS	Chowchilla-Certain Jct 115kV Line	Helms-Gregg 230kV #1 (Helms-Northern Fresno) Line& Helms-Gregg 230kV #1 (Gregg-Northern Fresno)	P6	139.8 / 119.5
In-state/ OOS	Sharon-Certain Jct 115kV	Helms-Gregg 230kV #1 (Helms-Northern Fresno) Line& Helms-Gregg 230kV #1 (Gregg-Northern Fresno)	P6	119 / 102
In-state/ OOS	Avenal-Kettlemen tap 70kV	Helms-Gregg 230kV #1 (Helms-Northern Fresno) Line& Helms-Gregg 230kV #1 (Gregg-Northern Fresno)	P6	<100 / 115
In-state/ OOS	Sharon-Oakhurst 115kV line	Helms-Gregg 230kV #1 (Helms-Northern Fresno) Line& Helms-Gregg 230kV #1 (Gregg-Northern Fresno)	P6	117.6 / 100.25
In-state/ OOS	Panoche-Cheny 115kV Line Tap	Panoche - Schindler #1 115 kV Line& Gates 230/70 kV Bank #5	P6	<100 / 115
In-state/ OOS	Tornado-Coalinga 70kV Line	Panoche - Schindler #1 115 kV Line& Gates 230/70 kV Bank #5	P6	151 / 177
In-state/ OOS	Exchequer-Merced 70kV line	Merced 115/70kV TB #2 & Exchequer 115/13.8kV TB	P6	<100 / 102
In-state/ OOS	Huron-Calfax 70kV Line	Schindler-Coalinga 70 kV Line& Gates 230/70 kV Bank #5	P6	<100 / 126
In-state/ OOS	Pleasant Valley-Q526TP 70kV	Schindler - Gates - Huron 70 kV Line(SCHLNDLR - Q532SS) 7& Gates 230/70 kV Bank #5	P6	<100 / 128
In-state/ OOS	Schindler-Q526T 70kV	Schindler - Gates - Huron 70 kV Line(SCHLNDLR - Q532SS) 7& Gates 230/70 kV Bank #5	P6	111 / 161
In-state/ OOS	San Miguel-Coalinga 70kV	Panoche - Schindler #2 115 kV Line& Gates 230/70 kV Bank #5	P6	214 / 265
In-state/ OOS	Pleasant Valley-Coalinga 70kV	Schindler - Gates - Huron 70 kV Line(SCHLNDLR - Q532SS) 7& Gates 230/70 kV Bank #5	P6	<100 / 140
In-state/ OOS	Calfax-Q532SS 70kV	Q526 70 kV Tap (Schindler - Colinga)&Gates 230/70 kV Bank #5	P6	<100 / 118
In-state/ OOS	E2 -E1 230/115kV TB	Gregg-E1 #1 & #2 230 kV Line	P7	118 / 118
In-state/ OOS	E2 -E1 230/115kV TB	Gregg-E1 #1 & #2 230 kV Line	P7	118 / 118
In-state/ OOS	MossLanding-Las Aguillas 230kV line	Los Banos-Gates and Los Banos-Midway 500 kV lines	P7	<100 / 105
In-state/ OOS	Quinto-Los Banos 230 kV line	Los Banos-Tesla& Los Banos-Tracy 500 kV	P7	<100/129

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Gates-Midway 230kV line	Gates-Midway 500kV line & Los Banos-Midway 500kV Line	P6	106 / 149
In-state/ OOS	Gates-Panoche #1 & #2 Lines	Los Banos-Midway 500kV Line & Los Banos-Gates 500kV Line	P6	<100 / 114
In-state/ OOS	Herndon-Kearney 230kV Line	Gates-Gregg 230kV Line & Gregg-Henrietta Tap 230kV Line	P6	<100 / 113
In-state/ OOS	Gates-Calflatss 230kV Line	Los Banos-Midway 500kV Line & Gates-Midway 500kV Line	P6	<100 / 113

The constraints observed in Westlands CREZ are of both area-wide and local nature. The Gates-Midway and Gates-Panoche Nos. 1 & 2 230 kV lines overload under N-1-1 contingencies are area-wide constraints. These constraints can be mitigated by SPS which could include 200 to 300 MW of renewable curtailment. Congestion due to these constraints were also captured in the production cost simulation. Constraints observed on the 115 and 70 kV systems are mostly of local nature. Additional curtailment is expected in Westlands CREZ from these local constraints unless resources are connected to the 230 kV system.

Tehachapi

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-12.

Table 3.4-12: Transmission capability estimates and portfolio utilization - Tehachapi

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Tehachapi	5,000	5,000	5,000

Reliability Concerns

The following overloads which would result in renewable curtailment were observed in Tehachapi zone under the snapshots selected for in-state and out-of-state portfolios.

Table 3.4-13: Reliability issues in Tehachapi zone

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state & OOS	BIG Creek 66 kV	Base case and several contingencies	P0 and P1	High Vol
In-state	Whirlwind 500/230 kV #1 or #3 or #4	Base case	P0	101.59

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state/ OOS	Midway-Whirlwind 500 kV #3	Base case	P0	125.77 / 105.02
In-state/ OOS	Windhub 500/230 kV #1 ot #2 or #3 or #4	Windhub 500/230 kV #1 ot #2 or #3 or #4	P1	103.2 / 99.66
In-state/ OOS	Whirlwind 500/230 kV #1 or #3 or #4	Whirlwind 500/230 kV #1 or #3 or #4	P1	127.67 / 115.42
In-stat/ OOS	Vincent-Whirlwind 500 kV #1 or #2	Antelope-Vincent 500 kV #1 and Antelope-Vincent 500 kV #2	P7	118.91 / 111.59
In-state/ OOS	Antelope-Whirlwind 500 kV #1	Antelope-Windhub 500 kV #1 and Antelope-Whirlwind 500 kV #1 with reinsert	P6	120.6 / 116.7
In-state/ OOS	Midway-Whirlwind 500 kV #3	Antelope-Windhub 500 kV #1 and Antelope-Whirlwind 500 kV #1 with reinsert	P6	141.4 / 126.9
In-state	Vincent-Whirlwind 500 kV #3	Midway-Whirlwind 500 kV #3 and Antelope-Whirlwind 500 kV #1	P6	106.54
In-state/ OOS	Antelope-Vincent 500 kV #1 or #2	Antelope-Vincent 500 kV #2 or #1 and Antelope-Pardee 230 kV #1	P6	109.58 / 102.71
In-state/ OOS	Antelope-Vincent 500 kV #1 or #2	Antelope-Vincent 500 kV #2 or #1 and Vincent-Whirlwind 500 kV #3 without by pass	P7	120.93 / 114.22
In-state/ OOS	Antelope-Vincent 500 kV #1 or #2	Antelope-Vincent 500 kV #2 or #1 and Vincent-Whirlwind 500 kV #3 with by pass	P7	149.98 / 140.19
In-state/ OOS	Antelope-Vincent 500 kV #1 or #2	Midway-Whirlwind 500 kV #3 and Vincent-Whirlwind 500 kV #3	P6	108.84 / 100.24
In-state/ OOS	Antelope-Vincent 500 kV #1 or #2	Antelope-Vincent 500 kV #2 or #1 and Windhub-Whirlwind 500 kV #1	P6	112.06 / 104.77
In-state/ OOS	Antelope-Vincent 500 kV #1 or #2	Antelope-Vincent 500 kV #2 or #1 and Midway-Whirlwind 500 kV #3	P6	119.03 / 108.86
In-state/ OOS	Antelope-Windhub 500 kV #1	Antelope-Whirlwind 500 kV #1 and Vincent-Whirlwind 500 kV #3	P7	108.44 / 104.32
In-state	Midway-Whirlwind 500 kV #3	Antelope-Whirlwind 500 kV #1 and Vincent-Whirlwind 500 kV #3	P7	100.64
In-state/ OOS	Antelope-Windhub 500 kV #1	Antelope-Windhub 500 kV #1 and Vincent-Whirlwind 500 kV #3	P6	120.57 / 115.97
In-state/ OOS	Windhub 500/230 kV remaining	Windhub 500/230 kV two banks	P6	156.4 / 150.9
In-state/ OOS	Whirlwind 500/230 kV remaining	Whirlwind 500/230 kV two banks	P6	264.82 / 243.91
In-state	Midway-Whirlwind 500 kV #3	Midway-Vincent 500 kV #1 and Midway-Vincent 500 kV #2	P7	103.28

The constraints observed in this zone are of an area-wide nature due to the amount of generation that may be limited due to these concerns under certain operating conditions. While some future SPS to drop generation may mitigate some of these concerns, SPS will not be adequate to mitigate the overloads caused by N-2 contingency of Antelope – Vincent No. 1 or 2 and Vincent – Whirlwind 500 kV line No. 3. In addition to this constraint, several N-1-1 contingencies listed above will result in more than 1,000 MW of renewable curtailment after the first contingency in order to prepare the system for the next worst single contingency. This suggests that maintenance outages could result in severe renewable curtailment not captured by production cost simulations.

Riverside East and Palm Springs

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-14.

Table 3.4-14: Transmission capability estimates and portfolio utilization – Riverside and Palm Springs

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Riverside East and Palm Springs	4,917	2,571 + 2,063 (NM wind)	4,917

Reliability Concerns

The following overloads which would result in significant renewable curtailment were observed in Riverside and Palm Springs zones under the snapshots selected for in-state and out-of-state portfolios.

Table 3.4-15: Reliability issues in Riverside and Palm Springs zones

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state	Devers-RedBluff 500 kV Ck 1	Devers-RedBluff 500 kV Ck 2	P1	126.4
In-state	Devers 500/230 kV Transformer #1	Alberhill-ValleySC 500 kV Ck 1	P1	120.6
In-state	Devers 500/230 kV Transformer #2	Alberhill-ValleySC 500 kV Ck 1	P1	102.6
In-state	Devers-RedBluff 500 kV Ck 2	Devers-RedBluff 500 kV Ck 1	P1	115.02
In-state	RedBluff 500/230 kV Transformer #1 or #2	RedBluff 500/230 kV Transformer #1 or #2	P1	183.24
In-state	Colorado River 500/230 kV Transformer #1 or #2	Colorado River 500/230 kV Transformer #1 or #2	P1	182.95

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state	Divergence	Alberhill-ValleySC 500 kV Ck 1 AND Palo Verde-Colorado River 500 kV Ck1	P6	N/A
In-state	Divergence	Devers 500/230 kV Transformer #1 AND Devers-RedBluff 500 kV Ck 2	P6	N/A
In-state	Divergence	Devers 500/230 kV Transformer #1 AND Devers-RedBluff 500 kV Ck 1	P6	N/A
In-state	Divergence	Palo Verde-Colorado River 500 kV Ck1 AND Devers-RedBluff 500 kV Ck 2	P6	N/A
In-state	Divergence	Palo Verde-Colorado River 500 kV Ck1 AND Devers-RedBluff 500 kV Ck 1	P6	N/A
In-state	Divergence	Palo Verde-Colorado River 500 kV Ck1 AND Delaney-Colorado River 500 kV Ck2	P6	N/A
In-state	Devers 500/230 kV Transformer #1	Alberhill-ValleySC 500 kV Ck 1 AND Devers 500/230 kV Transformer #2	P6	207.2
In-state	Devers-RedBluff 500 kV Ck 1	Devers-RedBluff 500 kV Ck 2 AND Delaney-Colorado River 500 kV Ck2	P6	149.36
OOS	Devers 500/230 kV Transformer #1	Alberhill-ValleySC 500 kV Ck 1 AND Devers 500/230 kV Transformer #2	P6	146.13
In-state	ETIWANDA-SANBRDNO 230 kV Ck 1	Alberhill-ValleySC 500 kV Ck 1 AND SANBRDNO - VSTA 230 kV Ckt 2	P6	122.06
In-state	ETIWANDA-VSTA 230 kV Ck 1	Alberhill-ValleySC 500 kV Ck 1 AND MIRALOME-VSTA 230kV Ck2	P6	114.89
In-state	VISTA-SANBRDNO 230 kV Ck 2	Alberhill-ValleySC 500 kV Ck 1 AND ETIWANDA-SANBRDNO 230 kV Ck 1	P6	112.5
OOS	Devers-RedBluff 500 kV Ck 1	Devers-RedBluff 500 kV Ck 2 AND N.GILA-IMPRLVLY 500kV Ckt 1	P6	108.94
OOS	Devers-RedBluff 500 kV Ck 1	Devers-RedBluff 500 kV Ck 2 AND Palo Verde-Colorado River 500 kV Ck1 with RAS	P6	105.42
In-state	Divergence	Delaney-Palo Verde 500 kV Ck 1 AND Palo Verde-Colorado River 500 kV Ck1	P7	N/A
In-state	Divergence	Devers-RedBluff 500 kV Ck 1 AND Devers-RedBluff 500 kV Ck 2	P7	N/A
In-state	Divergence	Delaney-Colorado River 500 kV Ck2 AND Palo Verde-Colorado River 500 kV Ck1	P7	N/A

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state	Divergence	Delaney-Colorado River 500 kV Ck2 AND Palo Verde-Colorado River 500 kV Ck1	P7	N/A
In-state	Devers 500/230 kV Transformer #1	Devers-ValleySC 500 kV Ck 1 AND Devers-ValleySC 500 kV Ck 2	P7	120.81

The constraints observed in this zone are of an area-wide nature due to the amount of generation that may be limited due to these concerns under certain operating conditions. While some future SPS to drop generation may mitigate some of these concerns, SPS will not be adequate to mitigate the overloads caused by N-2 contingency (P7) of Devers – Valley 500 kV No. 1 and No. 2 lines. In addition to this constraint, several N-1-1 contingencies (P6) listed above will result in more than 1,000 MW of renewable curtailment after the first contingency in order to prepare the system for the next worst single contingency. This suggests that maintenance outages could result in severe renewable curtailment not captured by production cost simulations.

Kramer and Inyokern

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-16.

Table 3.4-16: Transmission capability estimates and portfolio utilization – Inyokern and Kramer

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Kramer and Inyokern	750	750	750

Reliability Concerns

The main constraint in Inyokern and Kramer zones that could results in renewable curtailment under the snapshots selected for in-state portfolio was the overload of Kramer – Victor 220 kV line for the N-1 (P1) contingency of the remaining Kramer – Victor 220 kV line. A future SPS will be adequate to mitigate this issue. Congestion due to this constraints was also captured in the production cost simulation.

Mountain Pass and Eldorado

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-17.

Table 3.4-17: Transmission capability estimates and portfolio utilization – Mountain Pass and Eldorado

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Mountain Pass and Eldorado	1,226	1,226 + 2,141 (WY wind)	2,982

Reliability Concerns

The following overloads were observed in Mountain Pass and Eldorado zones under the snapshots selected for in-state and out-of-state portfolios.

Table 3.4-18: Reliability issues in Mountain Pass and Eldorado zones

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
OOS	(i) Pahrump - Bob 230 kV (ii) Bob - Mead 230 kV line (iii) 138kV lines in VEA	Eldorado 5AA (T-1)	P1	(i) 142% (ii) 135% (iii) < 105%
OOS	Eldorado – McCullough 500 kV	Eldorado - Lugo 500 KV + Mohave - Lugo 500 kV	P6	112%
In-state and OOS	Ivanpah 230/115 kV banks 1 & 2	Several combinations of Ivanpah - Eldorado 230 kV line, Mtn Pass - Coolwater 115 kV line and Ivanpah 230/115 kV bank 1 or 2	P6	101%

The constraints observed in this zone are of an area-wide nature due to the amount of generation that may be limited due to these concerns under certain operating conditions. A SPS will be adequate to mitigate the overloads caused by category P1 contingency of Eldorado 500/230 kV 5 AA bank. Category P6 overload on Eldorado – McCullough 500 kV line is expected to result in ~800 MW of renewable curtailment after the first contingency in order to prepare the system for the next worst single contingency in the snapshot that was studied for Out-of-state portfolio.

Greater Imperial

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in table 3.4-19.

Table 3.4-19: Transmission capability estimates and portfolio utilization – Greater Imperial

Zone	In-state (MW)	Out-of-state (MW)	Transmission capability estimate (MW)
Greater Imperial	2,633	1,341	2,633

Reliability Concerns

The following overloads were observed in Mountain Pass and Eldorado zones under the snapshots selected for in-state and out-of-state portfolios.

Table 3.4-20: Reliability issues in Mountain Pass and Eldorado zones

Scenario	Limiting element	Contingency	Contingency Type	Loading (%)
In-state	Miguel 500/230 kV bank 80 & 81	Miguel 500/230 kV bank 80 or 81	P1	106%
In-state and OOS	Sycamore - Suncrest 230 kV line 1 & 2	Eco - Miguel 500 kV (IV PST adjustment for the next contingency)	P1	118%
In-state and OOS	Miguel 500/230 kV bank 80 or 81	Ocotillo – Suncrest 500 kV + Miguel 500/230 kV bank 80 or 81	P6	143%
In-state and OOS	Divergence	Eco - Miguel 500 kV line + Ocotillo - Suncrest 500 KV line (with gen-drop)	P6	N/A
In-state and OOS	Sycamore - Suncrest 230 kV line 1 or 2	Eco - Miguel 500 kV + Suncrest - Sycamore 230 kV line 1 or 2	P6	112%

The constraints observed in this zone are of an area-wide nature due to the amount of generation that may be limited under certain operating conditions. A SPS will be adequate to mitigate the overload on Miguel 500/230 kV banks caused by category P1 and P6 contingencies. Category P6 contingency of Sunrise Power Link and Southwest Power Link is expected to require increased internal SDG&E generation to be dispatched for increased renewable production in the Imperial zone. In addition to this internal generation dispatch a reduction in imports from the East may also be required which in turn can result in some renewable curtailment in Greater Imperial region.

3.4.6.3 *Transient stability assessment*

The study methodology for transient stability assessment and the dynamic models for the new renewable resources are described in section 3.4.5.2. The study used the latest WECC Master Dynamic File as a starting point. For the new resources modeled in the 50 percent renewables portfolios generic dynamic data was used depending on the technology and the size of the plant. Since the exact parameters of the new plants included in the In-State and Out-of-State portfolios were not known, typical parameters recommended by GE were used. The load in all of WECC was modeled with composite load models according to the conditions studied.

Study Results. Northern Cases

The studies of the PG&E Bulk system contingencies for the Northern In-State and Out-of-State cases did not identify any criteria violations except for the frequency dip slightly higher than allowed by the criteria with a three-phase fault on the Table-Mountain 500/230 kV transformer in the In-State case. This frequency dip was observed on several 13.8 kV and 60 kV buses in the Table Mountain area. This may be a modeling error in the models of small generating units in the area. Tripping the Honey Lake generator with the fault mitigated the frequency violations.

Tripping of some renewable generators following three-phase faults close to these generators' points of interconnection was observed in the transient stability studies. The units tripped for the following reasons:

- Low voltage – the units that tripped for low voltage were existing wind units consisting of induction generators (type 1 and type 2) that did not have low voltage ride through capability. There were also two existing solar PV plants modeled without low- or high- voltage and low- or high- frequency ride through capability. It is not clear if these plants indeed don't have low/high voltage and low/high frequency ride through capability or it was a modeling error and that portion of the models wasn't included. The ISO will work with PG&E and the generation owners to update the models.
- High voltage – several wind and solar PV units were tripped by over-voltage protection with three phase faults in their vicinity. Some units tripped due to high voltage on the buses at which they were modeled in the base case. Other units were tripped due to the spike of the voltage on the inverters with the fault. These units were wind generators with high gains on the control systems. The majority of these new renewable resources were modeled on the sub-transmission and transmission systems without modeling the collector system and step-up transformers. This caused the units to be closer to the transmission faults and the voltage on the units to be higher due to lower impedance between the fault location and the unit.

Study Results. Southern Cases

Tripping of some renewable generators following three-phase faults close to these generators' points of interconnection was observed in the southern California transient stability studies. The units tripped for the following reasons:

- High voltage – several wind and solar PV units were tripped by over-voltage protection with three phase faults in their vicinity. Some units tripped due to high voltage on the buses at which they were modeled in the base case. Other units were tripped due to the spike of the voltage on the inverters with the fault. These units were wind generators with high gains on the control systems. Majority of these new renewable resources were modeled on the sub-transmission and transmission systems without modeling the collector system and step-up transformers. This caused the units to be closer to the transmission faults and the voltage on the units to be higher due to lower impedance between the fault location and the unit.

Further investigation in future study cycles is warranted due to lack of certainty about the exact interconnection data and technology of the new resources.

Conclusions

Transient stability studies of the cases with 50 percent of generation coming from renewable resources did not identify any dynamic stability issues related to the large amount of renewable resources under the snapshots that were selected for studies, but they identified several modeling issues. The modeling issues involved tripping of renewable generators with three-phase faults. Two primary reasons for tripping of renewable resources by over-voltage protection were identified:

1) High voltages in the base cases
2) High gains of the control systems of the inverters modeled in the study that caused voltage spikes with faults.

High voltages and subsequent tripping of the units was also partly due to the units being modeled on the high voltage buses and the collector systems, as well as low voltage step-up transformers, not being modeled. This was done due to the screening nature of the study that did not include more detailed modeling of the new renewable resources. In more detailed studies, collector systems and step-up transformers need to be modeled to reflect the generation interconnections more accurately. Modeling higher impedance between the location of the fault and the bus to which a renewable unit is connected will result in lower voltage on the renewable unit and lower possibility of its tripping in the transient stability simulations.

In addition, detailed values of the parameters of the new renewable resources models including control systems of inverters and plant controllers are needed. Using generic models with typical parameters will give less accurate results compared with models with actual parameters.

Other renewable generation tripping was due to under-voltage protection for the units that don't have low voltage ride-through. These were existing wind generators of Type 1 or 2 (induction generators, or induction generators with variable rotor resistance). Newer wind and solar PV generators are inverter-based and they have low- and high-voltage and low- and high-frequency ride through capability.

3.4.7 Recommendations

One of the main objectives of this study was to evaluate the initial transmission capability estimates and refine these estimates to inform the RPS calculator to generate more reasonable renewables portfolios for future use. As a result of this investigation the ISO is recommending certain changes to the transmission capability estimates. The study also helped identify certain areas of concerns which could be evaluated in future planning cycles. The recommendations are primarily centered around but not limited to the following factors:

- The extent of renewable curtailment observed in production cost simulations.
- Possibility of considerably greater reliance on congestion management in ISO market and challenges and implications of doing so.
- Possibility of substantially increased number of binding constraints.
- Difficulty in taking transmission equipment outages without substantial renewable curtailment.

Table 3.4-21 presents a brief summary of study results and corresponding recommendations with regards to the transmission capability estimates. The table summarizes production cost simulation results ("Renewable Curtailment" column) and reliability assessment results ("Reliability Concerns" column) discussed in sections 3.4.6.1 and 3.4.6.2 respectively.

Table 3.4-21: Reliability issues in Mountain Pass and Eldorado zones

Zones	Transmission Estimate	MW modeled		Renewable Curtailment* (%)		Reliability Concerns	Recommendation for Transmission Capability Estimate
		In-State	Out-of-State	In-State	Out-of-State		
Greater Carrizo	1,140	798	559	1%	~0%	Additional curtailment expected from local constraints.	Connect resources in Santa Barbara to 230 kV.
Central Valley North & Los Banos	2,000	240	240	~0%	~0%	Local 70 kV issue. No significant curtailment expected.	No change
Greater Imperial	2,633	2,633	1,341	~0%	~0%	Area wide - SPS and conventional generation dispatch can mitigate the issues	No change

Zones	Transmission Estimate	MW modeled		Renewable Curtailment* (%)		Reliability Concerns	Recommendation for Transmission Capability Estimate
		In-State	Out-of-State	In-State	Out-of-State		
Kramer & Inyokern	750	750	750	27%	23%	Kramer – Victor 220 kV overload. Can be mitigated by a future SPS.	No change
Mountain Pass & El Dorado	2,982	1,226	1,226 + 2,141 (WY)	~0%	~0%	Area wide - SPS and renewable curtailment under N-1-1	No change
Northern California	3,404	3,404	869	50%	36%	Area wide - Widespread overloads in Pit and Caribou 230 kV systems. Additional curtailment expected in Sacramento River from local constraints.	Split into more granular zones. Recommended breakdown and new transmission capability estimates are provided in Table 3.4-x
Riverside East & Palm Springs	4,917	4,917	2,571 + 2,063 (NM)	~0%	~0%	N-1-1 issues → curtailment under maintenance conditions	No change. Evaluate maintenance conditions in future cycles.

Zones	Transmission Estimate	MW modeled		Renewable Curtailment* (%)		Reliability Concerns	Recommendation for Transmission Capability Estimate
		In-State	Out-of-State	In-State	Out-of-State		
Solano	1,101	1,101	1,101	~0%	~0%	Additional curtailment expected from local constraints.	Connect resources to 230 kV or 500 kV.
Tehachapi	5,000	5,000	5,000	~0%	~0%	Midway – Whirlwind overload. N-1-1 issues → curtailment under maintenance conditions	No Change. Evaluate maintenance conditions in future cycles.
Westlands	2,900	894	749	~0%	~0%	Widespread local overloads. couple of area wide issues	Connect resources to 230 kV.

