2016-2017 TRANSMISSION PLAN

California ISO

March 8, 2017

REVISED DRAFT

Foreward to REVISED DRAFT 2016-2017 Transmission Plan

This revised draft transmission plan reflects a number of changes from the draft plan released on January 31, 2017. To assist our stakeholders following the transmission plan cycle, we have summarized a number of those changes:

- The model estimating the impact of the transmission plan on the ISO's High Voltage TAC has been updated and the results added to the model.
- Documentation of special study results that were not available in January have been added to sections 6.1 (Risks of early economic retirement of gas fleet), 6.4 (50 Percent Renewable Generation and Interregional Coordination) and 6.5. (Large scale storage benefits)
- The recommendation for one additional previously approved transmission project in the PG&E service area that is recommended to be placed on hold has been modified to support completion of siting and engineering activities.

A number of clarifications and edits have also been added throughout the plan to address other stakeholder comments.

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Executive Summary

The California Independent System Operator Corporation's 2016-2017 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.

Transmission planning issues affecting the ISO's annual transmission plans have changed materially over recent years. This year's transmission plan reflects those changes and also reflects the particular point in time the California industry is at in a number of fronts and demonstrates particular trends emerging since the ISO revised its transmission planning process in 2010.

- The progress past transmission plans made in addressing reliability issues is demonstrated in the steady decline in reliability projects over the last several years, especially since the the spike in infrastructure projects required to address the transition away from coastal once-through cooling gas-fired generation and the early retirement of the San Onofre Nuclear Generating Station;
- Consistently declining load forecasts across the entire forecast period – especially for the one-in-ten peak load forecasts - as well as higher than anticipated development of behind the meter solar photovoltaic generation have put additional downward pressure on load-driven transmission projects, leading to re-evaluation of the need for certain previously approved upgrades that were predominantly load driven;
- Transmission needs to achieve the state's 33 percent renewable generation goals by 2020 have largely been approved and are moving forward. New policy driven transmission projects to achieve the state's 50 percent renewable energy goal by 2030 will not be identified until policy direction is set on the incremental renewable portfolio (technology, geographic location) needed to meet this goal. This year's plan includes some preliminary 50 percent renewable energy study scenarios that should help inform the final policy direction; and,
- Opportunities for ISO regional economic-driven development has been explored through a number of planning cycles, with a number of projects initiated in past cycles and no new regional economic driven projects identified in this planning cycle. Future development of economic driven projects may be more dependent on the interregional planning processes now in place.

The 2016-2017 Transmission Plan has therefore continued the trend of a declining amount of new capital transmission projects being identified – to the lowest level of new capital since the planning process was revised - and yet significantly 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.

Other issues are emerging that may increase the need for further reinforcement in the future as the impacts of industry transformation are more fully explored. The ISO's special studies undertaken in the planning process help supplement the forward thinking on emerging issues such as consideration of voltage control issues crossing the transmission and distribution boundaries, the broader effects of distributed energy resources on the planning and operation of the system, and the transmission grid implications of the renewable integration needs. These issues will require new study approaches and coordination with the utilities distribution planning processes.

Key analytic components of the plan include the following:

- continuing to review the adequacy of previously approved transmission needed to support meeting the 33 percent RPS goals, which using renewable resource portfolios produced through a process established by the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) to identify 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;
- performing economic analysis that considers whether transmission upgrades or additions could provide additional ratepayer benefits; and
- continuing the coordination with state agencies on demand side forecast assumptions as well as supply side potential.

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. However, given the paucity of needed reliability solutions in this year's plan, these efforts are predominantly reflected in the special studies analysis.

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

- The ISO identified 2 transmission projects as needed to maintain transmission system reliability and is recommending approval of those projects which have an estimated cost of approximately $24 million (not including the LADWP's portion of a joint project). The ISO

[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.

has also identified and recommended a number of refinements to special protection systems and protection upgrades;

- As a part of the 2016-2017 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 were found to be no longer required and are recommended to be cancelled. Further, a number of other previously approved projects in the PG&E service territory have been identified as requiring further review in the 2017-2018 planning cycle;
- The need and viability of one previously approved transmission project in the SDG&E area has been impacted by the siting decision of the CPUC in approving SDG&E's application for a CPCN for the Sycamore-Penasquitos project, resulting in the need to review the project in next year's transmission plan;
- 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 through the ISO's competitive solicitation process.

Special studies focusing on emerging grid transition and renewable integration issues expanded in the 2016-2017 Transmission Plan from previous years, including the following:

- A refocused effort studying gas pipeline and electricity coordination given the evolving role of gas fired generation in southern California building on the analysis conducted in the 2015-

2016 transmission planning cycle and the Aliso Canyon Risk Assessment Technical Report[2] that was prepared and posted in April 2016 by the Reliability Task Force;

- An exploratory study of the capabilities of the ISO grid to accommodate renewable generation resources for meeting a 50 percent renewables goal. Note that this is an "informational only" study to assist industry in considering options in moving beyond 33 percent. This special study is also the foundation for the ISO's participation in the first biennial interregional coordination process established by the ISO and the ISO's neighboring planning regions in response to FERC Order No. 1000;
- A further analysis of the benefits of large scale energy storage in managing oversupply periods in moving beyond 33 percent; this study explored a 50 percent renewables portfolio standard scenario and also considered the possible locational benefits of a handful of known potential large scale pumped storage sites;
- Continuing frequency response study efforts through improved modeling of generation – building on the results of the frequency response analysis conducted in last year's cycle and the observed gap between actual measured performance and study results.
- Preliminary analysis of the necessary characteristics for slow response resources in local capacity areas to be relied upon for local resource adequacy capacity.
- A review of the risks to system reliability of existing gas-fired generation retirements triggered by a response to economic conditions, both from an overall supply perspective as well as a transmission grid perspective.

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.

[2] http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf

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 2016-2017 planning cycle, for example, began in January 2016 and concluded in March 2017. 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

The 2016-2017 planning assumptions and scenarios were developed through the annual agency coordination 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 2016-2017 transmission planning process were communicated via an assigned commissioner's ruling in the 2014 LTPP.[3] These assumptions were further vetted by stakeholders through the ISO's stakeholder process which resulted in this year's study plan.[4] 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 for moving beyond 33 percent.

Key Reliability Study Findings

During the 2016-2017 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. This plan proposes approving 2 reliability-driven transmission projects, representing an investment of approximately $24 million in infrastructure additions to the ISO controlled grid. Both of these projects are in the Southern California Edison area and are not eligible for the ISO's competitive solicitation process.

Renewables Portfolio Standard Policy-driven Transmission Assessment

The ISO's policy driven transmission framework has been in place for a number of years, beginning with its introduction into the ISO's planning process in 2010 and refined through changes driven by FERC Order No. 1000. 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 past 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.

[3] Rulemaking 13-12-010 "Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for use in the California Independent System Operator's 2016-17 Transmission Planning Process and Future Commission Proceedings" on May 17, 2016.

[4] http://www.caiso.com/Documents/Final2016-2017StudyPlan.pdf

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.

The CPUC and CEC provided policy direction the ISO regarding renewable generation portfolios for 2016-2017 policy-driven transmission planning purposes via a letter dated June 13, 2016. In that communication, the CPUC and CEC recommended that the ISO re-use the "33% 2025 Mid AAEE" RPS portfolio used in the 2015-16 TPP studies, as the base case renewable resource portfolio in the 2016-17 TPP studies[5]. Because these portfolios were already studied in the 2015-2016 TPP, the ISO only needed to reassess in the 2016-2017 TPP those portions of the system that had material changes to their transmission plans that would affect the ability to deliver renewable generation in the portfolio. After reviewing the changes to the planning models from the 2015-2016 TPP to the 2016-2017 TPP, the ISO determined that material changes had been made to the transmission system only in the Imperial Valley area, so the ISO needed to reassess this area.

The ISO performed the reliability assessment described in chapter 2 on base cases that modeled the renewable portfolio referred to above, so the powerflow and stability analysis performed as part of the reliability assessment also serve as a policy-driven need assessment from a powerflow and stability reliability perspective. Therefore, the ISO only needed to perform a generation deliverability analysis of the Imperial Valley to complete the 2016-2017 TPP policy-driven need assessment. The ISO is has not identified the need for additional transmission solutions for policy purposes.

A summary of the various transmission elements of the 2016-2017 Transmission Plan for supporting California's renewables portfolio standard in addition to providing other reliability benefits is shown in Table 1. 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.

5 http://www.caiso.com/Documents/2016-2017RenewablePortfoliosTransmittalLetter.pdf

Table 1: Elements of 2016-2017 ISO Transmission Plan Supporting 33% Renewable Energy Goals

Transmission Facility	Online
Transmission Facilities Approved, Permitted and Under Construction	
Tehachapi Transmission Project	2016 - completed
Path 42 and Devers-Mirage 230 kV Upgrades	2016 - completed
West of Devers Reconductoring	2021
Sycamore – Penasquitos 230kV Line	2018
Additional Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
Borden Gregg Reconductoring	2018
Policy-Driven Transmission Elements Approved but not Permitted	
Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Swap	2018
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[6]
Lugo-Mohave series capacitors	2019
Additional Policy-Driven Transmission Elements Recommend for Approval	
None identified in 2016-2017 Transmission Plan	

[6] In service date to be revisited by project sponsor when Environmental Impact Report is completed.

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 2016-2017 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 10th planning year (2026). 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, high priority congestion areas or projects were selected for further assessment.

Considering the high priority studies, the ISO determined that there were no economic upgrade recommendations needed in this plan.

Non-Transmission Alternatives and Preferred Resources

As in past transmission planning cycles, the ISO has continued to make efforts to facilitate the use of preferred resources to meet local transmission system needs. Given the limited and specific new requirements for reinforcement identified in this year's transmission plan, there were few opportunities to consider additional preferred resource alternatives utilizing the ISO's proposed methodology[7] beyond those already included in the planning assumptions developed by the ISO and state agencies. To further support California's policy emphasis on the use of preferred resources,[8] the ISO has explored in this planning cycle:

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

[8] 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.

- conducted initial informational studies on the necessary characteristics for slow response demand response products to be capable of providing resource adequacy local capacity, and advanced the analysis of large energy storage; and,
- reviewed previously approved projects to consider where changing load forecasts and increases in preferred resource forecasts may enable transmission project cancelation or postponement.

Conclusions and Recommendations

The 2016-2017 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 2 transmission projects, estimated to cost a total of approximately $24 million, as needed to maintain the reliability of the ISO transmission system, meet the state's renewable energy mandate, and deliver material economic benefits. The ISO has also identified 13 smaller previously approved transmission projects that are recommended to be cancelled, and a number that require further evaluation in next year's planning cycle before applications proceed for construction permitting.

The additional "special" studies conducted in parallel with the transmission planning cycle provide additional clarity on issues that need to be considered in developing future transmission plans.

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. The plan also identifies non-transmission solutions that will be pursued in other venues to avoid building additional transmission facilities if possible. This document serves as the comprehensive transmission plan for the 2016-2017 planning cycle.

The ISO has prepared this plan in the larger context of supporting important energy and environmental policies and assisting the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system. In this regard, the transmission plan is somewhat of a bellwether of the changing demands placed on the transmission system and the broader range of conditions the transmission system will need to address and manage than in past transmission plans. The transition to a generation fleet with significantly increased renewables penetration and “duck curve” issues are generally first thought of predominantly as impacting the ramping needs and flexible generation requirements within the electricity market. Those same changes, however, have an even more pronounced impact on the transmission grid as flow patterns change – and change frequently through each day – from traditional patterns. These drive new thermal loading, stability, and voltage control issues. Further, the industry transformation is occurring rapidly and more quickly than originally anticipated, due in large part to the faster growth of behind-the-meter rooftop solar generation than previously forecast. At the same time, each year’s transmission plan is also a product of timing, reflecting heavily the particular status of various initiatives and industry changes in the year the plan is developed. The 2016-2017 Transmission Plan is heavily influenced by the success in past transmission planning cycles to address historical reliability issues as well as those triggered by more recent events, the progress made to meeting 33 RPS goals, and state agency forecasting efforts to adapt to new paradigms – particularly in the consideration of behind the meter generation.

Within this context, the transmission plan’s primary purpose is to identify needed transmission facilities based upon three main categories of transmission solutions: reliability; public policy; and economic needs. A transmission plan may also identify any 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.

Since implementing the current transmission planning process in 2010, the ISO has also considered and placed a great deal of emphasis on assessing non-transmission alternatives, both conventional generation and, in particular, preferred resources such as energy efficiency, demand response, renewable generating resources, and energy storage programs. Although the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades. Further, load modifying preferred resource assumptions incorporated into the load forecasts adopted through state energy agency activities provide an additional opportunity for preferred resources to address transmission needs.

The ISO identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria, and ISO transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2016-2017 planning cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to verify compliance with applicable NERC reliability standards. The ISO performed this analysis across a 10-year planning horizon and modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities ranging in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns including upgrading transmission infrastructure, implementing new operating procedures, 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, section 7.3 summarizes how preferred resources will address specific reliability needs. In addition, discussion throughout chapter 2 and Appendix B show the reliance on preferred resources to meet identified needs on an area-by-area study basis. In recommending solutions for identified needs, the ISO takes into account an array of considerations. Furthering the state's objectives of a cleaner future plays a major part in those considerations.

This transmission plan documents ISO analyses, results, and mitigation plans.[9] 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 transmission planning cycles, the focus of public policy analysis continues to be on planning to ensure achievement of California's renewable energy goals. The trajectory to achieving the 33 percent renewables portfolio standard set out in the state directive SBX1-2 has been largely established. As a result, the prior year's 33 percent renewable energy portfolios have not been modified. Efforts to establish state policy direction for resource planning to achieve the longer term renewable energy goal of 50 percent by 2030 set

[9] This document provides detail of all study results related to transmission planning activities. However, consistent with the changes made in the 2012/2013 transmission plan, the ISO has removed from this year's plan additional documentation necessary to demonstrate compliance with NERC and WECC standards but not affecting the transmission plan itself. The ISO has compiled this information in a separate document for future NERC/FERC audit purposes. In addition, detailed discussion of material that may constitute Critical Energy Infrastructure Information (CEII) is restricted to appendices that the ISO provides only consistent with CEII requirements. The publicly available portion of the transmission plan provides a high level, but meaningful, overview of the comprehensive transmission system needs without compromising CEII requirements.

out in SB 350 are underway, and the ISO anticipates that, at the earliest, direction will be incorporated into the 2017-2018 planning cycle, but more likely it will be incorporated into the 2018-2019 planning cycle. The policy-driven analysis in this cycle therefore continues to focus on confirming the effectiveness of the plans for achieving the 33 percent RPS goal.

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

In addition to undertaking the aforementioned analyses required by the tariff, the ISO has also pursued a number of additional "special studies" in parallel relating to issues emerging from the transformation of the California electricity grid. This helps the CAISO better prepare for future planning cycles. In the past, the focus was on meeting traditional electric system needs through a combination of conventional resources and incremental increases of non-conventional and preferred resources. The future the ISO is now considering is where the industry transformation is also fundamentally changing the nature of the needs the power system must meet. Preferred resources are expected to play a major role in both driving and addressing those new needs, and this will require a higher level of coordination among a much more diverse portfolio of solutions. The special studies the ISO has undertaken in this planning cycle, and the issues driving those studies, are discussed in the following sections and are listed below:

- Continuing frequency response study efforts through improved modeling
- Large scale storage benefits
- Slow response resources in local capacity areas
- Risks of early economic retirement of gas fleet
- Gas/electric reliability coordination
- 50 Percent Renewable Generation and Interregional Coordination

1.2 Impacts of the Increasing Pace of Industry Transformation

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – and use of coastal water for once-through-cooling at thermal generating stations continues to be phased out, the ISO, through its planning process, must address a growing range of considerations to ensure overall safe, reliable, and efficient operation.

Recent trends triggered directly or indirectly by the need to integrate increased quantities of renewable generation, including higher than previously expected levels of behind-the-meter solar generation, are producing new and more complex operating paradigms for which the ISO must consider in planning the grid. Increased renewable generation and state policies phasing out reliance on coastal waters for once-through cooling has accelerated the retirement of gas-fired generation in these areas. Further, the retirement of the San Onofre Nuclear Generating Station has materially affected California's generation fleet and the historical loading patterns on California's interconnected transmission network, as will the planned retirement of Diablo Canyon Nuclear Generating Station in 2024. These changes cumulatively drive increased reliance on the gas generation fleet and other resources for dynamic performance to support the operational needs of California's energy infrastructure. These changes, among others such as the issues associated with the Aliso Canyon gas storage facility have and will continue to increase the need for effective gas/electric coordination.

Coupled with the changing generation resource fleet inside California, the increased emphasis on regionalism as a means to manage more economic dispatch and maximize the benefits of renewable generation development is both changing the nature of interchange with the ISO's neighboring balancing authority areas and increasing the variability in flows on a more dynamic basis. The success of and growing participation in the ISO's energy imbalance market results in more dynamic import and export conditions.

Further, exploring an increased role for preferred resources to address both traditional and emerging needs poses new technical challenges. The grid is already being called upon to meet broader ranges of generating conditions and more frequent changes from one operating condition to another, as resources are committed and dispatched on a more frequent basis and with higher ramping rates and boundaries than in the past. This necessitates managing thermal, stability, and voltage limits constantly and across a broader range of operating conditions.

Also, this has led to the need for greater accuracy in planning studies, and in particular, to the special study initiative in this 2016-2017 planning cycle reviewing all generator models for use in dynamic stability studies and frequency response analysis. Please refer to section 6.2.

The significant amount of new renewable generation being added to the grid is also putting economic pressure on downsizing the existing gas-fired generation fleet. As generation owners are independently assessing market conditions and their own particular circumstances, the ISO has also undertaken preliminary analysis of potential risks to transmission system reliability if several similarly situated generators retire more or less simultaneously in a given area as well as to the overall ability to maintain adequate supply/demand balance. This special study looks more broadly than existing defined local capacity areas, and is discussed in section 6.1.

The combined effects of flat or declining gross load forecasts and reductions in the net load forecasts due to behind-the-meter generation continue to significantly impact the planning process. First, declining net peak loads have led to the review of several previously approved load growth-driven transmission projects, particularly in the PG&E area[10]. Also, the increasing variable loading on the transmission system is resulting in more widely varying voltage profiles, resulting

[10] Because most of PG&E's low voltage sub-transmission facilities are under ISO operational control, there are a relatively large number of previously approved small and substantially unrelated projects in the PG&E area that were predominantly load-growth driven. This enabled the ISO to conduct a more programmatic approach in reviewing those projects in the 2015-2016 transmission planning cycle and again in this planning cycle. In contrast, the ISO has focused on a more case-by-case basis on a smaller number of larger and more heavily inter-related projects in the SDG&E and SCE service areas mitigating the loss of the San Onofre Nuclear Generating Station and once-through-cooling thermal generation retirements.

in an increased need for reactive control devices to maintain acceptable system voltages. This is discussed in more detail in later sections.

Distributed Energy Resources Growth Scenarios and Impact on Transmission Planning

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.

The rapid acceleration of behind the meter rooftop solar generation installations has led to the need for interim consideration of the impacts of the pace of development. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted to a time outside of the traditional daily peak load period due to the amount of behind-the-meter solar PV generation. The CEC's California Energy Demand 2016-2026 Revised Forecast (CED 2015) states the following with respect to the impact of PV at the time of the forecast peak load:

> *"At some point, continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through CED 2015, since staff has not yet developed models to forecast hourly loads in the long term. Staff expects to develop this capability for the 2017 Integrated Energy Policy Report (2017 IEPR), and such an adjustment to PV peak impacts could significantly affect future peak forecasts.*[11]*"*

In this 2016-2017 TPP, the ISO used the CEC energy and demand forecast as the base scenario analysis for identifying new transmission system needs, as identified in section 4.11.1 of the Study Plan. As the ISO conducted sensitivities on a case by case basis and to comply with the NERC TPL-001-4 mandatory reliability standard, the ISO took into account – with the information available - the effect of the shift of peak loads described above and other forecasting uncertainties to develop sensitivity scenarios as needed as set out in section 4.11.2 of the Study Plan. The ISO relied on the results of the its reliability analysis of select sensitivity scenarios, such as distributed PV peak shift or no AAEE, to review previously-approved projects or procurement of existing resource adequacy resources to maintain local reliability. The ISO did not use the sensitivity scenarios to identify new needs triggering new transmission projects.

The ISO also continued to work with the CEC on the hourly load forecast issue. Through discussions with the ISO and the CPUC, the CEC will address this issue more effectively in the California Energy Demand Updated Forecast 2017-2027 (CEDU 2016), which will include a sensitivity scenario of the potential peak shift and the resulting impact on peak demand. The ISO believes that there is consensus that the results of the final adjusted managed peak scenario analysis will be used in TPP studies to review previously-approved projects or procurement of existing resource adequacy resources to maintain local reliability. In the future 2017-2018 transmission planning process, as in this year's planning cycle, the ISO will use the scenario analysis to review previously-approved projects or procurement of existing resource adequacy resources to maintain local reliability, and the ISO will not use the sensitivity scenario to identify new needs triggering new transmission projects given the preliminary nature of the approach taken in the CEDU 2016[12] [13]. Further refinements are also expected in the development of the California Energy Demand Forecast 2018-2028 (CED 2017) that the ISO will use in the 2018-2019 transmission planning process.

Renewable Integration Issues and Initiatives

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – the ISO must address a broader range of considerations to ensure overall safe, reliable and efficient operation. Specifically, the changing nature and location of generation resources and their diurnal output pattern plus evolving load profiles, change the resulting demands on the transmission system.

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

Renewable integration operational studies to date have focused primarily on the need for flexible resource capabilities. The genesis of the ISO's analysis of flexibility needs was the CPUC 2010-2011 Long-term Procurement Plan (LTPP) proceeding, docket R.10-05-006, wherein the ISO completed an initial study of renewable integration flexible generation requirements under a range of future scenarios, and the ISO has continued to analyze those issues. The ISO's analysis and resulting initiatives have led to a number of changes in market dispatch and annual resource adequacy program requirements, including incorporating ramping needs into the market dispatch and developing flexible resource adequacy capacity requirements in the state's resource adequacy program. In addition to those promising steps, the ISO has launched a stakeholder process to address a number of potential areas requiring refinements. Of particular concern from the infrastructure perspective is that "the flexible capacity showings to date indicate that the

[12] CEC California Energy Demand 2016-2026, Revised Electricity Forecast Volume1: Statewide Electricity Demand and Energy Efficiency, January 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf, Page 37.

[13] http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN214635_20161205T142341_California_Energy_Demand_Updated_Forecast.pd f

Page 7: "For CEDU 2016, staff developed a scenario analysis of potential peak shift and the resulting impact on peak demand served by utilities for the investor-owned utility planning (transmission access charge) areas for the managed forecast (that is, the mid baseline case combined with mid AAEE). The results of the final adjusted managed peak scenario analysis can be used by the California ISO in transmission planning process studies to review previously-approved projects or procurement of existing resource adequacy resources to maintain local reliability but should not be used in the identification of new needs triggering new transmission projects given the preliminary nature of the analysis.

flexible capacity product, as currently designed, is not sending the correct signal to ensure sufficient flexible capacity will be maintained long-term."[14]

The full future impact of the resource changes underway on the generation fleet are not fully understood at this time. A number of the special studies the ISO has undertaken in conjunction with the annual transmission planning cycle focus on dealing with the uncertainties the system is facing and enabling faster, informed response to future developments. These include the previously-mentioned studies focusing on the impacts of potential economic-driven early retirement of gas-fired generation and the review and upgrade of generation models used in frequency response studies. The latter builds on the frequency response analysis the ISO conducted in the 2015-2016 planning cycle, where the ISO observed that simulated results varied from real-time actual performance – necessitating a review of the generator models employed in ISO studies.

Further, the ISO is expanding and refining a special study focusing on the potential benefits of a large scale storage project, both to help managing system-wide ramping and flexibility needs and potentially provide locational transmission benefits to the transmission system.

The special studies in chapter 6 document these efforts. At this time, voltage control issues tend to be more localized, and the ISO is considering them throughout existing reliability analysis (see chapter 2).

Non-Transmission Alternatives and Preferred Resources

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

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 the ISO presented in a paper[15] issued on September 4, 2013, as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[16] — 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

[14] Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Supplemental Issue Paper: Expanding the Scope of the Initiative, November 8, 2016

Page 3: http://www.caiso.com/Documents/SupplementalIssuePaper-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf

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

[16] To be precise, the term "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 ISO uses the term more generally here consistent with the preference for certain resources in lieu conventional generation.

the ISO could apply annually in each transmission planning cycle, the paper also described how the ISO would apply the proposed methodology in future transmission planning cycles. Although the Board cannot “approve” non-transmission solutions, the ISO can identify these solutions as preferred solutions to transmission projects and then work with the appropriate state agencies to support their development. This is particularly viable when the transmission solution is not needed to be initiated immediately and 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 examining the benefits preferred resources can provide, the ISO relies heavily on preferred resources identified through various resource procurement proceedings as well as proposals received 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 immediate action is not required. The ISO expects that developers interested in this approach have been reviewing those areas and highlighting the potential benefits of preferred resource proposals in their submissions into utilities’ procurement processes. To assist interested parties, the ISO has summarized areas where preferred resources are being targeted in lieu of transmission solutions to address reliability issues in section 7.3.

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 facilitate energy storage development overall, including past efforts refining the generator interconnection process to better address the needs of energy storage developers. One such effort is the continued refinement of the analysis of the benefits of large scale energy storage in addressing flexible capacity needs, as mentioned earlier and documented in chapter 6. This analysis began in the 2015-2016 transmission planning cycle, and the ISO has updated and expanded it to consider locational benefits. Through 2016, the ISO also worked with San Diego Gas and Electric and Southern California Edison to interconnect energy storage procured as part of the CPUC’s Resolution E-4791, authorizing expedited procurement of storage resources to ensure electric reliability in the Los Angeles Basin due to limited operation of the Aliso Canyon Gas Storage Facility, dated May 26, 2016.

Use-limited resources, including demand response:

The ISO continues to support integrating demand response, which includes bifurcating and clarifying the various programs and resources as either supply side or load-modifying. Activities such as participating in the CPUC’s demand response related proceedings support identifying the necessary operating characteristics that demand response should have to fulfill a role in meeting transmission system needs. The ISO anticipates that there will be more progress for demand response and other use-limited resources in this area. In this planning cycle, the ISO is particularly emphasizing a special study where it is working with the CPUC and industry to develop the necessary performance characteristics to enable slow response resources to provide local capacity benefits.

Southern California Reliability and Gas-Electric Coordination

As in previous transmission plans, the ISO placed considerable emphasis in the 2016-2017 planning cycle on requirements in the Los Angeles basin and San Diego areas. The ISO has expanded the focus in past planning cycles on addressing the implications of the San Onofre Nuclear Generating Station's early retirement and the anticipated retirement of once-through-cooling gas fired generation to also consider the impact of the uncertainty regarding the Aliso Canyon gas storage facilities on local area gas supply. The high expectations of preferred resources being part of a comprehensive solution, which also includes transmission reinforcement and conventional generation, has resulted in the ISO analyzing the role of preferred resources in that area, including the expedited storage procurement discussed above.

Successfully mitigating reliability concerns remains dependent on materially higher levels of preferred resources in the future than have previously been achieved. Given the uncertainty regarding forecast resources materializing as planned, the ISO is continuing to monitor the progress of the forecast procurement of conventional and preferred resources and ISO-approved transmission upgrades underway. Sections 2.6 and 3.2 touch on these issues.

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. 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 determined in the 2013-2014 planning cycle. The CPUC incorporated that information to adjust the renewable generation portfolios provided to the ISO for the 2015-2016 planning cycle and which are now also being used in this 2016-2017 cycle. This is discussed in chapter 3.

As noted in the 2015-2016 Transmission Plan, in October 2015 the Imperial Irrigation District (IID) provided new base cases modifying its future transmission plans as comments into the ISO's planning process. As IID stated in its comments, the ISO's study timelines did not permit the ISO taking into account that information in the 2015-2016 plan. The ISO has taken that input and IID's most recent input into account this 2016-2017 transmission planning cycle. As a result, the ISO revisited the Imperial area from a policy-driven transmission perspective in this planning cycle, to ensure that the CPUC's renewable generation portfolios provided for policy-driven transmission planning were met.

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 established the following goals:

- By 2030, double energy efficiency for electricity and natural gas by retail customers
- 50 percent renewables portfolio standard (RPS) by 2030

- o Existing RPS counting rules remain unchanged
- o Requires LSEs to increase purchases of renewable energy to 50 percent by December 31, 2030
- o Sets interim targets as follows
  - 40 percent by the end of the 2021-2024 compliance period
  - 45 percent by the end of the 2025-2027 compliance period
  - 50 percent by the end of the 2028-2030 compliance period

SB 350 creates a pathway to increased levels of renewable generation and lower greenhouse gas emissions. The ISO looks forward to helping achieve these goals.

Although considerable work remains to be done to ensure that the transmission plans in place are achieved, the ISO's focus in the 2016-2017 planning cycle was to confirm the effectiveness of current plans in the Imperial area and begin analysis to support moving beyond the 33 percent goal and driving to the 50 percent goal. The ISO recognizes that one or more planning cycles will occur before state resource planners will provide actionable guidance in the form of renewable generation portfolios. In this planning cycle, the ISO has conducted exploratory informational special studies to help inform future resource planning that can be further refined in future planning cycles.

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 exploring the viability of renewable generation resources in California and throughout the West, considering critical land use and environmental constraints, and identifying potential transmission opportunities that could access and integrate renewable energy with the most environmental, economic, and community benefits.

California faced similar challenges in 2007 when the state implemented a 20 percent renewable energy target, 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.

Although RETI 2.0 is not a regulatory proceeding in itself, the insights, scenarios, and recommendations it generates 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 with a public workshop. The RETI 2.0 reports are now published and publicly available on the CEC website[17].

[17] http://www.energy.ca.gov/reti/

1.3 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. For example, the 2015-2016 planning cycle began in January 2015 and concluded in March 2016.