* Affected by assumptions about ISO simultaneous export limits. This column reflects curtailment under unconstrained export since it minimizes curtailment due to over-generation and is an indicator of curtailment due to transmission constraints.

The recommendations can be broadly divided into three different areas based on the nature of the recommendation.

Northern California

This is the zone in which highest amount of transmission congestion and the largest renewable curtailment was observed. Approximately 4,500 hours of transmission congestion was noticed and 30% to 50% of renewable energy in this zone was curtailed in the production cost simulations. The reliability assessment showed that resources cannot deliver to Round Mountain and Table Mountain without overloading the 230 kV system in this area as described in section 3.4.6.2. The number, location and the extent of overloads observed in this area are beyond the scope of conceptual SPS. The recommendation is to split this zone into more granular zones as shown in table 3.4-22.

Table 3.4-22: Reliability issues in Mountain Pass and Eldorado zones

Zone	Initial Transmission Capability Estimate	New recommendation
Lassen North + Round Mountain B	Northern CA – 3,404 MW	600 MW (Pit & Caribou 230 kV) + 700 MW (Round Mountain & Table Mountain 500 kV)
Sacramento River		2100 MW (Table Mountain, Rio Oso, Brighton, Cortina, Vaca Dixon 230 kV or Vaca Dixon 500 kV)

The expectation is that more granular transmission capability estimates in this area will result in an optimal locational distribution of renewable resources.

Tehachapi and Riverside

The initial transmission capability estimates in Tehachapi and Riverside zones were completely used up by the portfolios generated by RPS calculator. Negligible amount of transmission congestion was observed in production cost simulations, but a significant amount of total renewable curtailment was observed in these zones. This can primarily be attributed to over-generation. Reliability assessment in these zones demonstrated overloads caused by several N-1-1 and a few N-2 contingencies as described in section 3.4.6.2. Many of these issues indicate that more than 1,000 MW of renewable generation will have to be curtailed in order to operate the system in a reliable manner under contingency conditions. Specifically, the large amount of curtailment required for N-1-1 issues is an indication of potential challenges in taking maintenance outages on transmission system. The ISO recommends no change to the transmission capability estimates for Tehachapi and Riverside zones at this point, but recommends further investigation into potential operational challenges in Tehachapi and Riverside zones in future planning cycles.

Issues with delivering MW to transmission backbone

This issue was predominantly observed in Solano, Santa Barbara (Greater Carrizo), Westlands and Northern CA zones. As described in section 3.4.6.2, a large number of 115 kV and 230 kV facility overloads were observed in these zones. This indicates that a significant amount of congestion may be experienced by renewable resources trying to get to the 500 kV transmission backbone in these areas. A part of this sub-transmission level congestion is not captured by the production cost simulation models due to modeling limitations. The ISO recommends incorporating specific delivery points into RPS calculator to account for widespread local congestion and as a proxy for high local upgrade costs. The ISO will work with the CPUC to incorporate these changes to the next version of RPS calculator.

3.4.8 Conclusion

The 50 percent special study provided an opportunity to test the estimated transmission capability numbers provided by the ISO. This informational study provided an insight into the reliability impacts of adding more Energy-Only resources and also provided an indication of impact on renewable curtailment. An evaluation of in-state and out-of-state portfolios indicates that 50 percent renewable energy goal is feasible in terms of accommodating the resources on the transmission grid provided all the approved transmission upgrades assumed in this study materialize before 2030.

The study resulted in the following actionable recommendations:

- Split the northern California zone into smaller zones and update the transmission capability numbers as provided in table 3.4-22.
- Evaluate Tehachapi and Riverside zones for the risk of substantial renewable curtailment (>1000 MW) under maintenance scenarios in future planning cycles. Although, the RPS calculator completely utilized the initial transmission capability estimates in these zones, the ISO recommends no change to the transmission capability estimates at this point.
- Explore incorporating specific delivery points into RPS calculator to account for widespread local congestion and as a proxy for high local upgrade costs.

3.4.9 Next Steps

The ISO will assist the CPUC with incorporating the updated transmission capability estimates into the next version of RPS calculator. The ISO also intends to participate in future special studies. The scope of these studies will consider the CPUC's decisions regarding the next steps for the RPS calculator and any other renewable initiatives underway during 2016-2017 planning cycle.

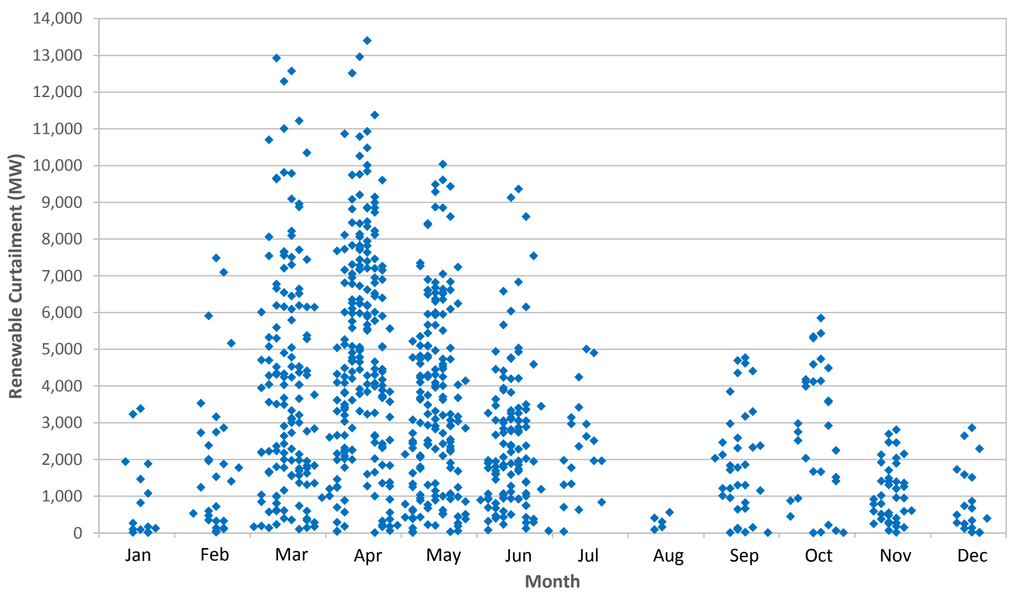
3.5 Bulk Energy Storage Resources Study with 40% RPS in 2024

3.5.1 Introduction

The ISO faces challenges – and potential opportunities – resulting from higher renewable generation development in California as the state moves to reach 33 percent renewable portfolio standard (RPS) target in 2020 and 50 percent in 2030. These include the potential for oversupply during periods of high solar generation output and the potential for much more severe ramping requirements on the rest of the conventional fleet. The ISO needs to manage ramping events and maintaining supply/demand balance while minimizing the curtailment of renewable generation. This special study explored the possible benefits of one resource type – large scale bulk energy storage - that may play a role in helping mitigate the challenges. This provides insights into the effectiveness of the particular resource type, and also helps clarify the scope of the issue itself. The study was provided on an information-only basis and the results are dependent on the assumptions made in the study.

In the studies prepared for the California Public Utilities Commission (CPUC) 2014 Long Term Procurement Plan (LTPP) proceeding the ISO found significant volumes of renewable generation being curtailed in order to maintain the reliability of the grid. The studies found renewable generation curtailment in 822 hours totaling 2,825 GWh in the 40% RPS scenario developed for that proceeding, as shown in figure 3.5-1. The maximum hourly curtailment was 13,402 MW.[130] Due to the amount of curtailment, the actual renewable generation did not meet the state's 40% Renewable Portfolio Standard (RPS) goal in that scenario.

Figure 3.5-1: Curtailment of Renewable Generation in the 2014 LTPP 40% RPS Scenario



[130] For more information, see the 2014 LTPP Phase 1.A. Direct Testimony of Shucheng Liu at http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13‐12‐010.pdf.

The benefits were studied considering bulk energy storage that can absorb large volume of excess energy during the oversupply hours and make use of the stored energy in other hours that additional generation is needed otherwise. The shift of energy can displace generation from other conventional generation resources and reduce the cost of generation and the emission of greenhouse gas (GHG).

The study assessed the benefits in reduction of renewable generation curtailment, CO2 emission and production cost as well as the financial costs to achieve the benefits. The methodology, assumptions, and results of the study are set out in this section.

3.5.2 Study Approach

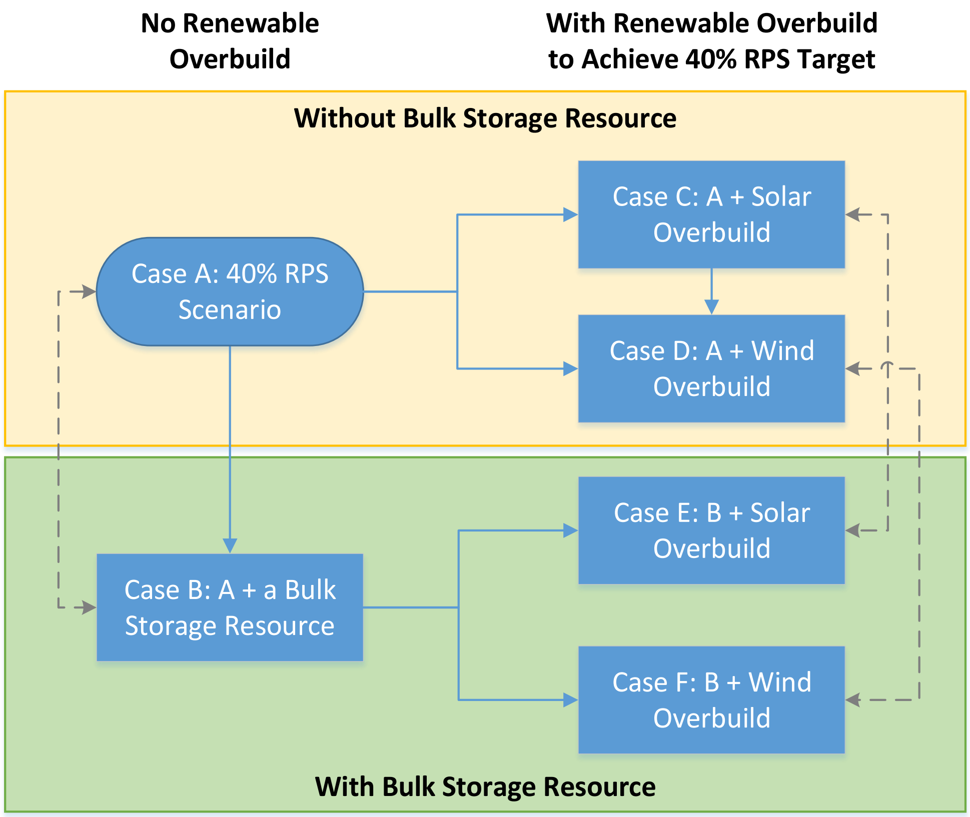
This study was conducted based on the CPUC 2014 LTPP 40% RPS in 2024 Scenario (the "40% RPS Scenario"). A new bulk energy storage resource was added to the 40% RPS Scenario production simulation model to evaluate its contribution to reduction of renewable curtailment, CO2 emission, and production cost.

A simple comparison of two production cost simulations – with and without the bulk energy storage resource – does not determine the full benefits the resource may provide, however, as the presence of the storage resource may lead to different levels of success of various resource mixes in achieving the 40 percent RPS target.

The study was therefore based on production simulations of the original case and five new cases, as shown in Figure 2. The five cases are all derived from the 40% RPS Scenario, which was designated as case **A** in this study. In all cases, renewable curtailment remains unlimited, as in the 40% RPS Scenario. Case **B** is case **A** with the new bulk energy storage resource added. As noted earlier, the actual renewable generation did not meet the state's 40% Renewable Portfolio Standard (RPS) goal in the production simulations due to the amount of curtailment. In case **B** the 40% RPS target was still not achieved due to curtailment. In the other four cases (case **C**, **D**, **E** and **F**), additional renewable generation resources were added to the renewables portfolio of case **A** and case **B** until the actual renewable generation met the 40% RPS requirement despite the curtailment. The additional renewable resources are in effect the renewable overbuild needed to achieve the 40% RPS target and overcome the curtailment impacts on total renewable energy production.

In this study the renewable overbuilds used two alternative resources; solar and wind. Solar and wind have very different generation patterns (hourly profiles). In the 40% RPS Scenario (case **A**), installed solar capacity was 52% of the total RPS portfolio and wind was 29%. Solar generation peaks in the midday. Solar overbuild further increased the solar dominance in the RPS portfolio and added more generation in the hours already having curtailment in case **A**. That portion of solar generation was then all curtailed. On the other hand, wind generation in California usually spreads over the whole day, with lower output in the midday than solar. Therefore, wind overbuild improved the diversification of the RPS portfolio. It has less generation to be curtailed than solar does. The needed wind overbuild was expected to be less than solar overbuild. Also the capital cost (per kW) of wind is lower than that of solar. As shown in figure 3.5-2, the four cases with renewable overbuild were constructed to have either solar (case **C** and **E**) or wind (case **D** and **F**) overbuild. The purpose was to establish two bookends in term of quantity (MW) and capital cost of the overbuild. As a solution to renewable curtailment, the actual renewable overbuild should be combinations of solar and wind, as well as other types of renewable resources.

Figure 3.5-2. Definitions of Bulk Energy Storage Study Cases



The results of the six cases provided all the necessary information to assess the benefits of the bulk energy storage resource and to determine the quantities and cost of renewable overbuild needed to achieve the 40% RPS target. From case **A** to **B**, **C** to **E** and **D** to **F**, the benefits of the new bulk energy storage resource under different situations (without overbuild, with solar or wind overbuild) could be identified. Also, the differences between case **C** and **D** and between **E** and **F** showed the effectiveness of using solar and wind overbuild to achieve the 40% RPS target. The cost of the solar and wind overbuilds in case **C**, **D**, **E** and **F** plus the cost of the new bulk energy storage resource in case **E** and **F** are the costs of renewable curtailments under difference situations. The comparison of the cost of the new bulk energy storage resource with its net market revenue from generation and from providing ancillary services and load following revealed the financial viability of the resource based on the study assumptions.

3.5.3 Study Assumptions

Basis of the Study

This study used the 40% RPS Scenario production simulation model in the 2014 LTPP deterministic studies as the basis. In the five new cases of the study (see figure 3.5-2) all assumptions, except the additional solar, wind and the new pumped storage resources, were consistent with the assumptions in the 40% RPS Scenario. It is important to point out that in all the five new cases, renewable generation curtailment was unlimited, as was in the 40% RPS Scenario. This ensured that the results of the five new cases were comparable to the results of the 40% RPS Scenario that were included in the CAISO testimony filed in the CPUC LTPP proceeding on August 13, 2014.[131]

Renewable Overbuild

In the study, additional renewable resources were added to the renewable portfolio of the 40% RPS Scenario (case **A**) such that the actual renewable generation met the state's 40% RPS target, with and without the new bulk energy storage resource. The renewable overbuild was achieved by scaling up the capacity and generation profiles of the ISO new RPS solar (excluding the 150 MW solar thermal with storage) or wind resources, in and out of state, in case **A**. The exact volume (MW) of the solar or wind overbuild that met the 40% RPS target was determined through running a set of experimental production simulations iteratively.

In these new cases transmission upgrades needed by the additional renewable resources were not explicitly modeled. However, the capital cost of renewable overbuild does include a component of transmission upgrade (table 3.5-2).

A New Pumped Storage Resource

The bulk energy storage in this study was represented by a pumped storage resource. In Case **B**, **E** and **F** a new pumped storage resource is added to the generation fleet. Table 3.5-1 shows the assumptions for the pumped storage resource. The ISO made the assumptions based on a review of publically available information.

[131] See footnote 1.

Table 3.5-1. Assumptions of the New Pumped Storage Resource

Item	Assumption
Number of units	2
Max pumping capacity per unit (MW)	300
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	250
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	50
Generation ramp rate (MW/min)	250
Round-trip efficiency	83%
VOM Cost ($/MWh)	3.00
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	Variable speed
Reserves can provide in generation and pumping modes	Regulation, spinning and load following
Reserves can provide in off-line modes	Non-spinning
Location	SCE zone

Based on the assumptions, the pumped storage resource has a maximum usable storage volume of 8 GWh that can support generation at maximum capacity for up to 12 hours without additional pumping. The resource can ramp from minimum to maximum generation in 1 minute and from minimum to maximum pumping in 5 minutes. It can provide ancillary services and load-following in both pumping and generation modes.

Revenue Requirement Assumptions

In calculation of the revenue requirements of the solar and wind overbuild and the new pumped storage resource, the assumptions in table 2 were used. Revenue requirement included capital cost, taxes, tax credits, insurances, etc. NQC Peak Factor is the percentage of installed capacity that is counted as qualified net capacity (NQC). NQC is the capacity of the resource that can meet the California Resource Adequacy (RA) requirement and receive resource adequacy capacity revenue.

The assumptions come from several sources that are listed in the footnotes of table 3.5-2.

Table 3.5-2. Assumptions of Revenue Requirements and RA Revenue of the New Resources[132]

Item	Revenue Requirement ($/kW-year)		NQC Peak Factor[133]	RA Revenue ($/kW-year)[134]
	Generation Resource[135]	Transmission Upgrade[136]		
Large Solar In-State	327.12	22.00	47%	16.13
Large Solar Out-State	306.26	22.00	47%	16.13
Small Solar In-State	376.99	11.00	47%	16.13
Solar Thermal In-State	601.71	22.00	90%	30.89
Wind In-State	286.62	16.50	17%	5.83
Wind Out-State	261.13	72.00	45%	15.44
Pumped Storage In-State	383.62	16.50	100%	34.32

3.5.4 Study Results

Table 3.5-3 is a summary of the simulation results and the calculated levelized annual revenue requirements of the solar and wind overbuild and the new pumped storage resource. The results are analyzed in more detail in the sections below.

[132] All revenue requirements and RA revenue are in 2014 dollars.

[133] References https://www.caiso.com/Documents/2012TACAreaSolar-WindFactors.xls and https://www.wecc.biz/Reliability/2024-Common-Case.zip

[134] Reference http://www.cpuc.ca.gov/NR/rdonlyres/2AF422A2-BFE8-4F4F-8C19-827ED4BA8E03/0/2013_14ResourceAdequacyReport.pdf

[135] References https://www.wecc.biz/Reliability/2014_TEPPC_GenCapCostCalculator.xlsm and https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

[136] Reference http://www.transwestexpress.net/scoping/docs/TWE-what.pdf and the CAISO assumptions.

Table 3.5-3. Simulation Results and Calculated Revenue Requirements

	Without Pumped Storage			With Pumped Storage		
Case	**A**	**C**	**D**	**B**	**E**	**F**
Renewable Curtailment (GWh)[137]	2,825	4,249	3,157	2,417	3,457	2,649
CA CO2 Emission (Million Ton)[138]	62.74	61.82	61.68	62.41	61.66	61.54
CA CO2 Emission Cost ($ mil)[139]	1,460	1,438	1,435	1,452	1,435	1,432
Production Cost ($ mil)[140]						
WECC	14,167	14,109	14,068	14,111	14,070	14,037
CA	3,866	3,826	3,795	3,803	3,779	3,751
Renewable Overbuild and Pumped Storage Capacity (MW)						
Solar		1,918			1,569	
Wind			1,129			950
Pumped Storage				500	500	500
Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($mil)						
Solar		703			575	
Wind			340			286
Pumped Storage				183	183	183
Pumped Storage Net Market Revenue ($mil)[141]				160	194	170

Renewable Overbuild

The volume (MW) of solar and wind overbuild needed to achieve the 40% RPS target, with and without the pumped storage resource, was the basis of the analysis of other results. The overbuild creates a levelized ground for assessing the benefits of the pumped storage resource under different situations. The capacity of solar and wind overbuild with and without the new pumped storage resources is shown in figure 3.5-3.

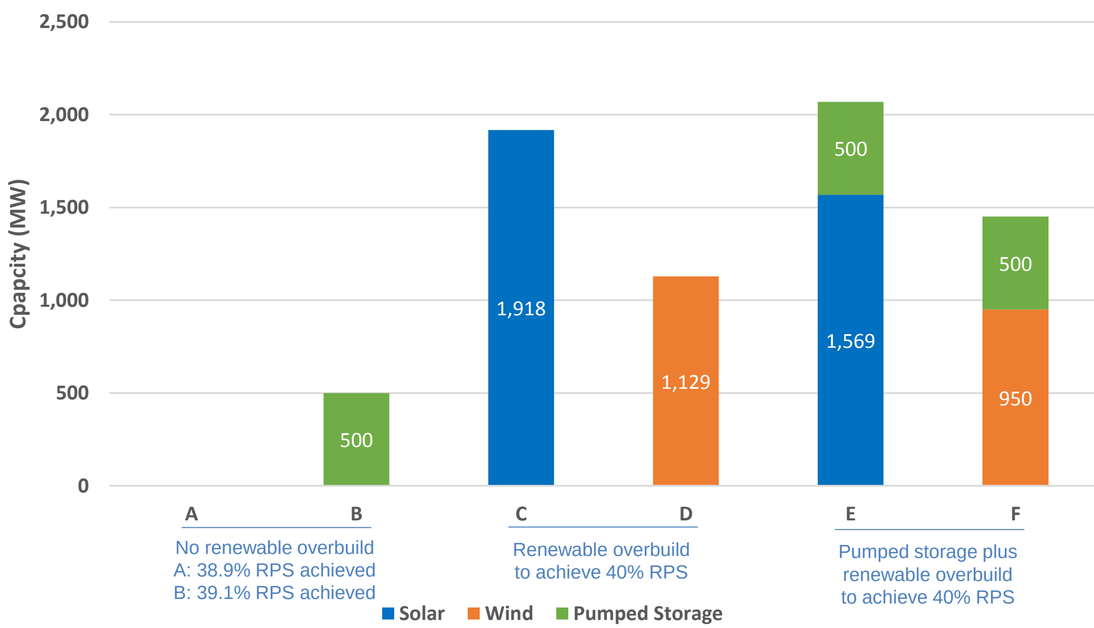
Without the new pumped storage resource, 1,918 MW of solar overbuild or 1,129 MW of wind overbuild was required in order to achieve the 40% RPS target. As expected, wind was more

[137] Renewable generation is curtailed at -$300/MWh price (MCP).
[138] It includes the CO2 emission from net import. Out-of-state renewable energy is emission free. 25% of the rest of the net import is assumed to be from Northwest, which has only 20% of the ARB average CO2 emission rate for imported electricity (0.435 metric-ton/MWh) according to the ARB rule (http://www.arb.ca.gov/regact/2010/ghg2010/ghgisoratta.pdf on p56 and 59).
[139] It is calculated using $23.27/m-ton price.
[140] It includes start-up, fuel and VOM cost, but not CO2 cost.
[141] Net revenue is revenue of energy and reserves minus cost of energy for pumping and VOM cost.

effective in term of the capacity amount of overbuild needed. Before the overbuild was added, e.g. in case **A**, there were 822 hours with renewable curtailment, mostly in the midday when solar generation was at high output. With solar overbuild in case **C**, the RPS portfolio has even higher solar concentration. As a result, the duration of renewable curtailment increased from 822 to 1,061 hours. The wind overbuild in case **D**, on the other hand, improved the diversification of the RPS portfolio. The additional energy was spread out to almost all the hours, resulting in less curtailment than case **C** (see figure 3.5-3). With case **D**, the duration of renewable curtailment was 888 hours. Therefore, Case **D** needed less overbuild than case **C** to achieve the 40% RPS target.

With the 500 MW new pumped storage resource added to the system, the overbuild needed to achieve the 40% RPS target was reduced. From case **C** to **E**, the solar overbuild was reduced by 349 MW. Similarly, from case **D** to **F**, the wind overbuild was reduced by 179 MW. The reduction of solar overbuild was greater than the reduction in wind overbuild, but both are smaller than the 500 MW capacity of the new pumped storage resource. This can be attributed to the following factors.