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.

In Phase 2, the ISO performs studies to identify the solutions to meet the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months and ends with Board approval of the transmission plan. Thus, phases 1 and 2 take 15 months to complete. Identifying non-transmission alternatives that the ISO is relying 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 regional 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 regional transmission facilities that are open to competitive solicitation in accordance with criteria specified in the ISO tariff.

In addition, the ISO may incorporate into the annual transmission planning process specific transmission planning studies necessary to support other state or industry informational requirements to efficiently provide study results that are consistent with the comprehensive transmission planning process. In this cycle, these focus primarily on grid transformation issues and incorporating renewable generation integration studies into the transmission planning process.

1.3.1 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 2016-2017 planning cycle. In 2016, the ISO sought to further improve the level of coordination between the policy-driven generating resource portfolios and other planning assumptions — in particular the load forecast and load modifying behind the meter distributed generation.

The unified planning assumptions establish a common set of assumptions for the reliability and other planning studies the ISO performs 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 pertinent 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 it will consider in assessing the need for new transmission infrastructure.

Development of the unified planning assumptions for this planning cycle benefited from further coordination efforts between the California Public Utilities Commission (CPUC), 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 resulted in improved alignment of the three core processes and agreement on an annual process to be undertaken in the fall of each year to develop planning assumptions and scenarios to be considered in infrastructure planning activities in the upcoming year. The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolio standard (RPS) portfolios discussed in more detail below, which are a key assumption.

The results of that annual process fed into this 2016-2017 transmission planning process and was communicated via a ruling in the 2014 LTPP[18]. These process efforts will continue in 2017 emphasizing the broad load forecast impacts of distributed generation and other material changes in customer needs and considering renewable integration challenges and the market impacts of increased renewable generation on the existing conventional generation fleet.

The ISO added public policy requirements and directives as an element of transmission planning process in 2010. Planning transmission to meet public policy directives is also 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 specified state and federal requirements or directives. The primary policy directive for the last number of years' planning cycles has been California's renewables portfolio standard that calls for 33 percent of the electric retail sales in the state by 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

[18] Rulemaking 13-12-010 "Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for use in the California Independent System Operator's 2016-17 Transmission Planning Process and Future Commission Proceedings" on May 17, 2016.

of the transmission planning process, but the ISO has taken steps 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, and with input from other state agencies including the CEC and the municipal utilities within the ISO balancing authority area. The CPUC, 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 annually within the ISO area, plays a primary role formulating the resource portfolios. The ISO reviews the proposed portfolios with stakeholders and seeks their comments, which the ISO then considers in determining the final portfolios.

The resource portfolios have played a crucial role in identifying needed 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 ISO has managed the uncertainty as to where the generation capacity will locate by balancing the need to have sufficient transmission 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 has entailed applying a “least regrets” approach, whereby the ISO first formulates alternative resource development portfolios or scenarios, then identifies the needed transmission to support each portfolio, and then selects for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

As we move closer to the 33 percent renewables portfolio standard compliance date of 2020, much of the uncertainty about which areas of the grid will actually realize most of this new resource development as a result of the utilities’ procurement and contracting processes has been addressed. As noted earlier, the portfolios intended to meet the 33 percent renewables portfolio standard vary less each year as we move closer to 2020, and the portfolios the ISO has relied upon in this planning cycle are unchanged from the last planning cycle. Accordingly, the ISO’s focus in the 2016-2017 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 toward the 50 percent goal by 2030 established by SB 350. This latter effort was reflected in the informational special studies 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. 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 selects high priority studies from these requests and includes them in the study plan published at the end of phase 1. The ISO may modify the list of high priority studies later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

In 2010, the ISO added a conceptual statewide transmission plan to the planning process recognizing the need for effective coordination on a statewide basis. This also recognized that

California planning authorities and load serving transmission providers had begun coordinating regarding transmission needs in California under the structure of the California Transmission Planning Group (CTPG). In the initial years of this process, the ISO developed its conceptual statewide plan in coordination with the entities participating in the CTPG. The conceptual statewide plan seeks to apply 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. However, the coordination activities undertaken by CTPG ceased when they were replaced with the planning entities’ Order No. 1000’s specific requirements for regional and interregional planning. Accordingly, the ISO 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. The ISO will need to revisit the conceptual state plan requirement given implementation of the new interregional planning processes as discussed below.

1.3.2 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 required to meet the infrastructure needs of the grid, including reliability, public policy, and economic-driven needs. In phase 2, the ISO conducts the following major activities:

- performs technical planning studies described in the phase 1 study plan and posts the study results;
- provides a request window for stakeholders to submit 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 and provides stakeholders an opportunity for stakeholders 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,[19] which is intended to minimize 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 that the ISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of phase 2 in March.

Board approval of the comprehensive transmission plan at the end of phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board's approval enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval.[20] As indicated above, the ISO will solicit and accept proposals in phase 3 from all interested project sponsors to build and own the regional transmission solutions that are open to competition.

By definition, category 2 solutions identified in the comprehensive plan are not authorized to proceed after Board approval of the plan, but are instead re-evaluated during the next annual cycle of the planning process. At that time, based on relevant new information about the patterns

[19] In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven solutions. Using these categories better enables 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. Section 24.4.6.6 of the tariff specifies the criteria considered in this evaluation.

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

of expected development, the ISO will determine whether the category 2 solutions 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 compete to build and own eligible regional transmission facilities reflected in the final Board-approved plan.[21]

1.3.3 Phase 3

Phase 3 takes place after Board approves the plan if there are projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional reliability-driven, category 1 policy-driven, or economic-driven transmission solutions, except for regional transmission solutions that are upgrades to existing facilities. Local transmission facilities are not subject to competitive solicitation.

If the approved transmission plan includes regional transmission facilities eligible for competitive solicitation, the ISO will commence phase 3 by opening a window for the entities to submit applications to compete to build and own such 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 an approved project sponsor by comparatively evaluating all of the qualified project sponsors based on the tariff selection criteria. Where there is only one qualified project sponsor, the ISO will authorize that sponsor to move forward to project permitting and siting.

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

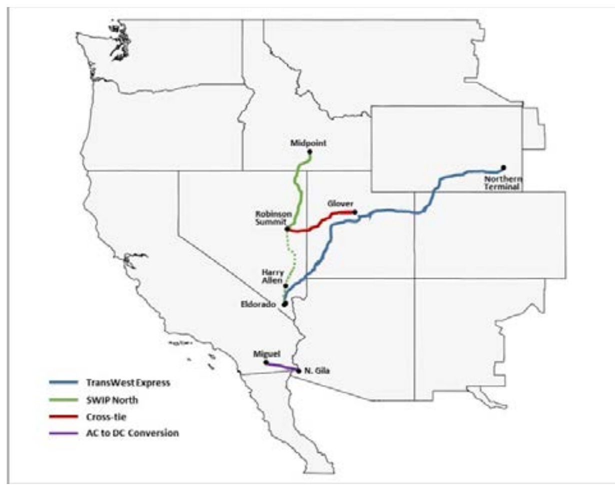
1.4 Interregional Transmission Coordination per FERC Order No. 1000

During the ISO's 2016-2017 planning cycle, the ISO continued to participate and advance interregional transmission coordination along with the other western planning regions[22] within the broader landscape of the western interconnection. January 1, 2016 marked the initiation of the 2016-2017 Western Planning Region interregional coordination cycle and to this end the western planning regions continued to refine aspects of their regional processes through the development of guiding principles to ensure that an annual exchange and coordination of planning data and information was achieved. A western planning regions annual interregional coordination meeting was held on February 25, 2016[23] to provide all stakeholders an opportunity to engage with the western planning regions on interregional related topics.

The ISO hosted its submission period in the first quarter of 2016 in which proponents were able to request evaluation of an interregional transmission project. The submission period began on January 1 and closed March 31st with four interregional transmission projects being submitted to the ISO. The submitted projects are shown in Figure 1.4-1.

Following the submission and successful screening of the interregional transmission project submittals, the ISO coordinated its interregional transmission project evaluation with the other relevant planning regions NTTG and WestConnect. Project evaluation plans were developed and shared with the project sponsors and ISO stakeholders[24]. A common theme among all projects was a possible role in providing access to out-of-state renewable generation to move beyond the 33 percent RPS toward a 50 percent RPS.

Figure 1.4-1: Interregional Transmission Projects Submitted to the ISO



Although there is considerable interest in exploring the benefits of interregional transmission projects in moving beyond 33 percent RPS towards 50 percent RPS in California, the policy direction is not in place at this time to consider these alternatives as policy-driven transmission. However, the ISO advanced the interregional coordination effort as an extension of the 50 percent RPS special studies that were being conducted inside the 2016-2017 transmission planning cycle - which are discussed in Section 6.4 of this transmission plan - and coordinated with the western planning regions on that basis.

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

23 http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=2B57345C-CEF0-4C07-8301-307F7B01CA2D

24 http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=EAEBC2EA-AE8D-4F8D-A7A6-E477B2ACD085

WECC Anchor Data Set

Currently, the western planning regions and WECC may represent load, resource, and transmission topology information differently based on their regulatory and analytical needs. These differences have led to inconsistent data in WECC's various planning models, resulting in challenges for WECC and its stakeholders' varying analytical needs. The WECC Joint PCC-TEPPC Review Task Force (JPTRTF) submitted an Anchor Data Set (ADS) proposal that was approved by the WECC Board of Directors in December 2016.[25] The purpose of the ADS is to establish consistent processes and protocols for gathering planning data that include reviews for consistency and completeness, and to generate production cost, power flow, and dynamic models with a common representation of the loads, resources, and transmission across the Western Interconnection 10 years in the future. The ADS will resolve existing inconsistencies and facilitate consistent data application for the western planning regions, WECC and other stakeholders in the Western Interconnection.

The ISO participated in and supported the development of the ADS proposal. Commensurate with its approval, the western planning regions immediately initiated an effort to coordinate with WECC staff on development of the necessary processes and protocols that will be necessary to make the ADS a reality. The success of the ADS development will depend on a collaborative effort between the western planning regions and WECC to integrate and align, as much as reasonably possible, western planning region data processes with existing WECC MOD-032 and production cost model processes which will be used to develop the 2028 production cost model by the end of June 2017.

[25] https://www.wecc.biz/Reliability/JPTRTF%20Recommendations%20to%20the%20WECC%20Board.pdf

1.5 ISO Processes coordinated with the Transmission Plan

The ISO coordinates the transmission planning process with several other ISO processes. These processes and initiatives are briefly summarized below.

Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

In July 2012, FERC approved the GIDAP, which significantly revised the generator interconnection procedures to better integrate those procedures with the transmission planning process. The ISO applied the GIDAP to queue cluster 5 in March 2012 and all subsequent queue clusters. Interconnection requests submitted into cluster 4 and earlier will 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 the ISO would identify and approve all major transmission additions and upgrades to be paid for by transmission ratepayers under a single comprehensive process — the transmission planning process — rather than having some projects come 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 to achieve the state's 33 percent renewables portfolio standard. In that context, the ISO plans the necessary transmission upgrades to enable the deliverability of the renewable generation forecast in the base renewables portfolio scenario provided by the CPUC, unless specifically noted otherwise. Every RPS Calculator portfolio the CPUC has submitted 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.[26]

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 the 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 who still want to build their projects and obtain deliverability status, are responsible for funding 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 ISO calculates the available transmission plan deliverability (TPD) in each year's transmission planning process in areas where the amount of generation in the interconnection queue exceeds 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 is sufficient. In this year's transmission planning process, the ISO considered queue clusters up to and including queue cluster 9.

[26] 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).")

Distributed Generation (DG) Deliverability

The ISO developed a streamlined, annual process for providing resource adequacy (RA) deliverability status to distributed generation (DG) resources from transmission capacity in 2012 and implemented it in 2013. 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 the ISO performs 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 to apportion 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 that are interconnected or in the process of interconnecting to their distribution facilities.

In the first step, during the transmission planning process the ISO 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, including new additions and upgrades 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 specified in the base case resource portfolio that was adopted in the latest transmission planning process cycle to identify 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 distribution utilities can use to assign deliverability status to generators in the current cycle. This ensures that the DG deliverability assessment aligns 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 the ISO performs this new DG deliverability process as part of and in alignment with the annual transmission planning process cycle, its only direct impact on the transmission planning process is adding the DG deliverability study to be performed in the latter part of Phase 2 of the transmission planning process.

Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[27] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that 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 only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

Planning Coordinator Footprint

The ISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area[28] in 2014, in part in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities. ISO staff 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.

Beginning in 2015, the ISO reached out to several "adjacent systems" that are inside the ISO's balancing authority area and were confirmed transmission owners, but which did not appear to be registered as a planning coordinator to determine whether they needed to have a planning coordinator and, if they did not have one, to offer to provide planning coordinator services to them through a fee based agreement.

To date, the ISO has executed planning coordinator services agreements with Hetch Hetchy Water and Power and the Metropolitan Water District, and the ISO has conducted the study efforts to meet the mandatory standards requirements for these entities within the framework of the annual transmission planning process.

The ISO is also providing planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities that are not under ISO operational control but which were found to be Bulk Electric System as defined by NERC.

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.

[27] 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 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.

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

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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
  - o Humboldt area;
  - o North Coast and North Bay areas;
  - o North Valley area;
  - o Central Valley area;
  - o Greater Bay area;
  - o Greater Fresno area;
  - o Kern Area; and
  - o Central Coast and Los Padres areas.
- SCE local areas
  - o Tehachapi and Big Creek Corridor;
  - o North of Lugo area;
  - o East of Lugo area;
  - o Eastern area; and
  - o Metro area.
  - o Valley Electric Association (VEA) area
  - o San Diego Gas Electric (SDG&E) local area

2.1.3 Peak Demand

The ISOmands-controlled grid peak demand in 2016 was 46,193 MW and occurred on July 27 at 4:55 p.m. The following were the peak de for the participating transmission owners areas:

- PG&E peak demand occurred on July 27, 2016 at 5:40 p.m. with 20,467 MW;
- The SCE peak demand occurred on June 20, 2016 at 3:55 p.m. with 23,752 MW;
- SDG&E peak demand occurred on July 22, 2016 at 5:30 p.m. with 4,294 MW; and
- VEA peak demand occurred on July 28, 2016 at 4:15 p.m. with 135 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.

2.2 Reliability Standards Compliance Criteria

The 2016-2017 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 2017-2026 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2016-2017 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[29]; 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.[30]

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.[31] 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.

[29] 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.

[30] https://www.wecc.biz/Standards/Pages/Default.aspx

[31] http://www.caiso.com/Documents/Final2016-2017StudyPlan.pdf

2.3 Study Assumptions and Methodology

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

2.3.1 Study Horizon and Years

The studies that comply with TPL-001-4 were conducted for both the near-term[32] (2017-2021) and longer-term[33] (2022-2026) per the requirements of the reliability standards. Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2018, 2021 and 2026.

2.3.2 Transmission Assumptions

2.3.2.1 *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 Table 7.1-1 and Table 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 Table 7.1-1 and Table 7.1-2 of chapter 7.

2.3.2.2 *Reactive 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.

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[32] System peak load for either year one or year two, and for year five as well as system off-peak load for one of the five years.

[33] System peak load conditions for one of the years and the rationale for why that year was selected.

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).[34]

2.3.2.3 *Protection System*

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

2.3.2.4 *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; (e.g., phase shifting transformer).

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.

2.3.3 Load Forecast Assumptions

2.3.3.1 *Energy and Demand Forecast*

The assessment used the California Energy Demand Forecast 2016-2026, Revised Electricity Forecast adopted by California Energy Commission (CEC) on January 27, 2016 using the Mid Case LSE and Balancing Authority Forecast spreadsheet of January 27, 2016.

During 2015, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2015 IEPR final report, adopted on February 10, 2016, based on the IEPR record and in consultation with the CPUC and the ISO, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC LTPP and ISO TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low-Mid AAEE scenario for local studies is more prudent at this time.

The 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

[34] 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.

geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

The CEC Energy and Demand Forecast states the following with respect to the impact of PV at the time of the forecast peak load:

"At some point, continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through CED 2015, since staff has not yet developed models to forecast hourly loads in the long term. Staff expects to develop this capability for the 2017 Integrated Energy Policy Report (2017 IEPR), and such an adjustment to PV peak impacts could significantly affect future peak forecasts."[35]

In the 2016-2017 transmission planning process, the ISO used the CEC energy and demand forecast for the base scenario analysis identified in section 2.3.8.1. The ISO conducts sensitivities on a case by case basis and to comply with the NERC TPL-001-4 mandatory reliability standard, these and other forecasting uncertainties were taken into account in the sensitivity studies identified in section 2.3.8.2. The ISO will continue to work with the CEC on the hourly load forecast issue during the development of 2017 IEPR.

2.3.3.2 *Self-Generation*

Peak demand in the CEC demand forecast was reduced by projected impacts of self-generation serving on-site customer load. The self-generation was further categorized as PV and non-PV. Statewide, self-generation was projected to reduce peak load by more than 6,900 MW in the mid case by 2025. In 2016-2017 transmission planning process base cases, the PV component of self-generation was modeled as discrete element. Self-generation peak impacts for PG&E, SCE and SDG&E planning areas are shown in Table 2.3-1.

[35] CEC California Energy Demand 2016-2026, Revised Electricity Forecast Volume1: Statewide Electricity Demand and Energy Efficiency, January 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf, Page 37.

Table 2.3-1: PG&E, SCE & SDG&E Planning Areas PV Self-Generation Peak Impacts (MW)

	CED 2015 Mid Demand		
	PG&E	SCE	SDG&E
1990	-	-	-
2000	0	0	0
2010	198	109	40
2015	579	441	154
2020	1026	896	302
2026	1818	1739	504

The CEC self-generation information is available on the CEC website at: http://www.energy.ca.gov/2015_energypolicy/documents/index.html#adoptedforecast.

PV Self-generation installed capacity by PTO are shown in Table 2.3-2. Output of the self-generation PV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Table 2.3-2: PV self-generation installed capacity by PTO36

Year	PG&E	SCE	SDG&E
2017	2,328	1,703	591
2018	2,534	1,920	659
2019	2,751	2,141	720
2020	2,988	2,358	779
2021	3,276	2,629	850
2022	3,610	2,947	929
2023	3,993	3,307	1,017
2024	4,416	3,701	1,110
2025	4,875	4,142	1,209
2026	5,370	4,611	1,312

[36] Based on self-generation PV calculation spreadsheet provided by CEC.

2.3.4 Generation Assumptions

Generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels for the peak demand bases cases. Qualifying facilities (QFs) and self-generating units were modeled based on their historical generating output levels. Renewable generation was dispatched as identified in section 2.3.4.2.

2.3.4.1 *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.

2.3.4.2 *Renewable Generation*

The RPS portfolio provided to the ISO by the CPUC and CEC[37] and described in chapter 3 was used in developing the base cases.

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

Renewable generation dispatch

The ISO has done a qualitative and quantitative assessment of hourly Grid View renewable output for stressed conditions during hours and seasons of interest. Available data of pertinent hours was catalogued by renewable technology and location on the grid. The results of active power output differ somewhat between locations and seasons as follows. Reactive limits of renewable generation will be as specified by Qmax and Qmin, which rely upon technology of the generation and may change as a function of active power output and power factor specified. Table 2.3-3, Table 2.3-4, Table 2.3-5, and Table 2.3-6 summarize the renewable output in each of the PTO areas.

Table 2.3-3: Summary of renewable output in PG&E

All years	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	3xNQC~=Pmax	High Output
Sum Off-Peak	NQC~=P Max	NQC~=Pmax	3xNQC~=Pmax	High Output
Sum Partial-Peak	NQC~=P Max	0	0	Low Output
Sum Peak	NQC~=P Max	25%xNQC~=25%xPmax	NQC~=33%xPmax	Low Output
Winter Peak	NQC~=P Max	0	50%xNQC~=16.6%xPmax	Low Output

[37] http://www.caiso.com/Documents/2016-2017RenewablePortfoliosTransmittalLetter.pdf

Table 2.3-4: Summary of renewable output in SCE

	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	2.8xNQC~= 93%xPmax	High Output
Sum Off-Peak	NQC~=P Max	93%xNQC~=93 %xPmax	2.8xNQC~= 93%xPmax	High Output
Sum Partial- Peak	NQC~=P Max	TBD	TBD	Low output
Sum Peak	NQC~=P Max	36%xNQC~=36 %xPmax	0	Low Output

Table 2.3-5: Summary of renewable output in SDG&E

All years	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	3xNQC~=Pmax	High Output
Sum Off-Peak	NQC~=P Max	81%xNQC~=81 %xPmax	2.9xNQC~= 96%xPmax	High Output
Sum Peak	NQC~=P Max	55%xNQC~=55 %xPmax	NQC~= 33%xPmax	Low Output

Table 2.3-6: Summary of renewable output in VEA

All years	Biomass/Biogas/Geothermal	Solar PV, ST	Wind	Stressed case
Sum Min Load	NQC~=P Max	0	N/A	High Output
Sum Off-Peak	NQC~=P Max	97%xNQC~=97 %xPmax	N/A	High Output
Sum Peak	NQC~=P Max	47%xNQC~=47 %xPmax	N/A	Low Output

Summer Peak = Peak time for the area of study – example PG&E hours 17:00 and 18:00
Summer Partial-Peak = Partial-Peak time the area of study – ex: PG&E hours 20:00 and 21:00
Summer Off-Peak = Load at 50-65% - summer weekend morning time.
Summer Min Load = Load at minimum – example PG&E hours 2:00 through 4:00 am
Winter Peak = Peak time for the area of study – example PG&E hours 17:00 and 18:00

2.3.4.3 *Thermal generation*

For the latest updates on new generation projects, please refer to CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html) the ISO relies on other databases to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases. Table A2-1 of Appendix A lists new thermal generation projects in construction or pre-construction phase that will be modeled in the base cases.

2.3.4.4 *Hydroelectric Generation*

During drought years, the availability of hydroelectric generation production can be severely limited. In particular, during a drought year the Big Creek area of the SCE system has experienced a reduction of generation production that is 80% below average production. The Big Creek area is a local capacity requirement area that relies on Big Creek generation to meet NERC Planning Standards.

2.3.4.5 *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 off-line based on the OTC compliance dates,
- Once Through Cooled (OTC) Retirements – As identified in section 2.3.1.
- 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.

2.3.4.6 *OTC Generation*

Modeling of the once-through cooled generating units, shown in Table 2.3-7, followed the compliance schedule from the State Water Resources Control Board's (SWRCB) policy on OTC plants with the following exceptions:

- 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.

Table 2.3-7: 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)	Notes
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. The base assumptions will be for all three units to be off-line. If there is a need identified, units 5 & 6 will be turned on to determine impact on identified need.
			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	12/31/2020*	510*	* Per Dynegy's Settlement Agreement with the SWRCB, executed on October 9, 2014, the Moss Landing generating units
			2	12/31/2020*	510*	
			6	12/31/2020	754	
			7	12/31/2020	756	

						will have until December 31, 2020 to be brought into compliance. Dynegy will pursue Track 2 compliance for Units 1 and 2 by installing technology control and implementing operational control to reduce impingement mortality and entrainment. Upon January 1, 2021, the capacity of Units 1 and 2 will also be de-rated by 15%. Dynegy will cease operation of Units 6 and 7 by December 31, 2020.
	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	Unit 4 was retired on December 31, 2015.
	Alamitos (2,011 MW)	AES	1	12/31/2020	175	On November 19, 2015, the CPUC, with Decision 15-11-041, approved 640 MW combined-cycle generating facility repowering project for AES Alamitos Energy, LLC. This authorizes Power Purchase and Tolling Agreement (PPTA) between SCE and AES Southland
			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	
	Huntington Beach (452 MW)	AES	1	12/31/2020	226	On November 19, 2015, the CPUC, with Decision 15-11-041, approved a repowering project for a 644 MW combined-cycle generating facility for AES Huntington Beach, LLC. This authorizes Power Purchase and Tolling Agreement (PPTA) between SCE and AES Southland,
			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
			4	12/31/2020	227	

						post 2017 studies as contract expires.
	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 proposed repowering with a new 500 MW project (Carlsbad Energy Center) – this was approved by the CPUC with the Decision 15-05-051 on May 21, 2015 and issued on May 29, 2015
			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)

2.3.4.7 *LTPP Authorization Procurement*

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 2.3-8 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 2.3-9 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 the San Diego area.

Table 2.3-8: Summary of 2012 LTPP Track 1 & 4 Authorized Procurement

LCR Area	**LTTP Track-1**		**LTTP Track-4**[38]	
	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**
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

Notes: Amounts shown are total including gas-fired generation, preferred resources and energy storage

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

Table 2.3-9: 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's procurement for the Western LA Basin[39]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark sub-area[40]	6.00	5.66	0.50	0	262	274.16
SDG&E's procurement	22.4*	0	25**-84*	33.6*	800[41]	881-940

Notes:

* Proxy preferred resource and energy storage assumptions are based on the maximum total amount of 140 MW that SDG&E is soliciting based on its 2016 RFO for Local Capacity Requirements Decision established by the CPUC via D.14-03-004 (the "Track 4" Decisions). These will be updated upon SDG&E's filing of final procurement selection for preferred resources and energy storage at the CPUC later in 2016 time frame.

** Based on the CPUC draft Scenarios and Assumptions for the 2016 LTPP and the 2016-2017 Transmission Planning Process, 25 MW will be assumed initially for the energy storage for San Diego and this amount can be increased (up to the net amount of the ceiling for preferred resources and energy storage subtracting other assumptions for LTPP related for preferred resources) if needed.

*** Pio Pico (300 MW) and Carlsbad Energy Center (500 MW) were approved by the CPUC as part of SDG&E-selected procurement for LTPP Tracks 1 and 4.

2.3.5 Preferred Resources

According to tariff Section 24.3.3(a), the ISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. In response, the ISO received demand response and energy storage information for consideration in planning studies from the following:

[39] SCE-selected RFO procurement for the Western LA Basin was approved by the CPUC with PPTAs per Decision 15-11-041, issued on November 24, 2015.

[40] SCE-selected RFO procurement (A. 14-11-016) for the Moorpark sub-area is currently at the CPUC for review and consideration.

[41] The CPUC, in Decisions 14-02-016 and 15-05-051 approved PPTAs for the Pio Pico and Carlsbad Energy Center projects.

- California Public Utilities Commission (CPUC)
- Pacific Gas & Electric (PG&E)

CPUC staff made the following recommendations with regard to demand response (DR) assumptions appropriate for use in the 2016-17 TPP studies.

- Demand response assumptions used in the TPP should reflect the guidelines described in the CPUC's ruling on standardized planning assumptions and scenarios.
- The TPP studies should use the allocations of demand response capacity to busbar provided by the IOUs.
- The TPP studies should count any new demand response capacity specifically contracted by the IOUs, and approved by the CPUC, to fulfill local capacity needs and other demand response procurement mechanisms.
- The CAISO should continue to participate in the CPUC's Demand Response rulemaking to better inform program development and future policy direction.

PG&E provided a bus-level model of PG&E's demand response (DR) programs for the inclusion in the Unified Planning Assumptions and 2016-2017 study plan.

Methodology

The ISO issued a paper[42] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO's transmission plan as an alternative to the conventional transmission or generation solution.

In previous planning cycles, the ISO applied a variation of this new approach in the LA Basin and San Diego areas to evaluate the effectiveness of preferred resource scenarios developed by SCE as part of the procurement process to fill the authorized local capacity for the LA Basin and Moor Park areas. In addition to these efforts focused on the overall LA Basin and San Diego needs, the ISO also made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified.

As in the 2015-2016 planning cycle, the reliability assessments in the current planning cycle considered a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies incorporate the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the portfolio provided by the

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

CPUC and CEC, and a mix of proxy preferred resources including energy storage based on the CPUC 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 that is embedded in the CEC load forecast.

For each planning area, reliability assessments will be initially performed using preferred resources other than DR to identify reliability concerns in the area. If reliability concerns are identified in the initial assessment, additional rounds of assessments will be performed using potentially available demand response and 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 considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including diurnal variation in the case of solar DG and use or energy limitation in the case of demand response and energy storage.

Demand Response

In reliability studies, only capacity from DR programs that can be relied upon to mitigate "first contingencies", as described in the 2012 LTPP Track 4 planning assumptions, are counted. DR that can be relied upon to mitigate post first contingencies in local reliability studies participates in, and is dispatched from, the ISO market in sufficiently less time than 30 minutes[43] from when it is called upon.

There is uncertainty as to what amount of DR can be projected to meet this criteria within the TPP planning horizon given that few current programs meet this criteria and the current DR Rulemaking R.13-09-011 expects to restructure DR programs to better meet ISO operational needs and has already produced one major policy decision towards that goal.[44] The rulemaking is expected to issue additional decisions that enable demand response to be more useful for grid needs, but ISO has several tasks it must complete in order to make integration of DR possible. The 2012 LTPP Track 4 planning assumptions estimated that approximately 200 MW of DR would be available to mitigate first contingencies within the combined LA Basin and San Diego local reliability areas by 2022. The 2016 LTPP planning assumptions, however, estimates that approximately 953 MW would be available to mitigate post first contingencies within the combined LA Basin and San Diego local reliability areas by 2024. The CPUC staff developed this latter estimated projections for 2026 time frame by screening DR projections in the Load Impact reports for programs that deliver load reductions in 30 minutes or less from customer notification. Table 2.3-10 identifies for each IOU the programs and capacities that meet this criteria. Currently, SCE has indicated that 475 MW of DR in SCE's service territory meets the 20-minute response time for mitigating contingency reliability concerns.

[43] The 30 minute requirement is based on meeting NERC Standard TOP-004-02. Meeting this requirement implies that programs may need to respond in 20 minutes, from customer notification to load reduction, in order to allow for other transmission operator activities in dealing with a contingency event.

[44] Commission Decision 14-03-026 approved the bifurcation of DR programs into two categories: Supply DR (DR that is integrated into ISO markets and dispatched when and where needed) and Load-Modifying DR (DR that is not integrated into ISO markets. This decision determined that bifurcation will occur by 2017.