Figure 3.5-3 Capacity of the Pumped Storage and Solar and Wind Overbuild



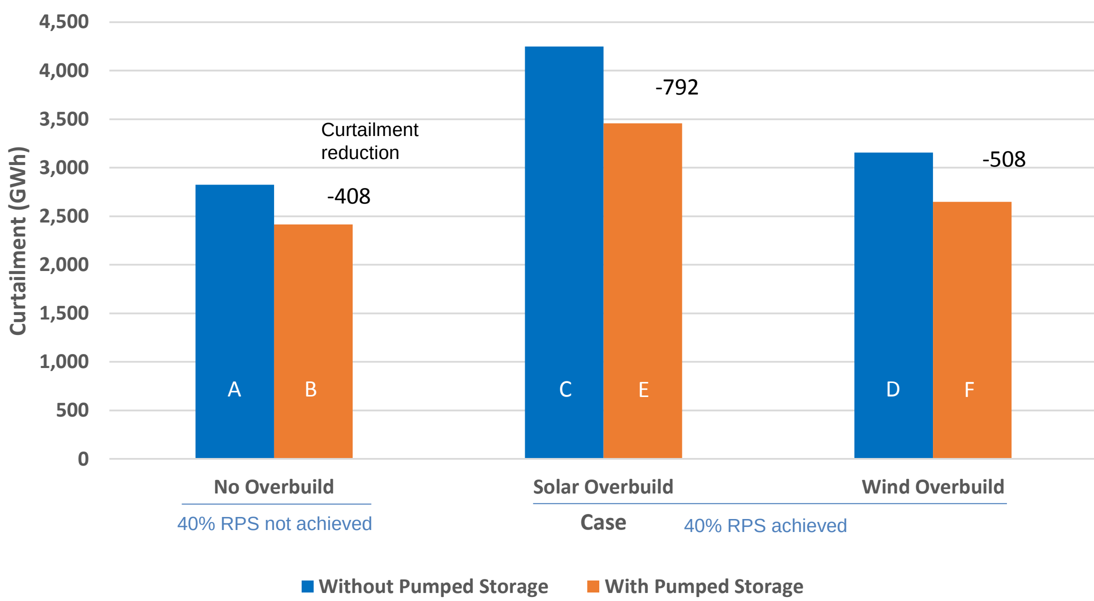
The most effective use of a large pumped storage resource is to move large chunk of energy from the hours with low generation cost to other hours with high generation cost. It matches with the solar generation pattern that concentrates in midday to drive down energy price or even causes curtailment. It has no generation before sunrise and after sunset, during which other higher cost generation is needed to meet the load. It. That is why the new pumped storage resource was more effective with solar overbuild than with wind overbuild to reduce curtailment and therefore the needed overbuild.

On the other hand, the effectiveness of the new pumped storage resource is limited by its maximum capacity in relative to the volume of potential renewable generation curtailment. In this study the new pumped storage resource has 600 MW maximum pumping capacity that converts to 500 MW maximum generation, with an efficiency factor of 83%. When the curtailment from the overbuild in case **C** or **D** is greater than 600 MW, the pumped storage resource in case **E** or **F** cannot store all the energy and use it in later hours. The portion of energy exceeding 600 MW is still curtailed. Also, of the 600 MW of energy stored, 17% is lost due to the round-trip efficiency of the pumped storage resource. As discussed above, 1,918 MW solar or 1,129 MW wind overbuilds in case **C** and **D** caused more curtailment, greater than 600 MW in many of the hours. Therefore the new pumped storage resource was only able to reduced renewable overbuild less than 500 MW from case **C** to **E** or **D** to **F**.

<u>Curtailment</u>

The renewable curtailments of the six cases are shown in figure 3.5-4. In the study the renewable generation was curtailed when the energy price (MCP) dropped to -$300/MWh. The assumption mimics the CAISO market rules about curtailing self-scheduled renewable generation.[142]

Figure 3.5-4. Renewable Curtailment by Case



The overbuild of solar and wind in case **C** and **D** led to more curtailment. Solar overbuild had an increase of 1,424 GWh curtailment, greater than the 333 GWh increase of curtailment with wind overbuild. That is because of the solar overbuild generation pattern closely matched the curtailment pattern in case **A,** as discussed above.

From case **C** to **E**, the reduction of curtailment was 792 GWh, greater that the 508 GWh reduction from case **D** to **F**. It is consistent with the discussion about needed overbuild to meet the 40% RPS target that the new pumped storage resource is more effective with solar overbuild than with wind overbuild in reducing renewable generation curtailment. However, even with the new

[142] The current CAISO curtailing price is -$150/MWh. It is the bid-price floor.

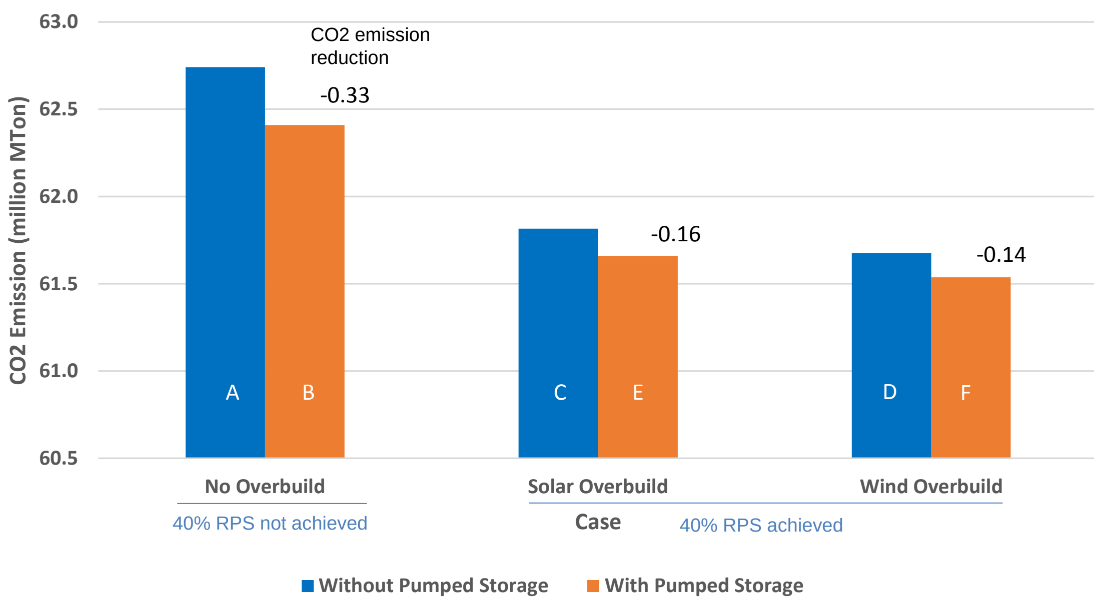
pumped storage resource, the total curtailment with wind overbuild (case **F**) was still 808 GWh lower than that with solar overbuild (case **E**). That is the benefit of a more diversified RPS portfolio.

California CO2 Emission

Figure 3.5-4 and figure 3.5-5 demonstrate that California CO2 emission results were highly correlated to the results of renewable generation curtailment in case **C**, **D**, **E** and **F**, but not in case **A** and **B**.

In case **C**, **D**, **E** and **F** more clean renewable generation was used to meet the load than in case **A** and **B**. It displaced the generation from conventional resources, which resulted in lower CO2 emission.

Figure 3.5-5. California CO2 Emission by Case



The new pumped storage resource was able to reduce curtailment and reduce CO2 emission. The CO2 emission reduction was highest without renewable overbuild. It was higher with solar overbuild than with wind overbuild, consistent with the finding in the discussion of renewable curtailment reduction above.

With and without the new pumped storage resource, wind overbuild resulted in lower emissions than solar overbuild. Solar overbuild made the morning and evening net load ramping processes steeper. This required more support of conventional resources to follow load. The required online conventional resources produced more emissions. The wind overbuild, on the other hand, had a relatively flat generation pattern. It did not steepen the net load ramping and therefore did not require the additional support of conventional resources. Wind overbuild was also able to displace generation of conventional resource in hours when there was no solar generation.

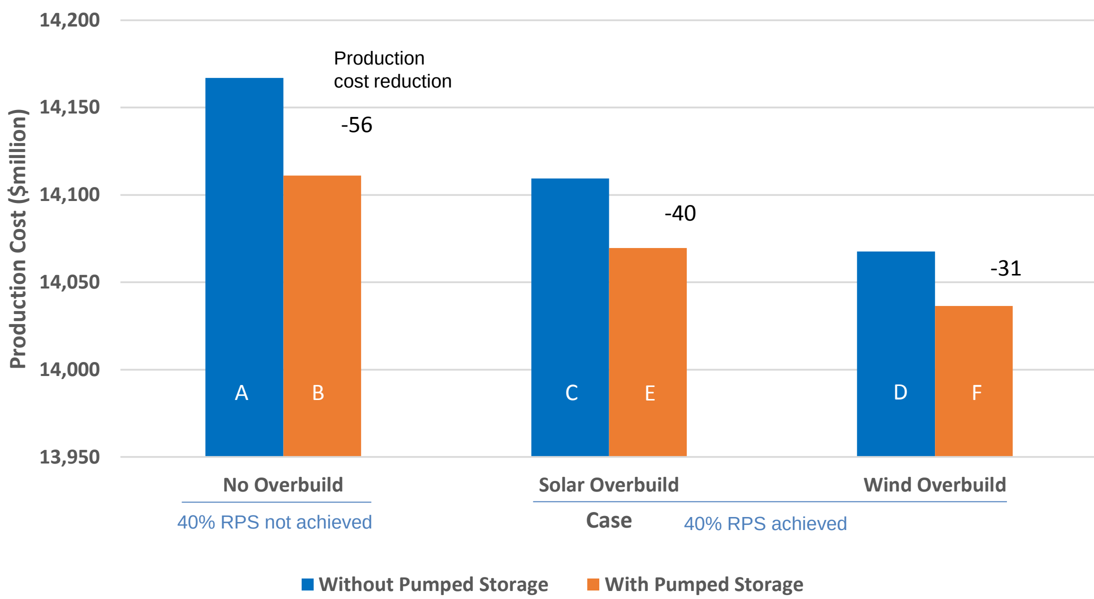
The California CO2 emission costs of the cases can be calculated by multiplying the CO2 emission amount by the CO2 emission price of $23.27/metric-ton.

Production Cost

The figure below shows the annual production cost of the whole western interconnect for all the cases.

The production cost in figure 3.5-6 includes generator start-up cost, variable operation and maintenance (VOM) cost, fuel cost, but not CO2 emission cost. In this study the renewable generation had a curtailment price of -$300/MWh. The production cost of renewable generation is assumed to be $0/MWh. The reported production cost also had the penalty price component from the load following-up and non-spinning shortfalls in a small number of hours removed.[143]

Figure 3.5-6. WECC Annual Production Cost by Case



Even though case **C**, **D**, **E** and **F** had the same amount of renewable generation, production costs were different. Case **D** had lower production cost than case **C** as the latter required more support of conventional resource in the morning and evening ramping processes than the former, as discussed in the CO2 emissions section above. That is the benefit of a more diversified RPS portfolio. That was also true comparing between case **F** and **E**.

The new pumped storage resource helped further reduce production cost because it reduced curtailment and used the stored clean energy to displace higher cost energy in other hours. The new pumped storage resource is very flexible. It can also provide ancillary services and load following to reduce the reliance on higher cost generation resource to stay online to provide these services. The production cost reduction with solar overbuild was higher than with wind overbuild. It further confirms that the new pumped storage resource was more effective with higher solar concentration RPS portfolio.

[143] See footnote 1.

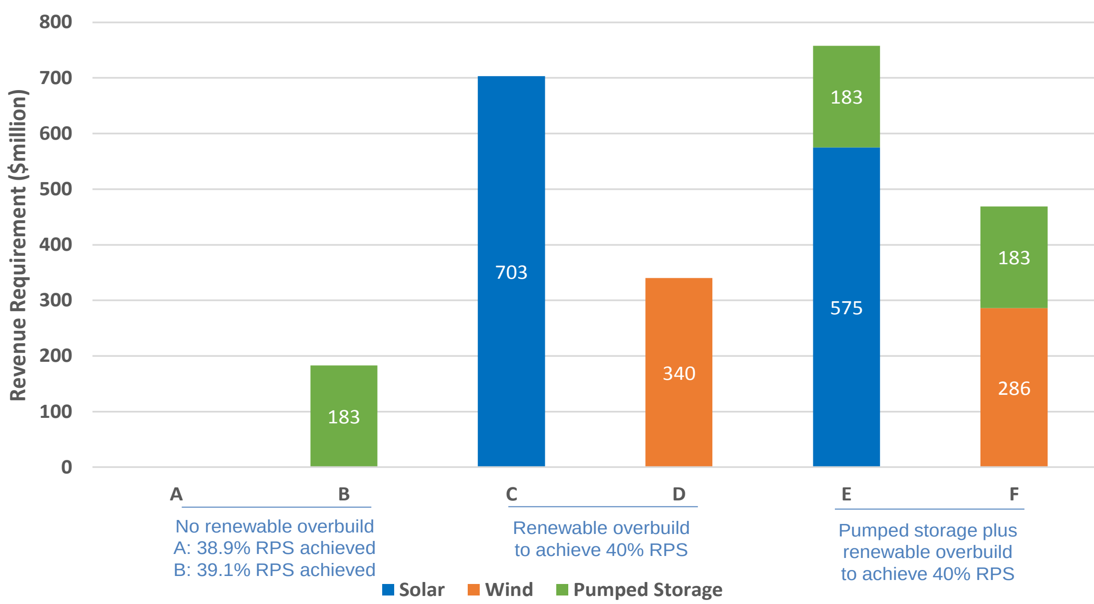
Levelized Annual Revenue Requirement

In figure 3.5-7 are the levelized annual revenue requirements of the renewable overbuild and the new pumped storage resource.

The calculated results show that the annual revenue requirement of wind overbuild was considerably lower than that of solar overbuild, even with the new pumped storage resource added. This was because less overbuild with wind was needed to achieve the 40% RPS target than with solar. Wind per unit cost was also lower than solar (see 3.5-2).

Considering its effectiveness in reducing needed overbuild, the new pumped storage was more expensive than the solar or wind overbuild it replaced. The analyses above show that the new pumped storage brought benefits to the system in reducing overbuild requirements, CO2 emissions, and production costs. These benefits should be considered in assessing the cost of the new pumped storage resource.

Figure 3.5-7. Levelized Annual Revenue Requirement



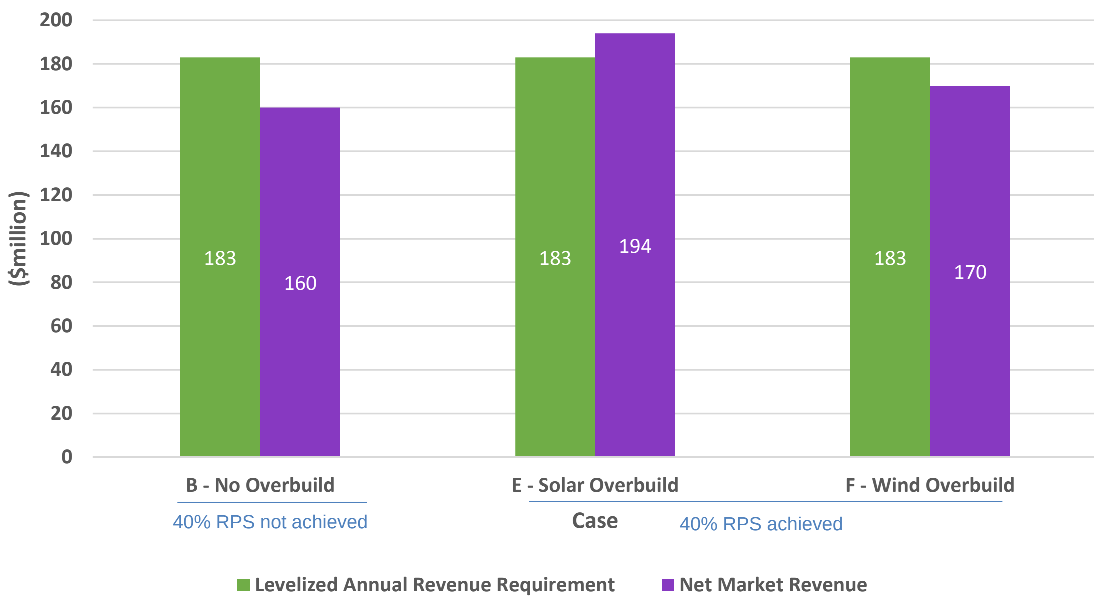
Revenue Requirement and Net Market Revenue of the New Pumped Storage Resource

Assuming the new pumped storage resource would be operated by an Independent Power Producer (IPP), the IPP would need to meet its revenue requirement with the net revenue from the market barring other revenue streams. Figure 8 shows the comparison of levelized annual revenue requirement with the net market revenue of the new pumped storage resource.

The net market revenue is the total revenue of the resource from generation and provision of ancillary services and load-following minus the cost on pumped energy and the resources VOM cost. The pumped storage resource was most profitable when it moved energy from hours with renewable curtailment to the hours the with higher energy prices. Therefore the net revenue of the pumped storage resource was highly dependent on the renewable generation curtailment price.

With the assumptions in this study, the new pumped storage resource should meet its revenue requirement with net market revenue only in case **E** with solar overbuild. It was $13 million short with wind overbuild and $23 million short without renewable overbuild.

Figure 3.5-8. Levelized Annual Revenue Requirement and Net Market Revenue of the New Pumped Storage Resource in 2024



The net revenue from the market would not reasonably be the only revenue stream – consideration should also be given to how the storage resource would be compensated for the benefits it brings to the system.

3.5.5 Conclusions

Based on the results of the study, it can be concluded that:

1) The new pumped storage resource brought significant benefits to the system, including
   - reduced renewable curtailment and reduced renewable overbuild needed to meet the 40% RPS target;
   - lower CO2 emissions, emission costs and production costs; and
   - the flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes.
2) Pumped storage was more effective with a high solar concentration renewables portfolio than with a more diversified renewables portfolios. However a more diversified renewables portfolio has more system benefits, resulting in overall lower costs through lower curtailment, CO2 emission, production cost and revenue requirement.

3) At 40% RPS, the new pumped storage has a higher levelized revenue requirement than that of the overbuild of solar or wind it replaces, but that might change with 50% RPS.
4) Assuming the new pumped storage resource was operated by an IPP, its net market revenue met the levelized annual revenue requirement only in the case with solar overbuild.
5) The benefits the new pumped storage resource brought to the system should be considered in assessing the financial viability of the resource.
6) The RPS portfolio in case **A** had high solar share. Wind overbuild made the portfolio more diversified than solar overbuild. So the wind overbuild was preferred over solar overbuild with all factors considered.

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Chapter 4

4 Policy-Driven Need Assessment

4.1 Study Assumptions and Methodology

4.1.1 33% RPS Portfolios

The CEC and CPUC on March 11, 2015 recommended two renewable resource portfolios to be studied in the ISO 2015-2016 transmission planning process[144]. As stated in the March 11 transmittal letter, the intent was to not re-run the renewables portfolio standard (RPS) calculator (v.5) because the anticipated changes were not envisioned to materially impact the RPS portfolios. After further review, specific and limited changes were made. One change incorporated additional transmission capacity resulting from recommendations in 2014-2015 Transmission Plan that materially impacted some Competitive Renewable Energy Zones (CREZ). The impact of cancelation of Coolwater - Lugo Transmission Project on the portfolios also needed to be taken into account. So, after these critical updates to transmission capacity were made, the RPS calculator (v.5) was re-run, and the updated portfolio was received by the ISO on April 29, 2015.[145]

The only CREZs that were impacted by this update were Imperial, Kramer and Riverside. Resource selection in all the other CREZs remained more or less the same as in 2014-2015 TPP. Because the impact was limited to the southern California system, the 2015-2016 policy-driven need assessment was limited to southern California.

The ISO performed a least regrets transmission need analysis as described in tariff section 24.4.6.6. The ISO and CPUC worked together to model the proposed renewables portfolios into the transmission planning base cases.

The installed capacity and energy per year of the portfolio by location and technology are shown in the following table.

[144] https://www.caiso.com/Documents/2015-2016RenewablePortfoliosTransmittalLetter.pdf
[145] https://www.caiso.com/Documents/Revised2015-2016RenewablePortfoliosTransmittalLetter.pdf

Table 4.1-1: Renewables portfolio for 2015-2016 TPP (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Total
Riverside East	0	0	0	0	2308	13	696	0	**3017**
Imperial	0	0	288	0	1172	25	0	265	**1750**
Tehachapi	10	0	0	0	1007	98	0	538	**1653**
Distributed Solar - PG&E	0	0	0	0	0	984	0	0	**984**
Carrizo South	0	0	0	0	900	0	0	0	**900**
Nevada C	0	0	116	0	400	0	0	0	**516**
Mountain Pass	0	0	0	0	300	0	358	0	**658**
Distributed Solar - SCE	0	0	0	0	0	565	0	0	**565**
NonCREZ	5	103	25	0	0	52	0	0	**185**
Westlands	1	0	0	0	300	174	0	0	**475**
Arizona	0	0	0	0	400	0	0	0	**400**
Alberta	0	0	0	0	0	0	0	300	**300**
Kramer	0	0	0	0	0	0	250	0	**250**
Distributed Solar - SDGE	0	0	0	0	0	143	0	0	**143**
Baja	0	0	0	0	0	0	0	100	**100**
San Bernardino - Lucerne	0	0	0	0	45	0	0	42	**87**
Merced	5	0	0	0	0	0	0	0	**5**
Grand Total	**20**	**103**	**429**	**0**	**6832**	**2054**	**1303**	**1245**	**11986**

The following table shows a comparison of renewables portfolios studied in 2014-2015 TPP and the portfolio studied in the 2015-2016 TPP. The only CREZs with a material change are Riverside East, Imperial and Kramer.

Table 4.1-2: Renewables portfolio for 2015-2016 TPP (MW)

CREZ	2015-2016 Portfolio	2014-2015 Portfolios	
	Base	Commercial Interest (base)	Sensitivity
Riverside East	3017	3800	1400
Imperial	1750	1000	2500
Tehachapi	1653	1653	1483
Distributed Solar - PG&E	984	984	984
Carrizo South	900	900	900
Nevada C	516	516	516
Mountain Pass	658	658	658
Distributed Solar - SCE	565	565	565
NonCREZ	185	185	182
Westlands	475	484	484
Arizona	400	400	400
Alberta	300	300	300
Kramer	250	642	642
Distributed Solar - SDGE	143	143	143
Baja	100	100	100
San Bernardino - Lucerne	87	87	42
Merced	5	5	5

4.1.2 Assessment Methods for Policy-Driven Transmission Planning

NERC and WECC reliability standards and ISO planning standards were followed in the policy-driven transmission planning study, which are described in chapter 2 of this plan. Power flow contingency analysis, post transient voltage stability analysis, and transient stability analysis were performed as needed to update the policy-driven transmission need analysis performed in the previous four ISO transmission plans. The contingencies that were used in the ISO annual reliability assessment for NERC compliance were revised as needed to reflect the network topology changes and were simulated in the policy-driven transmission planning assessments.

Generally, Category C3 overlapping contingencies (e.g., N-1 followed by system adjustments and then another N-1) were not considered in this assessment. In all cases, curtailing renewable generation following the first contingency can mitigate the impact of renewable generation flow prior to the second contingency. Given high transmission equipment availability, the amount of renewable energy – in MWh - expected to be curtailed following transmission outages is anticipated to be minimal.

Overlapping contingencies that could reasonably be expected to result in excessive renewable generation curtailments were assessed. Outages that potentially impact system-wide stability were extensively simulated and investigated. The existing SPS were evaluated using the base cases. The assessments that have been performed include, but were not limited to, post transient voltage stability and reactive margin analyses and time-domain transient simulations. Power flow studies following the generator deliverability assessment methodology were also performed.

Mitigation plans have been developed for the system performance deficiencies identified in the studies and the plans were investigated to verify their effectiveness. Multiple alternatives were compared to identify the preferred mitigations. If a concern was identified in the ISO Annual Reliability Assessment for NERC Compliance but was aggravated by renewable generation, then the preliminary reliability mitigation was tested to determine if it mitigated the more severe problem created by the renewable generation. Other alternatives were also considered. The final mitigation plan recommendation, which may have been the original one or an alternative, was then included as part of the comprehensive plan.

4.1.2.1 *Production Cost Simulation*

The production cost simulation results were used to identify generation dispatch and path flow patterns in the 2025 study year after the renewables portfolios were modeled in the system. Generation exports from renewable generation study areas as well as major transfer path flows from current and previously developed production models with various 33 percent renewables portfolios were reviewed. The ISO production cost simulation models were built from the WECC Transmission Expansion Planning Policy Committee (TEPPC) production simulation models. This information was used to identify high transmission system usage patterns during peak and off-peak load conditions. Selected high transmission usage patterns were used as reference in the power flow and stability base case development.

4.1.3 Base Case Assumptions

4.1.3.1 *Starting Base Cases Comparison of All Portfolios*

The consolidated peak and off-peak base cases used in the ISO Annual Reliability Assessment for NERC Compliance for 2025 were used as the starting points for developing the base cases used in the policy-driven transmission planning study.

4.1.3.2 *Load Assumptions*

For studies that address regional transmission facilities, such as the design of major interties, a 1-in-5 year extreme weather load level was assumed pursuant to the ISO planning standards. An analysis of the RPS portfolios to identify policy-driven transmission needs is a regional transmission analysis. Therefore, the 1-in-5 coincident peak load was used for the policy-driven transmission planning study. A typical off-peak load level on the ISO system is approximately 50 percent of peak load. Therefore, the load level that is 50 percent of the 1-in-5 peak load was selected as the reference for the off-peak load condition as show in table 4.1-3.

Table 4.1-3: Load condition by areas

Area in Base Cases	1-in-5 coincident peak load (MW)
Area 30 (PG&E)	29,761
Area 24 (SCE)	25,672
Area 22 (SDG&E)	5,050
VEA	152

4.1.3.3 *Conventional Resource Assumptions*

Conventional resource assumptions were the same as those in the reliability assessment. Details can be found in chapter 2.

4.1.3.4 *Transmission Assumptions*

Similar to the ISO Annual Reliability Assessments for NERC Compliance, the policy-driven assessment modeled all transmission projects approved by the ISO. Details can be found in chapter 2.

4.1.3.1 *Dispatch Assumptions*

For peak conditions, the dispatch assumptions used in 2014-2015 policy-driven study were used for the 2015-2016 policy-driven studies except for the wind dispatch assumption for Tehachapi zone. The assumption in 2014-2015 policy-driven study for wind dispatch in Tehachapi was 98 percent under peak load. This assumption was revised down to a more realistic 38 percent for the 2015-2016 policy-driven study under peak load conditions. Off-peak dispatch was derived from production cost simulation data and historical data. The reason for relatively low wind dispatch during off-peak conditions is that the most severe snapshots which demonstrated the highest level of renewable dispatch and high path utilization were found to be during daytime. Renewable dispatch assumptions for the CREZ in southern California are presented in table 4.1-4.

Table 4.1-4: Renewable dispatch assumption by CREZ

CREZ	Peak Dispatch (% of nameplate)		Off-peak dispatch (% of nameplate)	
	Solar	Wind	Solar	Wind
Riverside East	82	53	78	14
Imperial	80	44	85	14
Tehachapi	96	38	86	88
Nevada C	100	N/A	96	N/A
Mountain Pass	100	N/A	96	N/A
Distributed Solar - SCE	85	N/A	85	N/A
Arizona	80	44	85	14
Kramer	85	N/A	84	N/A
Distributed Solar - SDGE	75	N/A	96	N/A
Baja	80	44	85	14
San Bernardino - Lucerne	82	53	91	14

4.1.4 Power Flow and Stability Base Case Development

4.1.4.1 *Modeling Renewables Portfolio*

4.1.4.1.1 Power Flow Model and Reactive Power Capability

As discussed in section 4.1.1, CPUC and CEC renewables portfolios were used to represent RPS portfolios in the policy-driven transmission planning study. The commissions have assigned renewable resources geographically by technology to CREZ and non-CREZ areas, and to specific substations for some distributed generation resources. Using the provided locations, the ISO represented renewable resources in the power flow model based on information from generator interconnection studies performed by the ISO and utilities. The objective of modeling generation projects this way is not to endorse any particular generation project, but to streamline and focus the transmission analysis on least regrets transmission needs. In other words, transmission project needed for a specific generation project development scenario within a renewable resource area, but not for an alternative generation project development scenario within the same area would be a localized transmission need to be addressed in the interconnection study process. It would not be a least regret transmission need to be addressed in the transmission planning process.

If modeling data from ISO or PTO generation interconnection studies were used, they included the reactive power capability (the minimum and the maximum reactive power output). If modeling data came from other sources, an equivalent model was used that matched the capacity as listed in the portfolios. When an equivalent model was used for large scale wind turbine or solar PV generation, it was assumed that the generation could regulate bus voltage at the point of interconnection utilizing a power factor range of 0.95 lagging to leading. Unity power factor was assumed for solar PV distributed generation. For all other new generation modeled, typical data was used in the equivalent model with a power factor range of 0.90 lagging and 0.95 leading.

4.1.4.1.2 Dynamic Modeling of Renewable Generators

Similar to the power flow model, if the modeling data came from the ISO or PTO generation interconnection studies, then the dynamic models from the generation interconnection study, if available, were used.

If dynamic models were not available, then the WECC approved models from the GE PSLF library were used. For geothermal, biomass, biogas and solar thermal projects, dynamic models of similar existing units in the system were used, which included generator, exciter, power system stabilizer and governor models. For wind turbine and PV solar generators, GE Positive Sequence Load Flow Software models from the GE PSLF library were used. In this study, a Type 3 wind turbine generator model for doubly fed induction generators was used for wind generators if the generator type was not specified. For any future wind projects that were specified by interconnection customers as units with full converters, Type 4 inverter models were used.

The models for the wind Type 3 projects (doubly fed induction generator) included models for the generator/converter (regc_a), inverter electrical control models applicable to wind plants (reec_a), wind generator torque controller models (wtgq_a), drive train models (wtgt_a), simplified aerodynamic models (wtga_a), and pitch controller models (wtgp_a). In addition to these models, large plants (capacity 20 MW and higher) were assumed to have centralized plant control, which was modeled with a separate model (repc_a). The wind plants' models also included low and high voltage and low and high frequency protection models (lhvrt, lhfrt).

The models for the wind Type 4 projects (full converter) included generator/converter models, electrical controls for inverters and centralized plant control model for the large wind farms. In addition, the same protection that was modeled for the Type 3 projects was modeled for the Type 4. Depending on the design of the turbines, drive train models were also included in some Type 4 wind plants.

For both Type 3 and Type 4 dynamic models, the control parameters were set such that the generators have adequate low voltage ride through and low frequency ride through capability.

The dynamic data set used for transient stability simulations also had models for Type 1 (induction generator) and Type 2 (induction generator with variable rotor resistance) wind power plants, but these were existing projects built decades ago. Type 2 generators are not used in new installations.

Dynamic stability models for the solar PV plants distinguished between large solar plants, small plants and distributed solar PV generation. If no data from the interconnection customers was available, it was assumed that the solar PV plants 20 MW and higher connected to the transmission or sub-transmission systems will operate under centralized plant control. For these projects, dynamic stability models included models for the generator/converter (regc_a), inverter electrical control models applicable to solar PV plants (reec_b) and centralized plant control model (repc_a). The solar PV plant models also included low and high voltage and low and high frequency protection models (lhvrt, lhfrt). For the large plants, it was assumed that the centralized plant controller can regulate voltage at the point of interconnection and the power factor can be maintained between 0.95 leading and 0.95 lagging.

Smaller solar PV projects (less than 20 MW) were assumed as not having centralized plant control; therefore datasets for these projects did not include the centralized plant control model.

Both large and small solar PV plants were assumed to have adequate low voltage ride through and low frequency ride through capability.

Distributed solar PV generation was modeled with the simplified model (pvd1). It was assumed that these units have unity power factor and don't have voltage regulation.

4.1.4.2 *Generation Dispatch and Path Flow in Base Cases*

Production cost simulation software was used to predict unit commitment and economic dispatch on an hourly basis for the study year with the results used as reference data to predict future dispatch and flow patterns.

Certain hours that represent stressed patterns of path flows in the 2024 study year were selected from the production cost simulation results with the objective of studying a reasonable upper bound on stressed system conditions. The following three critical factors were considered in selecting the stressed patterns:

- renewable generation output system wide and within renewable study areas;
- power flow on the major transfer paths in California; and
- load level.

For example, hours that were selected for reference purposes were during times of near maximum renewable generation output within key study areas (Riverside, Imperial and Kramer) and high transfers across major ISO transmission paths in southern CA during peak hours or off-peak hours.

It was recognized that modeling network constraints had significant impacts on the production cost simulation results. The simplest constraints are the thermal branch ratings under normal and contingency conditions. It was not practical to model all contingencies and branches in the simulation because of computational limitations. Given this gap between the production cost simulation and the power flow and stability assessments, as well as the fact that the production cost simulation is based on the DC power flow model, the dispatch of conventional thermal units in power flow and stability assessments generally followed variable cost to determine the order of dispatch, but out of order dispatch may have been used to mitigate local constraints.

4.1.5 Testing Deliverability for RPS

To supplement the limited number of generation dispatch scenarios that can be practically studied using traditional power flow modeling techniques, and to verify the deliverability of the renewable resources modeled in the base portfolio, an assessment was performed based on the ISO deliverability study methodology.

The objectives of the deliverability assessment are as follows:

- test the target expanded maximum import capability (MIC) for each intertie to support deliverability for the MW amount of resources behind each intertie in the base portfolio;
- test the deliverability of the new renewable resources in the base portfolio located within the ISO balancing authority; and
- identify network upgrades needed to support full deliverability of the new renewable resources and renewable resources in the portfolio utilizing the expanded MIC.

4.1.5.1 *Deliverability Assessment Methodology*

The assessment was performed following the on-peak Deliverability Assessment Methodology. The main steps are described below.

4.1.5.2 *Deliverability Assessment Assumptions and Base Case*

A master base case was developed for the on-peak deliverability assessment that modeled all the generating resources in the base portfolio. Key assumptions of the deliverability assessment are described below.

Transmission

The same transmission system as in the base portfolio power flow peak case was modeled.

Load modeling

A coincident 1-in-5 year heat wave for the ISO balancing authority area load was modeled in the base case. Non-pump load was the 1-in-5 peak load level. Pump load was dispatched within expected range for summer peak load hours.

Generation capacity (Pmax) in the base case

The most recent summer peak NQC was used as Pmax for existing thermal generating units. For new thermal generating units, Pmax was the installed capacity. Wind and solar generation Pmax data were set to 20 percent or 50 percent exceedance production level during summer peak load hours. If the study identified 20 or more non-wind generation units contributing to a deliverability constraint, both wind and solar generations were assessed for maximum output of 50 percent exceedance production level for the deliverability constraint, otherwise up to a 20 percent exceedance production level was assessed.

Table 4.1-5: Wind and solar generation exceedance production levels (percentage of installed capacity) in deliverability assessment

Type	Area	20% Exceedance Level	50% Exceedance Level
Wind	SCE Northern & NOL	61%	38%
	SCE Eastern	73%	47%
	SDGE	51%	37%
	PG&E NorCal	58%	37%
	PG&E Bay Area (Solano)	71%	47%
	PG&E Bay Area (Altamont)	63%	32%
Solar	SCE Northern	99%	92%
	SCE/VEA others	100%	93%
	SDGE	96%	87%
	PG&E	99%	92%

Initial Generation Dispatch

All generators except for the once through cooled (OTC) units were dispatched at 80 percent to 92 percent of the capacity. The OTC generators were dispatched up to 80 percent of the capacity to balance load and maintain expected imports.

Import Levels

Imports are modeled at the maximum summer peak simultaneous historical level by branch group. The historically unused existing transmission contracts (ETC) crossing control area boundaries were modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts. For any intertie that requires expanded MIC, the import is the target expanded MIC value. Table 4.1-6 shows the import megawatt amount modeled on the given branch groups.

Table 4.1-6: Base Portfolio deliverability assessment import target

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville_BG	N-S	981	16
COI_BG	N-S	3770	631
BLYTHE_BG	E-W	72	0
CASCADE_BG	N-S	80	0
CFE_BG	S-N	-42	0
ELDORADO_MSL	E-W	405	0
IID-SCE_BG	E-W	702	0
IID-SDGE_BG	E-W		0
LAUGHLIN_BG	E-W	-42	0
MCCULLGH_MSL	E-W	0	316
MEAD_MSL	E-W	897	506
NGILABK4_BG	E-W	-137	168
NOB_BG	N-S	1544	0
PALOVRDE_MSL	E-W	2588	128
PARKER_BG	E-W	86	17
SILVERPK_BG	E-W	-3	0
SUMMIT_BG	E-W	13	0
SYLMAR-AC_MSL	E-W	340	311
Total		**11254**	**2093**

4.1.5.3 *Screening for Potential Deliverability Problems Using DC Power Flow Tool*

A DC transfer capability/contingency analysis tool was used to identify potential deliverability problems. For each analyzed facility, an electrical circle was drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5 percent or greater of the following:

- Distribution factor (DFAX) = (Δ flow on the analyzed facility / Δ output of the generating unit) *100%

  or

- Flow impact = (DFAX * capacity / Applicable rating of the analyzed facility) *100%.

Load flow simulations were performed, which studied the worst-case combination of generator output within each 5 percent circle.

4.1.5.4 *Verifying and refining the analysis using AC power flow tool*

The outputs of capacity units in the 5 percent circle were increased starting with units with the largest impact on the transmission facility. No more than 20 units were increased to their maximum output. In addition, generation increases were limited to 1,500 MW or less. All remaining generation within the ISO balancing authority area was proportionally displaced to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased by more than 1,500 MW, the impact of the remaining amount of generation to be increased was considered using a Facility Loading Adder. This adder was calculated by taking the remaining MW amount available from the 20 units with the highest impact multiplied by the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs was also included in the adder, up to 20 units. If the net impact from the contributions to adder was negative, the impact was set to zero and the flow on the analyzed facility without applying the adder was reported.

4.2 Policy-Driven Assessment in Southern California

This section presents the policy-driven assessment performed for the southern part of the ISO controlled grid including VEA, SCE, and SDG&E systems.

Tables 4.2-1 summarizes the renewable generation capacity modeled to meet the RPS net short in the studied areas in each portfolio.

Table 4.2-1: Renewable generation installed capacity in the southern part of the ISO controlled grid modeled to meet the 33% RPS net short

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Total
Riverside East	0	0	0	0	2308	13	696	0	**3017**
Imperial	0	0	288	0	1172	25	0	265	**1750**
Tehachapi	10	0	0	0	1007	98	0	538	**1653**
Nevada C	0	0	116	0	400	0	0	0	**516**
Mountain Pass	0	0	0	0	300	0	358	0	**658**
Distributed Solar - SCE	0	0	0	0	0	565	0	0	**565**
NonCREZ	5	103	25	0	0	52	0	0	**185**
Westlands	1	0	0	0	300	174	0	0	**475**
Arizona	0	0	0	0	400	0	0	0	**400**
Kramer	0	0	0	0	0	0	250	0	**250**
Distributed Solar - SDGE	0	0	0	0	0	143	0	0	**143**
Baja	0	0	0	0	0	0	0	100	**100**
San Bernardino - Lucerne	0	0	0	0	45	0	0	42	**87**

Previously Identified Renewable Energy-Driven Transmission Projects

The following transmission upgrades are needed to achieve 33% RPS. Most of these projects were approved by the Board in previous transmission plans as needed policy-driven transmission projects based on the 33% renewable generation portfolios provided by the CPUC. Because the need for these projects is driven by these renewable portfolios and the portfolios have not significantly changed since the projects were approved, these projects all continue to be needed to meet the 33% RPS, and have been included in the base cases.

West of Devers Project

The project involves rebuilding the four existing 220 kV transmission lines west of Devers with high capacity conductors. The completion date for this upgrade is estimated to be in 2020.

Tehachapi Renewable Transmission Project

The multi-phase project includes the new Whirlwind 500 kV Substation, new 500 kV and 220 kV transmission lines and upgrading existing 220 kV lines. Segments 6, 7, 8, 9 and 11 are still under construction. The expected completion date for all segments is 2016.

Devers-Mirage 230 kV Lines Upgrade

The project consists of SCE's portion of the Path 42 project, which includes reconductoring the Devers-Mirage 230 kV transmission line. The project engineering work is currently underway with an expected in-service date of 2015.

The Path 42 project also consists of IID's portion, which includes upgrading the Coachella Valley-Mirage 230 kV transmission line and upgrading the Coachella Valley-Ramon-Mirage 230 kV transmission line.

El Dorado – Lugo Series Caps Upgrade

This project includes upgrading El Dorado-Lugo series capacitor and terminal equipment at both ends of the 500 kV line. The expected in-service date is 2019.

Lugo – Eldorado 500 kV line reroute

This project includes rerouting a short segment of the Lugo-Eldorado 500 kV line so that it is not adjacent to the Lugo-Mohave 500 kV line. The expected in-service date is 2017.

Lugo – Mojave Series Caps Upgrade

This project includes upgrading Lugo-Mojave series capacitor and terminal equipment at both ends of the 500 kV line. The expected in-service date is 2019.

Suncrest 300 Mvar SVC

This project includes installation of 300 Mvar of dynamic reactive support at Suncrest 230 kV bus. The expected in-service date is 2017.

Sycamore – Penasquitos 230 kV Line

This project consists of a new 230 kV transmission line between Sycamore and Penasquitos 230 kV substations. The expected in-service date is 2017.

4.2.1 Southern California Policy-Driven Powerflow and Stability Assessment Results and Mitigations

Following is a summary of the study results identifying facilities in the SCE, SDG&E and VEA areas that did not meet system performance requirements. System performance concerns that were identified and mitigated in the reliability assessment are not presented in this section unless the degree of the system performance concern was found to materially increase. The discussion includes proposed mitigation plans for the system performance concerns identified.

Commercial Interest (base) Portfolio Assessment Results

Table 4.2-2 summarizes the powerflow and stability assessment results for the base portfolio.

Table 4.2-2: Summary of study results for base portfolio

Overloaded Facility	Contingency	Flow
Lugo - Victorville 500kV No. 1	Eldorado-Lugo 500 kV and Lugo-Mohave 500 kV (N-1-1)	123.7%
Case Divergence	Eldorado 500/230 kV 5AA transformer bank (T-1)	-

Thermal Overloads

Lugo – Victorville 500 kV Line Overload

Lugo – Victorville 500 kV line was overloaded for category P6 contingency of Eldorado – Lugo 500 kV and Lugo – Mohave 500 kV lines. The mitigation plan will require modification of the Lugo – Victorville N-1 SPS and N-2 Safety Net to include any new generation that materializes in this area to this generation tripping scheme

Case Divergence

Category P1 contingency of Eldorado 500/230 kV 5AA transformer bank resulted in case divergence. Modifying the existing Ivanpah SPS to include this contingency to the generation tripping scheme will mitigate this concern.

4.2.2 SCE and VEA Area Policy-Driven Deliverability Assessment Results and Mitigations

Base portfolio Deliverability Assessment Results

Deliverability assessment results for SCE and VEA area are discussed below.

Desert Area Constraint

The renewable generators in the Desert Area cause overloads in the neighboring utility's transmission system. This constraint limits deliverability in a wide electrical area that covers several renewable zones and has been identified as an area deliverability constraint.

Table 4.2-3: Base portfolio deliverability assessment results — Desert Area Constraint

Overloaded Facility	Contingency	Flow
Lugo - Victorville 500kV No. 1	Lugo - Eldorado 500kV No. 1	111.87%

Table 4.2-4: Desert Area Deliverability Constraint

Constrained Renewable Zones	Riverside East, Imperial, Mountain Pass, Nevada C, non-CREZ (Big Creek/Ventura)
Total Renewable MW Affected	4566 MW
Deliverable MW w/o Mitigation	2700 ~ 3800 MW
Mitigation	Increase rating of the Lugo – Victorville 500kV line or install flow control devices to reduce flow on the Lugo – Victorville 500kV line

Recommendation

For the renewable generation in the base portfolio to be deliverable, mitigation is needed to relieve the Desert Area constraint. It is recommended to increase rating of the Lugo – Victorville 500kV line or install flow control devices to reduce flow on the Lugo – Victorville 500kV line. The mitigation will be further investigated and needs to be coordinated with neighboring utilities.

Transmission Plan Deliverability with Approved Transmission Upgrades

An estimate of the generation deliverability supported by the existing system and approved transmission upgrades is listed in table 4.2-5. The transmission plan deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. For study areas not listed in table 4.3-12, the transmission plan deliverability is greater than the MW amount of generation in the ISO interconnection queue up to and including queue cluster 8.

Table 4.2-5: Deliverability for Area Deliverability Constraints in SCE area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
Desert Area Lugo – Victorville flow limit	Mountain Pass	5,500 ~ 8,500[146]
	Riverside East	
	Tehachapi (Big Creek and Ventura)	
	Distributed Solar – SCE (Big Creek and Ventura)	
	Imperial	
	Nevada C	
Lugo AA Bank capacity limit	Kramer	~1600
	San Bernardino - Lucerne	
Lugo - Pisgah 220kV flow limit	San Bernardino – Lucerne	~370
South of Kramer 220kV flow limit	Kramer	~470

[146] The Desert Area constraint involves multiple contingency overloads. The deliverability MW amount represents the MW in the combined 5% DFAX circle for all overloads that are deliverable. For an individual overload, the deliverability MW might be significantly lower because the 5% DFAX circle is smaller than the combined one.

4.2.3 SDG&E Area Policy-Driven Deliverability Assessment Results and Mitigations

Base Portfolio Deliverability Assessment Results

Deliverability assessments in previous transmission planning cycles have demonstrated that the dispatch of generation at Encina was a pivotal assumption associated with certain deliverability constraints in the San Diego area. This deliverability assessment was performed with the assumption that existing Encina units 1, 2, 3, 4 and 5 would be retired and replaced with 200 MW at Encina 230 kV and 300 MW at Encina 138 kV.

Pio Pico Energy Center was modeled in the deliverability assessment consisting of 308 MW at Otay Mesa 230 kV.

The results of the assessment are discussed below.

Miguel 500/230 kV Transformers Constraint

Deliverability of new renewable resources in the Baja and Imperial zones is limited by Category P1 overloads on the Miguel 500/230 kV transformers. The overloads can be mitigated by relying on short term ratings of the transformers and an SPS to trip generation at Imperial Valley and ECO/Boulevard East or by opening the parallel transformer and ECO – Miguel 500 kV line and relying on the SPS associated with the line outage.

Table 4.2-6: Base portfolio deliverability assessment results — Miguel 500/230 kV Transformers Deliverability Constraint

Overloaded Facility	Contingency	Flow
Miguel 500/230 kV #1	Miguel 500/230 kV #2	122%
Miguel 500/230 kV #2	Miguel 500/230 kV #1	122%

Miguel-Bay Boulevard 230 kV Deliverability Constraint

The assessment identified a Category P7 overload on Miguel – Bay Boulevard 230 kV line. The overload can be mitigated by an SPS to trip generation at Otay Mesa, ECO/Boulevard East, and Imperial Valley. The need for the SPS was identified in the GIP studies.

Table 4.2-7: Base portfolio deliverability assessment results — Miguel-Bay Boulevard 230 kV Deliverability Constraint

Overloaded Facility	Contingency	Flow
Miguel-Bay Boulevard 230 kV line	Miguel-Mission 230 kV #1 and #2	100%

ECO-Miguel 500 kV Deliverability Constraint

The assessment identified Category P1 and P7 overloads on ECO-Miguel 500 kV line. The overloads can be mitigated by an SPS to trip generation at ECO/Boulevard East and Imperial Valley.

Table 4.2-8: Base portfolio deliverability assessment results — ECO-Miguel 500 kV Deliverability Constraint

Overloaded Facility	Contingency	Flow
ECO-Miguel 500 kV	Suncrest-Ocotillo 500 kV	100%
	Suncrest-Sycamore 230 kV #1 and #2	100%
	Imperial Valley-Ocotillo 500 kV	99%

Transmission Plan Deliverability with Recommended Transmission Upgrades

With the above recommended transmission upgrades, an estimate of the generation deliverability supported by the existing system and approved transmission upgrades is listed in table 4.2-9. Transmission plan deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. For study areas not listed in table 4.2-9, the transmission plan deliverability is greater than the MW amount of generation in the ISO interconnection queue up to and including queue cluster 8.

Table 4.2-9: Deliverability for Area Deliverability Constraints in SDG&E area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
East of Miguel Constraint	Arizona	2,660 ~ 3,554
	Baja	
	Imperial	

4.2.4 Southern California Policy-Driven Conclusions

The policy-driven assessment of Commercial Interest (base) portfolio identified certain category P1, P6 and P7 issues in the southern California area. Deliverability studies identified constraints that limit deliverability of RPS resources in SCE and SDG&E areas. One of the objectives of this year's study was to evaluate the impact of the mitigations recommended in 2014-2015 policy-drives studies on the deliverability of Imperial zone. These recommended mitigation measures included the following:

- by-passing series capacitors on ECO – Miguel 500 kV and Ocotillo – Suncrest 500 kV lines;
- modifying Imperial Valley SPS to include generation tripping following a Miguel 500/230 kV transformer outage and following a Suncrest 500/230 kV transformer outage; and
- relying on 30-minute emergency rating of 500/230 kV transformer banks at Miguel, Imperial Valley and Suncrest.

Since all the constraints observed in Imperial zone can be mitigated by using SPS, the 2015-2016 policy-driven analysis confirms that the mitigation measures recommended in 2014-2016 TP have restored Imperial zone deliverability to ~1,700 to 1,800 MW.

The Desert Area deliverability constraints in SCE area can be mitigated by increasing the rating of the Lugo – Victorville 500kV line or by installing flow control devices to reduce flow on the Lugo – Victorville 500kV line. The mitigation will be further investigated and needs to be coordinated with neighboring utilities.