Table 2.3-10: Existing DR Capacity Range in Local Area Reliability Studies

"First Contingency " DR Program MW in 2024 using 1-2 weather year ex ante impacts	**PG&E**	**SCE**	**SDG&E**
Base Interruptible	246	611	1.5
Agricultural Pumping Interruptible	n/a	66	n/a
AC Cycling Residential	59	218	12.8
AC Cycling Non-Residential	2	40	3.4

Given the uncertainty as to what amount of DR can be relied upon for mitigating first contingencies, the ISO's 2014-2015 TPP Base local area reliability studies examined two scenarios, one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions. Similarly, the ISO will examine two scenarios in the 2016-2017 TPP, one using the updated 20 minute DR data from SCE and the other consistent with the 2016 LTPP DR assumptions.

DR capacity will be allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs. The DR capacity amounts will be modeled offline in the initial reliability study cases and will be used as potential mitigation in those planning areas where reliability concerns are identified.

Table 2.3-11 shows the factors that were applied to the DR projections to account for avoided distribution losses.

Table 2.3-11: Factors to Account for Avoided Distribution Losses

	PG&E	**SCE**	**SDG&E**
Distribution loss factors	1.067	1.051	1.071

Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the ISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs. Energy storage that will be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision is subsumed within the 2020 procurement target.

As the 2016-2017 TPP studies identify transmission constraints in the local areas, the ISO will identify the effective busses that the storage capacity identified in the table below can be distributed amongst within the local area as potential development sites. Table 2.3-12 describes the assumptions that shall be used for the technical characteristics and accounting of the three classes of storage mandated by D.13-10-040. These storage capacity amounts will not be included in the initial reliability analysis. The storage capacity amounts will be used as potential mitigation in those planning areas where reliability concerns have been identified.

Table 2.3-12: Storage Operation Attributes

Values are MW in 2024	Transmission-connected	Distribution-connected#	Customer- side
Total Installed Capacity	700	425	279**
Amount providing capacity in power flow studies	560 *	170 *	135@
Amount providing flexibility	700	212.5	135
Amount with 2 hours of storage	280	170	100
Amount with 4 hours of storage	256 ^	170	135
Amount with 6 hours of storage	124 ^	85	0

Charging rate: If a unit is discharged and charged at the same power level, assume it takes 1.2 times as long to charge as it does to discharge. Example: 50 MW unit with 2 hours of storage. If the unit is charged at 50 MW, it will take 2.4 hours to charge. If the same unit is charged at 25 MW, it will take 4.8 hours to charge.

Distribution-connected energy storage is assumed to provide 50% of its installed capacity for modeling in power flow studies

* This reflects a 50 % derating of capacity value of 2 hour storage due to not being able to sustain maximum output for 4 hours per Resource Adequacy accounting rules.

@This reflects 135 MW from SCE 2014 LCR RFO

^ This amount was adjusted down to reflect the assumption that the 40 MW Lake Hodges storage project satisfies the storage target for a portion of SDG&E’s share of the target.

** SCE procured 164 MW of BTM ES via its 2014 LCR RFO, exceeding its 85 MW BTM ES 2020 target; these 164 MW added to PG&E’s and SDG&E’s BTM ES target (85 MW and 30 MW respectively) results in 279 MW of BTM ES expected to be online by 2020.

2.3.6 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 2.3-13 lists the capability and power flows modeled in each scenario on these paths in the northern area assessment[45].

Table 2.3-13: Major paths and power transfer ranges in the Northern California assessment[46]

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[47]	
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 2.3-14 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.

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

[46] 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)

[47] The Path 66 flows was modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch.

Table 2.3-14: 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

2.3.7 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.

2.3.8 Study Scenarios

2.3.8.1 *Base Scenarios*

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

Generation:

Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 2.3.4.

Demand Level:

Since most of the ISO footprint is a summer peaking area, summer peak conditions were evaluated in all study areas. However, winter peak, spring off-peak, summer off-peak or summer partial-peak were also be studied for areas in where such scenarios may result in more stress on system conditions. Examples of these areas are the coastal sub-transmission systems in the PG&E service area (e.g. Humboldt, North Coast/North Bay, San Francisco, Peninsula and Central Coast), which were studied for both the summer and winter peak conditions. Table 2.3-15 lists the scenarios that were conducted in this planning cycle.

Path flows:

For local area studies, transfers on import and monitored internal paths will be modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths will be stressed as described in section 2.3.4.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable. Table 2.3-15 summarizes these study areas and the corresponding base scenarios for the reliability assessment.

Table 2.3-15: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2018	2021	2026
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
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
SDG&E bulk transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Valley Electric Association	Summer/Winter Peak Summer Off-Peak	Summer/Winter Peak Spring Light Load	Summer/Winter 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.			

2.3.8.2 *Sensitivity study cases*

In addition to the base scenarios that the ISO assessed in the reliability analysis for the 2016-2017 transmission planning process, the ISO assessed the sensitivity scenarios identified in Table 2.3-16. 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 2.3-16: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2018	2021	2026
Summer Peak with high CEC forecasted load		PG&E Local Areas SCE Metro SCE Northern SDG&E Bulk SDG&E Sub-transmission	-
Summer Peak with no behind-the-meter PV	PG&E Local Areas SCE Metro SCE Northern SDG&E Bulk SDG&E Sub-transmission	-	PG&E Bulk PG&E Local Areas SCE Metro SCE Northern SDG&E Bulk SDG&E Sub-transmission
Off-peak with maximum PV Output	PG&E Bulk Southern California Bulk	-	-
Summer Peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Bulk	-
Summer Off-peak with heavy renewable output and minimum gas generation commitment (renewable generation addition)	-	VEA Area	-
Summer Peak with Diablo on-line	-	-	PG&E Bulk
Summer Peak with low hydro output	-	SCE Northern Area	-
Summer Peak with heavy northbound flow north of SONGS switchyard	-	-	SDG&E Bulk
Retirement of QF Generations	-	-	PG&E Local Areas

2.3.9 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)[48]
- 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)[49]
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)

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

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

- Loss of a single pole of DC lines (P3.5)
- Loss of both poles of the Pacific DC Intertie (WECC exemption)

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[50] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme Event 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 been included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

2.3.10 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.

2.3.10.1 *Study Tools*

The GE PSLF is the main study tool for evaluating system performance under normal conditions and following the outages (contingencies) of transmission system components for post-transient and transient stability studies. PowerGem TARA was used for steady state contingency analysis. The studies in the local areas focus on the impact from the grid under system normal conditions and following the Categories P1-P7 outages of equipment at the voltage level 60 through 230 kV. In the bulk system assessments, governor power flow was used to evaluate system performance following the contingencies of equipment at voltage level 230 kV and higher.

2.3.10.2 *Technical Studies*

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

Power Flow Contingency Analysis

The ISO performed power flow contingency analyses based on the ISO Planning Standards[51] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the ISO controlled grid and with select contingencies outside of the ISO controlled grid. The transmission system was evaluated under normal system conditions NERC Category P0 (TPL 001-4), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category P1-P7 (TPL 001-4) contingencies against emergency ratings and emergency voltage range.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[52]. Examples of these outages are combined

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

[51] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

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

cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

Line and transformer bank ratings in the power flow cases are updated to reflect the rating of the most limiting component. This includes substation circuit breakers, disconnect switches, bus position related conductors, and wave traps.

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

Post Transient Analyses

Post Transient analyses was conducted to determine if the system is in compliance with the WECC Post Transient Voltage Deviation Standard in the bulk system assessments and if there are thermal overloads on the bulk system.

Post Transient Voltage Stability Analyses

Post Transient Voltage stability analyses was conducted as part of bulk system assessment for the outages for which the power flow analyses indicated significant voltage drops, using two methodologies: Post Transient Voltage Deviation Analyses and Reactive Power Margin analyses.

Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies were selected for further analysis using WECC standards of 5% voltage deviation for “N-1” contingencies and 10% voltage deviation for “N-2” contingencies.

Voltage Stability and Reactive Power Margin Analyses

As per WECC regional criterion, voltage stability is required for the area modeled at a minimum of 105% of the reference load level or path flow for system normal conditions (Category P0) and for single contingencies (Category P1). For other contingencies (Category P2-P7), post-transient voltage stability is required at a minimum of 102.5% of the reference load level or path flow. The approved guide for voltage support and reactive power, by WECC TSS on March 30, 2006, was used for the analyses in the ISO controlled grid. According to the guideline, load is increased by 5% for Category P1 and 2.5% for other contingencies Category P2-P7 and studied to determine if the system has sufficient reactive margin. This study was conducted in the areas that have voltage and reactive concerns throughout the system.

Transient Stability Analyses

Transient stability analyses was also conducted as part of bulk area system assessment and local for critical contingencies to determine if the system is stable and exhibits positive damping of oscillations and if transient stability criteria are met as per ISO Planning Standards.

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

Figure 2.4-1 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 2018, 2021 and 2026; spring off-peak cases for 2018 and 2026; spring light load case for 2021; and summer partial peak case for 2026. In addition, 3 sensitivity cases were studied: the 2018 spring off-peak with high renewable dispatch, 2021 summer peak cases with high renewable generation dispatch and low gas-fired generation, and a 2026 summer peak case with no behind the meter (BTM)-PV distributed generation. 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. The total generation in each of the local planning areas within the PG&E system are provided in section 2.5.

Since the studies analyzed the most critical conditions, the flows on the 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 retirement of several large OTC power plants in northern California, flow on Path 26 between northern and southern California was modeled in the 2021 and 2026 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	2018 Summer Peak	2018 Spring Off-Peak	2021 Summer Peak	2021 Spring Light Load	2026 Summer Peak	2026 Summer Partial Peak	2026 Spring Off-Peak	2018 Sensitivity Spring Off-Peak Max PV	2021 Sensitivity Summer Peak, High Renewables, Minimum Gas Gen.	2026 Sensitivity Summer Peak No BTM-PV
California-Oregon Intertie Flow (N-S) (MW)	4,760	-2,060	4,780	2,140	4,660	4,770	-1,960	-2,110	4,780	4,800
Pacific DC Intertie Flow (N-S) (MW)	2,960	0	2,800	2,800	2,240	2,440	0	0	2,780	2,260
Path 15 Flow (S-N) (MW)	-1,150	4,890	-870	-690	-400	1,710	4,820	4,890	3,310	755
Path 26 Flow (N-S) (MW)	3,550	-750	3,150	1,000	450	-2,980	-2,700	-340	-1,610	-900
Northern California Hydro % dispatch of nameplate	82	82	84	74	84	56	59	82	84	84

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 50-60 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.

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.

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

Scenario	Area	Net Load * (MW)	Loss (MW)	Total (MW)
2018 Summer Peak	PG&E	27,283	1,043	28,326
	SDG&E	5,427	213	5,640
	SCE	24,433	426	24,859
	ISO	57,143	1,682	58,825
2018 Spring Off-Peak	PG&E	18,116	901	19,017
	SDG&E	3,381	77	3,458
	SCE	8,495	140	8,635
	ISO	29,992	1,118	31,110
2021 Summer Peak	PG&E	27,280	1,012	28,292
	SDG&E	5,195	214	5,409
	SCE	23,980	529	24,509
	ISO	56,455	1,755	58,210
2021 Spring Light Load	PG&E	15,936	573	16,509
	SDG&E	3,381	92	3,473
	SCE	8,495	181	8,676
	ISO	27,812	846	28,658
2026 Summer Peak	PG&E	27,318	960	28,278
	SDG&E	5,245	157	5,402
	SCE	24,314	464	24,778
	ISO	56,877	1,581	58,458
2026 Summer Partial Peak	PG&E	27,187	894	28,081
	SDG&E	5,245	154	5,399
	SCE	24,314	478	24,792
	ISO	56,746	1,526	58,272
2026 Spring Off-Peak	PG&E	18,462	771	19,233
	SDG&E	2,654	42	2,696
	SCE	11,294	204	11,498
	ISO	32,410	1,017	33,427
2018 Sensitivity Spring Off-Peak Max PV	PG&E	17,215	872	18,087
	SDG&E	3,381	78	3,459
	SCE	8,495	138	8,633
	ISO	29,091	1,088	30,179
2021 Sensitivity Summer Peak, High Renewables, Minimum Gas Gen.	PG&E	24,802	1,116	25,918
	SDG&E	5,195	200	5,395
	SCE	20,683	429	21,112
	ISO	50,680	1,745	52,425
2026 Sensitivity Summer Peak No BTM-PV	PG&E	29,138	1,042	30,180
	SDG&E	5,245	156	5,401
	SCE	24,314	455	24,769
	ISO	58,697	1,653	60,350

* Net load is the effective load after subtracting distributed generation (DG)

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:

Category P0: One overload (Los Banos-Quinto 230 kV line) and one heavily loaded line (Moss Landing – Las Aguilas 230 kV) were identified on the PG&E Bulk system in the off-peak base cases. The Moss Landing – Las Aguilas 230 kV, was identified as overloaded under normal system conditions in the off-peak sensitivity case. The same transmission lines were also overloaded with single and double contingencies. A possible solution is to use congestion management to reduce loading on the transmission line. Another solution may be an upgrade of the overloaded lines if it appears to be economic.

Two Category P1 overloads (two circuits in the same corridor) under summer peak conditions and four overload under off-peak conditions were identified, including two transmission lines overloaded and heavily loaded under P0 conditions. Same facilities were also overloaded in the sensitivity cases with higher loadings. Possible solutions are to use congestion management to bypass series capacitors on the Round Mountain-Table Mountain 500 kV lines should they overload under peak load conditions. Another solution to mitigate the Round Mountain-Table Mountain overload is to operate the system within the seasonal COI nomogram. 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. Other overloaded facilities with the Category P1 contingencies in addition to the Los Banos-Quinto and Moss Landing – Las Aguilas 230 kV lines included Round Mountain and Olinda 500/230 kV transformers that may overload under off-peak conditions when an outage of Olinda 500/230 kV transformer may overload the Round Mountain 500/230 kV transformer and vice versa. The mitigation is congestion management by reducing Pit River generation or using and modifying the existing Colusa SPS.

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 under off-peak conditions. 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 Moss Landing-Los Banos 500 kV line along with the outage of Moss Landing -Tesla 500 kV line appeared to be the most severe. 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 at the low output and new renewable project connected to the Moss Landing-Panoche and Panoche-Coburn 230 kV lines is at the high output. In the studies, it was assumed that the Moss Landing #6 and #7 units are retired and the units # 1 and # 2 are re-powered at the 85% of their capacity. Potential mitigation measures may include: using short-term ratings for the overloaded transmission line, increasing generation from Moss Landing and reducing generation from the new project, and dispatching all available generation in San Jose.
- 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, Moss Landing-Coburn 230 kV line, Los Esteros-Newark 230 kV line, Trimble-San Jose B 115 kV line and Los Banos-Quinto 230 kV line. 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. Trimble-San Jose B 115 kV line may overload with 500 kV Category P6 contingencies between Metcalf, Tesla, Los Banos and Moss Landing also under peak load conditions if generation in San Jose is low.
- 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 or Midway 500/230 kV transformer banks with an outage of two parallel transformers under off-peak conditions. These overloads 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 for Metcalf, and reducing some generation at Midway for the Midway transformer overload. Other overloaded facilities identified in the P6 contingencies studies were Olinda 500/230 kV transformer under 2018 off-peak conditions, Tracy 500/230 kV transformers #1 and #2 under summer partial peak conditions in 2026 and Cottonwood-Round Mountain #3 230 kV line under summer peak and 2018 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 contingencies only under 2018 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 P6 contingencies,

may be limiting COI within the seasonal nomograms or reducing Pit River generation after first contingency.

- Studies of the Summer Peak cases and 2026 partial 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. Some of the overloads are addressed if the COI flow was reduced to 3200 MW after the first contingency which is required by the COI Operational procedure. Mitigation solutions for remaining overloads may be reducing COI below 3200 MW after the first contingency, or bypassing series capacitors on the overloaded transmission line.
- Studies of the 2018 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 P7 contingencies in 2018 summer peak case. The limiting element is terminal equipment which is planned to be upgraded by PG&E.
- Other Category P6 overloads were identified in the 2018 and 2021 summer peak case in the Palermo-Rio Oso area (Pease-Palermo 115 kV in the 2021 sensitivity case and Rio Oso-Greenleaf tap 115 kV in 2018 peak case). 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 two N-1-1 outages under 2018 and 2026 off-peak conditions. This overload can be mitigated by reducing generation from the future renewable project connected to this transmission line. Morro Bay-Switching Station # 1 and # 2 sections of the Morro Bay- Midway 230 kV circuits may overload with Category P6 contingencies of the parallel 230 kV line and one of the 500 kV facilities in the area under off-peak load conditions. The mitigation will require reducing generation from the Topaz renewable project. The Tesla-Los Banos 500 kV transmission line may 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 or reducing Path 15 flow.
- Delevan-Cortina 230 kV line was identified as overloaded for several Category P6 contingencies under peak load conditions and for a Category P7 contingency in the 2026 Summer Peak case without behind-the-meter generation. Possible solutions are to use congestion management or to re-rate or upgrade this line. Delevan-Cortina 230 kV line overload substantially depends on the output of Colusa generation. Its overload was not identified for other contingencies in the base case because in these cases Colusa power plant was not fully dispatched.

There were 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, Table Mountain-Rio Oso 230 kV lines and Pease-Rio Oso 115 kV and Bogue-Rio Oso 115 kV lines. While the South of Palermo project addresses the issues on 115 kV lines, potential mitigation measures for other line overloads are as follows: operate COI within the seasonal nomogram, upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line, possible upgrade of Cottonwood-Round Mountain 230 kV line #3 line.
- Under off-peak conditions, Category P7 contingency overload included overload on the Los Banos-Quinto, Moss Landing–Las Aguilas, and Los Banos-Panoche 230 kV lines. These overloads may be mitigated by congestion management or tripping some generation in the area.
- No overloads were identified under minimum load conditions for the Category P7 contingencies

The ISO-proposed solutions to mitigate the identified reliability concerns are to manage COI flow according to the seasonal nomogram, to implement congestion management, as well as possible upgrade of the Cottonwood-Round Mountain 230 kV line #3 if it appears to be economic, 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 identified high voltages in the 500 kV system in Central California starting from 2026 when Diablo Canyon Nuclear Power Plant retires. The ISO is considering installing additional reactive devices - preferably dynamic - so that they could both absorb reactive power under normal system conditions and supply reactive power with contingencies as needed. The ISO is working with PG&E on the reactive modeling and will be conducting a detailed assessment to determine reactive needs on the bulk system in the 2017-2018 Transmission Planning Process.

High voltages were identified on the sub-transmission system under off-peak conditions as well. These were due to large amount of renewable generation connecting to this system. If the new renewable generation projects have the ability to absorb reactive power, the voltages in the sub-transmission system will be more manageable.

The sensitivity studies identified insufficient reactive margin with several contingencies in the 2021 Summer Peak case with high renewable and low gas generation. The reason for insufficient reactive margin was that several conventional generation units in Northern California were off-line in this sensitivity case and high output from renewable resources was mainly in Central California. In addition, the renewable projects did not provide as much of the reactive support as the conventional units. A potential mitigation solution is to install additional dynamic reactive support in Central and Northern California 500 kV system in case of high penetration of renewable resources that would cause many conventional generation units to mainly be offline. Another solution is to keep conventional units online so that they would provide necessary reactive support.

In the dynamic stability studies, the load in WECC, including the ISO, was modeled with WECC composite load models. In addition to loads, behind the meter distributed generation (solar PV) was explicitly modeled as well. The dynamic studies showed that in case of three-phase faults, some load and some of the distributed generation in the vicinity of the fault will be tripped by under-voltage protection. Assuming the composite load models are accurate, the load tripping following certain three-phase faults may be rather significant. Single-phase-to-ground faults either did not identify any loss of load, or the loss of load was very insignificant. 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.

The stability studies identified several possible modeling issues that that will be reported to WECC and to the generation owners, so that the equipment will be re-tested to update the model parameters.

Request Window Proposals

Creekside 400 MW Battery Energy Storage System (BESS)

This project was submitted in the 2016 Request Window as a transmission solution to resolve several 230 kV transmission facilities overloads that may occur with Category P6 contingencies of the loss of 500 kV transmission lines between Metcalf, Moss Landing and Tesla. The overloads were observed primarily in off-peak conditions with high renewable generation and low generation from the Moss Landing Power Plant. The project was proposed by a non-PTO entity.

The Creekside BESS project will be nominally rated at 418 MW, 4 hours (1672 MWh) configured in racks connected in strings to bi-directional inverters and transformers. It is proposed to be connected to the Metcalf-Moss Landing 230 kV line #1 by two 230/34.5 kV transformers. The estimated cost of the proposed Creekside 400MW BESS Project is $509 million in 2020 dollars with an estimated in-service date of 2020.

The ISO reviewed this proposal and determined that there is no need for this project at this time. Therefore, the project was not recommended to be approved. More details about the ISO review of this project are provided in Appendix B.

2.5 PG&E Local Areas Assessment

In addition to the PG&E bulk area study, studies were performed for the eight PG&E local areas. The ISO also conducted a separate and standalone review of a 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 or put on hold for further review in future planning cycles, and these recommendations are noted on tables 7.1.1 and 7.1.2 of chapter 7. In reviewing those projects, the results set out in sections 2.5.1 through 2.5.8 were reviewed to ensure that cancelling or putting those projects on hold did not affect the result and recommendations in sections 2.5.1 through 2.5.8.

To address the identified voltage criteria violations, the ISO is planning to perform system-wide voltage assessment studies on the PG&E system as part of the 2017-2018 transmission planning process. The objective of the study is to ensure that the location, type, size and timing of different voltage support devices are optimally selected and are well coordinated with major changes in the system such as the retirement of the Diablo Canyon nuclear power plant. In addition, the ISO will be working with PG&E to assess any modeling related issues such as transformer tap settings and reactive load requirements. Until the solutions are identified, approved and in-service, operating action plans will be relied upon to address the thermal overloads and voltage issues.

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 PG&E Humboldt area.

Humboldt's electric transmission system is comprised of 60 kV and 115 kV transmission facilities. Electric supply to this area is provided primarily by generation at Humboldt Bay power plant 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 2016-2017 transmission planning studies, a summer peak and winter peak assessment was performed. In addition, the spring off-peak condition for 2018 and spring light load condition for 2021 assessments were also performed. For the summer peak assessment, a simultaneous area load of 131 MW in the 2021 and 135 MW in the 2026 timeframes were assumed. These load levels include the Additional Achievable Energy

Efficiencies (AAEE). For the winter peak assessment, a simultaneous area load of 131 MW and 135 MW in the 2021 and 2026 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 2018, 2021 and 2026. In addition, a 2018 spring off-peak condition and a 2021 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 172 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 ISO performed additional sensitivity studies that assess the impact of qualifying facility retirements. Table 2.5-1 lists a summary of the generation resources in the Humboldt area with detailed generation listed in Appendix A.

Table 2.5-1: Humboldt area generation summary

Generation	Capacity (MW)
Thermal	205
Hydro	5
Biomass	37
Total	247

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)		
	2018	2021	2026
Humboldt	141	131	135

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)		
	2018	2021	2026
Humboldt	145	141	135

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;
- Four Category P1 thermal loading concerns were identified for five facilities;
- Five Category P2 thermal loading concerns were identified for five facilities. The facilities identified for the Category P2 contingency overloads were the same as those that resulted from the Category P1 contingencies;
- Two Category P3 thermal loading concerns were identified;
- Five Category P6 thermal loading concerns were identified;
- One Category P7 thermal loading concerns were identified;

The transmission facilities that experienced thermal loading concerns in this planning cycle for the Humboldt area are primarily along the Humboldt Bay-Rio Dell Jct 60 kV, Rio Dell Jct-Bridgeville 60 kV, Bridgeville-Garberville 60 kV and Garberville-Willits 60 kV line sections.

- Low voltages and voltage deviations were observed at the Bridgeville 115 kV Substation for a Category P2-3 contingency.
- High voltages were observed at both the Bridgeville and Humboldt 115 kV Substations as well as the Bridgeville-Garberville 60 kV systems for Category P1 through P6 contingency conditions.
- Voltage deviations were observed at the Bridgeville 115 kV and Garberville 60 kV substations for Category P2 contingency conditions.
- Voltage and voltage deviation concerns were identified on several 60 kV buses along the Bridgeville-Garberville 60 kV and Garberville-Laytonville 60 kV lines in the summer and winter peak conditions for various contingencies categories.
- Low voltages and voltage deviations may occur for various contingency categories prior to the new Bridgeville-Garberville 115kV line coming into service;

A number of transient stability concerns were identified under various summer peak loading scenarios for Category P1 through P7 contingency conditions. The transient stability analysis was conducted with generic protection clearing times. The ISO recommends that PG&E review and upgrade the protection systems for the transient conditions identified. The ISO will continue to monitor this issue in future planning cycles.

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

- The new Bridgeville-Garberville 115 kV transmission line project that was approved in the 2011-2012 transmission plan. This transmission was approved to address the overloads on the various 60 kV line sections in the Bridgeville-Mendocino 60 kV corridor that are expected under multiple contingencies categories as well as solve voltage concerns in the Bridgeville area. As identified in section 2.9, the ISO will be reviewing the scope of this project in the 2017-2018 transmission planning process.

The voltage concerns in the Humboldt and Bridgeville 60 kV system were observed 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 via existing action plans and operating procedures.

No capital project proposals were received 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 666 MW in 2021 and 758 MW in 2026 time frames was assumed. For the winter peak assessment, a simultaneous area load of 737 MW and 732 MW in the 2021 and 2026 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 667 MW and 751 MW in the 2021 and 2026 time frames was assumed. For the winter peak assessment, a simultaneous area load of 682 MW and 685 MW in the 2021 and 2026 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 2018, 2021 and 2026. Additionally a 2021 summer light Load condition and a 2018 spring 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. 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	1,453
Biomass	6
Total	**1539**

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 2.5-5: 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)**		
	2018	**2021**	**2026**
North Coast	718	666	758
North Bay	707	667	751

Table 2.5-6: 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)		
	2018	2021	2026
North Coast	741	737	732
North Bay	683	682	685

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 P0 thermal loading concerns were found in this planning cycle.
- Four Category P1 thermal concerns were found in this year's analysis.
- Overall there were 15 Category P2, 2 Category P3, 8 Category P5, and 10 Category P7 thermal overloads identified.
- 42 Category P6 contingency thermal loading concerns were identified.
- Low voltage violations have been identified for Category P2, P6 and P7 contingency conditions.
- Voltage deviation concerns were identified for Category P2 and P7 contingency conditions.
- High voltages were identified under non peak base case/normal loading conditions.
- A number of transient stability concerns were identified under various summer peak loading scenarios for Category P1 through P7 contingency conditions. The transient stability analysis was conducted with generic protection clearing times. The ISO recommends that PG&E review and upgrade the protection systems for the transient conditions identified. The ISO will continue to monitor in future planning cycles.

The identified violations will be addressed as follows:

- Most of the observed Category P1 through 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 interim action plans and operating procedures as required including appropriate mitigation for the identified high voltages under non-peak base case or normal system conditions.

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:

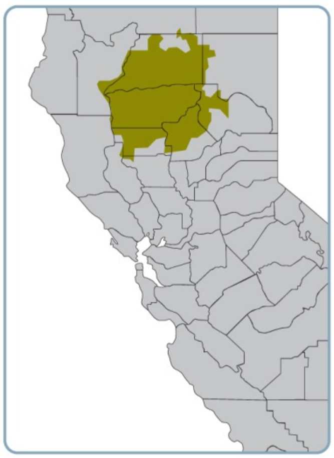
- Fulton-Fitch Mtn 60 kV Line Reconductoring
- Fulton 230/115 kV Bank
- Ignacio-Alto 60 kV Line Voltage Conversion Project;
- Clear Lake 60kV system reinforcement project;
- Napa-Tulucay No. 1 60 kV Line Upgrade;
- Big River SVC.

No capital project proposals were received in this planning cycle for the North Coast North and Bay planning areas.

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 894 MW by 2026.

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 2.5-7 lists a summary of the generation in the North Valley area with detailed generation listed in Appendix A.

Table 2.5-7: 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 2.5-8 shows loads modeled for the North Valley area assessment.

Table 2.5-8: Load forecasts modeled in the North Valley area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area Name	**Summer Peak (MW)**		
	2018	**2021**	**2026**
North Valley	884	898	927

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 2016 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.
- Three facilities were identified with thermal overloads for Category P1 performance requirements. Five facilities were identified with low voltage concerns and four facilities were identified with high voltage deviations.
- Seven facilities were identified with thermal overloads for Category P2 performance requirements. Six facilities were identified with low voltage concerns and nineteen facilities were identified with high voltage deviations.
- Six facility was identified with thermal overloads for Category P3 performance requirements.
- Twenty three facilities were identified with thermal overloads for Category P6 performance requirements.
- Two facilities were identified with thermal overloads for Category P7 performance requirements.

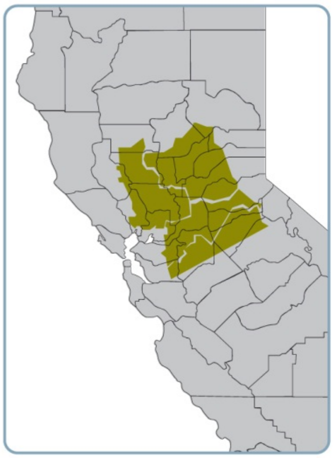
This year's reliability assessment of the PG&E North Valley area identified several reliability concerns that consist of thermal overloads and low voltages under normal or Category P0 operating conditions and Category P1, P2, P3, P6 and P7 contingency conditions. The ISO's previously approved solutions 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.

No capital project proposals were received in this planning cycle for the North Valley planning areas.

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.



Sacramento Division

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.

Sierra Division

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

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

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 area experiences its highest demand during the summer season. Load forecasts indicate the Central Valley should reach its summer peak demand of 3,894 MW by 2026.

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 2.5-9 lists a summary of the generation in the Central Valley area with detailed generation listed in Appendix A.

Table 2.5-9: 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. Note that the net load levels are shown in Table 2.5-10 which are the gross load minus AAEE and BTM-PV. For example in 2026, the gross summer peak load in Central Valley area is 4,512 MW but after considering the impact of 258 MW of AAEE and 360 MW of BTM-PV, the net load is 3,894 as provided in Table 2.5-10.

Table 2.5-10: Load forecasts modeled in the Central Valley area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area	**Summer Peak (MW)**		
	2018	**2021**	**2026**
Sacramento	1,110	1,047	1,119
Sierra	1,180	1,091	1,200
Stockton	1,327	1,251	1,300
Stanislaus	283	260	275
TOTAL	**3,890**	**3,649**	**3,894**

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 2016-2017 reliability assessment of the PG&E Central Valley area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P0 to P7 contingencies. The ISO previously approved solutions will address overload concerns in the long term, with the exception of the minor overload (2%) on the Nicolaus-Marysville 60 kV Line that occurs in 2026. A potential mitigation measure is to reconductor the line. The ISO will continue to monitor the loading on the line and will initiate a project to solve the issue. To address the identified voltage criteria violations, the ISO is planning to perform system-wide voltage assessment studies on the PG&E system as part of 2017-2018 transmission planning process as described in section 2.5.

Request Window Proposals

<u>Placer 115 kV Area Voltage Support</u>

The Placer 115 kV Area Voltage Support project was submitted in the 2016 Request Window by PG&E as a transmission solution to address voltage issues in Placer County. PG&E proposed to install a +100/-200 Mvar SVC at Placer substation to address both high and low voltage issues. High voltage issues occur under off-peak load with high levels of BTM-PV. Low voltage occurs for the loss of 230 kV sources under clearance conditions, especially from Gold Hill. The project is estimated to cost between $30M and $40M and the expected ISD is December 2022.

The ISO will assess this project as part of the system-wide voltage assessment studies on PG&E system in future planning cycles.

<u>Central Valley Cortina 230 kV 50 MW Battery Energy Storage System (BESS)</u>

This project was submitted by Exelon Transmission Company, LLC in 2016 Request Window as a transmission solution to address category P7 reliability issues on the Delevan to Cortina 230 kV line that was identified in the ISO's 2016-2017 Reliability Assessment.

The project scope includes a 50 MW, 200 MWh BESS that will be installed in a new substation next to the Cortina substation. The cost estimate for the project is $72M in 2017 dollars with expected ISD of Dec 2020.

The ISO reviewed different mitigation measures including the proposed project to address the reliability issues. The ISO concluded that since the overload occurs only in year 2021 under category P7 contingency conditions, an SPS alternative would be a more cost effective solution for this reliability issue.

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 2.5-11 lists a summary of the generation in the Greater Bay area, with detailed generation listed in Appendix A.

Table 2.5-11: 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 2.5-12: Summer Peak load forecasts for Greater Bay Area assessment

1-in-10 Year Non-Simultaneous Load Forecast			
PG&E Area	**Summer Peak (MW)**		
	2018	**2021**	**2026**
East Bay	921	869	890
Diablo	1,598	1,519	1,612
San Francisco	916	873	898
Peninsula	858	800	814
Mission	1,223	1,155	1,211
De Anza	920	861	877
San Jose	1,796	1,669	1,758
TOTAL	8,232	7,745	8,060

Table 2.5-13: 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)**		
	2018	**2021**	**2026**
San Francisco	967	956	945
Peninsula	899	880	854

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 2016-2017 reliability assessment of the PG&E Greater Bay Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies that are addressed by previously approved projects.

No capital project proposals were received in this planning cycle for the Greater Bay planning areas.

East bay Area Sensitivity Study

The load forecast in East Bay area decreased by about 4% from last year's 2025 to this year's 2026 case due to increases in behind-the-meter DG and AAEE. As such the extent of reliability issues in East Bay area reduced slightly compared to last year's assessment without the local generation being available. With the reliance on aging generation in the area, the ISO is continuing to assess the transmission needs in the East Bay area without the generation being available.

The ISO is working with the Oakland generator owner to assess the expected life of the existing generation prior to recommending any alterative developments as the existing generation and previously approved projects mitigate the issues in the area.

The alternatives that the ISO assessed in the 2015-2016 transmission planning process are remain valid to address the identified need. The preferred alternative at this time is a combination of transmission and non-transmission mitigation solutions:

- the P2 bus-tie breaker contingencies would be addressed by installing an additional bus-tie breakers at Moraga, Station X and Claremont; and,
- the P6 contingencies would addressed by the procurement of preferred resources in the area. This could involve a portfolio of demand response, energy efficiency, distributed generation and storage to meet the area requirements based upon the load profile.

The ISO will continue to work with the Oakland generator owner and reassess the situation assess in the 2017-2018 transmission planning process.

Request Window Submission – Caltrain Electrification Project- Load Interconnection

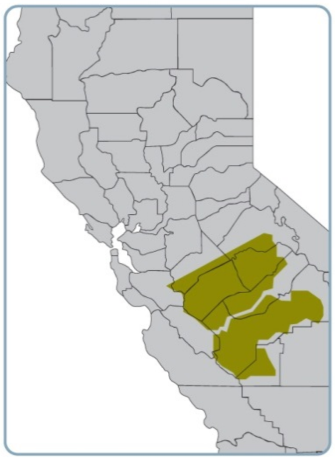
PG&E submitted two large load interconnection projects for ISO's review and approval. These projects support the Caltrain Electrification Project, led by the Peninsula Corridor Joint Powers Board, which consists of the electrification of Caltrain's commuter rail corridor between San Francisco and San Jose and covers a distance of over 50 miles. These projects propose to interconnect the Caltrain Rail system to PG&E's transmission system via two Traction Power Substations (TPS) near PG&E's East Grand 115 kV substation in South San Francisco and FMC 115 kV substation in South San Jose, as well as address an increase in load resulting from the future Blended System Project (Caltrain and California High-Speed Rail blended service). These projects (including radial lines to the TPS) are expected to cost approximately $228 Million with a requested in-service date of June 2020.

The ISO has reviewed the interconnections proposed by PG&E and worked with PG&E to evaluate alternative interconnection configurations. The alternative configurations were found to be infeasible. As such, the ISO concurs with the proposed interconnections.

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	1389
Hydro	1892
Solar	2234
Biomass	150
Behind the meter	283
Total	**5948**

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)		
	2018	2021	2026
Yosemite	921	897	991
Fresno	2357	2214	2744

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 2016-2017 reliability assessment of the PG&E Greater Fresno Area has identified several reliability concerns consisting of thermal overloads under Category P1 to P7 contingencies.

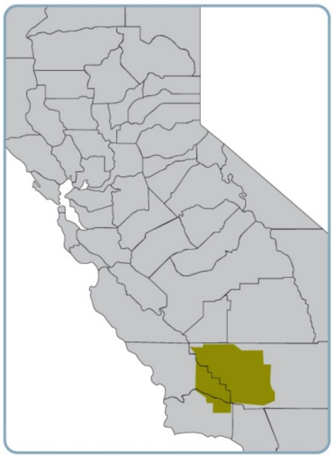
- The Fresno Area has over 30 previously approved TPP projects with the majority of them still needed to mitigate the identified 2016-2017 reliability assessment violations.
- Operations action plans are being developed for overloads which are in the near term years and have projects mitigating them in future years.
- Newly identified violations with long lead times will be monitored in the future TPP cycles.

No capital project proposals were received in this planning cycle for the North Coast North and Bay planning areas.

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 gereration summary (2026)

Generation	Capacity (MW)
Thermal	3314
Hydro	28.7
Solar	565
Behind the meter	108
Total	**4014**

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)**		
	2018	**2021**	**2026**
Kern	1948	1876	2041

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 or single contingency (i.e., NERC Category P0 and P1) conditions.
- The summer reliability assessment for the PG&E Kern area performed in 2016 confirmed the previously identified reliability concerns and their associated mitigation plans. The concerns were thermal overloads, low voltages, voltage deviations, and some transient stability issues.

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.

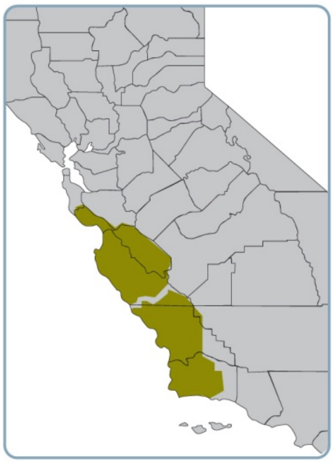
In the interim, all the previously identified action plans and operating procedures including the Semitropic and Famoso summer operating procedures will continue to be in effect until the corresponding approved projects are in-service.

No capital project proposals were received in this planning cycle for the Kern planning areas.

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 687 MW and 561 MW, respectively, by 2021. By 2026, the summer peak loading for Central Coast and Los Padres is forecasted to rise to 671 MW and 573 MW, respectively. Winter peak demand forecasts in Central Coast are approximately 648 MW in 2021 and 633 MW in 2026. 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. Table 2.5-19 and Table 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)**		
	2018	**2021**	**2026**
Central Coast	679	690	713
Los Padres	561	572	596
Total	**1240**	**1262**	**1309**

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)**		
	2018	**2021**	**2026**
Central Coast	639	650	672
Los Padres	563	574	597
Total	**1202**	**1224**	**1269**

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 2016 confirmed the previously identified reliability concerns and their associated mitigation plans.

The 2016 reliability assessment of the PG&E Central Coast area revealed several reliability concerns. These concerns consist of thermal overloads and low voltages under Categories P1, P2, P3, P6 and P7 contingencies.

- One facility was identified with thermal overloads for Category P1 performance requirements. Four facilities were identified with high voltage deviations.
- Eight facilities were identified with thermal overloads for Category P2 performance requirements. Four facilities were identified with low voltage concerns

- One facility was identified with thermal overloads for Category P6 performance requirements.

The 2016 reliability assessment of the PG&E Los Padres area revealed several reliability concerns. These concerns consist of thermal overloads and low voltages under Categories P1, P2, P3, P6 and P7 contingencies.

- Three facilities were identified with thermal overloads for Category P1 performance requirements. Six facilities were identified with high voltage deviations.
- Eight facilities were identified with thermal overloads for Category P2 performance requirements. Twenty one facilities were identified with low voltage concerns and eighteen facilities were identified with high voltage deviations.
- One facility was identified with thermal overloads for Category P3 performance requirements.
- Seventeen facilities were identified with thermal overloads for Category P6 performance requirements.

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 are no recommendations for new projects to be considered for approval for the Central Coast and Los Padres areas in this planning cycle.

2.5.9 Review of previously approved projects

As a part of the 2016-2017 transmission planning process, the ISO conducted a separate and standalone review of a number of low voltage transmission projects in the PG&E service territory that were predominantly load forecast driven and whose approvals date back several years to assess their potential cancellation. The ISO also reviewed the results set out in sections 2.5.1 through 2.5.8 to ensure that any project cancellation would not affect the results and ISO recommendations in sections 2.5.1 through 2.5.8. The ISO undertook this review because of changed assumptions – particularly current load forecast projects that differed considerably from the load forecasts that were in place when the ISO originally approved the projects. 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 ISO conducted the analysis on the system topology in the 2016 base case and with load levels escalated to the 2026 forecast. The ISO performed the assessment with base case forecast and the following sensitivities (similar to the sensitivity studies conducted in this planning cycle.):

- behind the meter PV off to represent the PV peak shift; and
- behind the meter PV off and with the without AAEE

Although this approach does not emulate all of the resource and bulk system changes expected to occur by 2026, it provides a reasonable basis for assessing local area issues. Further, the ISO reviewed results of this analysis and the results of the analysis set out in sections 2.5.1 through 2.5.8 for consistency.

Based on this analysis, the ISO found that 13 projects are no longer required based on reliability and local capacity requirements and deliverability assessments, and the ISO recommends cancelling these projects:

- Pease-Marysville #2 60 kV Line
- Almaden 60 kV Shunt Capacitor
- Monta Vista – Los Gatos – Evergreen 60 kV Project
- Lockheed No. 1 115 kV Tap Reconductor
- Mountain View/Whisman-Monta Vista 115 kV Reconductoring
- Stone 115 kV Back-tie Reconductor
- Kearney - Kerman 70 kV Line Reconductor
- Cressey - North Merced 115 kV Line Addition
- Taft-Maricopa 70 kV Line Reconductor
- Natividad Substation Interconnection
- Soledad 115/60 kV Transformer Capacity
- Tesla-Newark 230 kV Path Upgrade
- Vaca Dixon-Lakeville 230 kV Reconductoring

In addition, the ISO's review indicates that the following projects require further evaluation in future planning cycles. Although mitigation solutions continue to be needed for some of the issues addressed by these projects, the ISO must further evaluate the uncertainties in variations in load forecast and other parameters and reassess the scope of these projects.

The following five projects are in the late stages of design, siting, and permitting, and continuing the design, siting and permitting activities will assist in the review. However, the ISO is recommending that the project sponsors do not proceed with filings for permitting and certificates of public convenience and necessity for the following projects until the ISO completes the reviews:

- Midway-Andrew 230 kV Project
- Spring Substation
- Wheeler Ridge Junction Substation
- Lockeford-Lodi Area 230 kV Development
- Vaca-Davis Voltage Conversion Project

For the following projects, all development activities are recommended to be put on hold until a review is complete.

- Gates-Gregg 230 kV Line (see additional information in section 2.5.9.1)
- Watsonville Voltage Conversion
- Atlantic-Placer 115 kV Line
- Northern Fresno 115 kV Area Reinforcement[53]
- South of San Mateo Capacity Increase
- Evergreen-Mabury Conversion to 115 kV
- New Bridgeville Garberville No. 2 115 kV Line
- Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230 kV Substation Project
- Kern PP 115 kV Area Reinforcement
- Wheeler Ridge-Weedpatch 70 kV Line Reconductor[54]

In future planning cycles the ISO may again reassess previously approved transmission projects to determine if there are material changes in the assumptions supporting the need for previously approved projects.

2.5.9.1 *Gates-Gregg-230 kV Line Project*

The ISO approved the Gates-Gregg 230 kV Line project in the 2012-2013 transmission planning process as a Reliability Driven Project with renewable integration benefits. The reliability-driven need for the line was to increase the pumping opportunities at the Helms pumped storage/generation facility to ensure there would be adequate water available when the generation was called upon to support local area loads. The 2012-2013 transmission planning

[53] The Northern Fresno 115 kV Area Reinforecement is recommended to be on hold with the exception of the installation of sectionalizing breakers at McCall and Herndon substations that are recommened to proceed per the original scope of work for the previously approved project.

[54] The Wheeler Ridge-Weedpatch 70 kV Line Reconductor is recommended to be on hold with the exception of reconducting the 3/0 Cu section of the line between Weedpatch Substation and structure 9/199 (approximately 5.5 miles) is recommended to proceed to remove the shoofly that was installed in June 2013 as an temporary interim measure to address operational loading needs.

process identified that the availability of pumping would begin to decrease in the 2023 timeframe with inadequate pumping opportunities to provide sufficient water for generation to meet reliability needs in Fresno local area by the 2029 timeframe.

In this planning cycle, the ISO reassessed the need for the Gates-Gregg 230kV line using the assumptions in the 2016-2017 transmission planning process based upon the CEC 2015 IEPR energy and demand forecast that reflected a lower load forecast and increased behind the meter PV generation. The resulting lower forecast in the area potentially would allow for increased pumping capability, thus reducing the reliability need for local area support from the Helms generation to maintain reliability. The ISO's analysis indicates that the changed factors defer the reliability need by approximately 10 years.

In addition, increased behind the meter PV has changed the load profile in the area and would allow increased pumping during the day time periods, particular in the off-peak seasons when there is a potential for oversupply on the system. The ISO reviewed the benefits of the increased pumping capability on renewable integration and in particular avoided potential renewable curtailment during periods of oversupply. Although there are economic benefits for renewable integration, the economic savings are not presently sufficient to justify the cost of the project.

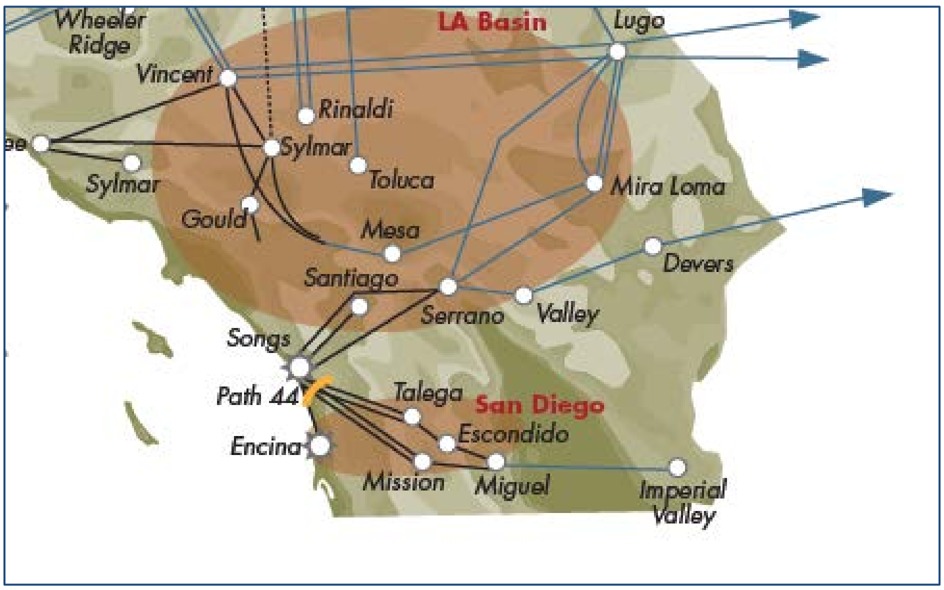
Also, there are uncertainties regarding renewable integration needs, and these need to be assessed further and taken into account. The ISO will study these issues in the 2017-2018 planning cycle. Given these uncertainties, the ISO is not recommending cancelling the project at this time despite recommending that no further development action be taken until the review is completed.

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 about 15 million people in a 50,000 square mile area of central, coastal and southern California, excluding the City of Los Angeles[55] and certain other cities[56]. 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 38.5 MW[57] on the average per year; however, after considering the projection for low additional achievable energy efficiency (AAEE), the demand forecast is declining at an average rate of 135.6 MW per year[58]. 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

[55] The City of Los Angeles' power need is served by the Los Angeles Department of Water and Power.

[56] Cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Pasadena, Riverside and Vernon have electric utilities to serve their own loads. The City of Cerritos Electric Department serves city-owned facilities, public and private schools and major retail customers.

[57] Based on the CEC-adopted California Energy Demand Forecast 2016-2026 (Updated Forecast) – Mid Demand Baseline Case, No AAEE Savings, January 2016 version

[58] Based on the CEC-adopted California Energy Demand Forecast 2016-2026 (Updated Forecast) – Mid Demand Baseline Case, Low AAEE Savings, January 2016 version

Metropolitan Water District of southern California pump loads. The 2026 summer peak forecast load, including system losses, is 23,552 MW[59]. The SCE area peak load is served by generation that includes a diverse mix of renewables, qualifying facilities, hydro and gas-fired power plants, as well as by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and the Desert Southwest.

SDG&E provides service to 3.4 million consumers through 1.4 million electric meters in San Diego and southern Orange counties. Its service area encompasses 4,100 square miles from southern Orange County to the U.S. and Mexico border. The existing points of imports are the South of SONGS[60] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2026 summer peak forecast load for the SDG&E area including system losses is 4,580 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 10,760 MW of generation (8,514 MW gas-fired generation and 2,246 MW San Onofre nuclear generation) in the region has been affected. A total of 4,062 MW of OTC-related electric generation has been retired since 2010. In the next three years, the remaining existing 6,698 MW of gas-fired generation is scheduled to retire to comply with the State Water Resources Control Board's Policy on OTC Plants. Some are scheduled to be replaced, such as Alamitos, Huntington Beach and Encina generation, albeit with lower capacity, through the CPUC long-term procurement plan for the local capacity requirement areas in the LA Basin and San Diego. Additionally, consistent with the CPUC's assigned commissioner's ruling addressing assumptions for the 2014 LTPP and 2016-2017 transmission plan[61] (the 2016-2017 LTPP/TPP A&S document), the ISO has also taken into account the potential retirement of 943 MW of aging non-OTC and mothballed generation in the area.[62]

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.[63] 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

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[59] Based on the CEC-adopted California Energy Demand Forecast 2016-2026 (Updated Forecast) – Mid Demand Baseline Case, Low AAEE Savings, January 2016 version

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

[61] 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.

[62] Includes generating units that are more than forty years of age, as well as units that have been mothballed by the owners.

[63] 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).

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, 5 MW of demand response, 37.92 MW of behind-the-meter solar photovoltaic 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 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 2016-2017 transmission plan studies for this area was to assess the adequacy of approved transmission and resource procurement authorizations with currently adopted 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 areas 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 5.1.1 and Appendix D provides further discussion and detailed results for the mid-term (2021) and long-term (2026) LCR study 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 a 1-in-10 year load forecast for the LCR areas only. The load forecast includes system losses. Table 2.6-1 provides a summary of the SCE and SDG&E area loads used in the regional bulk transmission summer peak assessment. Table 2.6-2 and Table 2.6-3 provide a summary for the 1-in-10 year peak demand for the LCR areas studied (i.e., Big Creek/Ventura, LA Basin and San Diego-Imperial Valley) for the mid-term (2021) and long-term (2026) LCR studies. The CEC-provided peak shift was added to the 1-in-10 peak demand for the LCR studies. The needs of the LA Basin area and San Diego sub-area have been considered taking into account the critical circumstances which include concerns for the potential of a peak shift issue associated with the impact of behind the meter solar generation and additional achievable energy efficiency.

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 (1-in-5) used in the regional southern California bulk transmission system assessment

	2018 (MW)	2021 (MW)	2026 (MW)
SCE Area	23,559	23,561	23,725
SDG&E Area	4,827	4,703	4,565
Total	28,386	28,264	28,290

Table 2.6-2: Summer peak load (1-in-10) plus peak shift used in the mid-term (2021) LCR assessments for the southern California LCR areas

LCR Areas	1-10 Peak Demand (MW)	Peak shift (MW)[64]	Total Adjusted Peak Demand (MW)
Big Creek/Ventura	3,772	77	3,849
LA Basin	19,268	238	19,506
San Diego	4,708	272	4,980

Table 2.6-3: Summer peak load (1-in-10) used in the long-term (2026) LCR assessments for the southern California LCR areas

LCR Areas	1-10 Peak Demand (MW)	Peak shift (MW)	Total Adjusted Peak Demand (MW)
Big Creek/Ventura	3,773	200	3,973
LA Basin	18,547	696	19,243
San Diego	4,587	720	5,307

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, western LA Basin, and the Moorpark subarea. For SDG&E, the CPUC approved a total of 800 MW of conventional (gas-fired) resources that include Pio Pico and Carlsbad Energy Center, but the procurement process for preferred resources is still ongoing.

[64] The CEC provided the ISO with calculated peak shift estimates for use with the CEC adopted 2015 IEPR 2016-2026 Mid Demand Base Case with Low AAEE.

Table 2.6-4: Summary of 2012 LTPP Tracks 1 & 4 Procurement (*)[65]

Area Name	Total (MW)	Gas-fired generation (MW)	Preferred Resources and Energy Storage (MW)	Assumed In-Service Date
SCE western LA Basin Area	1812.6	1382	430.6	2021
SCE Moorpark Area	274.16	262	12.16	2021
SDG&E Area	1100	800	93.5[66]	2017-2021
Total	**3256.76**	**2444**	**812.76**	

* 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.

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[67], 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. On May 26, 2016, the CPUC approved SCE-submitted LCR RFO for the Moorpark subarea. For the mid-term and long-term LCR analyses, the ISO modeled the approved procurements of local resources in the LA Basin and San Diego areas, as well as the Moorpark sub-area. A brief summary of the study results are included in chapter 5 with details provided in the 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

[65] Also see Table 4.7-7 of the ISO 2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan.

[66] Assumptions for preferred resources include 37.5 MW of battery energy storage (actual projects related to Aliso Canyon gas storage constraint), and proxy values for additional energy efficiency (22.4 MW) and demand response (33.6 MW).

[67] 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.

projection adjusted to include distribution loss avoidance. Table 2.6-4 summarizes the total AAEE modeled in the local reliability study cases.

Table 2.6-5: Summary of AAEE Assumptions

	2018 (MW)	2021 (MW)	2026 (MW)
SCE Area	491	919	1,658
SDG&E Area	112	197	344
Total	603	1,116	2,002

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[68] of October 16, 2014 in that proceeding established funding for 2015 and more importantly also established funding at the same (*i.e.,* 2015) level 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.

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 modeled two scenarios of DR as supply resource: one scenario assuming a base level of DR capacity that 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), and a second scenario assuming full

[68] 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)

availability of the 30-minute-responsive DR as described in the 2016-2017 LTPP/TPP A&S document.

The baseline amount continues to reflect the reasonable basis for long term planning at this time as the ISO/CPUC/PTO effort that is described in section 6.6 to determine the requirements for the slower-response resources to count for local resource adequacy on the basis of pre-contingency dispatch is still in progress.

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 locations for the demand response resources were provided by the utilities.

Table 2.6-6: Summary of Existing DR Assumptions

Service Area	Response time ≤ 20 minutes (MW)	Response time ≤ 30 minutes (MW)
SCE Area	547	986
SDG&E Area	19	19
Total	566	1005

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 “33% 2025 Mid AAEE" RPS trajectory portfolio. 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 0.369 (or 37 percent) peak impact factor per the Small Solar PV Operational Attributes from the 2016-2017 LTPP/TPP A&S document [69] on planning assumptions for the ISO 2016-2017 TPP power flow studies.

[69] Assigned Commissioner’s Ruling Adopting Assumptions and Scenarios for Use in the California Independent System Operator’s 2016-2017 Transmission Planning Process and Future Commission

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

Service Area	2026 (MW)
SCE Area	565
SDG&E Area	143
Total	**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)	18SP (MW)	21SP (MW)	26SP (MW)	18OP (MW)	21LL (MW)
Path 26	4000 (N-S)	4,042	4,008	2,996	-1,267 (S-N)	255
PDCI	3100	3100	3100	3100	466	1,550
SCIT	17,870	16,220	16,810	15,101	4,757	7,532
Path 45	800 (S-N) 408 (N-S)	98 (S-N)	55 (S-N)	30 (N-S)	61 (N-S)	49 (N-S)
Path 46 (WOR)	11,200	6,583	6,967	6,268	4,195	5,032
Path 49 (EOR)	9600	4,155	3,673	2,687	1,212	1,036

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 5 and Appendix D.

The SCE bulk transmission system reliability assessment identified several system performance issues under various contingency conditions. The issues identified can be mitigated in the operations horizon by operational measures such as reconfiguring the system or re-dispatching resources as discussed in Appendix B. As a result, no transmission upgrades are identified as a result of this bulk transmission system assessment.

2.6.3.2 *Conclusions of Mid-Term and Long-Term Local Capacity Requirement Assessments*

The ISO performed a mid-term (2021) and a long-term (2026) local capacity requirement assessments for the Big Creek-Ventura, Los Angeles Basin and the Greater San Diego-Imperial Valley areas. The following is the summary of findings:

- The CPUC-approved long-term local capacity procurement, together with the ISO Board-approved transmission upgrades, are needed to provide adequate resources to meet reliability requirements for the LA Basin and San Diego LCR areas and to enable compliance with the State Water Resources Control Board's Policy on once-through-cooled generation.
- The CPUC-approved long-term local capacity procurement for the Moorpark subarea is needed to provide adequate resources to satisfy reliability requirements for the area as well as complying with the State Water Resources Control Board's Policy on once-through-cooled generation.

Additional summary of the mid-term and long-term LCR assessments is provided in chapter 5, with further details provided in the Appendix D.

2.6.3.3 *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 2016-2017 Request Window. Also, the reliability assessment results did not indicate the need for additional resources beyond CPUC-approved and authorized procurements for the LTPP Tracks 1 and 4 for the combined LA Basin and San Diego area to meet local capacity area reliability requirements.

Request Window Proposals

The ISO has received the following project proposal in the Southern California Bulk Transmission System area through the 2016 Request Window.

Lake Elsinore Advanced Pumped Storage (LEAPS) and Talega–Escondido/Valley–Serrano 500 kV Interconnect Project (TE/VS)

LEAPS is a proposed 500 MW generation/600 MW pumping energy storage project with a capacity of 6,000 MWh. The project proposes to pump water from Lake Elsinore in Riverside County into a new impoundment to be constructed within the Cleveland National Forest at an elevation approximately 1,500 feet higher than Lake Elsinore. The TE/VS Project is a 32-mile-long, 500 kV transmission line interconnecting SDG&E"s existing Talega-Escondido 230 kV transmission line in or near Camp Pendleton in northern San Diego County with SCE's existing 500 kV Valley-Serrano transmission line in southwestern Riverside County. The TE/VS Project will also serve to interconnect LEAPS to the grid. The LEAPS Project has a proposed in-service date of December 1, 2021 and an estimated cost of $896 million. The TE/VS has a proposed in-service date of November 6, 2020 and an estimated cost of $760 million.

The Nevada Hydro Company submitted the LEAPS Project (together with the TE/VS Project) as a generation alternative and the TE/VS as a reliability transmission project, Location Constrained Resource Interconnection Facility (LCRIF) and a policy-driven project.

The ISO did not identify a reliability need for the TE/VS nor LEAPs in the current planning cycle and therefore the projects were found to be not needed for reliability purposes. Also, as discussed in chapter 3, no policy-driven transmission needs have been identified in this transmission planning cycle. The ISO is studying the benefits of the project as one of a number of pumped hydro storage sites for informational purposes, and those studies are discussed in chapter 6.

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:

- 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 in 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.

A summary of the generation in the Tehachapi and Big Creek areas is shown in Table 2.7-1. Detailed information about this generation is included in Appendix A.