The studies show that the mitigations recommended in 2014-2015 TPP and projects approved in prior planning cycles largely restore overall deliverability from the Imperial area to pre-SONGS retirement levels. However, as noted in chapter 1 and chapter 2, the ISO's studies documented in the 2015-2016 Transmission Plan are based on the transmission planning input provided by the Imperial Irrigation District (IID) for its system in the spring of 2015. In October, 2015, IID provided new base cases modifying its future transmission plans as comments into the ISO's planning process. As IID surmised in its comments, the ISO's study timelines do not permit restarting the process within a given cycle and thus the results to not take into account that information. IID's input will be taken into account in preparing the study plan for the future 2016-2017 transmission planning cycle, and the ISO will coordinate with IID to ensure use of the best possible and current information at that time.

Chapter 5

5 Economic Planning Study

5.1 Introduction

The ISO's economic planning study is an integral part of the ISO's transmission planning process and is performed on an annual basis as part of the transmission plan. The economic planning study complements the reliability-driven and policy-driven analysis documented in this transmission plan, exploring economic-driven network upgrades that may create opportunities to reduce ratepayer costs within the ISO.

This year's study used the Unified Planning Assumptions[147] and was performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan. All network upgrades identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the economic planning database. This ensured that all economic planning studies would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan. The economic planning study was then performed to identify additional cost-effective network upgrades to mitigate grid congestion and increase production efficiency within the ISO.

The studies used a production cost simulation as the primary tool to identify grid congestion and assess economic benefits created by congestion mitigation measures. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The simulation is conducted for all 8,760 hours for each study year. The potential economic benefits are quantified as reduction of ratepayer costs based on the ISO Transmission Economic Analysis Methodology (TEAM).[148]

[147] http://www.caiso.com/Documents/2015-2016FinalStudyPlan.pdf
[148] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, June 2004, http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf

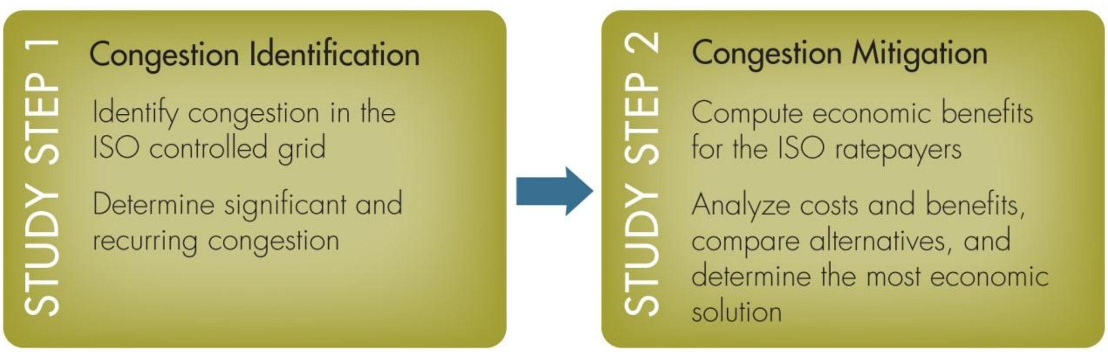
5.2 Study Steps

The economic planning study is conducted in two consecutive steps; congestion identification and congestion mitigation as shown in Figure 5.2-1.

Congestion identification is derived from a production cost simulation that is conducted for each hour of the study year. Identified congestion is tabulated and ranked by severity, which is expressed as congestion costs in U.S. dollars and congestion duration in hours. Based on the simulation results and after considering stakeholder requests for economic studies as described in tariff section 24.3.4.1 and the Transmission Planning BPM section 3.2.3, five high-priority studies were determined.

Congestion mitigation plans are evaluated for each of the high-priority studies determined in the identification step of the study. Using the production cost simulation and other means, the ISO quantifies economic benefits for each identified network upgrade alternative. From the economic benefit information a cost-benefit analysis is conducted to determine if the identified network upgrades provide sufficient economic benefits to be found to be needed. Net benefits are compared with each other where the net benefits are calculated as the gross benefits minus the costs to compare multiple alternatives that would address identified congestion issues. The most economical solution is the alternative that has the largest net benefit.

Figure 5.2-1: Economic planning study – two steps



5.3 Technical Approach

The production cost simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis is also used in quantifying other economic benefits such as system and local capacity savings.

Different components of benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the “pre-project” and “post-project” study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit includes three components of ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles. The production benefit is also called an energy benefit. As the production cost simulation models both energy and reserve dispatch, we prefer to call the calculated benefit a “production benefit”.

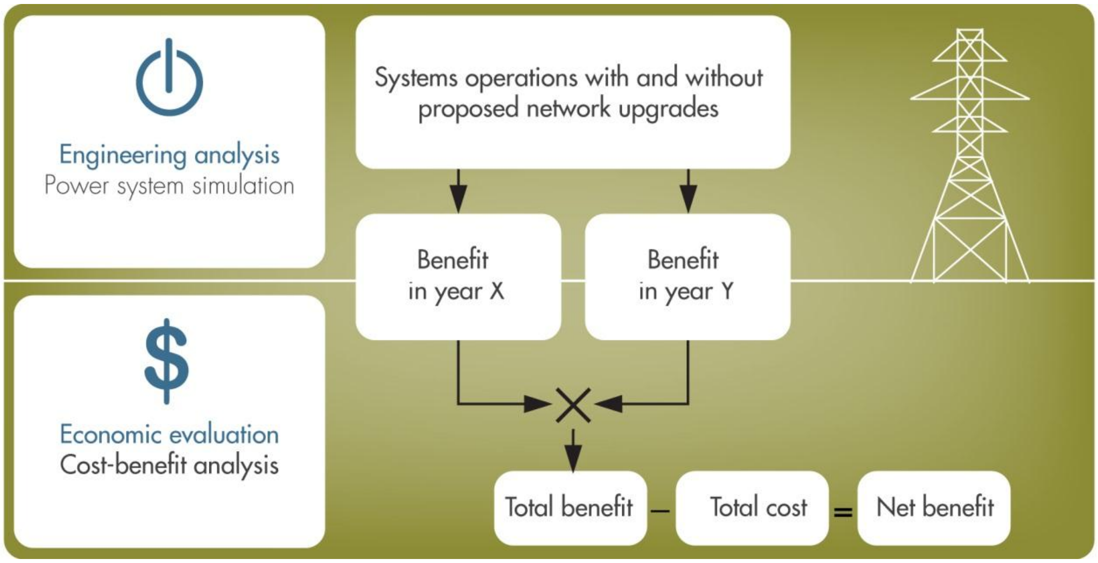
Second, capacity benefits are also assessed. Capacity benefits types include system resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a network upgrade for an importing transmission facility leads to a reduction of ISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where an upgraded transmission facility that leads to a reduction of local capacity requirement in a load area.

In addition to the production and capacity benefits, any other benefits — where applicable and quantifiable — can also be included. However, it is not always viable to quantify social benefits into dollars.

Once the total economic benefit is calculated, the benefit is weighed against the cost. To justify a proposed network upgrade, the required criterion is that the ISO ratepayer benefit needs to be greater than the cost of the network upgrade. If the justification is successful, the proposed network upgrade may qualify as an economic-driven project. Note that other benefits and risks must be taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven project.

The technical approach of economic planning study is depicted in figure 5.3-1. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). The engineering analysis phase is the most time consuming part of the study. Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis, which is a financial calculation that is generally conducted in spreadsheets.

Figure 5.3-1: Technical approach of economic planning study



5.4 Tools and Database

The ISO used the software tools listed in table 5.4-1 for this economic planning study.

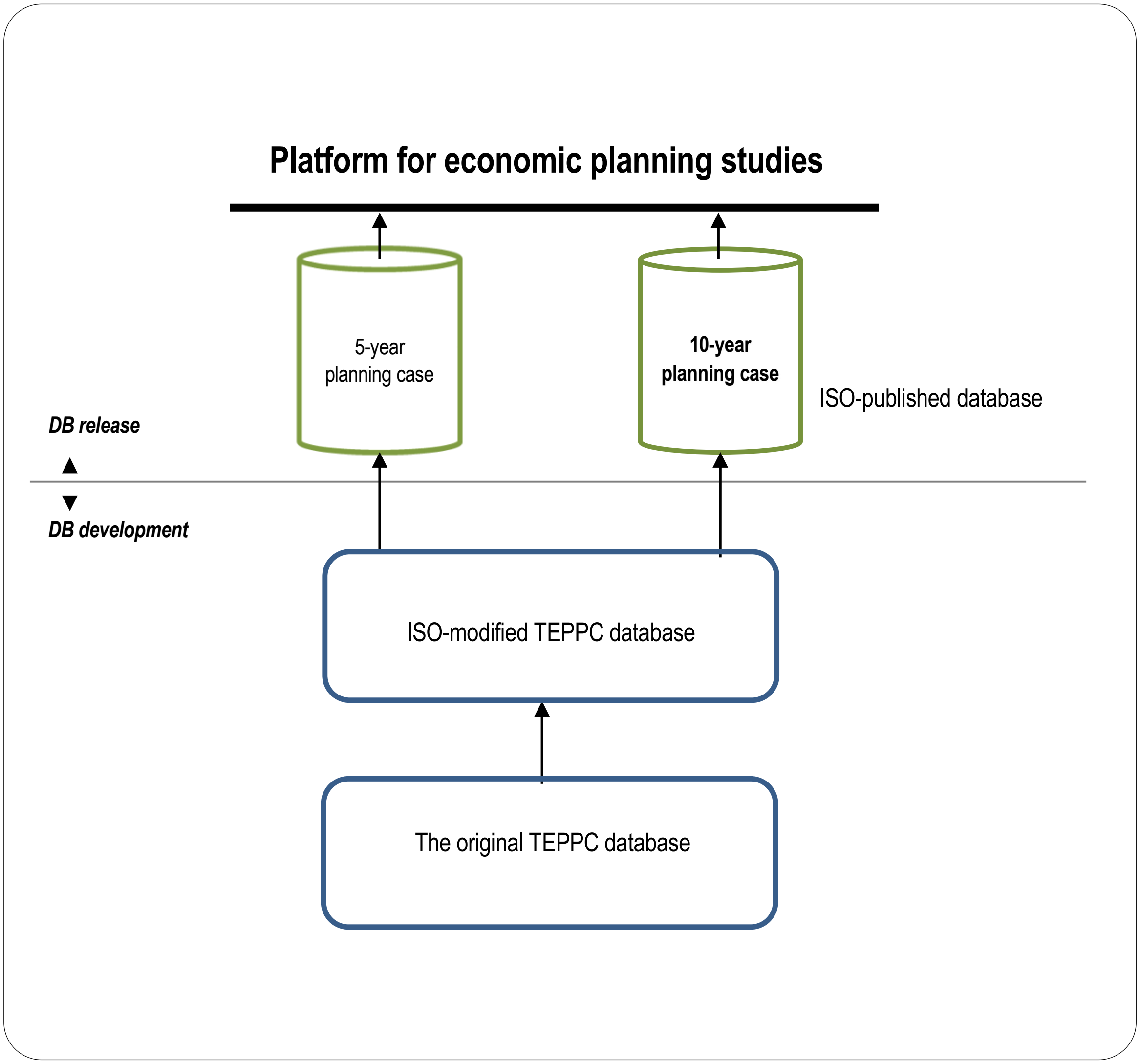
Table 5.4-1: Economic planning study tools

Program name	**Version**	**Functionality**
ABB GridView™	9.3.0.4	The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year.
GE PSLF™	19.0_00	The software program is an AC power flow tool to compute line loadings and bus voltages for selected snapshots of system conditions, e.g., summer peak or spring off-peak.

This study used the Transmission Expansion Planning Policy Committee (TEPPC) production cost simulation model as a starting database[149]. Using this database the ISO developed the 2020 and 2025 base cases for the ISO production cost simulation. These base cases included the modeling updates and additions described in section 5.5 (Study Assumptions) to ensure that the production cost model of the California power system was accurate.

[149] "TEPPC 2024 V1.5" dataset released in April 2015

Figure 5.4-1: Database setup



5.5 Study Assumptions

This section summarizes major assumptions used in the economic planning study. The section also highlights the ISO enhancements and modifications to the TEPPC database that were incorporated into the ISO's database.

5.5.1 System modeling

The TEPPC database uses a nodal model to represent the entire WECC transmission network. The ISO also uses a nodal model to represent the western interconnection as well as a detailed representation of its transmission network. The ISO then created a modified version of the database by, where appropriate, modifying the database to ensure that it accurately represented the ISO's transmission system and reflected the Unified Planning Assumptions that were included in the final study plan. These modifications are described in the following sections.

5.5.2 Load demand

As a norm for economic planning studies, the production cost simulation models 1-in-2 heat wave load in the system to represent typical or average load condition across the ISO transmission network. The base cases which the ISO developed used load modeling data from the following sources.

- California load - CEC demand forecast published in February 2015;
- Other WECC loads - 2012 final forecast data from the WECC Load and Resource Subcommittee (LRS). The TEPPC database had been developed using preliminary LRS 2012 data. For the ISO planning studies, the preliminary LRS 2012 data was replaced with the final LRS 2012 data.

5.5.3 Generation resources

The ISO replaced the TEPPC RPS modeling in California with the new 2015-2016 CPUC/CEC Commercial Interest portfolio. For more details about the renewables portfolios, please see their descriptions in chapter 4.

There are no major discrepancies between the TEPPC database and the ISO model for thermal generation. The TEPPC database covered all the known and credible thermal resources in the planning horizon. The ISO replaced Once-Through Cooling (OTC) generation retirement and replacement assumptions in the TEPPC database with the latest ISO assumptions.

5.5.4 Transmission assumptions and modeling

As noted earlier, the production cost database reflects a nodal network representation of the western interconnection. Transmission limits were enforced on individual transmission lines, paths (i.e., flowgates) and nomograms. However, the original TEPPC database only enforced transmission limits under normal condition for transmission lines at 230 kV and above, and for transformers at 345 kV and above.

An important enhancement is the transmission contingency constraints, which the original TEPPC database did not model. In the updated database, the ISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the California ISO transmission grid to make sure that in the event of losing one (and sometimes multiple) transmission facility, the remaining transmission facilities would stay within their emergency limits. In addition, transmission limit for some transmission lines in the California ISO transmission grid at lower voltage than 230 kV are enforced.

Finally, and as mentioned earlier, all reliability-driven and policy-driven network upgrades were modeled in the ISO base case. The added network upgrades are listed in the tables below.

Table 5.5-1: Reliability-driven network upgrades added to the database model[150]

#	Project approved or conceptual	Utility	ISO-approval	Operation year
1	Morro Bay – Mesa 230kV Line	PG&E	TP2010-2011	2017
2	Contra Costa Substation Switch Replacement	PG&E	TP2012-2013	2015
3	Kearney 230-70 kV Transformer Addition	PG&E	TP2012-2013	2015
4	Series reactor on Warnerville – Wilson 230 kV line	PG&E	TP2012-2013	2017
5	Reconductor Kearney – Herndon 230 kV line	PG&E	TP2012-2013	2017
6	Gates 500-230 kV transformer #2	PG&E	TP2012-2013	2017
7	Lockeford-Lodi Area 230 kV Development Project	PG&E	TP2012-2013	2017
8	Northern Fresno 115 kV Area Reinforcement	PG&E	TP2012-2013	2018
9	Estrella Substation Project	PG&E	TP2013-2014	2019
10	Midway-Kern PP No2 230 kV Line Project	PG&E	TP2013-2014	2019
11	Morgan Hill Reinforcement Project	PG&E	TP2013-2014	2021

[150] The "reliability-driven network upgrade" table lists major network upgrades of 230 kV and above. In addition, the ISO modeling additions included network upgrades of lower voltage levels. For brevity, minor and lower voltage upgrades are not listed here. For details of the listed network upgrades, please refer to relevant ISO Transmission Plan reports.

12	Wheeler Ridge Junction Project	PG&E	TP2013-2014	2021
13	Gates-Gregg 230 kV Line Project	PG&E	TP2013-2014	2022
14	Barre – Ellis 230kV Reconfiguration	SCE	TP2012-2013	2013
15	Mesa Loop-in	SCE	TP2013-2014	2022
16	Victor Loop-in	SCE	TP2013-2014	2015
17	Artesian 230 kV Sub and loop-in	SDG&E	TP2013-2014	2016
18	Imperial Valley Flow Controller	SDG&E	TP2013-2014	2016
19	Bob Tap 230 kV switchyard and Bob Tap – Eldorado 230 kV line	VEA	N/A	2015

Table 5.5-2: Policy-driven network upgrades added to the database model

#	Project approved or conceptual	Location	ISO approval	Operation year
1	IID-SCE Path 42 upgrade	IID, SCE	TP2010-2011	2013
2	Warnerville – Belotta 230 kV line reconductoring	PG&E	TP2012-2013	2017
3	Lugo – Eldorado series capacitors and terminal equipment upgrade	SCE	TP2012-2013	2016
4	Sycamore – Penasquitos 230 kV line	SDG&E	TP2012-2013	2017
5	Lugo-Mohave series capacitor upgrade	SCE	TP2013-2014	2016

Table 5.5-3: Economic-driven network upgrades added to the database model

#	Project approved or conceptual	Location	ISO approval	Operation year
1	Delany-Colorado River 500 kV project	APS, SCE	TP2013-2014	2020
2	Harry Allen – El Dorado 500 kV project	NVE, SCE	TP2013-2014	2020
3	Lodi – Eight Mile 230 kV upgrade	PG&E	TP2014-2016	2020

Table 5.5-4: GIP-related network upgrades added to the database model

#	Project approved or conceptual	Utility	Note	Operation year
1	South of Contra Costa reconductoring	PG&E	ISO LGIA	2012
2	West of Devers 230 kV series reactors	SCE	ISO LGIA	2013 (Till 2020)
3	West of Devers 230 kV reconductoring	SCE	ISO LGIA	2021

5.5.5 Energy Imbalance Market (EIM) modeling

Representations for the Energy Imbalance Markets were added in the ISO's databases in this planning cycle. According to the Benefit report of PacifiCorp and California ISO Integration[151] the energy cost in day-ahead market is about 93~96% of the total energy cost. In the current economic planning studies, it is assumed the day-ahead energy cost is 95% of the total energy cost, which is subject to the wheeling charge. Therefore, the export wheeling charge rates for each of all EIM regions were modeled as 95% of their original values in the ISO's databases. By doing so, the generation dispatch and the power flow on the interfaces from the production cost simulations provide a proxy for the actual market operation with EIM in place.

[151] https://www.caiso.com/Documents/StudyBenefits-PacifiCorp-ISOIntegration.pdf.

5.5.6 Financial Parameters Used in Cost-Benefit Analysis

A cost-benefit analysis was made for each economic planning study performed where the total costs were weighed against the total benefits of the proposed network upgrades. In these studies, all costs and benefits are expressed in 2014 U.S. dollars and discounted to the assumed operation year of the studied network upgrade to calculate the net present values. By default, the proposed operation year is 2020 unless specially indicated.

5.5.6.1 Cost analysis

In this study the total cost was considered to be the total revenue requirement in net present value in the proposed operation year. The total revenue requirement included impacts of capital cost, tax expenses, O&M expenses and other relevant costs.

In calculating the total cost of a potential economic-driven project, the financial parameters listed in table 5.5-5 were used. The net present value of the costs and benefits were calculated using a social discount rate of 7% which is consistent with the social discount rate used in the ISO's Transmission Access Charge (TAC) model[152].

Table 5.5-5 Parameters for revenue requirement calculation

Parameter	Value in TAC model
Debt Amount	50%
Equity Amount	50%
Debt Cost	6.0%
Equity Cost	11.0%
Federal Income Tax Rate	35.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2.5%

[152]http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=7A2CFF1E-E340-4D46-8F39-33398E100AE7

In the initial planning stage, detailed cash flow information is typically not provided with the proposed network upgrade to be studied. Instead, lump sum capital cost estimates are provided. The ISO then uses typical financial information to convert them into annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. As an approximation, the present value of the utility's revenue requirement is calculated as the capital cost multiplied by a "CC-to-RR multiplier". For screening purposes, the multiplier used in this study is 1.45 and is based on prior experiences of the utilities in the ISO. It should be noted that this screening approximation is replaced on a case by case basis with more detailed modeling if the screening results indicate the upgrades may be found to be needed.

5.5.6.2 Benefit analysis

In the ISO's benefit analysis, total benefit refers to the present value of the accumulated yearly benefits over the economic life of the proposed network upgrade. The yearly benefits are discounted to the present value in the proposed operation year before the dollar value is accumulated towards the total economic benefit. Because of the discount, the present worth of yearly benefits diminishes very quickly in future years.[153]

In this economic planning study, engineering analysis determined the yearly benefits through production cost simulation and power flow analysis. Production cost simulation and subsequent benefits calculations were was conducted for the 5th and 10th planning years or years 2020 and 2025. For the intermediate years between 2020 and 2025 the benefits were estimated by linear interpolation. For years beyond 2025 the benefits were estimated by extending the 2025 year benefit with an assumed escalation rate.

The following financial parameters were used in calculating yearly benefits for use in the total benefit:

- economic life of new transmission facilities = 50 years;
- economic life of upgraded transmission facilities = 40 years;
- benefits escalation rate beyond year 2025 = 0 percent (real); and
- benefits discount rate = 7 percent (real) with sensitivities at 5% as needed

5.5.6.3 Cost-benefit analysis

Once the total cost and benefit of a proposed network upgrade are determined a cost-benefit comparison is made. For a proposed upgrade to qualify as an economic project, the benefit has to be greater than the cost or the net benefit (calculated as cost minus gross benefit) has to be positive. If there are multiple alternatives, the alternative that has the largest net benefit is considered the most economical solution.

[153] Discount of yearly benefit into the present worth is calculated by $b_i = B_i / (1 + d)^i$, where b_i and B_i are the present and future worth respectively; *d* is the discount rate; and *i* is the number of years into the future. For example, given a yearly economic benefit of $10 million, if the benefit is in the 30th year, its present worth is $1.3 million based a discount rate of 7 percent. Likewise, if the benefit is in the 40th or 50th years, its present worth is $0.7 million or $0.3 million, respectively. In essence, going into future years the yearly economic benefit worth becomes very small.

5.6 Congestion Identification and Scope of High Priority Studies

Based on the economic planning study methodology presented in the previous sections, a congestion simulation of ISO transmission network was performed to determine which facilities in the ISO controlled grid were congested. From this information the scope of high priority studies were identified.

5.6.1 Congestion identification

The results of the congestion assessment are listed in table 5.6-1.

Table 5.6-1: Congested facilities in the ISO-controlled grid

No	Congested Facility	2020		2025	
		Costs (k$)	Duration (hr)	Costs (k$)	Duration (hr)
1	P26 Northern-Southern California	6,203	518	3,041	200
2	POE-RIO OSO 230 kV line #1	1,329	85	1,429	75
3	P45 SDG&E-CFE	18	22	966	210
4	EXCHEQUR-LE GRAND 115 kV line, subject to N-1 PG&E Merced-Merced M 115/70 kV xfmr	714	480	916	466
5	DELEVN-CORTINA 230 kV line, subject to PG&E N-2 Delevn-Vaca 230 kV	1,723	111	510	36
6	GATES-MIDWAY 230 kV line, subject to CA500kV C1 L-1 PG&E Gates-Midway	48	3	329	11
7	CA Path26 N2S with RAS	503	28	246	15
8	COI 2	533	241	235	90
9	EXCHEQUR-LE GRAND 115 kV line, subject to N-1 PG&E Merced-MrcdFLLs 70kV	232	151	197	133
10	MIDWAY-WIRLWIND 500 kV line #3	179	18	134	11
11	SNTA RSA-STNY PTP 115 kV line, subject to PG&E LCR NCNB Fulton Cat C	-	-	118	7
12	OTAYMESA-TJI-230 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	509	327	43	30
13	CA Path15 N2S-MidwayGen	69	12	28	8
14	P60 Inyo-Control 115 kV Tie	17	16	21	19
15	COI 1	202	45	19	7

16	GATES-MIDWAY 500 kV line, subject to CA500kV C1 L-1 LosBanos-Midway	-	-	19	1
17	LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	-	-	14	1
18	HUMBOLDT-TRINITY 115 kV line, subject to PG&E LCR Humboldt Cat B	5	20	9	30
19	IMPRLVLY 230/230 kV Phase Shifter	67	8	9	2
20	P24 PG&E-Sierra	-	-	5	5
21	OTAYMESA-TJI-230 230 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	21	9	4	3
22	P25 PacifiCorp/PG&E 115 kV Interconnection	4	7	3	4
23	LIVE OAK-KERN PWR 115 kV line, subject to PG&E LCR Kern Kern Oil Cat B	1	9	1	1
24	VSTA-DEVERS 230 kV line, subject to SCE N-2 Devers-Valley 500 kV with RAS	27,321	621	-	-
25	SERRANO-VILLA PK 230 kV line, subject to N-2 SCE Serrano-Lewis #1 and Serrano-Villa PK #2 230 kV	1,758	39	-	-
26	LEWIS-VILLA PK 230 kV line, subject to CA230kV S LAM2 L-2 SCE Serrano-Lewis	1,658	33	-	-
27	PANOCHEJ-HAMMONDS 115 kV line, subject to PG&E LCR Fresno Wilson Cat B	334	10	-	-
28	BARRE-LEWIS 230 kV line, subject to CA230kV S LAM2 L-1 SCE VillaPark-Barre	148	3	-	-
29	WARNERVL-WILSON 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	141	40	-	-
30	PANOCHE-GATES 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	24	6	-	-
31	VINCENT 500/230 kV transformer #4	24	1	-	-
32	WYANDJT2-BIG BEND 115 kV line, subject to PG&E LCR Sierra SOT Cat C	12	3	-	-
33	MORAGA-CLARMNT 115 kV line, subject to PG&E LCR Stock Lock Cat C	1	1	-	-
34	DELTA-CASCADE 115 kV line #1	1	2	-	-

Table 5.6-2 summarizes the potential congestion across specific branch groups and local capacity areas. The branch groups were identified by aggregating congestion costs and hours of congested facilities to an associated branch or branch group for normal or contingency conditions. The congestions subject to contingencies associated with local capacity requirements were aggregated by PTO service area based on where the congestion was located. The results are ranked by severity, based on the 2025 congestion cost.

Table 5.6-2: Simulated congestion in the ISO-controlled grid

No	Aggregated congestion	2020		2025	
		Costs (k$)	Duration (hr)	Costs (k$)	Duration (hr)
1	Path 26	6,885	564	3,421	226
2	POE-RIO OSO	1,329	85	1,429	75
3	Exchequer	946	631	1,113	599
4	Path 45	616	366	1,022	245
5	Delevan-Cortina	1,723	111	510	36
6	Path 15/CC (Central California)	141	21	376	20
7	COI	736	286	255	97
8	PG&E LCR (aggregated)	354	43	128	38
9	Inyo-Control	17	16	21	19
10	Lugo - Victorville	0	0	14	1
11	Path 24	0	0	5	5
12	Path 25	5	9	3	4
13	SCE LCR (aggregated)	3,565	75	0	0
14	Vincent bank	24	1	0	0
15	WARNERVL - WILSON	141	40	0	0
16	West of Devers	27,321	621	0	0

5.6.2 Economic Planning Study Requests

As part of the economic planning study process, Economic Planning Study requests are accepted by the ISO to address the congestion areas identified by the ISO. These study requests are individually considered for designation as a High Priority Economic Planning Study for consideration in the development of the transmission plan.

5.6.2.1 Buck-Colorado River-Julian Hinds 230 kV Loop-in (Southern CA Eastern area)

Study request overview

The Buck-Colorado River-Julian Hinds 230 kV Loop-in study request proposes to convert the Buck Boulevard-Julian Hinds 230 kV gen-tie to a network facility by looping in the line into either the Colorado River 230 kV substation or the Red Bluff 230 kV substation.

Evaluation

As discussed in section 2.7.4.3, the need for this project was assessed as part of the 2014-2015 ISO transmission planning cycle, and it has not been found to be needed at this time. Activities are continuing, as an extension of the 2014-2015 planning cycle, to explore the issues raised by the project proposal.

5.6.2.2 Southwest Intertie Project – North (SWIP North, Midpoint to Robinson Summit 500 kV AC) (Idaho/Nevada area)

Study request overview

The Southwest Intertie Project – North (SWIP North, Midpoint to Robinson Summit 500 kV AC) study request is comprised of a new 500 kV circuit between Midpoint (Idaho Power) and Robinson Summit (NV Energy). As well, the submitter clarified that construction of the circuit can also lead to scheduling capacity being brought under ISO operational control from Harry Allen, Nevada to Midpoint, Idaho and that this scheduling capacity should be considered part of the proposal.

Evaluation

The following table summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 5.6-3 Evaluating study request - Southwest Intertie Project-North

Study Request: Southwest Intertie Project – North (SWIP North, Midpoint to Robinson Summit 500 kV AC) (Idaho/Nevada area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Reduce congestion on all major ISO intertie paths, and in particular on COI, PACI, NOB and Path 26 • Recommend that ISO investigate the discrepancies and complete additional modelling, as needed, to benchmark "projected" vs "actual" congestion	• Economic studies performed by the ISO have identified congestion on COI • Economic studies performed by the ISO have identified congestion on Path 26; these congestion costs did not change significantly from previous transmission plans; and no economic justifications for network upgrades were identified in previous transmission plans.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Can potentially bring additional policy benefits by allowing out of state renewables to meet the likely incremental RPS goal (50%)	• There is no new generation in the area in the TPP portfolios at this time that would benefit from the proposed project. However, consideration of out-of-state resources in achieving a 50 percent renewable energy goal by 2030 needs to be taken into account in future planning forums.
Local Capacity Area Resource requirements	• Not addressed in submission	• No benefits identified by ISO
Increase in Identified Congestion	• Not addressed in submission	• Congestion is not expected to increase significantly over the planning horizon used in the Transmission Planning Process

Study Request: Southwest Intertie Project – North (SWIP North, Midpoint to Robinson Summit 500 kV AC) (Idaho/Nevada area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Integrate New Generation Resources or Loads	• See "Delivery of Location Constrained Resource Interconnection Generators" above	• See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	• Project will provide Capacity Benefits • Adding SWIP North relieves certain reliability and economic constraints related to imports across the ISO's California Oregon Intertie (COI) path. This translates into incremental import capability into the ISO. This increase in incremental import capability should be accounted for to estimate Capacity Benefits of SWIP North • Improve EIM transfer capability between PacifiCorp East (PACE), PacifiCorp West (PACW), ISO and NVE. • Directly addresses certain Northern CA bulk transmission overloads identified in ISO 2014/15 TPP • As seen in the studies ISO has performed under the 2014/15 LTPP process, over generation will be a challenging issue to address with 33% Renewable integration. This issue will undoubtedly become even worse if California's RPS procurement goal increases to 50%. SWIP North line may be potentially part of the solution in addressing this issue. SWIP North will allow geographical diversity to incremental RPS build out which will help reduce locational aspects of congestion caused by over generation. • Allow enhanced transmission capacity between PACW, PACE & ISO which should further enhance the benefits of ISO PacifiCorp integration	• The benefits described in the project submission do not provide actionable benefits in the ISO's planning process at this time. The stated benefits largely draw on parameters that produce value for the ISO in addressing needs that would only emerge beyond the 10 year horizon, or that relate to California resource procurement that may be undertaken to achieve a 50 percent renewable energy goal in California. The processes to determine state policy direction targeting procurement of resources outside the ISO have commenced but not concluded.

Conclusion

The ISO recognizes the potential for material benefits to be identified in the future as the state's processes for targeting resource procurement for a 50 percent renewable energy goal solidify. The bulk of the benefits attributed to the project cannot be meaningfully unilaterally assessed by the ISO at this time, due the need to coordinate benefits analysis with the ISO's neighboring planning regions and the need for policy direction from the state of California regarding renewable energy procurement plans for achieving 50 percent renewable energy goals.

The ISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Tier Transmission Group (NTTG) planning regions, respectively. The scheduling capacity from the Harry Allen end of the ISO's approved Harry Allen-Eldorado transmission line to Robinson Summit also extends the reach of the overall project to the ISO as well, which creates what appears to be a three-party ITP.

The ISO will consider participation in an interregional coordinated review should this project be appropriately submitted into the ISO's, NTTG's and WestConnect's regional processes as an ITP.

Due solely to the COI congestion issues identified in the submission, COI congestion was identified as a High Priority Economic Study for this planning cycle and is discussed later in this chapter.

5.6.2.3 Diablo Offline sensitivity study (Central California area)

Study request overview

The study request proposes to add a sensitivity study with Diablo Canyon Nuclear Generation offline for Year 2025 study case.

Evaluation

The following table summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 5.6-4 Evaluating study request – Diablo offline sensitivity study

Study Request: Diablo Offline sensitivity study (Central California area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Not addressed in submission	• No major impacts expected by ISO
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Not addressed in submission	• Diablo Canyon offline is not related to LCRIG driven transmission needs
Local Capacity Area Resource requirements	• Not addressed in submission	• Diablo Canyon is not located in a local capacity requirement area.
Increase in Identified Congestion	• Not addressed in submission	• No major impacts expected by ISO
Integrate New Generation Resources or Loads	• Not addressed in submission	• Diablo Canyon offline is not related to integrating new generation resources or loads

Study Request: Diablo Offline sensitivity study (Central California area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Other	• Purpose of study request is to obtain information on what steps may need to be taken if Diablo Canyon were to become unavailable (such as new transmission upgrades and/or new generation procurement through the LTPP process)	• No benefits identified by ISO that warrant an economically driven analysis of potential transmission reinforcement at this time. The ISO notes that a transmission system reliability analysis considering the impacts of Diablo Canyon retirement is available in the 2012-2013 Transmission Plan.

Conclusion

Based on the evaluation described above, the request was not designated as a High Priority Economic Study for consideration in the development of the transmission plan.

5.6.2.4 Path 15 Study (Central California area)

Study request overview

The study request proposes to increase the Path 15 rating in the range of 300-1000 MW.

Evaluation

The following table summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 5.6-5 Evaluating study request – Path 15 study

Study Request: Path 15 Study (Central California area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Study request states that there are numerous alternative projects and combinations of minor upgrades that can potentially be designed to achieve a Path 15 rating increase in the range of 300-1000 MW	• Economic studies performed by the ISO have identified congestion on Path 15 • Congestion costs did not change significantly from previous cycles • No economic justification for network upgrades were identified in previous cycles
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Not addressed in submission	• No benefits identified by ISO
Local Capacity Area Resource requirements	• Not addressed in submission	• No benefits identified by ISO

Study Request: Path 15 Study (Central California area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Increase in Identified Congestion	• Not addressed in submission	• Congestion on Path 15 is not expected to increase significantly over the ten year planning horizon used in the Transmission Planning Process
Integrate New Generation Resources or Loads	• Not addressed in submission	• No benefits identified by ISO
Other	• Submission requests that the ISO use a different approach in its economic study methodology to study Path 15, referring to these changes as enhancements.	• ISO's economic planning study follows an established methodology developed through stakeholder participation. Changes to this methodology require consideration of merit and ultimately stakeholder consideration. •

Conclusion

Based on the evaluation described above, Path 15 has been designated as a High Priority Economic Study for this planning cycle and is discussed further below. The ISO does not see the need to adopt the proposed analysis changes at this time.

5.6.2.5 Path 26 Study (Central/South California area)

Study request overview

The study request proposes to add a Midway-Vincent 500 kV line, a Midway-Vincent 230 kV line, Big Creek-Helms interconnection or other alternatives to solve Path 26 congestion.

Evaluation

The following table summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 5.6-6 Evaluating study request – Path 26 study

Study Request: Path 26 Study (Central/South California area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Study request proposes several alternatives to solve congestion on Path 26	• Economic studies performed by the ISO have identified congestion on Path 26 • Congestion costs did not change significantly from previous cycles • No economic justifications for network upgrades were identified in previous cycles

Study Request: Path 26 Study (Central/South California area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Not addressed in submission	• No benefits identified by ISO
Local Capacity Area Resource requirements	• Not addressed in submission	• No benefits identified by ISO
Increase in Identified Congestion	• Not addressed in submission	• Congestion on Path 26 is not expected to increase significantly over the planning horizon used in the Transmission Planning Process
Integrate New Generation Resources or Loads	• Not addressed in submission	• No benefits identified by ISO
Other	• The submission requests that the ISO use a different approach in its economic study methodology to study Path 15, referring to these changes as enhancements.	• ISO's economic planning study follows the ISO's established process and methodology and any changes in the future will require vetting with stakeholders.

Conclusion

Based on the evaluation described above, Path 15 has been designated as a High Priority Economic Study for this planning cycle and is discussed further below. The ISO does not see the need to adopt the proposed analysis changes at this time, however.

5.6.2.6 North Gila – Imperial Valley #2 Transmission Project (Southern California Imperial Valley/Arizona area)

Study request overview

The study request proposes to add a new 500 kV North Gila-Imperial Valley #2 transmission line. This line would parallel the existing North Gila-Imperial Valley line (also known as the Southwest Power Link, or SWPL) for the majority of its length, with an expected minimum separation of 250 feet from the existing SWPL.

Evaluation

The following table summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 5.6-7 Evaluating study request – North Gila – Imperial Valley #2 transmission project

Study Request: North Gila – Imperial Valley #2 Transmission Project (Southern CA Imperial Valley/Arizona area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Proposed project will bring substantial economic benefits by reducing congestion on the existing SWPL (under high transfers and contingencies)	• ISO studies did not identify congestion on SWPL
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Provides California additional access to export/import from generation resource zones where limited transmission access exists • Increases diversity of the inter-regional energy resource zones	• There is no new generation in the TPP portfolios for this area that would benefit from the proposed project
Local Capacity Area Resource requirements	• Provides additional capacity benefit under normal and emergency conditions for the southern portion of the CAISO system - capacity benefit, primarily based on the G-1/N-1 involving the outage of the existing North Gila – Imperial Valley 500kV line • Potential benefit to the System RA by reducing the Local RA for the SDGE area	• Limited benefits expected by ISO
Increase in Identified Congestion	• Not addressed in submission	• Congestion on SWPL is not expected to increase significantly over the ten year planning horizon used in the Transmission Planning Process
Integrate New Generation Resources or Loads	• See "Delivery of Location Constrained Resource Interconnection Generators" above	• See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	• Increases reliability for loss of the existing SWPL, and increases the inter-regional transfer capability between Arizona and load centers in southern California • Resource adequacy benefits to southern California for renewable energy delivered from the solar and geothermal rich areas of Imperial Valley and Arizona • Create a new ISO delivery point at the Highline 500kV substation • Increase EOR transfer capability • BCR analyses conducted to date assumed that no capacity benefit is attributed to the Project due to the “downstream bottleneck” (assumed to	• Limited benefits expected by ISO

Study Request: North Gila – Imperial Valley #2 Transmission Project (Southern CA Imperial Valley/Arizona area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
	be in the SDGE area). Economic Analysis should include some capacity benefit, primarily based on the G-1/N-1 involving the outage of the existing North Gila – Imperial Valley 500kV line. SDGE had also provided earlier comments to the potential benefit to the System RA by reducing the Local RA for the SDGE area earlier in response to the previous (2012-13) Economic Analysis. If some capacity benefit were included in the calculation, the BCR could also be greater than shown in recent analyses.	

Conclusion

Based on the evaluation described above, the request was not designated as a High Priority Economic Study for consideration in the development of the transmission plan.

5.6.2.7 Bishop Area Reconfiguration Study (Southern California North of Lugo area)

Study request overview

The study request proposes to reconfigure the system in the Bishop, CA area by looping-in the Dixie Valley generator tie-line and Austin-Carson Lake transmission line into a new ISO-NVE interchange substation. The substation would include a 100 MVA phase shifter to control the flow between ISO and NVE. The radial Dixie Valley line would be split in two: a 51-mile radial gen-tie portion that connects generator to the ISO bus at the new substation and a 161-mile transmission portion that connects the new substation to SCE’s Control substation.

Evaluation

The following table summarizes the benefits described in the submission and ISO’s evaluation of the study request.

Table 5.6-8 Evaluating study request – Bishop are reconfiguration study

Study Request: Bishop Area Reconfiguration Study (Southern CA North of Lugo area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Eliminates local congestion	• Economic studies performed by the ISO have identified congestion on Path 60 (Inyo-Control/Info Phase Shifter) • Proposed loop-in may mitigate the congestion on this line, however, since the magnitude of the congestion is small, the benefit is not expected to be significant
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Allows a controlled new outlet for local generation in the Bishop area and provides a means to operate the system reliably without curtailing local generation, most of which are renewable and contribute to state RPS goals • Allows the local generation to operate without curtailment during periods of extended maintenance outages on the SCE transmission system • Reconfigured system opens transmission capacity in the local area enabling new renewable generation, both base load and intermittent • If higher new local renewable resources are desired, the upgrade enables further expansion of transmission capacity via optimized use of existing SCE's transmission easements at a much lower cost than otherwise could be implemented today	• Existing generation experiences curtailments only during planned outages • There is no new generation in the area in the TPP portfolios that would benefit from the proposed project
Local Capacity Area Resource requirements	• Not addressed in submission	• North of Lugo is not part of a local capacity requirement area
Increase in Identified Congestion	• Not addressed in submission	• Congestion identified on Path 60 (Inyo-Control/Info Phase Shifter) is not expected to increase significantly over the planning horizon used in the Transmission Planning Process
Integrate New Generation Resources or Loads	• Reconfigured system provides an alternate path to serve load in the Bishop area and enables the opportunity, if needed, to revamp the ageing existing transmission and also supports increasing the existing system voltage (from 115 kV to 230 kV) while using SCE's existing transmission easements	• Existing operating procedures are sufficient to meet NERC Planning Standards

Study Request: Bishop Area Reconfiguration Study (Southern CA North of Lugo area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Other	• Reconfigured system mitigates voltage instability problems under contingency conditions and does so without the need to drop local generation • Historical high operating voltages in SCE's local transmission would be addressed and have a positive impact on the life of existing transmission assets	• With previously approved shunt reactors at Kramer, existing operating procedures are sufficient to meet NERC Planning Standards.

Conclusion

Based on the evaluation described above, the request was not designated as a High Priority Economic Study for consideration in the development of the transmission plan. The ISO may revisit the proposed project in the future if generation in the area will need to be curtailed under normal operating conditions and not only during planned outages.

5.6.2.8 California – Wyoming Grid Integration (Southern California/Wyoming area)

Study request overview

The study request proposes a new inter-regional transmission solution that would provide California consumers with access to Wyoming wind resources. The proposal would access Wyoming wind resources through a new 730-mile, 3,000 MW high voltage direct current (HVDC) transmission solution.

Evaluation

The following table summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 5.6-9 Evaluating study request – California – Wyoming grid integration

Study Request: California – Wyoming Grid Integration (Southern CA/Wyoming area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Not addressed in submission	• Limited congestion benefits expected by the ISO with generation portfolios assumed
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Access Wyoming wind resources	• There is no new generation in the area in the TPP portfolios that would benefit from the proposed project
Local Capacity Area Resource requirements	• Not addressed in submission	• No local benefits expected by ISO
Increase in Identified Congestion	• Not addressed in submission	• Limited congestion benefits expected by ISO with generation portfolios assumed
Integrate New Generation Resources or Loads	• See "Delivery of Location Constrained Resource Interconnection Generators" above	• See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	• Significant economic benefits • TransWest recommends that CAISO begin immediately to develop the specifics of a process to assess the cost-effectiveness of new transmission investments for energy-only resources with appropriate stakeholder involvement • TransWest's Economic Planning Study Request is to be included within the ISO's 50% Renewable Energy Goals for 2030 Special Study	• Limited congestion benefits expected by ISO with generation portfolios assumed

Conclusion

Based on the evaluation described above, the request was not designated as a High Priority Economic Study for consideration in the development of the transmission plan. The ISO recognizes the potential for material benefits to be identified in the future as the state's processes for targeting resource procurement for a 50 percent renewable energy goal solidify. The bulk of the benefits attributed to the project cannot be meaningfully unilaterally assessed by the ISO at this time, due the need to coordinate benefits analysis with the ISO's neighboring planning regions and the need for policy direction from the state of California regarding renewable energy procurement plans for achieving 50 percent renewable energy goals.

The ISO considers the submitted project to be an interregional transmission project between NTTG and the ISO as relevant planning regions and would need to be submitted into the NTTG's and ISO's regional planning processes for consideration in the next ISO planning cycle. At that time the ISO will coordinate with NTTG on the assessment of the submitted project.

The ISO will consider participation in an interregional coordinated review should this project be appropriately submitted into the ISO's and NTTG's regional processes as an ITP.

5.6.2.9 MAP upgrades (Marketplace – Adelanto 500 kV HVDC conversion) (Southern California/Nevada area)

Study request overview

The MAP Upgrade Project involves the conversion of the 202 mile Mead-Adelanto Project Upgrade ("MAP Upgrade Project") transmission line from its existing High-Voltage Alternating Current ("HVAC") to High-Voltage Direct Current ("HVDC") Operations. The MAP Upgrade Project scope involves the construction of two HVDC converter terminals: one near the MAP line's eastern terminus at Marketplace Substation in Southern Nevada and the second near the western terminus at the Adelanto Substation in southern California. The Project also requires minor modifications/upgrades to the existing transmission facilities to improve system reliability and to effectively integrate the new transmission capacity into the existing transmission system. These system upgrades will include the construction of an approximately 1.5 mile new 500 kV HVAC line from the Marketplace converter station to the Eldorado Substation; two approximately 17-mile single circuit HVAC lines connecting the 500 kV AC bus at the new Adelanto converter station to the existing Vincent-Lugo 500 kV line(s); and additional 500 kV HVAC lines from the AC buses at each converter station to the Marketplace and Adelanto substations, respectively.

Evaluation

The following table summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 5.6-10 Evaluating study request – MAP upgrades

Study Request: MAP upgrades (Marketplace – Adelanto 500 kV HVDC conversion) (Southern CA/Nevada area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Not addressed in submission	• Limited congestion benefits expected by ISO with generation portfolios assumed

Study Request: MAP upgrades (Marketplace – Adelanto 500 kV HVDC conversion) (Southern CA/Nevada area)		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Increased transmission capacity associated with the MAP Upgrade Project will facilitate the delivery of energy and capacity from both existing and new renewable resources (solar, wind and geothermal) as well as from highly-economical and environmentally-friendly gas fired resources from the generation-rich Eldorado region to the heart of Southern California • Project will provide access to Wyoming wind along with the preferred resources located in southern Nevada and Arizona	• There is no new generation in the area in the TPP portfolios that would benefit from the proposed project
Local Capacity Area Resource requirements	• Not addressed in submission	• No local benefits expected by ISO
Increase in Identified Congestion	• Not addressed in submission	• Limited congestion benefits expected by ISO with generation portfolios assumed
Integrate New Generation Resources or Loads	• See "Delivery of Location Constrained Resource Interconnection Generators" above	• See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	• Improve system reliability and reduce the cost of energy and capacity for California electrical energy consumers • Minimal environmental impact, with the increased transmission capacity associated with this project being achieved without requiring any significant modification/upgrades to the existing MAP transmission facilities • Enable California in achieving its proposed policy goal of increasing the state's Renewable Portfolio Standard ("RPS") from its existing 33% RPS to the recently proposed target of 50% RPS • As a controllable HVDC line, the MAP Upgrade Project will serve as an integral part in expanding the Energy Imbalance Market ("EIM") • The controllability and fast ramp rates associated with HVDC technology will allow the MAP Upgrade Project to provide system benefits similar to flexible generating capacity interconnected at the Adelanto substation	• The ISO recognizes the range of benefits to system operation the project could provide. However, the benefits described in the project submission do not provide actionable benefits in the ISO's planning process at this time. The stated benefits largely draw on parameters that produce value for the ISO in addressing needs that would only emerge beyond the 10 year horizon, or that relate to California resource procurement and potential flexible generation procurement that may be undertaken to achieve a 50 percent renewable energy goal in California. The processes to determine state policy direction targeting procurement of resources has commenced but not concluded. • The stated benefit of reducing cost of capacity needs to be examined by assessing the impact on the import capability into the CAISO BAA, and the cost difference between the resources at both ends of the importing interfaces on which the project has flow impacts. Further clarity of 50 percent renewable energy goal is also needed for conducting these assessments

Conclusion

Based on the evaluation described above, the request was not designated as a High Priority Economic Study for consideration in the development of the transmission plan. However, opportunities for the project will be revisited in future planning cycles as more clarity is obtained regarding resources necessary to achieve the state's 50 percent renewable energy goals and ensure adequacy of flexible generation and other reliability needs.

5.6.3 Scope of high-priority studies

After evaluating identified congestion and reviewing stakeholders' study requests, consistent with tariff section 24.3.4.2, the ISO selected five congested branch groups for further assessment, which are listed table 5.6-11.

Table 5.6-11: High-priority studies

Branch Group	Area	2020		2025	
		Costs (k$)	Duration (hr)	Costs (k$)	Duration (hr)
Path 26	PG&E, SCE	6,885	564	3,421	226
POE-RIO OSO	PG&E	1,329	85	1,429	75
Exchequer	PG&E	946	631	1,113	599
Path 15/CC	Central CA	141	21	376	20
COI	PG&E, NW	736	286	255	97

The identified congestion on the Serrano–Lewis/Villa PK-Barre corridor in the SCE's LA Basin area, (table 5.6-1) or equivalently the aggregated congestion for the SCE LCR constraint (table 5.6-2) each have a relatively large congestion cost, but were not selected as high priority study alternatives because congestion was identified in the 2020 study but not in the 2025 study. The change in 2025 was due to the Mesa Loop-in project, a reliability project approved by the ISO in the 2013-2014 planning cycle, which was modeled in the 2025 dataset but not in the 2020 dataset. This project helps to mitigate the flow on the Serrano-Lewis/Villa PK/Barre corridor which results in a corresponding reduction in congestion on this path in 2025. The planned in-service date for the Mesa Loop-in project is between 2020 and 2025.