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

Generation	Capacity (MW)
Thermal	1720.1
Hydro	1160.3
Wind	2968.1
Solar	2521.4
Total	**8369.9**

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 Tehachapi and Big Creek Corridor Coincident A-Bank Load Forecast (MW)

Load Forecast (MW)	2018	2021	2026
Total	1929	1896	1906

Study Scenarios

The Tehachapi and Big Creek Corridor study included five baseline and five 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				
2018 Summer Peak	2018 Spring Off-Peak	2021 Summer Peak	2021 Spring Light Load	2026 Summer Peak
Sensitivity scenarios				
2021 Summer Peak with High Load	2018 Summer Peak with no behind-the-meter PV	2026 Summer Peak with no behind-the-meter PV	2021 Summer Peak Heavy Renewable & Min Gas Gen	2021 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.

There were no thermal or voltage related concerns identified for the reliability assessment of the Tehachapi and Big Creek Corridor Baseline scenarios and four of the sensitivity scenarios. However, the 2021 Summer Peak with low hydro Sensitivity Scenario reliability assessment identified the following system performance concerns.

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

As documented in the 2016-2017 Transmission Study Plan section 4.7.4, the ISO considered drought conditions while establishing the hydroelectric generation production levels in the study cases. The ISO focused on the following four scenarios for the Big Creek & Tehachapi region to simulate low hydro conditions:

- 2018 Summer Peak base case (low hydro generation level)
- 2021 Summer Peak base case (low hydro generation level)
- 2026 Summer Peak base case (low hydro generation level)
- 2021 Summer peak sensitivity (extreme low hydro generation level)

The ISO worked with SCE to establish low Big Creek hydro study assumptions for base case and sensitivity scenarios.

- Summer Peak base cases: The existing Big Creek / San Joaquin Valley Remedial Action Scheme triggers load dropping at Rector and/or Liberty substations to mitigate overloads due to any one of the south of rector 220kV line N-1 contingencies. The ISO evaluated the minimum required Big Creek area generation to mitigate any N-1 overloads, without having to arm load. The ISO calculated the minimum total generation needed for 1308 MW Big Creek load levels to be 520 MW (380 MW hydro).

- 2021 Summer Peak sensitivity case: The sensitivity scenario models an extreme low hydro generation production level. The ISO analyzed the real time Big Creek generator data from summer 2015 to evaluate the periods of lowest hydro generation. Based on that, the ISO modeled total generation of 330 MW (240 MW hydro) in the Big Creek area.

The Tehachapi and Big Creek Corridor Baseline and Sensitivity Scenario reliability assessment also identified transient stability concerns under the 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.

2.7.1.4 *Request Window Proposals*

In response to the ISO study results and proposed alternative mitigations, two reliability project submissions were received through the 2016 request window.

Pittman Hill 230 kV Substation

NextEra Energy Transmission West, LLC (NEET West) proposed a $65 Million project to build a new Pittman Hill 230 kV substation that will tie the following transmission lines together:

- Helms – New E1 230 kV #1 & #2 Lines (PG&E)
- Big Creek 3 - Rector 230 kV Line #2 (SCE)
- Big Creek 4 - Springville 230 kV Line (SCE)
- Big Creek 1 - Rector 230 kV Line (SCE)

NEET West study results indicate that the proposed NEET West new 230 kV Pittman Hill substation resolves the CAISO identified P1, P3, and P6 contingency overloads identified in the CAISO 2016-2017 TPP analysis for low hydro sensitivity case.

The ISO has not found this project to be needed, as discussed below.

Big Creek Corridor Rating Increase

The project was submitted by Southern California Edison, to achieve capacity increases building upon other activities SCE is undertaking for purposes that are not subject to the ISO's transmission planning purposes. In early 2016, SCE decided to reconductor the Magunden-Vestal No. 1 and No. 2 and Rector-Vestal No. 1 and No. 2 230 kV lines in the Big Creek corridor using an Aluminum Conductor Composite Core (ACCC) conductor (714 kcmil “Dove”) as part of the Transmission Line Rating Remediation (TLRR) program coordinated with the CPUC to address the GO95 clearance issues. These circuits are among the locations on SCE's ISO controlled overhead transmission lines that did not meet clearance requirements per CPUC's General Order (GO) 95 that SCE provided to NERC in January, 2011.

Southern California Edison (SCE) proposed the Big Creek Corridor Rating Increase Project into this 2016-2017 planning cycle, which will increase the conductor rating of the Magunden-Vestal No. 1 and No. 2 and Rector-Vestal No. 1 and No. 2 230 kV lines in the Big Creek Corridor from a 4-hr emergency capacity of 936 amps to 1520 Amps. Work is needed to upgrade remaining limiting equipment in the line and increase the line ratings.

The planning level scope and cost estimate of the additional work is approximately $6 million and the scope includes the upgrade of four transmission structures and terminal equipment at Magunden and Vestal substations. The increase in ratings will eliminate the P1 (N-1) load shed during low hydro conditions. The scheduled completion date for this project is December 31, 2018. The ISO has found that this project is needed.

2.7.1.5 *ISO Assessment of Request Window Proposals*

The ISO reviewed the final reliability assessment results for the Big Creek area to evaluate potential mitigation options with respect to the identified need, including the projects submitted through the 2016 Request Window, and has identified potential benefits and a need for the Big Creek Corridor Rating Increase project in this year's planning assessment.

Several key factors were carefully considered in the evaluation of potential mitigation options for the Big Creek area and a narrative is provided below regarding the ISO's analysis of the Pitman Hill project alternative and the Big Creek Corridor Rating Increase Project alternative. Please refer to Appendix B for additional details.

Economic Factors:

Project Cost: Both the project proposals submitted through the 2016 Request Window mitigate the P1 (N-1) load shed during extreme low hydro conditions. The estimated cost of the proposed NEET West Pitman Hill substation is $65 million and the cost estimate for SCE Big Creek Corridor Rating Increase project is $6 million.

Big Creek Corridor Rating Increase project

- Stakeholders have raised questions in the ISO's planning process concerning the reconductoring of the four 230 kV transmission lines, including regarding the duration of outages associated with the reconductoring. However, the reconductoring of the transmission lines is not part of the proposed project subject to the ISO transmission planning process and is proceeding in any event. SCE's intention to reconductor the lines is a part of the CPUC approved Transmission Line Rating Remediation (TLRR) program to address the GO95 clearance issues. Additional outage times for the rating increase project that is being considered in this transmission planning process, which would resolve the identified overload and N-1 load drop, is minimal.
- The NEET West proposal also highlights power flow case divergence under couple of P6 outages in the Big Creek area with Big Creek Corridor Rating Increase project modelled.

The ISO observed this issue only in the extreme low hydro sensitivity scenario for N-1-1 and can be mitigated by system adjustments before the second contingency.

Transient stability issues

- The reliability assessment results show local instability following an outage of the Big Creek 1-Big Creek 2 230 kV line or the Big Creek 3 bus. As per the proposal submitted by NEET West, the Pittman Hill project will have a positive impact upon the local dynamic performance. However, SCE will be installing second (dual) high speed protection for this line with an in-service date of December 2017, so the instability issue needs no further mitigation.
- Midway extreme outage- The ISO did not identify any transient stability performance issues in and around Midway in this year's assessment.

PG&E system benefits

The Pitman Hill project submission states that the project appears to also mitigate thermal loading concerns in the PG&E 115 kV system around E1 substation following the simultaneous loss of Gregg-E1 230 kV Lines 1 & 2. Study results for the PG&E Greater Fresno area, as listed in Appendix C of this report, identify overloads only under one sensitivity scenario. The ISO did not identify overloads for any of the Base Case scenarios that were studied, and hence is not proposing upgrades.

Path 26 Benefits

The NEET West project proposal outlines benefits of this project in providing reduction to Path 26 flow by 450MW as an alternate/relief to Path 26 upgrades required for 33 percent and 50 percent RPS evaluation. The ISO has identified no Path 26 constraints as part of 2016-2017 reliability assessment. The ISO has also identified that no new system upgrades are needed to achieve the 33 percent RPS profile. Also, the 50 percent RPS portfolios are not final and special study results are for information only.

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 provides 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.

Transmission

The following transmission upgrades approved in prior transmission plan are modeled in the 2018, 2021 and 2026 study cases:

- Victor loop-in
- Kramer reactors

Generation

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 utilizes the CEC's 1-in-10 year heat wave load forecast. This load forecast includes 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 and spring off-peak base cases assume approximately 50 and 65 percent of the 1-in-2 year heat wave 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)			
Load Forecast (MW)	**2018**	**2021**	**2026**
Total	814	798	781

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 resulted in the following reliability concerns.

Steady-state assessment results

- Inyo 115 kV phase shifting transformer overload was observed under N-1, N-2 and N-1-1 contingency for spring off-peak and spring light load conditions. The recommended solution for this issue is to rely on a two-hour emergency rating of 90 MVA for the phase shifting transformer. If the overloading concern exceeds the two-hour emergency limit, precontingency congestion management can be utilized for the N-1 contingency. For the N-1-1 (or rather T-1-1) contingency condition, the High Desert Power Plant and Mohave Desert remedial action schemes (RAS) would be utilized to curtail generation to mitigate loading concerns.

- Case divergence was observed under T-1-1 contingency of Lugo 500/230 kV. The existing High Desert Power Plant and the Mohave Desert RAS would mitigate this reliability concern.
- Case divergence was observed for an N-1-1 contingency of Inyokern-Kramer 115 kV, followed by Inyokern –Tap 701 115 kV lines, or under an N-1-1 contingency of Inyokern-Kramer #1 115 kV, followed by Kramer – Inyokern – Randsburg #3 115 kV line. This would necessitate the need for an operating procedure to curtail generation as part system adjustment between contingencies.
- Case divergence was observed for the delayed fault clearing of either Kramer north or south 115 kV category P5.5 delayed clearing of bus fault. Delayed bus fault clearing may cause tripping up to nine 115 kV lines and two 230/115 kV transformer banks. Delayed fault clearing is caused by failure of a non-redundant relay. For bus fault delayed clearing, it falls within the category P5.5 of the NERC Standard TPL-001-4. The recommended mitigation for this reliability concern includes the following:
  - Further investigation by SCE transmission planning staff to confirm the study model of delayed clearing time as well as specific transmission facilities that are impacted and tripped as a result of the delayed bus section clearing.
  - If the delayed clearing time and impacted transmission facilities are validated, and the study still results in case divergence, a back-up relay will be investigated as potential mitigation option.
- Similar to the above reliability concern, case divergence was observed for the delayed fault clearing of Lugo 230 kV east or west bus fault. For this category P5.5 reliability concern, the recommended mitigation is similar to the mitigation discussed above.

Transient stability assessment results

In this planning cycle, there are six category P4.2 (stuck breaker), two category P5.5 (delayed bus fault clearing) and one P6.1.1 (overlapping N-1-1 transmission line outages) reliability concerns. The following is a summary of these reliability concerns:

Category P4.2 (stuck breaker) reliability concerns:

- Undamped voltage oscillations at and north of Randsburg 115 kV bus due to single-line-to-ground fault at Control on the Control – Casa Diablo 115 kV line with line clearing at Control end but no clearing at Casa Diablo end (30 seconds);
- No transient voltage recovery to 80% of pre-contingency voltage due to a single-line-to-ground fault at Kramer on the Kramer – Cool Water 115 kV line with line clearing at Kramer end but no clearing at Cool Water end;
- Undamped voltage oscillations north of Lugo 115 kV area due to a single-line-to-ground fault at Tortilla on the Cool Water – SEGS – Tortilla 115 kV line with line clearing at Tortilla end but no clearing at Cool Water end;
- Same results for the above but for the fault clearing at Cool Water end instead of at Tortilla end;

- No transient voltage recovery to 80% of pre-contingency voltage due to a single-line-to-ground fault at Kramer on the Kramer – Inyokern - Randsburg 115 kV line with line clearing at Kramer end but no clearing at Randsburg end;
- No transient voltage recovery to 80% of pre-contingency voltage due to a single-line-to-ground fault at Kramer on the Kramer – Tortilla 115 kV line with line clearing at Kramer end but no clearing at Tortilla end.

For all the above reliability concerns, it is recommended that a local breaker failure backup (LBFB) is evaluated as a potential option.

Category P5.5 (delayed bus fault clearing) reliability concerns:

Transient instability was observed for local area north of Lugo due to Lugo 230 kV east or west bus single-line-to-ground fault with delayed clearing (clearing in 15 cycles instead of 6 cycles).

For the above reliability concerns, it is recommended that back-up relay protection is considered as a potential mitigation.

Category P6.1.1 (normal three-phase fault clearing for an N-1-1 overlapping line outages) reliability concerns:

Undamped angular oscillation was observed for local area north of Kramer area due to overlapping outages of Kramer-Inyokern-Randsburg #1 115 kV, followed by the #3 line.

For the above reliability concerns, it is recommended an operating procedure to include generation curtailment as part of system adjustment between contingencies.

Post-transient stability assessment results

In this planning cycle, there are four category P5.5 (delayed bus fault clearing) reliability concerns for Control 115 kV northeast bus, Control 115 kV northwest bus, Control 115 kV southeast or southwest bus and Kramer 115 kV north (or south) bus. Case divergence was observed for these delayed bus fault clearing events. These category P5.5 reliability concerns have the following potential mitigation measures:

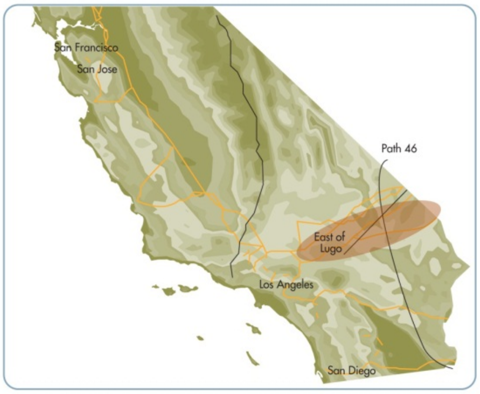
- Further investigation by SCE transmission planning staff to confirm the study model of delayed clearing time as well as specific transmission facilities that are impacted and tripped as a result of the delayed bus section clearing.
- If the delayed clearing time and impacted transmission facilities are validated, and the study still results in case divergence, a back-up relay will be investigated as potential mitigation option.

Details of the planning assessment results for north of Lugo area are included 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; is 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

There are no transmission upgrades modeled in 2018 study case. The transmission upgrades modeled in the 2021 and 2026 study cases are:

- Eldorado – Lugo 500 kV series capacitor and terminal equipment upgrade;
- Lugo – Mohave 500 kV series capacitor and terminal equipment upgrade;
- Re-route of the Eldorado – Lugo 500 kV Line

These upgrades were approved in 2012-2013 and 2013-2014 Transmission Plan as policy-driven projects.

In light of the FERC-approved transition agreement between ISO and Valley Electric Association, the planned interconnection tie between VEA's new Bob 230 kV Switching Station and SCE's new Eldorado 220 kV Substation is forecasted to be in-service by the end of 2018.

Generation

Over 600 MW of new renewable generation was modeled in this year's base cases compared to last year. In total, 1779 MW generation is modeled in 2018 cases in the East of Lugo area. There is approximately 832 MW of generation connected near the SDG&E owned Merchant substation and 947 MW of renewable generation connected to the Ivanpah system. However, some of the renewable generation is still under construction and is expected to be in service before 2018 summer. Table 2.7-6 lists the existing 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	525
Solar (including solar thermal)	605
Total	**1130**

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	2018	2021	2026
East of Lugo and Ivanpah 500/230 kV Area (MW)	13.7	12.8	14.0

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 2017-2026 reliability assessment for the SCE East of Lugo Area identified the following reliability concern that requires mitigation.

Steady State Assessment Results

In this planning cycle, the base case study identified two category P6 overloads issues and the sensitivity study identified one category P1 overload issue. Voltage concerns are able to be mitigated by the existing RAS in the area. The following is a summary of these concerns:

- Both Ivanpah 230/115 kV transformers were observed to be overloaded for the N-1-1 contingency of losing the Mountain Pass – Ivanpah 115kV Line and the other transformer.

- The Lugo – Victorville 500 kV line was observed to be overloaded for several N-1-1 contingencies involving 500 kV lines bringing power into Lugo 500 kV and into Devers 500 kV substations. The line would also be overloaded following the Eldorado – Lugo 500 kV single line outage in the 2021 summer peak heavy renewable sensitivity case.

Congestion management and line upgrades are recommended for the above issues.

Transient Stability Assessment Results

In this planning cycle, there are two category P4.2 stuck breaker reliability concerns. The following is a summary of these reliability concerns:

- Transient voltages dips were over 30% at the Cima and Pisgah 230 kV buses and the transient voltages fail to recover back to 80% of pre-contingency voltages due to a single-line-to-ground fault at Eldorado on the Eldorado – Cima – Pisgah 230 kV Line with line clearing at the Eldorado end but no clearing at the Pisgah end;
- The transient voltage dip was over 30% at Pisgah 230 kV bus and the transient voltage failed to recover back to 80% of pre-contingency voltage due to a single-line-to-ground fault at Lugo/Calcite on the Lugo/Calcite – Pisgah 230 kV Line with line clearing at the Lugo/Calcite end but no clearing at the Pisgah end.

For all the above reliability concerns, the ISO recommends installing Local Breaker Failure Backup (LBFB) at the Pisgah 230kV bus.

Post-transient Stability Assessment Results

In this planning cycle, Lugo – Victorville 500kV Line was found to be overloaded following the loss of the Lugo – Mohave and Eldorado – Lugo 500 kV lines after applying the planned Lugo – Victorville RAS. The ISO recommends line upgrades, described in the Lugo-Victorville 500 kV Request Window Proposal below, to address this concern.

2.7.3.4 *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 issues identified above.

Lugo-Victorville 500 kV Upgrade (SCE portion)

The project was submitted by Southern California Edison in the 2015 Request Window to address potential reliability needs. The Lugo-Victorville 500 kV transmission line is jointly owned by SCE and the Los Angeles Department of Water and Power (LADWP)[70]. 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

[70] Five of the Six Cities hold contractual entitlements to transmission service over the LADWP portion of this line, and one City has an entitlement to service through the Victorville substation. The ISO also has operational control over the Cities' entitlements to transmission service on the LADWP and SCE portions of the Lugo-Victorville 500 kV line and at the LADWP Victorville Substation.

LADWP's portion is $16 million. This is a joint project requiring the participation of both SCE and LADWP to complete, with an estimated in-service date of 12/31/2018.

2.7.3.5 *ISO Assessment of Request Window Proposals*

Based on the request window proposals submitted to the ISO, the following assessments were performed.

Lugo-Victorville 500 kV Upgrade (SCE portion)

In addition to the reliability needs SCE proposed the project to address, the ISO has also identified policy and potential economic benefits for the project. Overloading on the Lugo – Victorville 500 kV line was observed for several N-1-1 contingencies involving 500 kV lines bringing power into Lugo 500 kV and into Devers 500 kV substations. The line would also be overloaded following Eldorado – Lugo 500 kV single line outage in the 2021 summer peak heavy renewable sensitivity case. These constituted the reliability benefits the project would address.

The 33 percent RPS policy-driven studies documented in the CAISO's 2015-2016 Transmission Plan 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, resulting in economic impacts. In addition to the reliability and RPS policy-driven concerns, the accrued congestion cost of this constraint since January 2013 was found to be $61 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 aging generating units 40-year old or more 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 recognized that increasing the rating of Lugo-Victorville 500 kV line is needed and therefore, this project was found to be needed in the 2015-2016 Transmission Plan. While the project was found to be needed, the ISO deferred approving the project until this 2016-2017 transmission planning cycle, pending coordination with LADWP as a portion of this line is owned by LADWP. Over the course of 2016 the ISO worked with SCE and LADWP to coordinate the next steps on developing this project.

Recognizing that the benefit to LADWP – which also led to LADWP's interest in funding the LADWP portion of the upgrades - SCE and LADWP proposed to increase the rating of Path 46 West of the Colorado River ("WOR") through the WECC path rating process on October 7, 2016. This path rating increase will be made possible because LADWP and SCE are also pursuing upgrade projects involving existing transmission facilities on their respective transmission systems, which include the joint project to upgrade the Lugo-Victorville 500 kV line along with SCE upgrading series capacitors on the SCE Northern WOR 500 kV transmission lines, and LADWP upgrading series capacitors on LADWP's WOR 500 kV transmission lines. SCE's series capacitor project upgrades were previously approved by the ISO Board. LADWP plans to fund their portion of the Lugo-Victorville 500 kV line project, along with the cost of upgrading the LADWP owned series capacitors. The estimated cost of SCE's portion of the Lugo-Victorville 500 kV line project is $18 million, and this project has been found to be needed.[71]

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 recommends the following to address the reliability concerns identified:

- Modify the existing Ivanpah Area SPS to trip generation for the Eldorado 500/230 kV 5AA transformer bank contingency;
- Rely on the congestion management mechanism in the ISO market as needed;
- Coordinate with LADWP and SCE to upgrade the Lugo-Victorville 500 kV line as discussed in section 2.7.3.5.

[71] The ISO notes that various members of the Six Cities hold entitlements to transmission capacity over the LADWP portion of the line and at the Victorville Substation. To the extent that any of the $16 million cost of LADWP's portion of this project is recoverable from the Six Cities, the ISO expects that the Six Cities are entitled to reflect such costs in their respective Transmission Revenue Requirements. This reflects that the ISO's finding of need for this project pertains to the entirety of any project capacity that will be under the ISO's operational control.

2.7.4 SCE Eastern and MWD 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), 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 (2016);
- West of Devers Upgrade Project (2021), and
- Delaney-Colorado River 500 kV line Project (2020).

2.7.4.2 *Area-Specific Assumptions and System Conditions*

The SCE Eastern and Metropolitan Water District (MWD) 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 and MWD 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	856
Solar	926
Total	**3,288**

*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)			
	2018	**2021**	**2026**
Total	1,006	1,035	1,100

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
2018 Summer Peak	8 pumps/station	All units on
2021 Summer Peak	8 pumps/station	All units off
2026 Summer Peak	8 pumps/station	All units on
2018 Spring Off-Peak	0 pumps/station	All units on
2021 Spring 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 2017-2026 reliability assessment for the SCE Eastern and MWD Area identified the following reliability concern that requires mitigation.

The SCE Eastern and MWD area reliability assessment identified several system performance issues under various contingency conditions. The issues identified can be mitigated in the operations horizon by such operational measures as reconfiguring the system or re-dispatching resources as discussed in Appendix B. As a result, no transmission upgrades are identified for the Eastern and MWD area.

2.7.4.4 *Request Window Proposals*

The ISO has received the following project proposal in the Eastern area through the 2016 Request Window in connection with the reliability issue identified above.

AltaGas Loop-in Project

The project was submitted by AltaGas Services and consists of looping the existing privately owned Buck Boulevard-Julian Hinds 230 kV generation tie line into the Colorado River (or Red Bluff) 500 kV substation. The project creates a new 230 kV networked facility between Colorado River (or Red Bluff) and Julian Hinds and moves the point of connection of the Blythe generation facility to Colorado River (or Red Bluff). The project has an estimated cost of $41-59 million including the cost of the networked portion of the existing line. The proposed in-service date is June, 2020.

Desert Southwest Transmission Project (DSWTP)

The project was submitted by Regenerate Power LLC and consists of constructing a single circuit 500 kV transmission line connecting Colorado River and Devers substations. It will increase the import capacity between the Riverside County and the load center of Southern California. The project has an estimated cost of $370 million. The proposed in-service date is January, 2021.

Red Bluff-Mira Loma 500 kV Transmission Project

The Project was submitted by NextEra Energy Transmission West, LLC and consists of constructing a single circuit 500 kV transmission line connecting Red Bluff and Mira Loma substations with 50 percent series compensation. The project has an estimated cost of $1 billion. The proposed in-service date is 2023.

2.7.4.5 *ISO Assessment of Request Window Proposals*

Based on the request window proposals submitted to the ISO, the following assessments were performed.

AltaGas Loop-in Project

The need for this project was assessed as part of the 2014-2015 ISO transmission planning cycle, and was not found to be needed. As described above, the analysis in the 2016-2017 ISO transmission planning cycle did not find a reliability need for transmission projects in the Eastern and MWD area.

Desert Southwest Transmission Project (DSWTP)

The project has not been found to be needed at this time. There was no overloading found in the Colorado River corridor under N-1 or N-2 contingencies after the completion of the West of Devers upgrade project.

Red Bluff-Mira Loma 500 kV Transmission Project

The project has not been found to be needed at this time. There was no overloading found in the Colorado River corridor under N-1 or N-2 contingencies after the completion of the West of Devers upgrade project.

2.7.5 SCE Metro Area

2.7.5.1 *Area Description*

The SCE Metro area consists of 500 kV and 230 kV facilities that serve major metropolitan areas in the Orange, Los Angeles, Ventura and surrounding counties. The boundary of SCE 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 SCE Metro area.

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

- Mesa 500 kV Loop-In Project (12/31/2020);
- West of Devers Upgrade Project (8/1/2021);
- Orange Country Dynamic Reactive Support (12/31/2017);
- Laguna Bell Corridor Upgrade (12/31/2020);
- Lugo Substation - Install new 500 kV CBs for AA Banks (12/31/2020);
- Method of Service for Alberhill 500/115 kV Substation (6/1/2021); and
- Method of Service for Wildlife 230/66 kV Substation (6/1/2021).

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. The California Public Utilities Commission (CPUC) has authorized SCE to procure 1813 MW of local capacity in the LA Basin area and 274 MW in the Moorpark area to offset the retirements of SONGS and OTC generation.

2.7.5.2 *Area-Specific Assumptions and System Conditions*

The SCE Metro area study was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO secure market 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 SCE Metro area study are provided below.

Generation

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

Table 2.7-11: SCE Metro Area Existing Generation Summary

Generation	Capacity (MW)
Thermal	11,701[(1)]
Hydro	319
Solar	61
Biomass	140
Total	**12,221**

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

OTC generators were assumed to retire per their respective compliance dates. The local capacity resources that were authorized by the CPUC were modeled in the 2021 and 2026 base cases.

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 SCE Metro area 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 SCE Metro Area Assessment

SCE Metro Area Coincident 1-in-10 Year A-Bank Load Forecast (MW) (Note)			
Area	**2018**	**2021**	**2026**
Metro	20,302	19,925	19,376

Note: Load forecast values include the impact of additional achievable energy efficiency (AAEE) and behind-the-meter (BTM) PV.

Study Scenarios

The SCE Metro area study included five base and five sensitivity scenarios as described in Table 2.7-13 and Table 2.7-14, respectively.

Table 2.7-13: Base Scenarios Studied in the SCE Metro Area Assessment

2018 summer peak	2018 spring off-peak	2021 summer Peak	2021 spring light load	2025 summer peak

Table 2.7-14: Sensitivity Scenarios Studied in the SCE Metro Area Assessment

2021 summer peak with high CEC forecast load	2018 summer peak with no BTM PV	2026 summer peak with no BTM PV	2021 summer peak with high renewable output and minimum gas generation	2018 summer peak with high Redondo output

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 SCE Metro area reliability assessment identified several system performance issues under various contingency conditions. The issues identified can be mitigated in the operations horizon by such operational measures as reconfiguring the system or re-dispatching resources as discussed in Appendix B. As a result, no transmission upgrades are identified for the Metro area.

2.8 Valley Electric Association Local Area Assessment

2.8.1 Area Description

The Valley Electric Association (VEA) transmission system is comprised of 230 kV and 138 kV facilities. All the distribution load in VEA area is supplied from 138 kV system which is mainly supplied through 230/138 kV transformers at Innovation, Pahrump and WAPA's Amargosa substations. The Innovation and Pahrump 230 kV substations are connected to the NV Energy's Northwest and WAPS's Mead 230 kV substations through two 230 kV lines. The VEA system is also electrically connected to the neighboring system through the following lines:

- 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 line 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.

- New Charleston – Vista 138 kV Line. The Charleston and Thousandaire 138 kV substations which serve approximately one third of the VEA's load are fed radially from Gamebird 138 KV Substation. This new line will provide a looped source to these two substations. The expected in service date is end of 2018.
- 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. The expected in service date is end of 2018.
- A new Innovation – Mercury 138 kV 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 15 MW of renewable generation installed on the Valley Electric Association distribution 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	2018	2021	2026
Valley Electric Association area (MW)	142	146	155

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 2016-2026 reliability assessment of the VEA area resulted in the following reliability concerns:

Emergency overloads were observed on the VEA's 138 kV system and the Amargosa 230/138kV transformer following several P6 contingencies which would take out at least one 230 kV source feeding this area. The same contingencies also caused widespread voltage deviations and low voltages on the 138 kV system and at Innovation, Pahrump and Desert View 230kV buses. Most of these issues can be mitigated by the existing Under Voltage Load Shedding (UVLS) scheme in the VEA area. In addition to UVLS, the recommended mitigation is to operate VEA 138 kV system radially after the first outage.

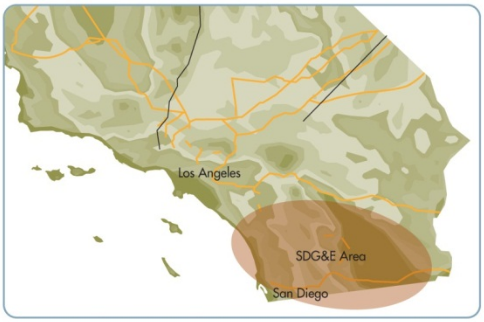
Voltage deviation issues were observed at Charleston, Gamebird and Thousandaire 138kV buses following loss of Gamebird – Pahrump 138kV Line. The new Vista – Charleston 138kV Line will mitigate this concern.

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 860,000 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,[72] covering two counties and 27 cities.



The SDG&E system, including its main 500/230 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 systems via Imperial Valley 500/230 kV substation, and the Otay Mesa-Tijuana 230 kV transmission line.