The consideration of the Vista-Devers path as a high priority study alternative was similar to the Serrano–Lewis/Villa PK-Barre corridor, where congestion observed in the 2020 analysis was not observed in the 2025 analysis. The West of Devers permanent solution is projected to be in service after 2020 but before 2025; hence it was modeled in the 2025 dataset but not in the 2020 dataset. Consequently, Vista-Devers congestion subject to the Devers-Valley 500 kV N-2 contingency was observed in 2020 but not in 2025, and was not selected as a high priority study.

Similarly, congestion on Wernersville – Wilson and Panoche – Gates was only observed in 2020 but not in 2025 because Gates-Gregg #2 line is projected to be in service in 2022 and was modeled in the 2025 dataset but not in the 2020 dataset. This congestion was therefore also not selected as a high priority study.

The congestion on Delevan – Cortina subject to the Delevan - Vaca Dixon N-2 contingency was not in the top 5 because the ISO and the PG&E are working on rerating this line to increase its emergency rating. It is expected that the congestion would be mitigated after the rerating. Further evaluation on this line and the associated contingencies will be conducted in the next planning cycle.

5.7 Congestion Mitigation and Economic Assessment

Congestion mitigation is the second step in the economic planning study. With a focus on high-ranking congestion, this study step produced proposed network upgrades, evaluated their economic benefits and weighed the benefits against the costs to determine if the network upgrades were economical.

Path 26 and Path 15/Central California congestions

These two congestions were also identified in the previous planning cycles (Path 26 congestion was identified in 2011-2012, 2012-2013, 2013-2014, and 2014-2015 cycles; Path 15 congestion was identified in 2012-2013 cycle). Upon further review of the economic planning study results, no economic justifications were seen for network upgrades identified for these congestions in the previous planning cycles. Considering there were no significant changes in the system models in these congestion areas, no detailed production cost simulation and economic assessment were conducted for these four congestions. The ISO will continuously and closely monitor and assess these congestions in the future planning cycles. The ISO also intends to explore the issues raised in these submissions regarding study methodologies.

Exchequer and POE-RIO OSO congestions

These two congestions are local congestions in PG&E area and related to hydro power plants. As shown in figure 5.7-1, Exchequer congestion was observed on Exchequer – Le Grand under contingencies of Merced 115/70 kV transformer or Merced – Merced Falls 70 kV line. The block in figure 5.7-1 represents the local 70 kV system. The generator that was impacted by the congestion is the Exchequer hydro power plant. Similarly, as shown in figure 5.7-2, POE-RIO OSO congestion also impacts several hydro power plants.

Figure 5.7-1 Exchequer congestion

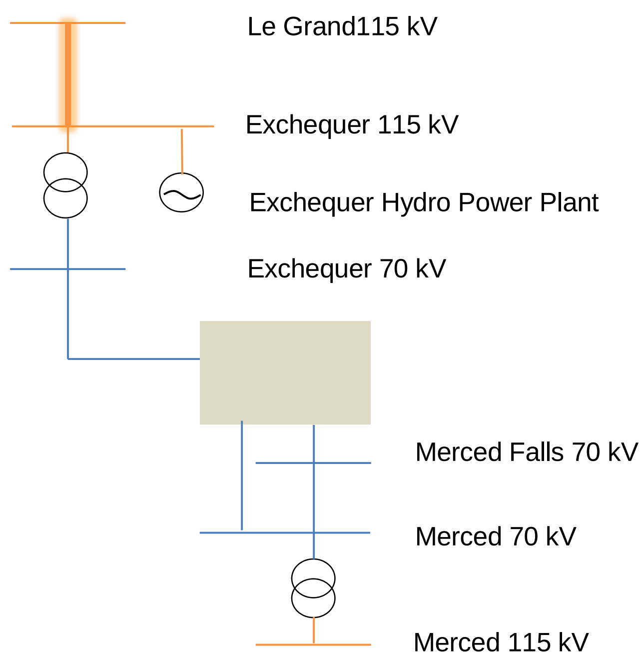
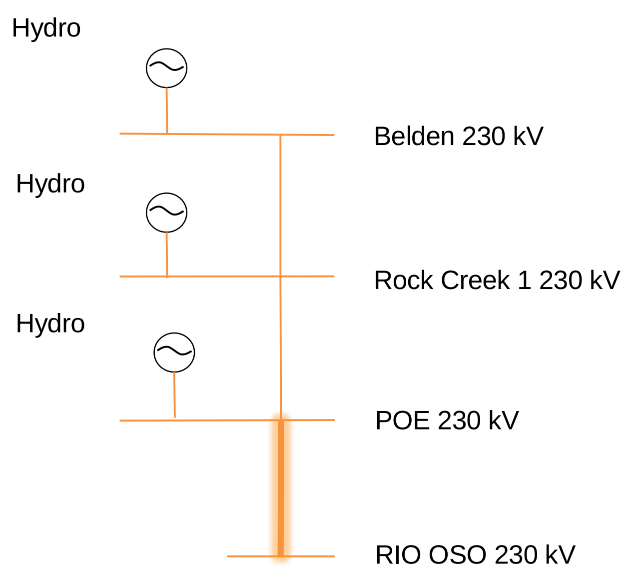


Figure 5.7-2 POE-RIO OSO congestion



Since there is no specific project proposed to mitigate Exchequer congestion, a generic project that was assumed to increase the rating of the congested line were modeled in the database in order to assess the benefit of mitigating the congestion. The new rating was set up high enough to completely mitigate the congestion. The simulations results showed that there were no material benefits to the ISO's ratepayers based on the current production cost model, as the overall benefits of reduced congestion were offset by reduced generation and transmission congestion revenue otherwise accruing to ISO ratepayers.

The same approach was applied to POE-RIO OSO congestion, and similarly the production cost model simulations did not identify benefits to the ISO ratepayers based on the current model for several reasons. The hydro generators behind the POE-RIO OSO congestion are owned by PG&E, and these generators are dispatchable in the current TEPPC hydro modeling, in which GridView's load following and hydro-thermal coordination routines are used to dispatch these hydro generators. Based on the logic of these two hydro dispatch routines, water can be stored for later use to follow the load and price changes. Therefore, there is no significant pricing advantage with mitigating the congestion of POE-RIO OSO. As well, reducing the congestion also reduces the congestion revenue that accrues to the ISO ratepayer. Although mitigating the congestion increases access to lower cost hydro at POE, there was no benefit to the ISO ratepayers based on the current production cost model.

Given the simulation results, no economic projects were recommended to mitigate these two congestions in this planning cycle. Instead, these two lines will be monitored in the future planning cycles and further analyses will be conducted if material congestions are identified. Also, it was noted that TEPPC will be upgrading the hydro modeling in its 2026 Common Case, which would be used as the starting point for the database of 2016~2017 planning cycle. Since both Exchequer and POE-RIO OSO congestions are in hydro-rich areas, the change of hydro modeling may affect their congestion costs and benefit assessments.

COI congestion

Comparing with last planning cycle's congestion results, the COI congestion cost forecast increased from a negligible level in 2024 to $0.25 million in 2025. The congestion cost showing in this planning cycle is still not material comparing with the cost of any potential upgrades that can help to mitigate the congestion on COI, such as a major 500 kV path between Northwest and California. The study request for Southwest Intertie Project – North (SWIP North) proposed by LS Power Development, LLC was evaluated since it provides a parallel path to COI.

The SWIP North project is comprised of a 500 kV line from Midpoint substation to Robinson Summit substation, and scheduling capacity that may be brought under ISO operational control from Harry Allen, Nevada to Midpoint, Idaho. Together with the existing transmission from Robinson Summit to Harry Allen and approved Harry Allen to Eldorado project, which have been modeled in the production cost simulation database, the SWIP North project creates a parallel path with COI. The congestions in 2025 with and without SWIP North project are shown in table 5.7-1. It can be seen that congestions on both Path 26 and COI were reduced with SWIP North modeled. However, given the magnitude of the forecast COI congestion, the SWIP North project does not bring sufficient benefit to the ISO's ratepayers to justify this project economically.

However, the production cost savings will have to be revisited in the future to take into account improved hydro modeling forthcoming in the TEPPC 2026 Common Case, further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources supporting California's 50 percent renewable energy goals in assessing production cost benefits and the other benefits alluded to in the project submission. Further, the Gridview version used in these studies did not support contract path modeling to capture the scheduling path the SWIP North project – including scheduling rights from Harry Allen to Midpoint – could provide the ISO. The impacts this modeling change could have on wheeling rates and hurdle charges could result in increased benefits to ISO ratepayers.

As well, there may be benefits to other western planning regions that can be explored and should be considered in the interregional planning process now in effect.

These benefits may be explored through the interregional coordination process as noted in the discussion of the SWIP North study request submission provide earlier in section 5.6.2.2.

Table 5.7-1 Congestions in 2025 -- pre and post SWIP North project

	Pre SWIP-North		Post SWIP-North	
Constraints	**Cost (k$)**	**Duration (hr)**	**Cost (k$)**	**Duration (hr)**
Path 26	3,421	226	3,102	202
POE-RIO OSO	1,429	75	1,428	75
Exchequer	1,113	599	1,112	602
Path 45	1,022	245	825	258
Delevn-Cortina	510	36	561	40
Path 15/CC	376	20	341	19
COI	255	97	160	59
PG&E LCR (aggregated)	128	38	107	31
Lugo - Victorville	14	1	20	1
Inyo-Control	21	19	19	18
Path 24	5	5	17	18
Path 25	3	4	4	8

5.8 Summary

The production cost simulation was conducted in each study year for 2020 and 2025 in this economic planning study and grid congestion was identified and evaluated. According to the identified areas of congestion concerns, five congestions were selected for further evaluation:

1. Path 26
2. Exchequer
3. POE-RIO OSO
4. Path 15/Central California
5. COI

Path 26 and Path 15/Central California congestions were compared with the results in the previous planning cycles. The congestion costs did not change significantly from previous planning cycles. Since no economic justification for network upgrades to mitigate these two congestions were identified in the previous planning cycles, these two congestions were not recommended to be mitigated in this planning cycle.

Exchequer and POE-RIO OSO congestions were in hydro-rich areas. The congestion costs and the potential benefits of mitigating the congestions highly depend on the hydro modeling. In this planning cycle no sufficient benefits were identified for mitigating these two congestions. Since the TEPPC will have new hydro modeling in the 2026 Common Case, these congestions will be monitored and the ISO will revisit the benefit assessment if congestions are observed in the next planning cycle.

COI congestion cost forecasts remained de minimis but increased from previous planning cycles. Therefore, a related study request, the SWIP North project, was studied. The study results showed that while the proposed project provides some benefit, the marginal reductions in congestion did not produce material benefits to support the project. Further analysis through interregional coordination would be necessary to more fully explore the benefits.

In summary, there are no economic upgrade recommended for approval in the 2015~2016 planning cycle. However, several paths and related projects will be monitored in future planning cycles to take into account improved hydro modeling, further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources supporting California's 50 percent renewable energy goals.

As well, several interregional projects have been submitted that the ISO expects will be pursued in the interregional coordination framework now in effect between the ISO and the other western regional planning entities and that the ISO will be interested in exploring.

Chapter 6

6 Other Studies and Results

6.1 Long-Term Congestion Revenue Rights Simultaneous Feasibility Test Studies

The Long-term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test studies evaluate the feasibility of the fixed LT CRRs previously released through the CRR annual allocation process under seasonal, on-peak and off-peak conditions, consistent with section 4.2.2 of the Business Practice Manual for Transmission Planning Process and tariff sections 24.1 and 24.4.6.4

6.1.4 Objective

The primary objective of the LT CRR feasibility study is to ensure that fixed LT CRRs released as part of the annual allocation process remain feasible over their entire 10-year term, even as new and approved transmission infrastructure is added to the ISO-controlled grid.

6.1.5 Data Preparation and Assumptions

The 2015 LT CRR study leveraged the base case network topology used for the annual 2015 CRR allocation and auction process. Regional transmission engineers responsible for long-term grid planning incorporated all the new and ISO approved transmission projects into the base case and a full alternating current (AC) power flow analysis to validate acceptable system performance. These projects and system additions were then added to the base case network model for CRR applications. The modified base case was then used to perform the market run, CRR simultaneous feasibility test (SFT), to ascertain feasibility of the fixed CRRs. A list of the approved projects can be found in the 2014-2015 Transmission Plan.

In the SFT-based market run, all CRR sources and sinks from the released CRR nominations were applied to the full network model (FNM). This forms the core network model for the locational marginal pricing (LMP) markets. All applicable constraints were considered to determine flows as well as to identify the existence of any constraint violations. In the long-term CRR market run setup, the network was limited to 60 percent of available transmission capacity. The fixed CRR representing the transmission ownership rights and merchant transmission were also set to 60 percent. All earlier LT CRR market awards were set to 100 percent. For the study year, the market run was set up for four seasons (with season 1 being January through March) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as save cases for further review and record-keeping.

The ISO regional transmission engineering group and CRR team must closely collaborate to ensure that all data used were validated and formatted correctly. The following criteria were used to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs:

- SFT is completed successfully;
- the worst case base loading in each market run does not exceed 60 percent of enforced branch rating;
- there are overall improvements on the flow of the monitored transmission elements.

6.1.6 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

- The base case network model data for long-term grid planning is prepared by the regional transmission engineering (RTE) group. The data preparation may involve using one or more of these applications: PTI PSS/E, GE PSLF and MS Excel;
- RTE models new and approved projects and perform the AC power flow analysis to ensure power flow convergence;
- RTE reviews all new and approved projects for the transmission planning cycle;
- applicable projects are modeled into the base case network model for the CRR allocation and auction in collaboration with the CRR team, consistent with the BPM for Transmission Planning Process section 4.2.2;
- CRR team sets up and performs market runs in the CRR study system environment in consultation with the RTE group;
- CRR team reviews the results using user interfaces and displays, in close collaboration with the RTE group; and
- The input data and results are archived to a secured location as saved cases.

6.1.7 Conclusions

The SFT studies involved eight market runs that reflected four three-month seasonal periods (January through December) and two time-of-use (on-peak and off-peak) conditions.

The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as planned.

In compliance with section 24.4.6.4 of the ISO tariff, ISO followed the LTCRR SFT study steps outlined in section 4.2.2 of the BPM for the Transmission Planning Process to determine whether there are any existing released LT CRRs that could be at risk and for which mitigation measures should be developed. Based on the results of this analysis, the ISO determined in May 2015 that there are no existing released LT CRRs at-risk” that require further analysis. Thus, the transmission projects and elements approved in the 2014-2015 Transmission Plan did not adversely impact feasibility of the existing released LT CRRs. Hence, the ISO did not evaluate the need for additional mitigation solutions.

Chapter 7

7 Transmission Project List

7.1 Transmission Project Updates

Tables 7.1-1 and 7.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous 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 project or enhance economic efficiencies.

Table 7.1-1: Status of previously approved projects costing less than $50M

No	Project	PTO	Expected In-Service Date
1	Imperial Valley Transmission Line Collector Station Project	IID	May-15
2	Estrella Substation Project	NEET West	May-19
3	Almaden 60 kV Shunt Capacitor	PG&E	May-17
4	Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor	PG&E	May-18
5	Bay Meadows 115 kV Reconductoring	PG&E	Canceled
6	Borden 230 kV Voltage Support	PG&E	May-19
7	Caruthers – Kingsburg 70 kV Line Reconductor	PG&E	May-17
8	Cascade 115/60 kV No.2 Transformer Project and Cascade – Benton 60 kV Line Project	PG&E	Nov-22
9	Cayucos 70 kV Shunt Capacitor	PG&E	May-18
10	Christie 115/60 kV Transformer No. 2	PG&E	Jul-17
11	Clear Lake 60 kV System Reinforcement	PG&E	Feb-20

No	Project	PTO	Expected In-Service Date
12	Contra Costa – Moraga 230 kV Line Reconductoring	PG&E	Jan-16
13	Contra Costa Sub 230 kV Switch Replacement	PG&E	Dec-17
14	Cooley Landing – Los Altos 60 kV Line Reconductor	PG&E	Canceled
15	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	Dec-17
16	Cortina No.3 60 kV Line Reconductoring Project	PG&E	Dec-18
17	Cressey – North Merced 115 kV Line Addition	PG&E	May-26
18	Del Monte – Fort Ord 60 kV Reinforcement Project	PG&E	Canceled
19	Diablo Canyon Voltage Support Project	PG&E	Feb-19
20	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	Jan-19
21	Estrella Substation Project	PG&E/NEET West[154]	May-19
22	Evergreen-Mabury Conversion to 115 kV	PG&E	May-22
23	Fulton 230/115 kV Transformer	PG&E	May-21
24	Fulton-Fitch Mountain 60 kV Line Reconductor	PG&E	Aug-18

[154] NEET West was awarded the 230 kV substation component of the project through competitive solicitation. PG&E will construct and own the 70 kV substation and associated upgrades.

No	Project	PTO	Expected In-Service Date
25	Glenn #1 60 kV Reconductoring	PG&E	Apr-18
26	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	Apr-21
27	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	May-17
28	Helm-Kerman 70 kV Line Reconductor	PG&E	May-17
29	Ignacio – Alto 60 kV Line Voltage Conversion	PG&E	Mar-20
30	Jefferson-Stanford #2 60 kV Line	PG&E	On hold
31	Kern – Old River 70 kV Line Reconductor Project	PG&E	Dec-16
32	Kern PP 230 kV Area Reinforcement	PG&E	Apr-23
33	Kearney-Caruthers 70 kV Line Reconductor	PG&E	May-17
34	Kearney – Hearndon 230 kV Line Reconductoring	PG&E	Dec-17
35	Kearney-Kerman 70 kV Line Reconductor	PG&E	May-18
36	Kerchhoff PH #2 – Oakhurst 115 kV Line	PG&E	Canceled
37	Lemoore 70 kV Disconnect Switches Replacement	PG&E	May-16
38	Lockheed No.1 115 kV Tap Reconductor	PG&E	May-21
39	Lodi-Eight Mile 230 kV Line	PG&E	May-22
40	Los Banos-Livingston Jct-Canal 70 kV Switch Replacement	PG&E	May-17
41	Los Esteros-Montague 115 kV Substation Equipment Upgrade	PG&E	Mar-18

No	Project	PTO	Expected In-Service Date
42	Maple Creek Reactive Support	PG&E	May-17
43	Mare Island – Ignacio 115 kV Reconductoring Project	PG&E	Canceled
44	McCall-Reedley #2 115 kV Line	PG&E	Apr-22
45	Menlo Area 60 kV System Upgrade	PG&E	May-16
46	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	Apr-17
47	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	May-19
48	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	May-19
49	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Jan-19
50	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	May-18
51	Missouri Flat – Gold Hill 115 kV Line	PG&E	Dec-18
52	Monta Vista – Los Altos 60 kV Reconductoring	PG&E	Canceled
53	Monta Vista – Los Gatos – Evergreen 60 kV Project	PG&E	May-22
54	Monte Vista 230 kV Bus Upgrade	PG&E	Dec-19
55	Monta Vista-Wolfe 115 kV Substation Equipment Upgrade	PG&E	Canceled
56	Moraga Transformers Capacity Increase	PG&E	Feb-16
57	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Mar-21
58	Moraga-Oakland “J” SPS Project	PG&E	Jan-19

No	Project	PTO	Expected In-Service Date
59	Morro Bay 230/115 kV Transformer Addition Project	PG&E	May-18
60	Mosher Transmission Project	PG&E	Aug-18
61	Mountain View/Whisman-Monta Vista 115 kV Reconductoring	PG&E	May-22
62	Napa – Tulucay No. 1 60 kV Line Upgrades	PG&E	Jul-20
63	Navidad Substation Interconnection	PG&E	May-23
64	Newark-Applied Materials 115 kV Substation Equipment Upgrade Project	PG&E	Canceled
65	North Tower 115 kV Looping Project	PG&E	Dec-21
66	NRS-Scott No. 1 115 kV Line Reconductor	PG&E	Dec-17
67	Oakhurst/Coarsegold UVLS	PG&E	May-17
68	Oro Loma – Mendota 115 kV Conversion Project	PG&E	May-18
69	Oro Loma 70 kV Area Reinforcement	PG&E	May-20
70	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	Aug-19
71	Pease-Marysville #2 60 kV Line	PG&E	Jun-22
72	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	May-22
73	Pittsburg-Lakewood SPS Project	PG&E	Mar-16
74	Potrero 115 kV Bus Upgrade	PG&E	Canceled
75	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	May-19

No	Project	PTO	Expected In-Service Date
76	Reedley 70 kV Reinforcement	PG&E	May-18
77	Reedley 115/70 kV Transformer Capacity Increase	PG&E	May-21
78	Reedley-Dinuba 70 kV Line Reconductor	PG&E	May-17
79	Reedley-Orosi 70 kV Line Reconductor	PG&E	May-17
80	Rio Oso – Atlantic 230 kV Line Project	PG&E	Apr-24
81	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Jan-20
82	Rio Oso Area 230 kV Voltage Support	PG&E	Dec- 20
83	Ripon 115 kV Line	PG&E	Mar-19
84	San Bernard – Tejon 70 kV Line Reconductor	PG&E	May-18
85	San Mateo – Bair 60 kV Line Reconductor	PG&E	May-22
86	Semitropic – Midway 115 kV Line Reconductor	PG&E	Dec-18
87	Series Reactor on Warnerville-Wilson 230 kV Line	PG&E	Dec-18
88	Soledad 115/60 kV Transformer Capacity	PG&E	Apr-22
89	South of San Mateo Capacity Increase	PG&E	Feb-29
90	Spring 230/115 kV substation near Morgan Hill	PG&E	May-21
91	Stagg – Hammer 60 kV Line	PG&E	May-19
92	Stockton 'A' –Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	Dec-18
93	Stone 115 kV Back-tie Reconductor	PG&E	Oct-20

No	Project	PTO	Expected In-Service Date
94	Table Mountain – Sycamore 115 kV Line	PG&E	May-22
95	Taft 115/70 kV Transformer #2 Replacement	PG&E	Canceled
96	Taft-Maricopa 70 kV Line Reconductor	PG&E	May-21
97	Tesla 115 kV Capacity Increase	PG&E	Jun-16
98	Tesla-Newark 230 kV Path Upgrade	PG&E	Feb-19
99	Tulucay 230/60 kV Transformer No. 1 Capacity Increase	PG&E	Canceled
100	Vaca Dixon – Lakeville 230 kV Reconductoring	PG&E	Mar-19
101	Vierra 115 kV Looping Project	PG&E	Apr-21
102	Warnerville-Bellota 230 kV line reconductoring	PG&E	May-17
103	Watsonville Voltage Conversion	PG&E	Apr-20
104	Weber 230/60 kV Transformer Nos. 2 and 2A Replacement	PG&E	Jun-16
105	Weber-French Camp 60 kV Line Reconfiguration	PG&E	Mar-16
106	West Point – Valley Springs 60 kV Line	PG&E	Jun-19
107	West Point – Valley Springs 60 kV Line Project (Second Line)	PG&E	Canceled
108	Wheeler Ridge Voltage Support	PG&E	May-20
109	Wheeler Ridge-Weedpatch 70 kV Line Reconductor	PG&E	May-18
110	Wilson 115 kV Area Reinforcement	PG&E	May-19

No	Project	PTO	Expected In-Service Date
111	Wilson-Le Grand 115 kV line reconductoring	PG&E	Dec-20
112	Woodward 115 kV Reinforcement	PG&E	Canceled
113	2nd Escondido-San Marcos 69 kV T/L	SDG&E	Jan-20
114	2nd Pomerado - Poway 69kV Circuit	SDG&E	Jun-18
115	Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously approved New Sycamore - Bernardo 69 kV line)	SDG&E	Jun-17
116	Miguel 500 kV Voltage Support	SDG&E	Jun-17
117	Miramar-Mesa Rim 69 kV System Reconfiguration	SDG&E	Jun-18
118	Mission Bank #51 and #52 replacement	SDG&E	Jun-18
119	Mission-Penasquitos 230 kV Circuit	SDG&E	Jun-19
120	Reconductor TL663, Mission-Kearny	SDG&E	Nov-17
121	Reconductor TL676, Mission-Mesa Heights	SDG&E	Feb-17
122	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	Oct-21
123	Rose Canyon-La Jolia 69 kV T/L	SDG&E	Jun-18
124	Sweetwater Reliability Enhancement	SDG&E	Jun-17
125	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	Jun-17
126	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Dec-19

No	Project	PTO	Expected In-Service Date
127	TL633 Bernardo-Rancho Carmel Reconductor	SDG&E	Jun-17
128	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Jun-18
129	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	Jun-21
130	TL690A, San Luis Rey-Oceanside Tap	SDG&E	Jun-17
131	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	Feb-21
132	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	Jan-15
133	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Jun-18
134	TL 13820, Sycamore-Chicarita Reconductor	SDG&E	Jun-17
135	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	Jun-18
136	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	Jun-15
137	Upgrade Los Coches 138/69 kV bank 51	SDG&E	Jun-15
138	Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Swap	SCE	May-17
139	Kramer Reactors	SCE	Jun-17
140	Laguna Bell Corridor Upgrade	SCE	Dec-20
141	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-17

No	Project	PTO	Expected In-Service Date
142	Method of Service for Wildlife 230/66 kV Substation	SCE	Jan-20
143	Path 42 and Devers – Mirage 230 kV Upgrades	SCE	Jun-16
144	Victor Loop-in	SCE	Dec-16
145	Trans Bay Cable Dead Bus Energization Project	TransBay Cable	May-16
146	CT Upgrade at Mead-Pahrump 230 kV Terminal	VEA	Dec-15

Table 7.1-2: Status of previously approved projects costing $50M or more

No	Project	PTO	Expected In-Service Date
1	Delaney-Colorado River 500 kV line	DCR Transmission	May-20
2	Suncrest 300 Mvar dynamic reactive device	NEET West	Jun-17
3	Atlantic-Placer 115 kV Line	PG&E	Apr-24
4	Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project	PG&E	Jun-23
5	Embarcadero-Potrero 230 kV Transmission Project	PG&E	Jul-16
6	Fresno Reliability Transmission Projects	PG&E	Mar-16
7	Gates #2 500/230 kV Transformer Addition	PG&E	May-18
8	Gates-Gregg 230 kV Line[155]	PG&E/MAT	Apr-20
9	Kern PP 115 kV Area Reinforcement	PG&E	Dec-20
10	Lockeford-Lodi Area 230 kV Development	PG&E	Dec-24
11	Martin 230 kV Bus Extension	PG&E	Dec-21
12	Midway-Andrew 230 kV Project	PG&E	May-25
13	Midway – Kern PP #2 230 kV Line	PG&E	Jun-21
14	New Bridgeville – Garberville No. 2 115 kV Line	PG&E	Jan-24
15	Northern Fresno 115 kV Area Reinforcement	PG&E	Sep-20
16	South of Palermo 115 kV Reinforcement Project	PG&E	Apr-22

[155] During its 2012-2013 transmission planning cycle, the ISO approved the Gates-Gregg 230 kV project as a double-circuit tower line with a single conductor to be strung initially. Through the solicitation process the project has been awarded to PG&E, MidAmerican Transmission, and Citizens Energy (the “Gates-Gregg project sponsors”). At this time the ISO has not approved the need for the second circuit; however the ISO noted in the 2013-2014Transmission Plan that it would be prudent for the Gates-Gregg project sponsors to seek permits for the second circuit in parallel with or as a part of their permitting for the currently-approved Gates-Gregg project.