The existing SDG&E 500 kV system consists of SWPL (North Gila-Imperial Valley- Miguel) and the 500 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 Boulevard) 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. Three of the more significant changes to the SDG&E transmission system are the addition of the Imperial Valley phase shifting transformers, and the Suncrest SVC (static VAR compensator) project, along with implementation of an operational mitigation of by-passing the series capacitor banks on SWPL, and Sunrise Powerlink 500 kV lines under normal system conditions that was approved by the ISO in the 2014-2015 transmission planning process. These three projects substantially improve the reliability to southern California load and the deliverability of Imperial area generation.

[72] These numbers were provided by SDG&E in their 2015/2016 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 2015-2016 or earlier ISO transmission plans, which include South Orange County Reliability Enhancement (SOCRE), Sycamore-Penasquitos 230 kV line, Mission-Penasquitos 230 kV line, Miguel-Bay Boulevard 230 kV line #2, the phase shifting transformers at the Imperial Valley 230 kV substation, and the new reactive power support facilities to be installed at the Miguel/Suncrest/San Luis Rey/SONGS substations. The Sycamore-Penasquitos 230 kV line project was approved with required in-service date of 2017 in the ISO 2012-2013 transmission plan, and was assumed to be in service on May 2017 in the base scenario studies. On October 14, 2016, the CPUC granted SDG&E a certificate of public convenience and necessity to construct the Sycamore-Penasquitos 230 kV line project. However, the project is behind schedule due to delays in the CPUC permitting process. The existing series capacitors on the SWPL and the Sunrise PowerLink 500 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 IID's latest system development plan which has cancelled its previously planned projects connecting to the Imperial Valley 230 kV substation. The power flow models for neighboring systems were refined based on updated information provided by IID, WAPA, APS, and CENACE, formerly known as CFE, in coordination with the ISO.

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, and 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 2018 base cases, but retired by the end of 2018 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. Generating facilities totaling 1281 MW are assumed to be retired in the base cases by the year of 2026 in the San Diego study area, which includes units at Encina, Kearny, Miramar GT, El Cajon GT, Division, Naval Station Metering as well as Applied Energy's units at Point Loma, and Goal Line's units at Escondido.

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

Generation resources			2018	2021	2026
By type	Gas	MW	3774	3677	3641
	PV	MW	2334	2334	2334
	Wind	MW	671	671	671
	Storage	MW	40	40	40
By location	San Diego Metro	MW	2845	2749	2712
	East County	MW	396	396	396
	Ocotillo	MW	265	265	265
	Imperial Valley	MW	2387	2387	2387
	Hassayampa and Hoodoo Wash	MW	925	925	925
Total		MW	6818	6722	6685

Generation resources totaling 6685 MW are modeled by the year of 2026, including conventional, 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 2018, a total of 1307 MW of PV solar generation with power injected into the Imperial Valley 230 kV substation that are expected in service by the summer of 2018. The Lake Hodges pump-storage plant is composed of two 20 MW units. Both units became operational in summer 2012. In addition to the generation plants internal to San Diego, 1080 MW (NQC) of existing thermal power plants are connected to the 230 kV bus of the Imperial Valley 500/230 kV substation, and 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 2026 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 808 MW of gas-fired resources that the CPUC authorized SDG&E to procure and 225 MW 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 (308 MW) and Carlsbad Energy Center (500 MW) power purchase agreements have been approved by the CPUC as part of the 2012 LTPP Track 1 and 4.

Table 2.9-2: Authorized Conventional Gas Fired, Preferred Resources and Energy Storage

		Unit	2018	2021	2026
Track 1 and 4 Authorized Conventional Gas Fired		MW (in NQC)	808.0	808.0	808.0
CPUC Authorized Preferred Resources and Energy Storage	LTPP EE	MW	5.0	11.0	22.4
	Demand Response	MW	0.0	33.6	33.6
	Existing Repurposed Demand Response	MW	19.0	19.0	19.0
	RPS Distributed Generation	MW	28.8	65.6	65.6
	Energy Storage	MW	0.0	45.0	84.0
	Subtotal of MW in NQC	MW	52.8	174.2	224.6

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 and behind-the-meter PV solar projected. The gross load demand, AAEE, and behind-the-meter PV solar for 2026 were assumed at 5429 MW, 344 MW, and 505 MW, respectively. Therefore, the SDG&E net peak load for the year of 2026 was 4580 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 1-in-5-year 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

Load Forecast	Unit	2018	2021	2026
Gross Peak Load	MW	5171	5235	5429
Low-Mid AAEE	MW	-112	-197	-344
Behind-the-Meter Solar PV	MW	-254	-330	-505
Net Peak Load	MW	4805	4708	4580

Power flow cases for the study modeled a load power factor of 0.992 lagging at nearly all load buses in 2021 and 2026. Power factors for the year 2018 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 and Major Path Flow

Major area interchanges, also known as net area imports/exports, and major path flows were assumed and modeled for the studies. Table 2.9-4 summarizes area interchanges and path flows assumptions for the base scenario in the SDG&E area studies.

Table 2.9-4: Area Interchanges and Path Flow Assumptions in the Base Scenario Studies

		2018 Summer Peak	2021 Summer Peak	2026 Summer Peak	2018 Off-Peak	2021 Light Load
SCE Net Export	MW	-10,734	-10,065	-9,887	-1071	-4203
SDG&E Net Export	MW	-1,290	-1,365	-1,428	1938	-902
IID Net Export	MW	515	485	394	617	623
CFE Net Export	MW	-100	0	0	300	0
Path 26 Flow	MW	3997	3950	3034	-1635	418
Path 46 Flow	MW	7914	8071	8400	3609	4917
northbound flow via the north of SONGS interface	MW	-120	-264	-404	1401	159
SDIT Flow	MW	3232	3309	3212	762	1440
SCIT Flow	MW	17385	17528	17206	3697	7583

Sensitivity Study Scenario

In addition to the base scenarios, the ISO assessed the five and three sensitivity scenarios for the SDG&E bulk and its sub-transmission systems respectively, which covers impacts of load forecast, generation output, transfers on major paths, and delay of the Sycamore-Penasquitos 230 kV line project. Table 2.9-5 summarizes major assumptions for the sensitivity scenario specified in the study plan. Since the CPUC recently granted SDG&E a certificate of public convenience and necessity to construct the Sycamore-Penasquitos 230 kV line project on October 14, 2016 approving an alternative line route, an extra sensitivity study was performed to evaluate system performance if the project is not in service by the summer of 2018.

Table 2.9-5: Assumptions in the Sensitivity Scenario Studies

		High CEC load forecast	No BTM Solar PV		Heavy RPS Output	Heavy north flow via north of SONGS interface
		2021 Summer Peak	2018 Summer Peak	2026 Summer Peak	2021 Summer Peak	2026 Summer Peak
Net Peak Load	MW	4866	5059	5085	4708	4580
RPS Output	MW	1505	1505	1505	2279	2279
SCE Net Export	MW	-10806	-11078	-10539	-6850	-7308
SDG&E Net Export	MW	-1535	-1565	-1518	-1150	522
IID Net Export	MW	485	515	394	485	800
CFE Net Export	MW	0	-100	0	0	300
Path 26 Flow	MW	3994	3948	2534	1948	974
Path 46 Flow	MW	8932	8437	9576	6878	6057
northbound flow via the north of SONGS interface	MW	-302	-222	-332	-206	1124
SDIT Flow	MW	3472	3492	3448	3527	1881
SCIT Flow	MW	18414	17277	17808	14526	12717

2.9.3 Assessments and Recommendations

The ISO conducted a detailed reliability 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 following summarizes the reliability assessment results for the SDG&E study areas, including the SDG&E bulk transmission system 500/230 kV and its sub-transmission system 138/69 kV. The results identify reliability needs for transmission additions or operational mitigations to meet applicable reliability standards in the planning horizon.

Bulk Transmission System

- 9 branches 500 kV overloaded for P1/P2/P3/P4/P6 outages
- 18 branches 230 kV overloaded for P1/P2/P3/P4/P6/P7 outages
- 1 branch 230 kV flow exceeded its protection relay setting

- 1 bus 500 kV high voltage concern for P1/P2/P4/P6 outages
- 1 transient voltage dip concern for P6 outage

Sub-Transmission System

- 60 branches 69 kV overloaded for P0/P1/P2/P3/P4/P6/P7 outages
- 9 branches 138 kV overloaded for P2/P6 outages
- 2 transformers 230/138 kV overloaded for P6 outages

In response to the ISO study results and proposed alternative mitigations, 10 reliability project submissions were received through the 2016 request window, which includes alternatives for reliability enhancement in the local SDG&E and the southern California regional transmission systems:

- Otay Lake 69 kV Tap Removal & Loop-in
- Miramar GT 230 kV Loop-in
- Install 2nd Sycamore 230/138 Bank
- New Pala 230/69 kV Substation
- Mission-Miguel 230 kV lines TL23022 & TL23023 reconductor
- Mission-Old Town 230 kV lines TL23027 & TL23028B reconductor
- North Gila – Imperial Valley #2 Project
- STEP Midway-Devers 500 kV AC Inter-tie
- STEP North Gila-Midway-Devers 500 kV AC Inter-tie
- Renewable Energy Express (HVDC Conversion Project)

Of these projects, some were submitted as economic and/or policy-driven projects. As these projects were submitted into the reliability request window, they were nonetheless reviewed for reliability benefits as well. They would be considered in chapter 3 policy analysis or chapter 4 economic analysis only to the extent they could mitigate an identified need in either of those chapters. In accordance with the ISO tariff and section 3.2.2.2 of the Business Practice Manual, stakeholders should submit economic project study ideas as requests for economic planning studies in future transmission planning processes. Stakeholders can also submit comments on the ISO's economic planning studies or policy project throughout the transmission planning process in the next planning cycle.

The ISO evaluated the proposed transmission mitigation alternatives and did not find the long-term reliability need for the 10 projects. The ISO recommends four special protection systems and four operational mitigations to address the reliability concerns identified in the SDG&E transmission system. The ISO's recommendations for the SDG&E area in the 2016-2017 transmission planning process are summarized below and described in greater detail in Appendix B.

Request Window Projects

Otay Lake 69 kV Tap Removal & Loop-in

The Otay Lake Tap Removal and Loop-in project was received through the 2016 Request Window as a transmission upgrade mitigation to address power flow concerns identified by SDG&E on the Otay-Otay Lake Tap 69 kV line (TL649A) for category P1 contingency. The scope of the project includes combining the San Ysidro-Otay Lake Tap 69 kV line (TL649D) and Otay Lake Tap-Otay 69 kV line (TL649A) and extending the Broder Tap-Otay Lake Tap (TL649F) to the Otay 69 kV substation for an estimated cost of $15~20 million.

The thermal violation can be mitigated by dispatching generation at the Border substation. The ISO has not identified a reliability need for this project.

Miramar GT 230 kV Loop-In

The Miramar GT 230 kV loop-in project, which is similar to the Miramar 230kV Tap (also known as the Miramar 230/69 kV Substation) project that was received through the 2015 Request Window, was submitted as a transmission addition to mitigate the overload concern on the Sycamore – Scripps 69 kV transmission line (TL6916) that establishes local capacity need in the Miramar sub-area. The estimated cost of the project is $ 23.6~28.3 million, which involves:

- building a new Miramar GT 230/69 kV substation at the site of the retired Cabrillo II CT units nearby the Miramar 69 kV switchyard, and
- Looping the previously approved Mission-Penasquitos 230 kV line into the Miramar 230/69 kV substation

The ISO's study results did not identify Cabrillo Power II CT units as generation necessary for reliable load serving capability since they were already assumed to be retired in the base cases. In addition, the previously approved Sycamore-Penasquitos and second Miguel–Bay Boulevard 230 kV transmission projects would significantly reduce the local capacity need in the Miramar sub-area. The ISO has not identified a reliability need for this project.

Install 2nd Sycamore Canyon 230/138 Bank

The 2nd Sycamore Canyon 230/138 Bank project was received through the 2016 Request Window as a transmission upgrade mitigation to address power flow concerns identified by SDG&E on the 1st Sycamore Canyon 230/138 bank for category P0 contingency under the assumption that the Sycamore- Penasquitos 230 kV line project would not be in service by 2018. The scope of the project includes installing a second 230/138 kV transformer at the Sycamore Canyon substation for an estimated cost of $8~10 million.

The thermal violation can be mitigated by pre-dispatching generation at the Encina substation. It will also be mitigated after the Sycamore Canyon- Penasquitos 230 kV line project is in service. The ISO has not identified a reliability need for this project.

New Pala 230/69 kV Substation

The Pala 230 kV Loop-in project was received through the 2016 Request Window as a transmission upgrade mitigation to address power flow concerns identified by SDG&E on the Melrose-Morro Hill 69 kV line and Morro Hill-Monserate 69 kV line (TL694A and TL694B) for category P6 contingencies. The San Luis Rey-Ocean Ranch 69 kV line (TL6979) was also overloaded under the category P1 contingency of San Luis Rey-Melrose 69 kV line (TL693) and serving non-coincidental peak load at the Melrose 69 kV substation. Moreover, the project mitigates Local Capacity Requirement (LCR) for the Pala area. The scope of the project includes expanding the existing Pala 69 kV substation, looping the Escondido-Talega 230 kV line (TL23030) into the Pala substation, and adding a 230/69 kV transformer for an estimated cost of $20~30 million.

The thermal violation can be mitigated by dispatching generation at the Pala substation. Also, the project would not completely eliminate the LCR need in the Pala sub-area because the Melrose-Morro Hill 69 kV line is still overloaded under the category P6 contingency of Pendleton-San Luis Rey 69 kV line (TL6912) and Pala-Avocado-Monserate 69 kV line (TL698). An operating procedure would still be needed to mitigate the overload for that contingency. The ISO has not identified a reliability need for this project.

Mission-Miguel 230 kV lines TL23022 & TL23023 reconductor

The Miguel-Mission 230 kV lines reconductor project was received as a transmission upgrade mitigation to address the overload concerns on the Miguel-Mission 230 kV lines (TL23022 and TL23023) for category P6/P7 contingencies before the Sycamore–Penasquitos 230 kV line project is in service. The scope of the project includes reconductoring approximate 8 miles of 230 kV sections on both TL23022 and TL23023 from the Mission 230 kV substation to Fanita Junction to achieve continuous rating of 912 MVA for an estimated cost of $23.3~25.6 million. It remains unclear at this point how long it would take to complete the permitting process and implement the project.

The overload concerns can be mitigated by relying on congestion management until the Sycamore-Penasquitos 230 kV line project is completed, so there is no reliability need for this project.

Mission-Old Town 230 kV lines TL23027 & TL23028B reconductor

The Old Town-Mission 230 kV lines reconductor project was received as a transmission upgrade mitigation to address the Mission-Old Town 230 kV lines overload concern which occurs until the Sycamore–Penasquitos 230 kV line project is in service. The scope of the project includes reconductoring both TL23028B and TL23027 to achieve a minimum continuous rating of 912 MVA for an estimated cost of $15~20 million. It remains unclear at this point how long it would take to complete the permitting process and implement the project.

Given the uncertainty around the completion date for this project, the ISO is not recommending approval of this project. A temporary SPS or operating procedure, as discussed above, can be utilized to address the Mission-Old Town 230 kV lines overload concern for a limited period of time.

North Gila – Imperial Valley #2 Transmission Project (NG-IV #2)

The NG-IV #2 project was submitted through the 2016 Request Window as a transmission projects that purportedly would provide reliability, economic, and resource adequacy benefits to the southern California and APS areas. The project is currently in the WECC three-phase rating process. The proposed project would build a 95-mile 500kV transmission line, which would parallel the existing North Gila-Imperial Valley 500 kV line TL50002 for the majority of its length. The estimated cost is $313 million.

The project could eliminate the ISO identified the thermal overload concern on the Imperially Valley – El Centro 230 kV line if simultaneous outages of the existing North Gila-Imperial Valley and the proposed 500 kV lines could be excluded from a credible category P7 or N-2 event. However, the ISO has not identified a reliability need for this project since the ISO's further evaluations confirmed that the reliability concern could be mitigated by the CAISO electricity market and operation procedure. The ISO is aware that the operational solution could potentially limit the power transfer capability through the North Gila – Imperial Valley 500 kV line and is exploring other possible mitigations as a policy-driven or economic-driven solutions. In addition, as mentioned above, stakeholders can submit economic project request and/or policy project ideas in the next planning cycle.

STEP Midway-Devers 500 kV AC Inter-tie

The project was submitted as a reliability, economic, and policy-driven transmission project. The proposed 500 kV transmission line is approximately 85 miles long from a new 500 kV switchyard adjacent to IID's existing 230 kV Midway substation to the existing SCE's Devers 500 kV substation in Riverside County. Preliminary cost estimate is $388 million with an expected in-service date of June, 2021.

The ISO has not identified a reliability need for this project. As mentioned above, stakeholders can submit economic project study requests and/or policy project ideas in the next planning cycle.

STEP North Gila-Midway-Devers 500 kV AC Inter-tie

The project was submitted as a reliability, economic, and policy-driven transmission project. The proposed 500 kV transmission line is approximately 152 miles long from APS' North Gila 500 kV substation then looping through a new 500 kV switchyard adjacent to IID's existing 230 kV Midway substation and continuing on to SCE's Devers 500 kV substation in Riverside County. Preliminary cost estimate is $750 million with an expected in-service date of June, 2021.

The ISO has not identified a reliability need for this project. As mentioned above, stakeholders can submit economic project study requests and/or policy project ideas in the next planning cycle.

Renewable Energy Express (HVDC Conversion Project)

The Renewable Energy Express project was received through the 2016 Request Window as a reliability, economic, and policy-driven transmission project. The project would convert the 500 kV Southwest Powerlink system to a multi-terminal and multi-Polar terminal HVDC system with three terminals at the North Gila, Imperial Valley, and Miguel Substations. The estimated cost is $900~1000 million.

The ISO conducted a high-level evaluation on the project and has not identified a reliability need for this project. There are some policy and technical uncertainties associated to the project, such as implementation of the 50 percent RPS goal, regional system impact, and engineering feasibilities of the multi-terminal HVDC convention and new transmission route between the ECO and Ocotillo 500 kV substations. The ISO's evaluations indicated that the project would not effectively eliminate the congestion issue on the Imperially Valley – El Centro 230 kV line, and that therefore local capacity requirement in the San Diego and Imperial Valley subarea could not be significantly reduced. In addition, some downstream thermal overload concerns in the San Diego 230 kV system would surface with the project in-service. Additional detail for this evaluation is described in Appendix B.

Operational Mitigations

Modification on Existing Miguel 500/230 kV Banks #80 and #81 SPS and Operating Procedure

The need for modifying the existing Miguel BK80/81 SPS was confirmed to mitigate the bank overload concern for category P1, P3, or P6 contingency. The ISO will work with SDG&E to modify the existing SPS by adding a new remedial action scheme that opens the remaining Miguel bank for the other bank outage. The SPS can be enabled under normal condition and is required to be enabled when Sunrise Powerlink is out of service. If the SPS is not enabled under normal condition, an operation procedure would be required to de-energize the remaining bank for the loss of the other bank even it is not overloaded. The system adjustment after the first contingency is required, which includes but is not limited to adjusting the phase shifting transformers and lowering import level via the San Diego import transmission interface (SDIT), to avoid cross-tripping the 230 kV tie lines with CENACE and risk of the voltage instability in the LA basin and the San Diego area. Retard phase angles of the phase shifting transformers at Imperial Valley need be managed to maintain system reliability while minimizing energy cost and system losses under normal condition and power flow via the phase shifting transformers should be adjusted after the first contingency. The modified SPS and operating procedure are needed to be in service by the summer of 2017 when the two phase shifting transformers are expected in service at the Imperial Valley 230 kV substation. Additional detail for this SPS and operating procedure are described in Appendix B.

Suncrest 500/230 kV Banks #80 and #81 SPS and Operating Procedure

The ISO confirmed the need for the previously recommended Suncrest BK80/81 SPS addressing the thermal overload concern on the Suncrest banks for category P6 contingency, and will work with SDG&E to implement the SPS that opens the remaining Suncrest bank for the other bank outage and sheds generation as needed in the greater Imperial area. The SPS is required to be enabled when SWPL is out of service between Imperial Valley and Miguel. In addition, an operation procedure would be required as part of the system adjustment to open the remaining bank for the other bank outage even it is not overloaded in order to prepare the system for the next contingency in SWPL between Imperial Valley and Miguel. The system adjustment after the first contingency is required, which includes but is not limited to adjusting the phase shifting transformers and lowering import level via SDIT, in order to avoid cross-tripping the 230 kV tie lines with CENACE and the voltage instability in the LA basin and the San Diego area. Retard phase angles of the phase shifting transformers at Imperial Valley need be managed under normal condition and after the first contingency. The SPS and operating procedure are needed to be in service by the summer of 2017. Additional detail for this SPS and operating procedure are described in Appendix B.

Suncrest–Sycamore 230 kV lines TL23054/TL23055 SPS and Operating Procedure

The ISO is recommending that SDG&E refines the previously recommended Suncrest-Sycamore TL23054/TL23055 SPS, and will work with SDG&E to implement the refined SPS that should be designed to open the Ocotillo-Suncrest 500 kV line TL50003 instead of the remaining 230 kV line for loss of one of the Suncrest-Sycamore 230 kV lines. The SPS will provide more reactive power support to the San Diego metro area from the Sunrise SVC facilities via the remaining Suncrest – Sycamore Canyon 230 kV line, compared to the previously recommended SPS. In addition, an operation procedure would be required as part of the system adjustment to de-energize the remaining 230 kV line for the other line outage even it is not overloaded in order to prepare the system for the second contingency in SWPL. The system adjustment after the first contingency is required, which includes but is not limited to adjusting the phase shifting transformers and lowering import level via SDIT, in order to avoid cross-tripping the 230 kV tie lines with CENACE and the voltage instability in the LA basin and the San Diego area. The phase angles of the two phase shifting transformers at Imperial Valley need be managed under normal condition and after the first contingency. The SPS and operating procedure are needed to be in service by the summer of 2017. Additional detail for this SPS and operating procedure are described in Appendix B.

Temporary SPS or Operating Procedure for the Mission-Old Town 230 kV Lines

Due to delays of the Sycamore–Penasquitos 230 kV line project in the CPUC permitting process, thermal overload concerns were identified on the two Old Town-Mission 230 kV lines for various category P6 contingencies. The ISO is recommending implementation of a temporary SPS or operating procedure as needed to bridge the gap between real-time operations and the time when the Sycamore–Penasquitos 230 kV line is in service. The interim mitigation intends to shed load in the Old Town area to address the overload concerns on the Mission-Old Town and Mission-Old Town Tap 230 kV line for various category P6 contingencies. In addition, an operation procedure to re-dispatch generation in the San Diego area for these contingencies is also needed. Once the Sycamore-Penasquitos 230 kV project is in service, this mitigation is not needed. The worst P6 contingency is the loss of Miguel-Otay Mesa-Bay Blvd three-terminal 230 kV line followed by the outage of Mission-Old Town or Mission Old Town Tap 230 kV line, or vise versa. The mitigation needs to be in service by the summer of 2017, which shall be enabled after a single outage of the Mission-Old Town TL23027, Mission-Old Town Tap-Silvergate TL23028, or Miguel-Otay Mesa-Bay Blvd 230 kV lines.

Modification on the Protection Relay System of Sycamore – Palomar 230 kV line

Power flow on the Sycamore – Palomar 230 kV line exceeded its directional current protection relay setting for various category P2, P4, P6 and P7 contingencies, which could trigger cascading events and ultimately result in system separation. The ISO is recommending to review the protection system and modify it as needed to address this reliability concern.

Coordination of the Reactive Power Facilities in the Suncrest area

The ISO recommends that the control scheme for the Suncrest SVC (static var compensator) and the control scheme for the existing shunt capacitors and reactors at the Suncrest 500/230 kV substation are coordinated to avoid a potential high voltage issue on the Suncrest 500 kV bus for category P1, P2 and P4 contingencies.

Imperial Valley – El Centro 230 kV tie with IID

Due to the cancellation of previously planned upgrade projects connecting to the Imperial Valley 230 kV substation, the ISO identified the thermal overload concern on the Imperial Valley – El Centro 230 kV tie with IID (IID's S Line) for various category P1, P3, and P6 contingencies. The worst P3 contingency (G-1/L-1) is the loss of Termoeléctrica de Mexicali (TDM) power plant followed by the outage of North Gila – Imperial Valley 500 kV line TL50002. The ISO's further evaluations confirmed that the reliability concern could be mitigated by the ISO electricity market and operation procedure. The ISO is aware that the operational solution could potentially limit the power transfer capability through the North Gila – Imperial Valley 500 kV line, resulting in potential economic impact. North Gila – Imperial Valley 500 kV line congestion has also been identified in the economic planning study described in chapter 4. Please refer to chapter 4 for the findings regarding observed congestion in the ISO's production cost simulations.

Relay Rating on Rose Canyon

The ISO was notified that the directional relay limited emergency rating of Rose Canyon-Claremont Tap 69 kV line (TL600A) was only 71 MVA instead of 100 MVA. Under the category P6 contingency of Kearny-Mission 69 kV line (TL663) and Mesa Heights-Mission 69 kV (TL676), the Rose Canyon-Claremont Tap 69 kV relay setting was exceeded at 104%. The ISO identified the need to upgrade the relay at the Rose Canyon end to avoid inadvertently tripping the line.

Previously Approved Projects

Mission – Penasquitos 230 kV Circuit

The Mission-Penasquitos 230 kV circuit project was approved in the ISO 2014-2015 Transmission Plan substantially based on previous project scope of the Sycamore-Pensaquitos 230 kV line. The CPUC recently approved an alternative line route for the Sycamore-Pensaquitos 230 kV project, which results in material changes to implement the Mission-Penasquitos 230 kV line project. In addition, additional analysis will be needed to confirm the need for the project because of the scope change of the Sycamore-Penasquitos 230 kV line project and reduction of the load forecast. The ISO is recommending to defer this project and re-evaluate the need in next planning cycle.

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Chapter 3

3 Policy-Driven Need Assessment

3.1 Study Assumptions and Methodology

3.1.1 33 Percent RPS Portfolios

The CPUC and CEC provided policy direction the ISO regarding renewable generation portfolios for policy-driven transmission planning purposes via a letter dated June 13, 2016. In that communication, the CPUC and CEC recommended that the ISO re-use the "33% 2025 Mid AAEE" RPS portfolio used in the 2015-16 TPP studies, as the base case renewable resource portfolio in the 2016-17 TPP studies[73]. Because these portfolios were already studied in the 2015-2016 TPP, the ISO only needed to reassess in the 2016-2017 TPP those portions of the system that had material changes to their transmission plans that would affect the ability to deliver renewable generation in the portfolio. After reviewing the changes to the planning models from the 2015-2016 TPP to the 2016-2017 TPP, the ISO determined that material changes had been made to the transmission system only in the Imperial Valley area, so the ISO needed to reassess this area.

The ISO performed the reliability assessment described in chapter 2 on base cases that modeled the renewable portfolio referred to above, so the powerflow and stability analysis performed as part of the reliability assessment also serve as a policy-driven need assessment from a powerflow and stability reliability perspective. Therefore, the ISO only needed to perform a generation deliverability analysis of the Imperial Valley to complete the 2016-2017 TPP policy-driven need assessment.

[73] http://www.caiso.com/Documents/2016-2017RenewablePortfoliosTransmittalLetter.pdf

The installed capacity and energy per year of the portfolio by location and technology are shown in Table 3.1-1.

Table 3.1-1: Renewables portfolio for 2016-2017 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**

3.1.2 Testing Deliverability for RPS

To verify the deliverability of the renewable resources modeled in the base portfolio in the Imperial Valley area, the ISO performed an assessment 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.

3.1.2.1 *Deliverability Assessment Methodology*

The ISO performed the assessment following the on-peak Deliverability Assessment Methodology. The main steps are described below.

3.1.2.2 *Deliverability Assessment Assumptions and Base Case*

The ISO developed a master base case 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 ISO modeled the same transmission system as in the base portfolio power flow peak case.

Load modeling

The ISO modeled a coincident 1-in-5 year heat wave for the ISO balancing authority area load 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 ISO used the most recent summer peak NQC 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, the ISO assessed both wind and solar generations for maximum output of 50 percent exceedance production level for the deliverability constraint, otherwise up to a 20 percent exceedance production level was assessed. The wind and solar generation exceedance production levels modeled in the deliverability assessment are shown in Table 3.1-2.

Table 3.1-2: Wind and Solar Generation Exceedance Production Levels (percentage of installed capacity) in the 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

The ISO modeled imports 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 3.1-3 shows the import megawatt amount modeled on the given branch groups.

Table 3.1-3: Base Portfolio deliverability assessment import targets

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville_BG	N-S	1109	13
COI_BG	N-S	4567	68
BLYTHE_BG	E-W	29	0
CASCADE_BG	N-S	76	0
CFE_BG	S-N	-35	0
ELDORADO_MSL	E-W	300	0
IID-SCE_BG	E-W	462[74]	0
IID-SDGE_BG	E-W		0
LAUGHLIN_BG	E-W	-38	0
MCCULLGH_MSL	E-W	0	316
MEAD_MSL	E-W	831	606
NGILABK4_BG	E-W	-155	168
NOB_BG	N-S	1283	0
PALOVRDE_MSL	E-W	3139	115
PARKER_BG	E-W	76	25
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	13	0
SYLMAR-AC_MSL	E-W	111	337
Total		12008	1648

3.1.2.3 *Screening for Potential Deliverability Problems Using DC Power Flow Tool*

The ISO used a DC transfer capability/contingency analysis tool to identify potential deliverability problems. For each analyzed facility, the ISO drew an electrical circle that 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%.

The ISO performed load flow simulations, which studied the worst-case combination of generator output within each 5 percent circle.

3.1.2.4 *Verifying and refining the analysis using AC power flow tool*

The ISO increased the outputs of capacity units in the 5 percent circle 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

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[74] Existing IID located generation was utilized to produce the Target MIC schedules and flows. IID located generation in the renewable portfolio was explicitly modeled and scheduled as an import over and above the initial MIC level.

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. The ISO calculated this adder by taking the remaining MW amount available from the 20 units with the highest impact multiplied by the DFAX for each unit. The ISO also included an equivalent MW amount of generation with negative DFAXs in the adder, up to 20 units. If the net impact from the contributions to adder was negative, the ISO set the impact to zero, and reported the flow on the facility without applying the adder.

3.2 Policy-Driven Deliverability Assessment Results and Mitigations

Base Portfolio Deliverability Assessment Results

The ISO performed a deliverability assessment focusing on the Imperial Zone. The 33 percent renewable portfolio used in the ISO's 2016-2017 TPP studies is approximately the same that was used for the 2015-2016 TPP studies, and the MW amounts in each zone are approximately the same. Because recently completed renewable projects have been modeled, this resulted in some modifications in the MW amounts, type, and location of renewables within each zone. Table 3.2-1 shows the renewable generation modeled in the study area.

Table 3.2-1: Renewable generation installed capacity

Zone	Renewable Generation (MW)
Imperial – SDGE	1572
Imperial – IID	417[75]
Baja	322
Arizona	330

As noted in the ISO's 2015-2016 TPP Report, the 2015-2016 studies were based on the transmission planning input provided by 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. The ISO's study timelines do not permit restarting the process within a given cycle and thus the 2015-2016 results did not take into account that information. The following IID upgrades were modeled in 2015-2016 TPP studies:

- Imperial Valley-Dixieland 230 kV line
- Highline-El Centro Upgrade
- Imperial Valley Policy Project (230 kV Liebert Switching Station and 230 kV transmission line connecting to Imperial Valley 230 kV substation, loop-in of IID's existing S-Line to new Fern 230 kV switchyard)

Based on IID's revised input, none of these upgrades were modeled in 2016-2017 TPP studies. The constraints identified in the study are shown in Table 3.2-2.

[75] This amount includes 240 MW of contracted solar which creates an expanded MIC. The additional 177 MW of potential renewable generation is from the CPUC portfolio and is in addition to existing geothermal generation in the area.

Table 3.2-2: Base portfolio deliverability assessment results

Overloaded Facility	Contingency	Flow
Imperial Valley-El Centro 230 kV intertie	Imperial Valley-North Gila 500 kV	102%

The identified overload can be alleviated by reducing approximately 20 MW of renewable generation deliverability. Given the modest shortfall in deliverability and the state agencies' objective of avoiding triggering new reinforcement additions until 50 percent policy renewable generation portfolios are available, the ISO is not recommending any transmission solutions at this time for policy purposes.

Transmission Plan Deliverability with Recommended Transmission Upgrades

An estimate of the generation deliverability supported by the existing system and approved transmission upgrades is listed in Table 3.2-3 and Table 3.2-4. 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 3.2-4, the transmission plan deliverability is greater than the MW amount of generation in the ISO interconnection queue up to and including queue cluster 9.

Table 3.2-3: Deliverability for Area Deliverability Constraints in SDG&E area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
East of Miguel Constraint	Arizona	2,336 ~ 3,768
	Baja	
	Imperial	

Table 3.2-4: Deliverability for Area Deliverability Constraints in SCE area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
Desert Area Constraint	Mountain Pass	7,000 ~ 10,000[76]
	Riverside East	
	Tehachapi (Big Creek and Ventura)	
	Distributed Solar – SCE (Big Creek and Ventura)	
	Imperial	
	Nevada C	
Lugo AA Bank capacity limit	Kramer	~1200
	San Bernardino - Lucerne	
Lugo - Pisgah 220kV flow limit	San Bernardino – Lucerne	~450
South of Kramer 220kV flow limit	Kramer	~380

[76] 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.

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Chapter 4

4 Economic Planning Study

4.1 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[77] 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. This type of economic benefit is normally categorized as an energy benefit or production benefit. Other benefits are also taken into account on a case by case basis using a range of other tools, such as power flow-type study that is normally used to identify capacity benefits. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all 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).[78]

[77] http://www.caiso.com/Documents/2016-2017FinalStudyPlan.pdf

[78] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, June 2004, http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf

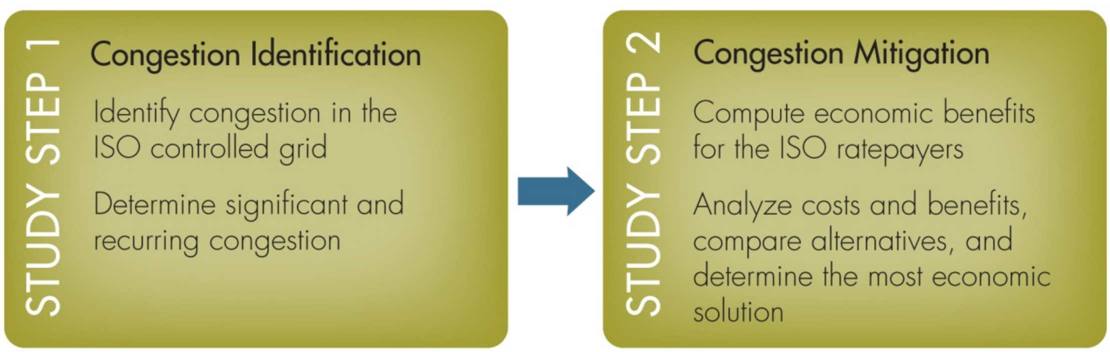
4.2 Study Steps

The economic planning study is conducted in two consecutive steps; congestion identification and congestion mitigation as shown in Figure 4.2-1.

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 and 4.9 high-priority studies were determined.

Congestion and potential mitigations 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 4.2-1: Economic Planning Study – Two Steps



4.3 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, energy 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 energy 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.

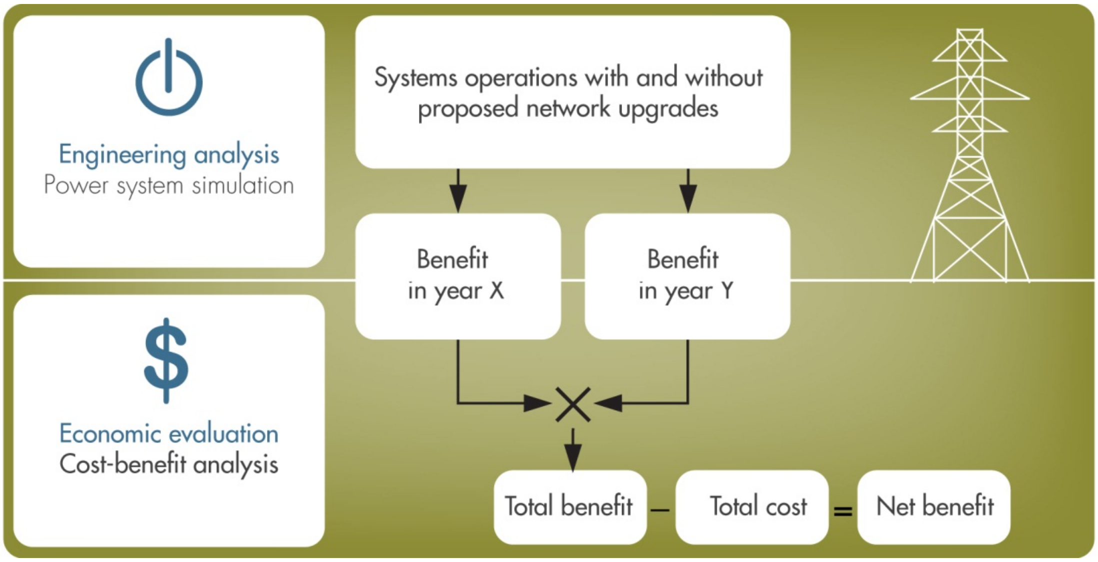
Second, capacity benefits are also assessed. Capacity benefits types include system resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a network upgrade for an importing transmission facility leads to a reduction of ISO system resource requirements, 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 or accessing an otherwise inaccessible resource.

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 4.3-1. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). 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 4.3-1: Technical approach of economic planning study



4.4 Tools and Database

The ISO used the software tools listed in Table 4.4-1 for this economic planning study.

Table 4.4-1: Economic Planning Study Tools

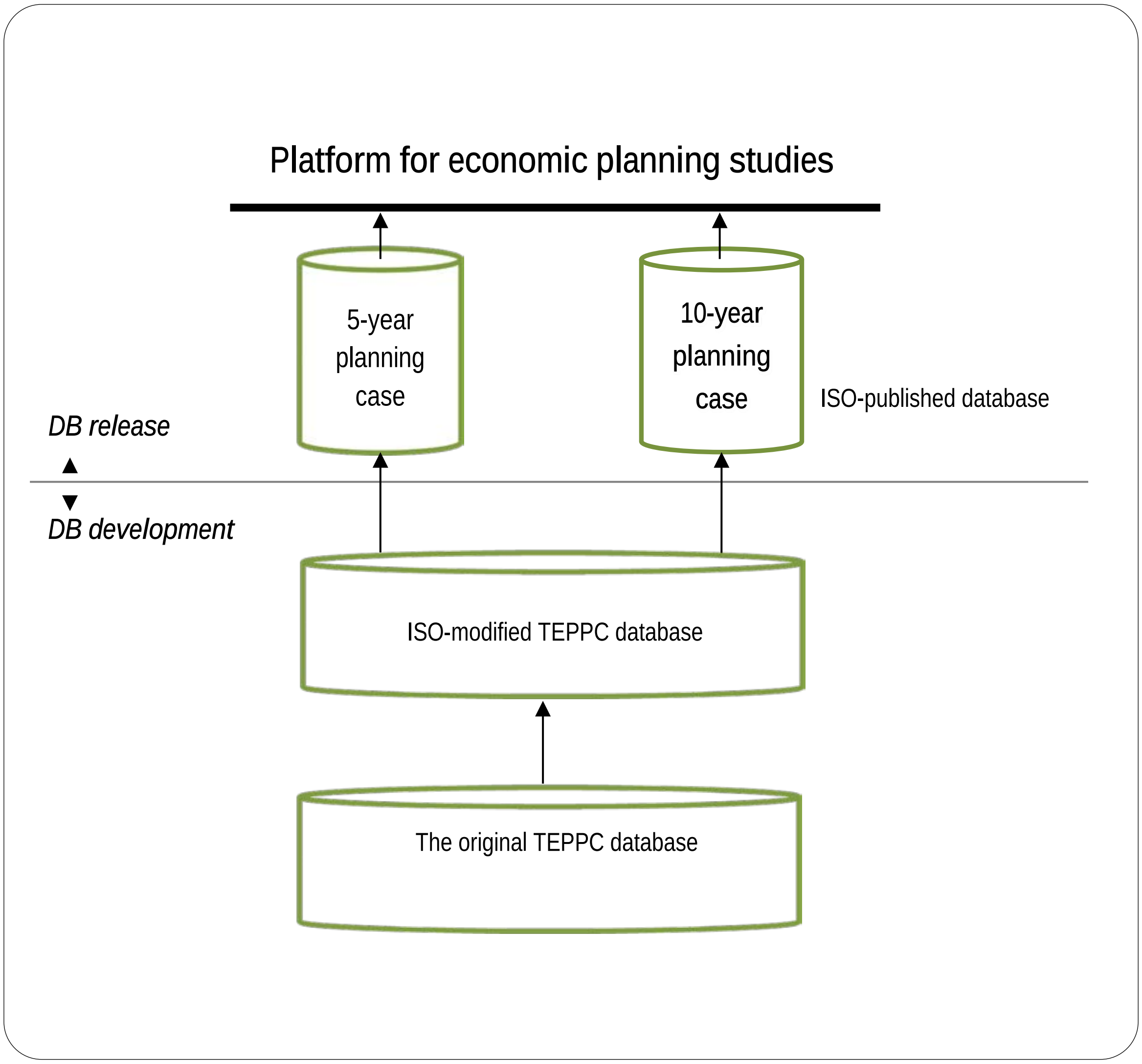
Program name	Version	Functionality
ABB GridView™	9.7.15	The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year.

This study used the Transmission Expansion Planning Policy Committee (TEPPC) production cost simulation model as a starting database[79]. Using this database the ISO developed the base cases for the ISO production cost simulation. These base cases included the modeling updates and additions described in section 4.5 (Study Assumptions) to ensure that the production cost model of the California power system was accurate.

Normally the ISO develops two databases; a 5-year case and a 10-year case. However, the 5-year case is often only used for providing a data point in validating the benefit calculation of transmission upgrades by assessing at most a five year period of benefits before the 10-year case becomes relevant. The 10-year case is the primary case for both congestion analysis and benefit calculation. In this planning cycle, the ISO decided to only develop the 5-year case if the 10 year case indicated sufficient benefits for any of the high priority study areas to warrant developing the additional data point. The set-up of these databases is shown in Figure 4.4-1.

[79] "TEPPC 2026 V1.3" dataset released in August 2016

Figure 4.4-1: Database Setup



4.5 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.

4.5.1 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.

4.5.2 Load demand

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions 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.

4.5.3 Generation resources

The ISO replaced the TEPPC RPS modeling in California with the "33% 2025 Mid AAEE" RPS portfolio provided by the CPUC and CEC and described in chapter 3, to be consistent with the renewable modeling in the reliability and policy studies in 2016-2017 planning cycle. For more details about the renewables portfolio, please see its description in chapter 3.

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.

4.5.4 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.

The ISO made an important enhancement in expanding the modeling of 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 transmission facility (and sometimes multiple transmission facilities), the remaining transmission facilities would stay within their emergency limits. The contingencies that were modeled in the ISO's database mainly are the ones that identified as critical in the ISO's reliability assessments, local capacity requirement (LCR) studies, and generation interconnection (GIP) studies. While all N-1 and N-2 (common mode) contingencies were modeled to be enforced in both unit commitment and economic dispatch stages in production cost simulation, N-1-1 contingencies that included multiple transmission facilities that were not in common mode, were normally modeled to be enforced in the unit commitment stage only. This modeling approach reflected the system reliability need identified in the other planning studies in production cost simulation, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits 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 Table 4.5-1, Table 4.5-2, Table 4.5-3, and Table 4.5-4.

Table 4.5-1: Reliability-driven network upgrades added to the database model[80]

#	Project	Location	TPP cycle	Operation year
1	Series reactor on Warnerville – Wilson 230 kV line	PG&E	TP2012-2013	2018
2	Reconductor Kearney – Herndon 230 kV line	PG&E	TP2012-2013	2017
3	Gates 500-230 kV transformer #2	PG&E	TP2012-2013	2018
4	Lockeford-Lodi Area 230 kV Development Project	PG&E	TP2012-2013	2024
5	Northern Fresno 115 kV Area Reinforcement	PG&E	TP2012-2013	2020
6	Estrella Substation Project	PG&E	TP2013-2014	2019
7	Midway-Kern PP No2 230 kV Line Project	PG&E	TP2013-2014	2019
8	Morgan Hill Reinforcement Project	PG&E	TP2013-2014	2021
9	Wheeler Ridge Junction Project	PG&E	TP2013-2014	2020
10	Mesa Loop-in	SCE	TP2013-2014	2020
11	Victor Loop-in	SCE	TP2013-2014	2016
12	Artesian 230 kV Sub and loop-in	SDG&E	TP2013-2014	2020
13	Imperial Valley Flow Controller	SDG&E	TP2013-2014	2017
14	Panoche – OroLoma 115 kV upgrade	PG&E	TP2015~2016	2021

[80] 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.

Table 4.5-2: Policy-driven network upgrades added to the database model

#	Project	Location	TPP cycle	Operation year
1	IID-SCE Path 42 upgrade	IID, SCE	TP2010-2011	2016
2	Warnerville – Belotta 230 kV line reconductoring	PG&E	TP2012-2013	2017
3	Lugo – Eldorado series capacitors and terminal equipment upgrade	SCE	TP2012-2013	2019
4	Sycamore – Penasquitos 230 kV line	SDG&E	TP2012-2013	2017
5	Lugo-Mohave series capacitor upgrade	SCE	TP2013-2014	2019

Table 4.5-3: Economic-driven network upgrades added to the database model

#	Project	Location	TPP cycle	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	2022

Table 4.5-4: GIP-related network upgrades added to the database model

#	Project	Location	Note	Operation year
1	West of Devers 230 kV reconductoring	SCE	ISO LGIA	2021

4.5.5 Energy Imbalance Market (EIM) modeling

Representations for the participation in the ISO's energy imbalance market were added in the ISO's databases in this planning cycle. According to the Regional Coordination in the West: Benefit of PacifiCorp and California ISO Integration[81] report, 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 when it is necessary to consider the impacts of the EIM.

The database model therefore contains provision for emulating the energy imbalance market, as pursuing transmission projects for benefits that are already being provided by the EIM would be counterproductive. However, in considering the economic benefits of a transmission project, it is not reasonable to consider the full impact of benefits that also depend on the EIM, given the relative ease for entities to exit EIM and the long life of transmission assets. Therefore, EIM was not modeled in the ISO's databases in this planning cycle.

4.5.6 Financial Parameters Used in Cost-Benefit Analysis

A cost-benefit analysis is made for each economic planning study performed where the total costs are 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 2021 unless specially indicated.

4.5.6.1 *Cost analysis*

In these studies, the total cost is considered to be the total revenue requirement in net present value in the proposed operation year. The total revenue requirement includes impacts of capital cost, tax expenses, O&M expenses and other relevant costs.

In calculating the total cost of a potential economic-driven project, when necessary, the financial parameters listed in Table 4.5-5 are used. The net present value of the costs (and benefits) are calculated using a social discount rate of 7 percent (real) with sensitivities at 5 percent as needed.

[81] https://www.caiso.com/Documents/StudyBenefits-PacifiCorp-ISOIntegration.pdf.

Table 4.5-5: 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%

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.

4.5.6.2 *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.[82]

When detailed analysis of a high priority study area is required, production cost simulation and subsequent benefits calculations are conducted for the 5th and 10th planning years - in this case, for years 2021 and 2026. For the intermediate years between 2021 and 2026 the benefits are

[82] Discount of yearly benefit into the present worth is calculated by bi = Bi / (1 + d)i, where bi and Bi 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.

estimated by linear interpolation. For years beyond 2026 the benefits are estimated by extending the 2026 year benefit with an assumed escalation rate.

The following financial parameters for calculating yearly benefits for use in determining the total benefit in this year's transmission planning cycle are:

- economic life of new transmission facilities = 50 years;
- economic life of upgraded transmission facilities = 40 years;
- benefits escalation rate beyond year 2026 = 0 percent (real); and
- benefits discount rate = 7 percent (real) with sensitivities at 5 percent as needed

4.5.6.3 *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 gross benefit minus cost) has to be positive. If there are multiple alternatives, the alternative that has the largest net benefit is considered the most economical solution.

4.6 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.

4.6.1 Congestion identification

The results of the congestion assessment are listed in Table 4.6-1.

Table 4.6-1: Potential congestion in the ISO-controlled grid in 2026

Constraints Name	***Type***	***Costs (F) (K$)***	***Duration (F) (Hrs)***	***Costs (B) (K$)***	***Duration_ (B) (Hrs)***	***Costs (K$)***	***Duration (Hrs)***
MEAD S-BOB SS 230 kV line #1	Branch	0	0	23,719	600	23,719	600
SNTA RSA-STNY PTP 115 kV line, subject to PG&E LCR NCNB Fulton Cat C	Contingency	9,696	639	0	0	9,696	639
P26 Northern-Southern California	Interface	22	6	4,139	274	4,162	280
EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-Merced M 115/70 kV xfmr	Contingency	1,681	651	0	0	1,681	651
J.HINDS-MIRAGE 230 kV line #1	Branch	1,086	187	0	0	1,086	187
MIDWAY-WIRLWIND 500 kV line #3	Branch	0	0	547	13	547	13
P45 SDG&E-CFE	Interface	206	283	273	276	479	559
LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	Contingency	0	0	476	32	476	32
P66 COI	Interface	440	89	0	0	440	89
GATES-MIDWAY 500 kV line #1	Branch	0	0	411	23	411	23
MIDWAY-VINCENT 500 kV line, subject to SCE N-1 Midway-Vincent #1 500kV	Contingency	186	18	0	0	186	18
ISO v COI Summer 1-2	Nomogram	164	12	0	0	164	12
ISO v COI Summer 1-1	Nomogram	150	11	0	0	150	11
IMPRLVLY PFC	Branch	0	0	143	90	143	90
MIDWAY-VINCENT 500 kV line, subject to PGE N-1 Midway-Whirlwind #3 500kV	Contingency	0	0	91	6	91	6

MARBLE 63.0/69.0 kV transformer #1	Branch	0	0	80	79	80	79
ISO v COI Summer 3-2	Nomogram	64	6	0	0	64	6
CAMANCH-BELLOTA 230 kV line #2	Branch	0	0	62	2	62	2
INYO 115/115 kV transformer #1	Branch	45	50	10	16	55	66
ISO Path26 N2S with RAS	Nomogram	41	3	0	0	41	3
TESLA-AEC_TP1 115 kV line, subject to PG&E LCR Stock TesBel Cat B	Contingency	0	0	37	37	37	37
ISO v COI Summer 3-1	Nomogram	22	2	0	0	22	2
LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	Contingency	0	0	18	2	18	2
IMPRLVLY-ELCENTSW 230 kV line, subject to SDGE N-1 N.Gila-Imperial Valley 500kV	Contingency	0	0	18	219	18	219
GATES-MIDWAY 230 kV line, subject to PGE N-1 Gates-Midway #1 500kV	Contingency	0	0	16	2	16	2
OTAYMESA-TJI-230 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	Contingency	0	0	11	6	11	6
ECO-MIGUEL 500 kV line, subject to SDGE N-1 Ocotillo-Suncrest 500 kV with RAS	Contingency	9	1	0	0	9	1
PANOCHE-GATES 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	Contingency	0	0	11	7	11	7
HUMBOLDT-TRINITY 115 kV line, subject to PG&E LCR Humboldt Cat B	Contingency	2	7	0	0	2	7
P24 PG&E-Sierra	Interface	1	1	0	0	1	1
MORAGA-CLARMNT 115 kV line, subject to PG&E LCR Stock Lock Cat C	Contingency	1	1	0	0	1	1

Table 4.6-2 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 based on the 2026 congestion cost.

Table 4.6-2: Aggregated potential congestion in the ISO-controlled grid in 2026

No	Aggregated congestion	2026	
		Costs (M$)	Duration (hr)
1	BOB SS (VEA) - MEAD S 230 kV line	23.72	600
2	PG&E LCR	9.73	684
3	Path 26	5.03	320
4	PG&E/TID Exchequer	1.68	651
5	J.HINDS-MIRAGE 230 kV line #1	1.09	187
6	COI	0.84	120
7	Path 45	0.63	655
8	SCE LCR	0.49	34
9	Path 15/CC	0.44	32
10	PG&E/Sierra MARBLE transformer	0.08	79
11	PGE& CAMANCH-BELLOTA 230 kV line	0.06	2
12	Inyo-Control	0.05	66
13	IID-SDGE	0.02	219
14	SDGE ECO-Miguel 500 kV line	0.01	1
15	Path 24	0.00	1

In this planning cycle, detailed investigations were conducted on the constraints that may have a large impact on the bulk system and showed recurring congestion. Specifically, these constraints selected for further analysis were COI and the constraints in the Imperial Valley area including the tie between IID and SDGE and Path 45. The detailed analysis results are in Section 4.7.

Other constraints were also analyzed, but not at the same detailed level for different reasons as discussed below.

- A detailed analysis was performed on the congestion on the Exchequer-La Grant 115 kV line in the 2015-2016 transmission planning cycle and no economic justification was identified. There is no change in circumstance for this constraint, therefore the ISO did not conduct further detailed study.
- Congestion in PG&E North Cost North Bay (NCNB) LCR area under N-2 contingency, which is a critical contingency identified in LCR studies, was observed for the first time in this planning cycle. This congestion is related to the geothermal generator in the PG&E NCNB

LCR area. The operation condition of geothermal generators such as normal output has direct impact on the congestion. These geothermal generators are owned by Independent Power Producers (IPP) or non-ISO utilities. Similar to Exchequer-La Grant congestion, with congestion mitigated the majority benefit will go to the generator owners rather than the ISO ratepayers. Therefore, the ISO did not conduct detailed economic analysis on PG&E NCNB LCR related congestion in this planning cycle. It will be monitored in the future planning cycles.

- Bob SS to Mead S 230 kV line congestion was observed for the first time in this planning cycle. Bob SS to Mead S 230 kV line is a tie between the ISO and WAPA. The congestion was observed when the flow was from Bob SS to Mead S, i.e. exporting from the ISO. Mitigating this congestion will not bring benefit to ISO's ratepayers. Also, the congestion was not only related to ISO's system but also related to the system outside the ISO. Detailed analysis requires coordination with neighboring systems. Therefore, the ISO did not conduct detailed economic analysis on Bob SS – Mead S congestion in this planning cycle. It will be monitored in the future planning cycles.

- Congestions on Path 26 and Path 15 were also identified in the previous planning cycles. 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. Comparing with the results in previous planning cycle, it was observed that the congestion on Path 26 was observed mainly on the south to north direction in this planning cycle due to the retirement of Diablo Canyon Nuclear units, and increasing renewable generation in Southern California. However, the overall congestion cost remained similar for both Path 26 and Path 15 from the previous year. Therefore, no detailed production cost simulation and economic assessment were conducted for these two congestions. The ISO will continuously and closely monitor and assess these congestions in the future planning cycles.

No detailed analyses on other congestions in Table 4.6-1 and Table 4.6-2 were conducted due to the congestions are not significant for justifying an upgrade, based on either the studies in previous planning cycles or engineering judgement. Still they will be monitored in the future planning cycles and will be studied as needed.

4.6.2 Economic Planning Study Requests

As part of the economic planning study process, Economic Planning Study requests are accepted by the ISO, to be considered in addition to 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.

4.6.2.1 *Southwest Intertie Project - North*

Study request overview

Southwest Intertie Project - North (SWIP North) is comprised of a single circuit 500 kV transmission line from Midpoint substation (in Idaho) to Robinson Summit substation (in Nevada).

Evaluation

Table 4.6-3 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.6-3: Evaluating study request - Southwest Intertie Project - North

Study Request: Southwest Intertie Project - North		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• CAISO's Transmission Planning studies in several previous cycles have shown congestion on the California Oregon Intertie (COI) interface and Path 26	• Economic studies performed by the ISO have identified congestion on COI and Path 26; these congestion costs did not change significantly from previous transmission plans; and were previously found not to be sufficient to warrant network upgrades in previous transmission plans. (Please refer to the separate discussion of COI congestion below).
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Project offers policy benefits by allowing out of state renewables (including Wyoming Wind) to meet the new California 50% RPS targets • Out of state wind also provides geographical diversity benefits to California	• Project will be studied in the informational 50% RPS and interregional transmission planning process
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
Integrate New Generation Resources or Loads	• See "Delivery of Location Constrained Resource Interconnection Generators" above	• See "Delivery of Location Constrained Resource Interconnection Generators" above

Study Request: Southwest Intertie Project - North		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Other	• Amount of congestion on COI and Path 26 shown in the CAISO studies is very small as compared to the real time congestion on this path as shown in CAISO's OASIS and Market Update reports. LS Power believes that certain modelling enhancements to the economic study models may be necessary to be able to investigate these discrepancies. Some of the discrepancies may be related to the use of hurdle rates in the TEPPC common case (for transfers from Pacific Northwest into California) that do not reflect economics of flows in real time. These hurdle rates should be examined and corrected, as appropriate. • The economic study model may not be able to accurately reflect the dynamic path limit on COI, which CAISO should look into implementing in studies to be done under this year's cycle. • Capacity Benefits from SWIP North. Adding SWIP North relieves certain reliability and economic constraints related to imports across CAISO's COI path. This translates into incremental import capability into CAISO that should add to the net benefits attributed to SWIP North • If SWIP North were to be built, CAISO could have access to a complete path from Midpoint to Eldorado. Under the Transmission Use and Capacity Exchange Agreement among affiliates of LS Power and NV Energy, once SWIP North is built there would be an exchange of capacity such that NV Energy would get a share of the capacity between Midpoint and Robinson Summit and LS Power would get a share of capacity between Robinson Summit and Harry Allen, without either party having to pay any additional amount to the other. As a result of this capacity exchange, each party would have bidirectional transmission capacity on the entire path from Midpoint to Harry Allen. Study request is that CAISO study the benefits of approximately 1000 MW of bidirectional transmission capacity between Midpoint and Harry Allen, which is what LS Power will have, and will be available to the CAISO market	• Project will be studied in the informational 50% RPS and interregional transmission planning process

Study Request: Southwest Intertie Project - North		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
	upon completion of construction of SWIP North • SWIP North also brings reliability and grid security benefits to California and the entire WECC region. SWIP North is a major 500 kV WECC path that parallels several major WECC paths in North to South direction. Adding this new path not only relieves loadings on the existing WECC paths but also provide grid security benefits. SWIP North has the potential to reduce (if not eliminate) the impact of triggering WECC NE/SE separation scheme, that breaks WECC into two systems, under certain contingency conditions. This can potentially prevent major black out in California, which leads to economic and societal benefits. These benefits are typically not captured for internal CAISO transmission projects, but for a major WECC project such as SWIP North, these benefits should be quantified	

Conclusion

The economic analysis does not demonstrate sufficient economic benefit to proceed unilaterally as a regional (ISO high voltage) transmission project. Please refer to the separate discussion of COI congestion below.

The ISO therefore 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 proposed project will be studied in the informational 50 percent RPS and interregional transmission planning process.

4.6.2.2 *Buck-Colorado River-Julian Hinds 230 kV Loop-In Project*

Study request overview

The Buck-Colorado River-Julian Hinds 230 kV Loop-in project was initially submitted into the 2014-2015 ISO transmission planning cycle.

Evaluation

The ISO studied this project as a continuation of the 2014-2015 Transmission Planning Process. A presentation on that study was given on September 22, 2015. The ISO's studies did not support the need for this project.

4.6.2.3 *Eagle Mountain Pumped Storage Project*

Study request overview

The Eagle Mountain Pumped Storage Project is a 1,300 MW project in Riverside County, California.

Evaluation

The results of the evaluation are shown in Table 4.6-4.