No	Project	PTO	Expected In-Service Date
17	Vaca – Davis Voltage Conversion Project	PG&E	Feb-21
18	Wheeler Ridge Junction Substation	PG&E	May-20
19	Additional 450 Mvar of dynamic reactive support at San Luis Rey (i.e., two 225 Mvar synchronous condensers)	SDG&E	Jun-16
20	Artesian 230 kV Sub & loop-in TL23051	SDG&E	Mar-20
21	Bay Boulevard 230/69 kV Substation Project	SDG&E	Dec-16
22	Imperial Valley Flow Controller (IV B2BDC or Phase Shifting Transformer)	SDG&E	May-17
23	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	Jun-19
24	Sycamore-Penasquitos 230 kV Line	SDG&E	May-17
25	South Orange County Dynamic Reactive Support – San Onofre (now 1-225 Mvar synchronous condenser)[156]	SDG&E	Dec-17
26	South Orange County Dynamic Reactive Support - Santiago Synchronous Condenser - SCE's component (1-225 Mvar synchronous condenser)[157]	SCE	Dec-18
27	Alberhill 500 kV Method of Service	SCE	Oct-18

[156] The South Orange County Dynamic Reactive Support project was initially approved in the 2012-2013 Transmission Plan and initially awarded to SDG&E as it was expected to be located in the San Onofre area in SDG&E's service territory. In 2014, the project was split due to siting issues, replacing two synchronous condensers at a single site with instead locating one at the San Onofre substation and the second being awarded to SCE and located in the Santiago substation. This was reflected in system modeling and noted on Page 159 and in Table 3.2.6 in the 2014-2015 Transmission Plan, but Table 7.1-2 (line number 5) was inadvertently not updated to reflect the change.
[157] Refer to footnote 157.

No	Project	PTO	Expected In-Service Date
28	Harry Allen-Eldorado 500 kV transmission project	DesertLink LLC	May-20
29	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	Dec-19
30	Lugo-Mohave series capacitor upgrade	SCE	Dec-19
31	Mesa 500 kV Substation	SCE	Dec-20
32	Tehachapi Transmission Project	SCE	Oct-16

7.2 Transmission Projects found to be needed in the 2015-2016 Planning Cycle

In the 2015-2016 transmission planning process, the ISO determined that 15 transmission projects were needed to mitigate identified reliability concerns, no policy-driven projects were needed to meet the 33 percent RPS and no economic-driven project was found to be needed. The summary of these transmission projects are in the tables below. One of the projects found to be needed – the Lugo-Victorville 500 kV upgrade - is not being recommended for approval at this time, as coordination with LADWP will take place before approval is recommended.

A list of projects that came through the 2015 Request Window can be found in Appendix G

Table 7.2-1: New reliability projects found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	May-21	$20 M
2	Bellota 230 kV Substation Shunt Reactor	PG&E	Dec-20	$13-19 M
3	Cottonwood 115 kV Substation Shunt Reactor	PG&E	Dec-19	$15-19 M
4	Delevan 230 kV Substation Shunt Reactor	PG&E	Dec-20	$19-28 M
5	Ignacio 230 kV Reactor	PG&E	Dec-20	$23-35 M
6	Los Esteros 230 kV Substation Shunt Reactor	PG&E	Dec-20	$24-36 M
7	Wilson 115 kV SVC	PG&E	Dec-20	$35-45 M
8	15 Mvar Capacitor at Basilone Substation	SDG&E	Jun-16	$1.5-2 M
9	30 Mvar Capacitor at Pendleton Substation	SDG&E	Jun-17	$2-3 M
10	Bay Boulevard Third 230/69 kV Transformer Bank	SDG&E	Jun-18	$13-18 M
11	Reconductor TL 605 Silvergate – Urban	SDG&E	Jun-18	$5-6 M

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
12	Second Miguel – Bay Boulevard 230 kV Transmission Circuit	SDG&E	Jun-19	$20-45 M
13	TL600: “Mesa Heights Loop-in + Reconductor	SDG&E	Jun-18	$15-20 M
14	Eagle Mountain Shunt Reactors	SCE	Dec-18	$10 M
15	Lugo – Victorville 500 kV Upgrade (SCE portion)[158]	SCE		

[158] The Lugo-Victorville 500 kV upgrade was found to be needed but is not being recommended for approval at this time, as coordination with LADWP will take place before approval is recommended.

Table 7.2-2: New policy-driven transmission project found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
	No policy-driven projects identified in the 2015-2016 Transmission Plan			

Table 7.2-3: New economic-driven transmission project found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
	No economic-driven projects identified in the 2015-2016 Transmission Plan			

7.3 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2015-2016 Transmission Plan. In some areas, such as the LA Basin, this reliance has been overt through the testing of various resource portfolios being considered for procurement, and in other areas less direct through reliance on demand side resources such as additional achievable energy efficiency.

This section summarizes the reliance on preferred resources in the 2015-2016 Transmission Plan:

1. Additional achievable energy efficiency (AAEE) in PG&E service territory

   Sensitivity studies were conducted as a part of the 2015-2016 transmission planning process to assess the impact of the AAEE included in the base case for the local planning area assessments. In general, the results from the sensitivity studies without AAEE exhibited worsening of the reliability concerns identified in the base case (base case assumptions can be found in Section 2.3). However, in some areas, additional reliability concerns were identified if the AAEE does not materialize as included in the base case assumptions. No mitigation solutions were recommended for these incremental reliability concerns as these were not identified in the analysis of the base case – thus the AAEE is being relied upon to materialize to maintain compliance with planning standards. The results of the sensitivity studies are included in Appendix B within each of the local planning area sections. The conditions where the AAEE is being relied upon are:

   - The Ignacio – Mare Island #2 115kV line will be normally overloaded in 2025 in the No AAEE scenario. Load growth is seen in the area between 2017 and 2022, which will result in the overload of the 115kV line in the absence of AAEE. Several other overloads on lines that were seen to be overloaded in the base line scenario were seen to have worsened in the scenario that did not model the AAEE in the base case. (North Coast & North Bay area)
   - One new base case type P1 thermal overload was identified on Cottonwood-Anderson 60 kV line in the North Valley area from the sensitivity studies in No-AAEE case. (North Valley)
   - One new base case type P1 thermal overload was identified on the Palermo-Big Bend 60 kV Line in the North Valley area from the sensitivity studies in No-AAEE case. (North Valley)
   - One new overload in the Heavy Renewables case the Cottonwood-Benton 60kV Line for P2 type contingencies. Also, the contingency loading on most of the facilities overloaded in baseline scenario increased by about 10% to 20% in the no-AAEE case. Also, some facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE case. (North Valley)
   - For P6 contingencies there were 12 lines that are more heavily loaded in the no-AAEE case, with up to 20% higher loadings. (North Valley)
   - For P7 type contingencies the contingency loading on most of the facilities overloaded in the baseline scenario in the North Valley area increased by about

10% to 20% in the no-AAEE scenario. Also, some facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE scenario. (North Valley)

- For P6 type contingency results, there were five new substations including Anderson 60kV, Big Bend 115kV, Chester 60kV, Diryvlle 60kV and Grizzly 60kV which have voltages lower than 0.9 pu in the no-AAEE cases. (North Valley)
- In the Sacramento area, no new P0 thermal overloads were identified. One new base case type P1 thermal overload was identified on Cortina 230/60 kV Bank in the Central Valley area (Sacramento Area) from the sensitivity studies in No-AAEE cases. (Central Valley)
- In the Sierra area, no new P0 thermal overloads were identified. Three new base case type P6 thermal overloads were identified on East Nicolaus 115/60 kV Bank, Drum-Dutch Flat #1 115kV Line and Horseshoe-Newcastle #2115kV Line in the Sierra area from the sensitivity studies in No-AAEE. Also, the contingency loading on most of the facilities overloaded in baseline scenario increased by about 10% to 20% in the no-AAEE scenario. Also, some facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE case. (Central Valley)
- In the Stockton area, no new P0 thermal overloads were identified. No further new reliability concerns were identified in Stockton area from the sensitivity studies. However, the contingency loading on some of the facilities overloaded in baseline scenario increased by more than 10% in the no-AAEE case. (Central Valley)
- For P6 type contingency results there were five new substations including Cortina 115 kV, Drake 60 kV, Drum 60 kV, Flint 115 kV and Goldhill 115 kV that would result in voltage collapse in the no-AAEE cases. (Central Valley)
- In the Stanislaus area, no new P0 thermal overloads were identified. One new base case type P7 thermal overload was identified on Stanislaus-Melone SW Station-Manteca #3 115 kV Line in the Stanislaus area in the No-AAEE case. Also, the contingency loading on most of the facilities overloaded in baseline scenario increased by about 10% to 20% in the no-AAEE scenario. Also, some facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE scenario. (Central Valley)
- In the Oakland area, new thermal overloads were identified on Moraga-Station X and Moraga-Claremont 115 kV lines in the no-AAEE scenario. Also, the contingency loading on the East Shore 230/115 kV transformer increased by about 6% in the no-AAEE scenario. One new voltage deviation concern at Owens Brockway 115 kV station was also identified in the no-AAEE scenario. (Greater Bay Area)
- In the Metcalf 115 kV system, new thermal overloads were identified on Metcalf 230/115 kV banks and on the Trimble-San Jose 115 kV line in the no-AAEE scenario. Also, the contingency loading on most of the facilities overloaded in baseline scenario increased by about 10% in the no-AAEE scenario. Also, some

facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE scenario. (Greater Bay Area)

- In Palo Alto area, new thermal overloads were identified on the San Mateo-Belmont and Ravenswood-Cooley Landing 115 kV lines in the no-AAEE scenario. Also, the contingency loading on some of the facilities overloaded in baseline scenario increased by about 10% or less in the no-AAEE scenario. (Greater Bay Area)
- In the Peninsula 60 kV system, new thermal overloads were identified on the Jefferson-Stanford, Bair-Colley Landing and San Mateo-Hillsdale Jct. 60 kV lines in the no-AAEE scenario. Also, the contingency loading on most of the facilities overloaded in baseline scenario increased by more than 10% in the no-AAEE scenario. (Greater Bay Area)
- In Pittsburg-Moraga 115 kV system, a new thermal overload was identified on the Sobrante-Moraga 115 kV line in the no-AAEE scenario. Also, the contingency loading on most of the facilities overloaded in baseline scenario increased by about 10% to 20% in the no-AAEE scenario. Also, some facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE scenario. (Greater Bay Area)
- For P2 contingencies the loading on the Panoche-Oro Loma 115kV line worsened as high as 15% in the No AAEE case. (Fresno Area)
- For P2 contingencies the Merced-Merced Falls 70kV line loading is also worse in the no-AAEE case by about 10%. Herndon-Bullard 115kV lines are loading worse in the no-AAEE case about 10% higher. (Fresno Area)
- For P2 contingencies the Herndon-Manchester 115kV line is loading up higher in the no-AAEE with about 8% higher loading. (Fresno Area)
- For P2 contingencies the GWF-Kingsburg 115kV line is also more heavily loaded in the no-AAEE with a roughly 6% increase. (Fresno Area)
- For P6 contingencies there were 19 lines that are more heavily loaded in the no-AAEE cases; up to 15% higher loadings. (Fresno Area)
- Certain 115kV Jct voltages are slightly lower in the P1 type contingency scenario in the no-AAEE case. (Fresno Area)
- For P2 contingencies there were eight 115kV substations which the voltage was below 0.9 in the Heavy Renewables case. (Fresno Area)
- Chowchilla 115kV substation had voltages below 0.9 for a P3 type contingency in the no-AAEE cases. (Fresno Area)
- For P6 type contingency results there were seven new substations including Dairyland 115kV, Danish 115kV, West Fresno 115kV, California Ave 115kV, Santa Rita 70kV, Mariposa 70kV, Dos Palos 70kV which have voltages lower than 0.9 pu in the no-AAEE cases. (Fresno Area)
- The Kern Power 115/230 #5 kV Bank was thermally loaded at 104% with no-AAEE following Category P6 Kern PP230/115 #3 & #5 kV Bank contingency condition. (Kern area)

- The Midway 230/115 #1 kV Bank was thermally loaded at 107% with no-AAEE following the Category P6 Midway 230/115 #2 & #3 kV Bank contingency. (Kern area)
- The Midway 230/115 #2 kV Bank was thermally loaded at 107% with no-AAEE following the Category P6 Midway 230/115 #1 & #3 kV Bank contingency. (Kern area)
- The Midway 230/115 #3 kV Bank was thermally loaded at 104% with no-AAEE following the Category P6 Midway 230/115 #1 & #2 kV Bank contingency. (Kern area)
- The Midway-Cymric #1 115 kV Line experienced 111% loading with no-AAEE following the Category P6 Midway-Taft and Taft-Chalk Cliff 115 kV Lines contingency. (Kern area)
- The Midway-Oxybvh Tap #1 115 kV Line experienced 117% loading with no-AAEE following Category P6 Taft-Chalk Cliff and Midsun-Midway 115 kV Lines.
- The Coburn 230/60 kV #2 Bank was thermally loaded at 103% following a Category P3 contingency condition with no-AAEE following the loss of the King City Peaker Generator and Coburn 230/60 kV #1 Bank. (Central Coast & Los Padre area)
- The Green Valley 115 kV system as well as sections of the Green Valley-Watsonville-Crazy Horse 115 kV facility experienced thermal overloads up to 18% following Category P6 Moss Landing-Green Valley #1 & 2 115 kV Lines with no-AAEE study scenarios. (Central Coast & Los Padre area)
- The Prundale Jct 1-Moss Landing 115 kV #1 Line was thermally loaded at 103% with no-AAEE following the P6 contingency of the loss of Moss Landing-Salinas #1 & 2 kV Lines (Category P6). (Central Coast & Los Padre area)

2. A sensitivity study was conducted in the East Bay area of the Greater Bay Area to assess the reliance on aging generation. The assessment identified potential mitigation alternatives if the existing local generation were to retire, The potential alternatives assessed were:
   - Generation only alternative - that would require 200 MW of local generation either through repowering of existing generation or new generation
   - Transmission only alternative – that would require a new 230 kV transmission line into the area.
   - Substation upgrades in combination of preferred resources and a local SPS.

   The ISO will continue to assess in the 2016-2017 transmission planning process the transmission, generation or non-transmission alternatives to address the needs of the area.

3. Preferred resources in the LA Basin / San Diego area

   Similar to the PG&E area discussed above, AAEE assumptions were modeled and utilized in the reliability assessment of these two areas; 1,288 MW in the LA Basin and 401 MW in the San Diego area. Grid connected distributed generation amounting to 403 MW in the LA Basin and 143 MW in the San Diego area was also modeled based on the CPUC-provided 33 percent renewable generation portfolios. In addition, the ISO assumed 37.9 MW of behind-the-meter (BTM) solar photovoltaics (PV), 28.6 MW of ice-based storage (permanent load shift), 135.1 MW BTM energy storage, 100 MW in front of (IFO) meter energy storage, 124.2 MW of additional energy efficiency, and 5 MW of new demand response as part of the LTPP local capacity long-term procurement that was approved by the CPUC for the LA Basin. For the San Diego area, the ISO assumed 150 MW for BTM energy storage, 40 MW of additional energy efficiency, and 60 MW of demand response for LTPP preferred resources and energy storage assumptions. Existing demand response, in the amount of 190 MW, was also assumed to be repurposed with the necessary operational characteristics (i.e., 20-minute response) for use under overlapping contingency conditions. This amount of existing demand response is considered a baseline assumption to align with the CPUC LTPP Track 4 study assumptions. The above preferred resource amounts are in addition to the behind-the-meter solar, energy efficiency and demand response amounts that are embedded in the CPUC load forecast.

As discussed in more detail in Appendix B, these resources were used to mitigate the reliability issues identified below, particularly after the retirement of OTC generation in southern California:

- Mesa–Laguna Bell #1 230 kV line thermal overload due to N-2 and N-1-1 outages
- Mesa–Redondo 230 kV line thermal overload due to N-1-1 outages
- Sylmar–Pardee 230 kV line overload due to N-1-1 outages
- Serrano–Villa Park 230 kV line overload due to N-1-1 outages
- Serrano 500/230 kV transformer overload due to N-1-1 outages
- Voltage instability and transient voltage deviation due to N-1-1 outages (SRPL & SWPL)
- Pomerado-Sycamore 69 kV #1 or #2 line thermal overload due to N-1 line outage
- Old Town-Vine Sub 69 kV line thermal overload due to N-1-1 outages
- Miguel Tap-Miguel 69 kV line thermal overload due to N-1-1 outages
- Ash-Ash Tap 69 kV line thermal overload due to N-2 outages
- Naval Station Metering-Sweetwater 69 kV line thermal overload due to N-1-1 outages
- Ellis-Johanna 230 kV line thermal overload due to N-1-1 outages
- Ellis-Santiago 230 kV line thermal overload due to N-1-1 outages

As well, a long-term local reliability issue was identified in the LA Basin and San Diego area that does not require immediate action to mitigate. Additional repurposing of existing demand response in the LA Basin, as well as additional procurement of preferred resources and energy storage in these two areas are being considered as potential mitigation options, along with minor transmission upgrades, for meeting this long-term local reliability need in the LA Basin and San Diego area.

7.4 Competitive Solicitation for New Transmission Elements

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the ISO selects a regional transmission solution to meet an identified need in one of the three aforementioned categories that constitutes an upgrade to or addition on an existing participating transmission owner facility, the construction or ownership of facilities on a participating transmission owner's right-of-way, or the construction or ownership of facilities within an existing participating transmission owner's substation, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner.

No regional transmission solutions recommended for approval in this 2015-2016 transmission are eligible for competitive solicitation.

7.5 Capital Program Impacts on Transmission High Voltage Access Charge

7.5.1 Background

The ISO is continuing to update and enhance its internal tool used to estimate future trends in the High Voltage Transmission Access Charge (HV TAC) to provide an estimation of the impact of the capital projects identified in the 10 Year Transmission Plan on the access charge. This tool was first used in developing results documented in the 2012-2013 transmission plan, and the model itself was released to stakeholders for review and comment in October 2013. Additional upgrades to the model have been made reflecting certain of the comments received from stakeholders.

The final and actual determination of the High Voltage Transmission Access Charge is the result of numerous and extremely complex revenue requirement and cost allocation exercises conducted by the ISO's participating transmission owners, with the costs being subject to FERC regulatory approval before being factored in the determination of a specific HV TAC rate recovered by the ISO from ISO customers. In seeking to provide estimates of the impacts on future access rates, we recognized it was neither helpful nor efficient to attempt to duplicate that modeling in all its detail. Rather, an excessive layer of complexity in the model would make a high level understanding of the relative impacts of different cost drivers more difficult to review and understand. However, the cost components need to be considered in sufficient detail that the relative impacts of different decisions can be reasonably estimated.

The tool is based on the fundamental cost-of-service models employed by the participating transmission owners, with a level of detail necessary to adequately estimate the impacts of changes in capital spending, operating costs, and so forth. Cost calculations included costs associated with existing rate base and operating expenses, and, for new capital costs, tax, return, depreciation, and an operations and maintenance (O&M) component.

The model is not a detailed calculation of any individual participating transmission owner's revenue requirement – parties interested in that information should contact the specific participating transmission owner directly. For example, certain PTOs' existing rate bases were slightly adjusted to "true up" with a single rate of return and tax treatment to the actual initial revenue requirement incorporated into the TAC rate, recognizing that individual capital facilities are not subject to the identical return and tax treatment. This "true up" also accounts for construction funds already spent which the utility has received FERC approval to earn return and interest expense upon prior to the subject facilities being completed.

The tool does not attempt to break out rate impacts by category, e.g. reliability-driven, policy-driven and economic-driven categories used by the ISO to develop the comprehensive plan in its structured analysis, or by utility. The ISO is concerned that a breakout by ISO tariff category can create industry confusion, as, for example, a "policy-driven" project may have also addressed the need met by a previously identified reliability-driven project that was subsequently replaced by the broader policy-driven project. While the categorization is appropriately as a "policy-driven" project for transmission planning tariff purposes, it can lead to misunderstandings of the cost implications of achieving certain policies – as the entire replacement project is attributed to "policy". Further, certain high level cost assumptions are appropriate on an ISO-wide basis, but not necessarily appropriate to apply to any one specific utility.

7.5.2 Input Assumptions and Analysis

The ISO's rate impact model is based on publicly available information or ISO assumptions as set out below, with clarifications provided by several utilities.

Each PTO's most recent FERC revenue requirement approvals are relied upon for revenue requirement consisting of capital related costs and operating expense requirements, as well as plant and depreciation balances. Single tax and financing structures for each PTO are utilized, which necessitates some adjustments to rate base. These adjustments are "back-calculated" such that each PTO's total revenue requirement aligned with the filing.

Total existing costs are then adjusted on a going forward basis through escalation of O&M costs, adjustments for capital maintenance costs, and depreciation impacts.

Escalation of O&M costs and capital maintenance are applied on a single basis based on North American industry-wide experience. A 2% escalation of O&M costs was used, and capital maintenance of 2% of gross plant is applied. These estimates, and in particular, the capital maintenance and other capital costs which do not require ISO approval were vetted with transmission owners accounting for the bulk of the Transmission Access Charge. While these are not precise, these approximations are considered reasonable to determine a base upon which to assess the impact of the ISO's capital program on the HV TAC.

The tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

Draft Transmission Plan Editorial Note:

An estimate of future HV TAC rates is not available at this time. The ISO is currently in the process of updating the "starting point" for the HV TAC estimating tool to January 1, 2016. As well, the cost and timing of previously approved transmission is being reviewed. This is especially important as certain large projects can be capitalized in stages and also expenditures on projects that are receiving "CWIP-in-rate base" incentive treatment can impact rates before capitalization. Correct treatment of these issues is necessary to avoid double counting forecast impacts on rates.

Recognizing the interest stakeholders have in this analysis, the ISO will seek to complete the analysis such that draft results can be presented at the February 2016 stakeholder meeting.