Table 4.6-4: Evaluating study request – Eagle Mountain Pumped Storage Project

Study Request: Eagle Mountain Pumped Storage Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• As the 50% RPS Study in the last planning cycle illustrated, there may be localized congestion or other negative grid impacts that could be addressed by bulk storage facilities	• Economic studies performed by the ISO have shown that the addition of the proposed project does not have a significant impact to the identified congestion
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	• Additional renewables development in high-potential renewables areas such as East Riverside, or imports from other areas (which may become part of an expanded west-wide ISO/RTO by joining with the CAISO), could be accommodated through locating bulk storage facilities in that area	• The Eagle Mountain pumped storage project and other pumped storage projects are being studied in the large energy storage special study
Local Capacity Area Resource requirements	• Not addressed in submission	• No benefits identified by ISO
Increase in Identified Congestion	• Not addressed in submission	• No benefits identified by ISO
Integrate New Generation Resources or Loads	• See "Delivery of Location Constrained Resource Interconnection Generators" above	• See "Delivery of Location Constrained Resource Interconnection Generators" above

Study Request: Eagle Mountain Pumped Storage Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Other	• Given the state's ambitious carbon-reduction goals, the CAISO should consider potential future increases in carbon-emissions values over time, as well as any other emissions-related or other societal benefits.	• The Eagle Mountain pumped storage project and other pumped storage projects are being studied in the large energy storage special study

Conclusion

The Eagle Mountain pumped storage project and other pumped storage projects are being studied in the large energy storage special study.

4.6.2.4 *COI congestion*

Study request overview

Table 4.6-5 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.6-5: Evaluating study request – COI congestion

Study Request: COI congestion		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	• Recent economic studies performed by the CAISO indicate limited congestion on COI	• Economic studies performed by the ISO have identified congestion on COI • Congestion costs did not change significantly from previous cycles • No economic justifications 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
Increase in Identified Congestion	• Not addressed in submission	• Congestion on COI is not expected to increase significantly over the planning horizon used in the Transmission Planning Process

Study Request: COI congestion		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Integrate New Generation Resources or Loads	• Not addressed in submission	• No benefits identified by ISO
Other	• Study request states that the identified congestion on COI is limited due to normative assumptions in the studies. It is requested that the 2016-17 TPP study consider a broader range of operating conditions reflecting actual operating issues including expected and unexpected outages. The CAISO may also want to consider using additional analytic tools to quantify the economic benefits attributable to reduced congestion and greater intertie imports • Proposal states that an economic study that more effectively captures a historically and operationally accurate level of congestion will be able to identify economically viable solutions to help offset some of the congestion costs that have incurred on the COI, increase the load serving capability in northern California, and allow the customers in the CAISO and PacifiCorp to realize the benefits of the proposed regional expansion.	• Enhancement to the COI nomogram and the addition of scheduled outages and derates to COI that were modeled in the studies are discussed in Section 4.7.1

Conclusion

The detailed analysis results on the COI constraint are in section 4.7.

4.6.2.5 *Path 15 study*

Study request overview

The study request was for the ISO to conduct an economic assessment of Path 15 based on both a 33 percent RPS and a 50 percent RPS. It was proposed that the assessment consider production costs and potential costs to integrate renewable resources that cannot be absorbed within the ISO-controlled grid without and with Path 15 upgrades. It was suggested that south-to-north studies evaluate dry-year hydro-generation conditions in Northern California and the Northwest. Depending on the assessment results, such upgrades might be designed to achieve a Path 15 rating increase of about 300 MW to 1000 MW.

It was suggested that a 300 MW increase might be achieved with the Tesla/Tracy-Los Banos upgrade and relatively minor upgrades in the Gates and Arco areas. And a 1000 MW increase might be achieved with the Tesla/Tracy-Los Banos upgrade and upgrades of the Gates-Midway 500 kV and perhaps the Los Banos-Gates 500 kV.

Evaluation

Please refer to the discussion in section 4.6.1. As noted in that discussion, observed congestions in this planning cycle are not materially different from that observed in the more detailed studies conducted in the 2015-2016 transmission planning cycle and no economic justifications for upgrades were found in that cycle Therefore, no detailed production cost simulation and economic assessment was conducted in this cycle. The ISO will continuously and closely monitor and assess these congestions in the future planning cycles

Conclusion

The ISO will continue to review Path 15 congestion in future planning cycles, and in particular when 50 percent RPS portfolios are available for planning purposes.

4.6.2.6 *Path 26 study*

Study request overview

The study request was for the ISO to conduct an economic assessment of Path 26 based on both a 33 percent RPS and a 50 percent RPS. It was proposed that the assessment consider production costs and potential costs to integrate renewable resources that cannot be absorbed within the CAISO-controlled grid without and with Path 26 upgrades. It is suggested that the north-to-south assessment evaluate wet-year hydro-generations conditions in Northern California and the Northwest.

To the extent Path 26 is congested in this study, it was suggested that the ISO consider a Midway-Vincent 500 kV line, a Midway-Vincent 230 kV line, Big Creek-Helms interconnection or other alternatives as indicated by production simulation and power flow studies.

Evaluation

Please refer to the discussion in section 4.6.1. As noted in that discussion, observed congestions in this planning cycle are not materially different from that observed in the more detailed studies conducted in the 2015-2016 transmission planning cycle and no economic justifications for upgrades were found in that cycle Therefore, no detailed production cost simulation and economic assessment was conducted in this cycle. The ISO will continuously and closely monitor and assess these congestions in the future planning cycles

Conclusion

The ISO will continue to review Path 26 congestion in future planning cycles, and in particular when 50 percent RPS portfolios are available for planning purposes.

4.6.2.7 *Other projects submitted into Reliability Project Request Windows*

A number of proposed projects were submitted into the reliability request window ostensibly as potential reliability-driven projects, but suggesting significant economic benefits. These projects are addressed on a case-by-case basis in chapter 2 dealing with reliability projects, but referring to the congestion analysis performed as part of the economic study process. If significant congestion had been identified in the ISO's congestion assessment and any of those projects had the potential for significant economic benefits such that they warranted detailed study, they would have been specifically noted in this chapter.

4.6.3 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 two congested branch groups for further assessment, which are listed Table 4.6-6.

Table 4.6-6: High - Priority Studies

<table>
<tr><th colspan="2" rowspan="2">Branch Group</th><th rowspan="2">Area</th><th colspan="2">2026</th></tr>
<tr><th>Costs (M$)</th><th>Duration (hr)</th></tr>
<tr><td colspan="2">COI</td><td>PG&E, NW</td><td>0.84</td><td>120</td></tr>
<tr><td rowspan="2">Path 45 and IID-SDGE</td><td>Path 45</td><td>SDGE/IID/CFE area</td><td>0.63</td><td>655</td></tr>
<tr><td>IID-SDGE</td><td>SDGE/IID/CFE area</td><td>0.02</td><td>219</td></tr>
</table>

4.7 Congestion Mitigation and Economic Assessment

Congestion mitigation is the second step in the economic planning study. With a focus on high-ranking congestion in the high priority study areas, this study step conducts detailed investigation and modeling enhancements as needed. Based on the detailed study results, it is decided whether economic assessment for potential network upgrades is needed. If the need is identified, then this study step evaluates the economic benefits of potential network upgrades and weighed the benefits against the costs to determine if the network upgrades are economical.

4.7.1 COI congestion

In this planning cycle, COI congestion was investigated as a continuous work since the 2015-2016 planning cycle. First, the modeling of COI nomograms was further enhanced in order to correctly capture the impact of future renewable development and transmission upgrades in Northern California. Particularly, the planning nomograms for COI developed in 2013~2014 TPP were implemented in the ISO's production cost simulation model with considering both Northern California hydro and renewable generation. This enhancement allowed the production cost simulation to capture potential congestion on COI due to high hydro and high renewable conditions in Northern California. Another enhancement related to COI modeling is the scheduled outages and associated derate of COI capacity. In addition to the scheduled outages and derate that were already modeled in the previous planning cycles, the ISO worked with the COI facility owners to collect additional scheduled outages and derate data mainly related to relay maintenance. There new collected outages and derate data were further divided into three groups based how frequently they may happen. The annual events were added into the base database as the part of the baseline assumptions. The events that may happen every two to three years were the second group, and the third group included the events that may happen every four to six years. The second and the third groups were modeled as sensitivity studies. The events that may only happen every seven years or longer were not considered.

Table 4.7-1 shows the COI congestion in the baseline study. In this table, the interface congestion is the congestion due to the COI path rating or derates, and the nomogram congestion is the congestion due the COI nomogram. The constraint names in the first column are the names of these constraints in the database. For example, "ISO v COI Summer 1-2" is a segment of COI nomograms for summer. There are two sets of COI nomograms in the database, one is for summer and the other is for the rest of the year. Each set of COI nomograms has multiple segments for different system conditions including hydro and renewable generation output.

Table 4.7-1: COI Congestion Breakdown in Baseline Study

Constraints Name	*Type*	*Costs (M$)*	*Duration (Hrs)*
P66 COI	Interface	0.440	89
ISO v COI Summer 1-2	Nomogram	0.164	12
ISO v COI Summer 1-1	Nomogram	0.150	11
ISO v COI Summer 3-2	Nomogram	0.064	6
ISO v COI Summer 3-1	Nomogram	0.022	2

Table 4.7-2 compared the impact of scheduled outages on COI congestion. It showed that the COI congestion increased as additional outages and derates were modeled, but the changes were not significant. The results are as expected since the scheduled outages are only happened in limited hours and normally scheduled during the periods when the system normally has sufficient capacity.

Table 4.7-2: COI congestion comparison with additional outages modeled

COI Outage group	Cost ($M)	Hours
Base (annual outage)	0.84	120
1~3 year	0.93	124
1~6 year	1.19	185

Figure 4.7-1, Figure 4.7-2, and Figure 4.7-3 show COI path flows and path ratings in the simulation results with modeling annual COI outage, 1~3 year COI outages, 1~6 year COI outages, respectively. The path ratings were the ratings after derates due to outages.

Figure 4.7-1: COI Path Flow and Path Rating with Annual Outages Modeled

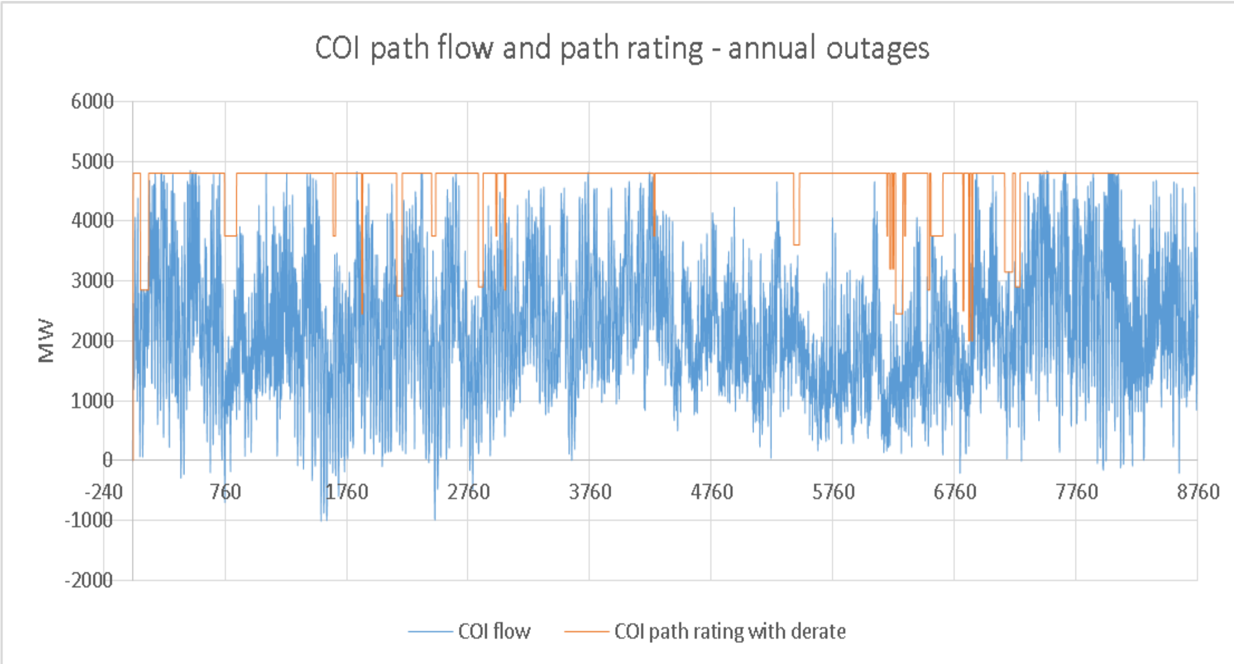


Figure 4.7-2: COI path flow and path rating with 1~3 year outages modeled

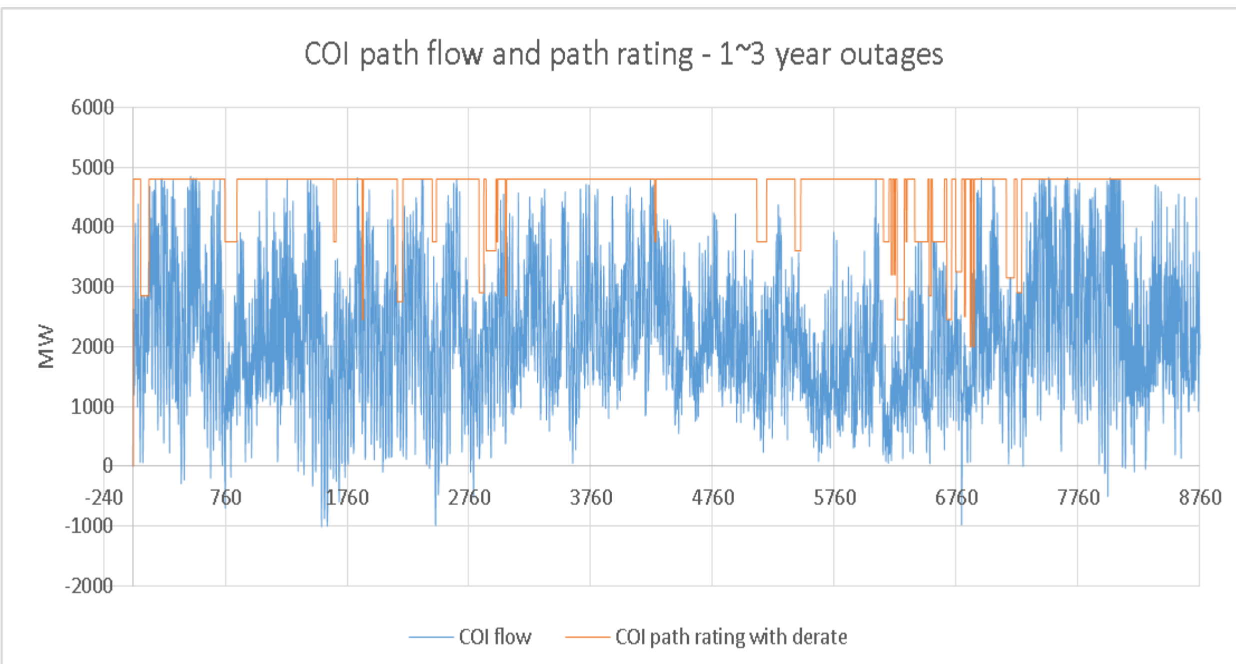
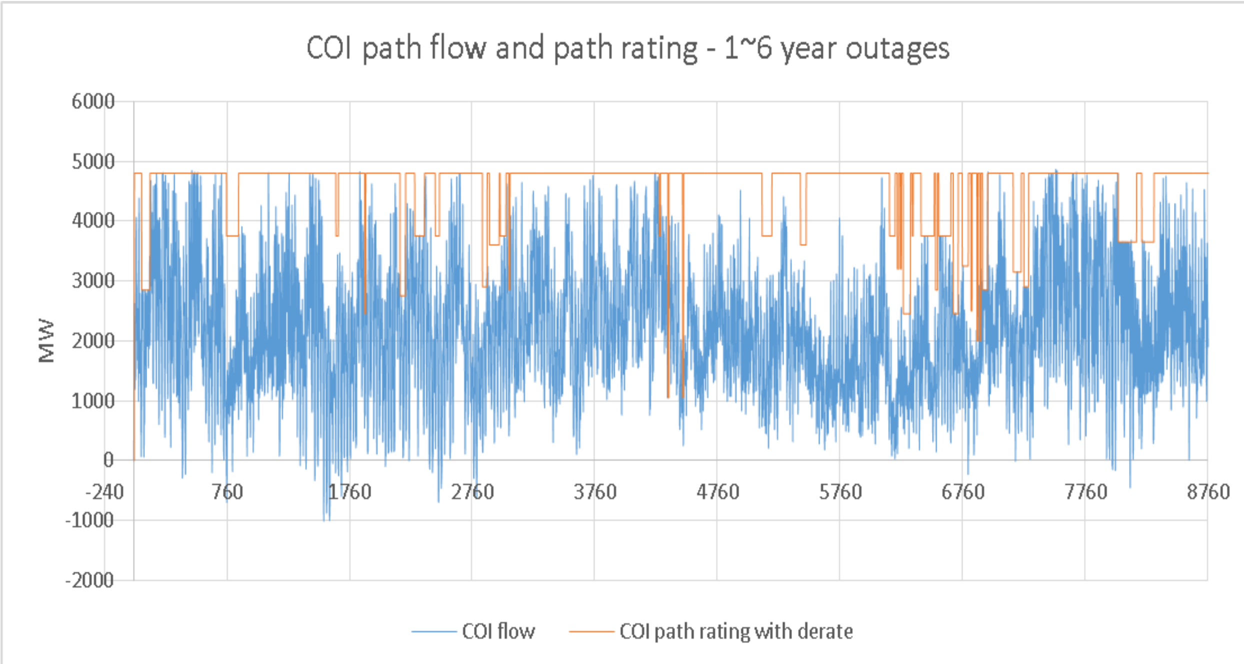


Figure 4.7-3: COI path flow and path rating with 1~6 year outages modeled



With the enhancements on COI modeling, the COI congestion in the production cost simulation in 2026 increased from previous planning cycles but the changes were not significant or sufficient to triggering detailed economic assessment for potential network upgrades. It is worth noting that there are other factors that may impact COI flow, for example the assumption of renewable development in Northern California and the assumption of resources in Northwest and Canada. The former relies on the further clarity of the 50 percent renewable energy goal in California, and the latter requires coordination among related entities in the interregional transmission planning process. Despite not leading to forecast congestion supporting transmission development, the enhancements on COI modeling that have been implemented in this planning cycle provided an enhanced framework for any future studies on COI congestion.

4.7.2 Path 45 and IID-SDGE Congestions

Path 45 is a WECC path that includes two 230 lines between SDGE and CFE areas. One of the two 230 kV lines is from SDGE's Otay Mesa substation to CFE's TJI substation. The other is from SDGE's Imperial Valley substation to CFE's ROA substation. Two phase shifters are being installed in 2017 in the Imperial Valley substation to control the flow between Imperial Valley and ROA substations. Figure 4.7-4 illustrated the electrical interconnection in the SDGE/CFE area in the production cost model, which was also consistent with the power flow model in the reliability study. Also shown in this figure are the 500 kV lines between SDGE's San Diego and Imperial Valley areas, and the 500 kV line between SDGE's Imperial Valley area and Arizona. The 230 kV tie between IID and SDGE system is also shown in Figure 4.7-4, which is the line between El Centro and Imperial Valley.

Figure 4.7-4: SDGE/IID/CFE area electrical interconnections

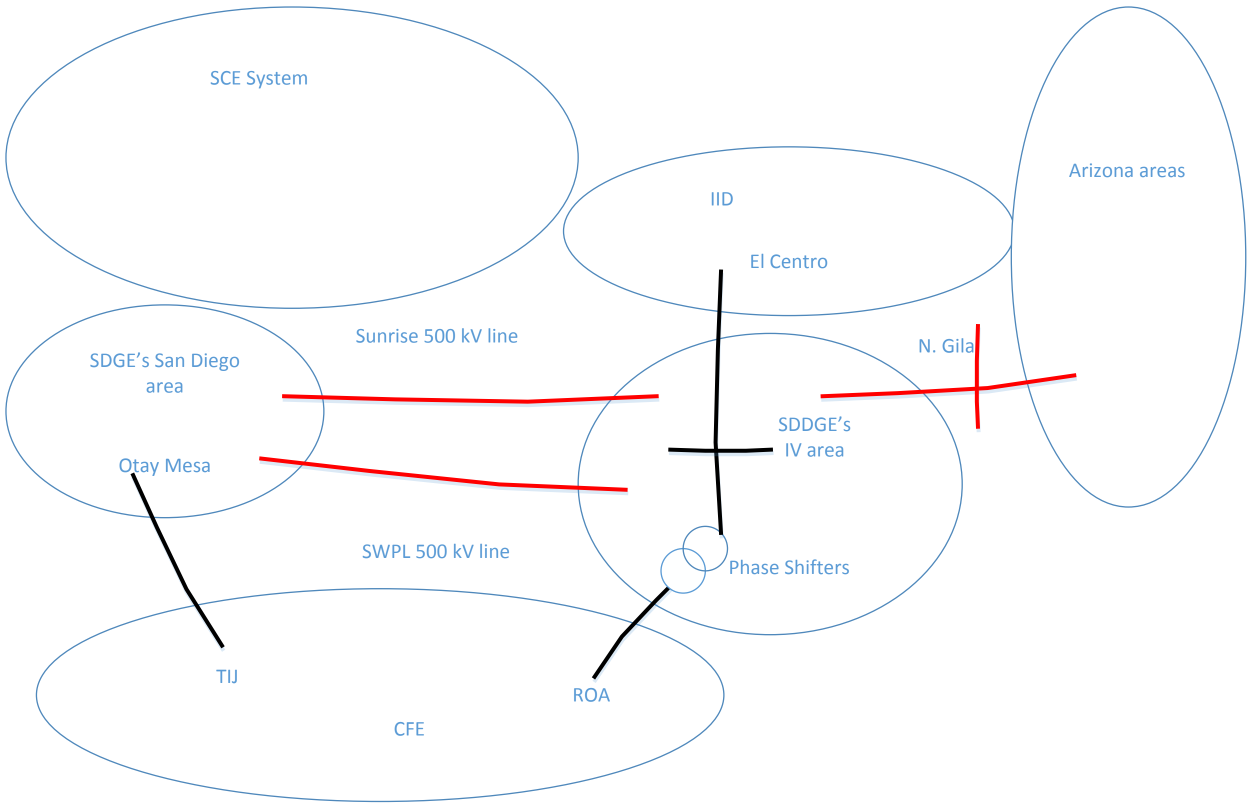


Table 4.7-3 shows the congestions in the SDGE/IID/CFE area identified in 2016-2017 transmission planning cycle. The congestion on Path 45 was mainly on Path 45 itself and the Imperial Valley phase shifters due to the path rating and the facility normal rating of the phase shifters, respectively. Small amounts of congestion were also observed on Otay Mesa to TIJ 230 kV line, which is a part of Path 45, under both normal and contingency conditions. The congestion between IID and SDGE was observed on the direction from IID to SDGE under N-1 contingency of N. Gila to Imperial Valley 500 kV line.

Table 4.7-3: SDGE/IID/CFE area congestion breakdown in baseline study

Constraints Name	*Costs (F) (K$)*	*Duration (F) (Hrs)*	*Costs (B) (K$)*	*Duration (B) (Hrs)*	*Costs (T) (K$)*	*Duration (T) (Hrs)*
P45 SDG&E-CFE	206	283	273	276	479	559
IMPRLVLY Phase Shifters	0	0	143	90	143	90
OTAYMESA-TJI-230 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	0	0	11	6	11	6
IMPRLVLY-ELCENTSW 230 kV line, subject to SDGE N-1 N.Gila-Imperial Valley 500kV	0	0	18	219	18	219

Some key factors affected the study results in this area.

- First is the assumption of renewable development in future years. In the 2016-2017 planning cycle, the production cost model used the same assumption of renewable development as in the reliability studies conducted in this planning cycle, which was to meet the 33 percent RPS requirement and consider the actual renewable development status as well. Specifically, a total of 2007 MW of renewable generation, including existing and future generators, was modeled in SDGE's Imperial Valley area, which includes Imperial Valley South and San Diego South CREZs. An additional 417 MW of renewable generation was modeled in the IID area on top of the IID-connected generators that were already in the WECC case. Regarding the congestion on IID's El Centro – SDGE's Imperial Valley 230 kV line, the flow was impacted by how the total renewable capacity was allocated between IID and SDGE systems and the allocation may increase or decrease the congestion on the line. All the renewable generation in SDGE and IID contributed to the Path 45 congestion in the direction from ISO to CFE. As renewable generation increased in SDGE and IID, the Path 45 congestion also increased on this direction.

- Another factor is the operation of Imperial Valley phase shifters. Two phase shifters are being installed in parallel in Imperial Valley substation to control the flow on the Imperial Valley to ROA 230 kV line. These phase shifters were first proposed and approved by the ISO in the 2012-2013 planning cycle. The main purpose was to improve the system reliability when the import into San Diego was high. It was also desired to utilize the phase shifters to optimize the flow through the CFE system to minimize transmission losses in the CFE system. In addition, the transmission limits or constraints into the San Diego area would be potentially affected by the operation of phase shifters, which would also affect the congestions in surrounding areas.

- In the current production cost simulation software (GridView), the angles of phase shifters were set to minimize the total generation cost. This approach serves well for most phase shifters in the system, with certain fine-tuned parameters based on historical operational data. However, it may not provide expected results for Imperial Valley phase shifters because of the specific reliability and operation needs for these phase shifters. Also, there is no historical data that can be used to tune the parameters in the production cost model since the phase shifters will be in service for the first time in 2017. The ISO is engaged with the vendor of GridView software (ABB) to enhance the phase shifter modeling in GridView so that the reliability and operational needs can be captured in the production cost simulation.

With further clarity of renewable development in the SDGE and IID areas, and with the enhancement of phase shifter modeling in production cost simulation, the ISO will continuously monitor and investigate the congestions on Path 45 and in the SDGE and IID areas.

4.8 Summary

The production cost simulation was conducted in 2026 in this economic planning study and grid congestion was identified and evaluated. According to the identified areas of congestion concerns, two areas that showed recurring congestions with system-wide impact were selected for further evaluation:

- COI
- SDGE/IID/CFE area

The ISO production cost model was further enhanced on COI outage and derate modeling to incorporate the additional outage data provided by the COI facility owners. The COI nomograms for planning horizon were also implemented in the ISO production cost model through the enhanced production cost simulation software. With the changes, COI congestion cost forecasts remained de minimis but increased from previous planning cycles. Further analysis through interregional coordination would be necessary to more fully explore the benefits of alleviating the observed congestion.

The congestions on Path 45 and in the SDGE and IID areas have impacts on renewable development and economic dispatch locally and system-wide. Recognizing the effects of renewable development in the surrounding areas and the operation of Imperial Valley phase shifters, the study on the congestions on Path 45 and in the SDGE and IID areas in the 2016~2017 planning cycle focused on the clarification of the reliability and operation needs for the phase shifters and the software and modeling enhancements for the phase shifter modeling. Further studies would be conducted based on updated information of renewable development and system operation with phase shifters in service, as the enhancements are in place.

In summary, there are no economic upgrades recommended for approval in the 2016-2017 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.

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Chapter 5

5 Other Studies and Results

The studies discussed in this chapter have not been addressed elsewhere in the transmission plan. The studies focus on other recurring study needs not previously addressed and either set out in the ISO tariff or forming part of the ongoing collaborative study efforts taken on by the ISO to assist the CPUC with state regulatory needs. These presently include the reliability requirements for resource adequacy studies, both short term and long term, and the long-term congestion revenue rights (LT CRR) simultaneous feasibility test studies.

5.1 Reliability Requirement for Resource Adequacy

Section 5.1.1 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 2017.

5.1.1 Local Capacity Requirements

The ISO conducted short- and long-term local capacity technical (LCT) analysis studies in 2016. A short-term analysis was conducted for the 2017 system configuration to determine the minimum local capacity requirements for the 2017 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 in January through April through a transparent stakeholder process with a final report published on April 29, 2016.

For detailed information on the 2017 LCR Report please visit:
http://www.caiso.com/Documents/Final2017LocalCapacityTechnicalReportApril292016.pdf

Two long-term analysis were also performed identifying the local capacity needs in the 2021 and 2026 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five and ten years respectively.

The 2021 LCR Report was published on January 30, 2017 and for detailed information please visit:

http://www.caiso.com/Documents/Final2021Long-TermLocalCapacityTechnicalReportJan312017.pdf

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 5.1-1 and Figure 5.1-1.

Table 5.1-1: 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 5.1-1: 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 160 MW. In contrast, the requirements of the Los Angeles Basin are approximately 8,000 MW. The short- and long-term LCR needs from this year's studies are shown in Table 5.1-2.

Table 5.1-2: Local capacity areas and requirements for 2017, 2021 and 2026

LCR Area	**LCR Capacity Need (MW)**		
	2017	**2021**	**2026**
Humboldt	157	169	171
North Coast/North Bay	721	480	547
Sierra	2,043	1,686	1,004
Stockton	745	404	516
Greater Bay Area	5,617	5,194	5,732
Greater Fresno	1,779	1,160	1,474
Kern	492	105	392
Los Angeles Basin	7,368	6,898	7,234
Big Creek/Ventura	2,057	2,398	2,528
Greater San Diego/Imperial Valley	3,570	4,357	4,649
Valley Electric	0	0	0
Total	**24,549**	**23,044**	**24,247**

Notes:
1) For more information about the LCR criteria, methodology and assumptions please refer to the ISO LCR manual.
2) For more information about the 2017 LCT study results, please refer to the report posted on the ISO website.
3) For more information about the 2021 LCT study results, please refer to the report posted on the ISO website.
4) For more information about the 2026 LCT study results, please refer to the Appendix D herein.

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 2026 long-term LCT study results, please refer to the stand-alone report in the Appendix D of the 2016-2017 Transmission Plan.

5.1.2 Resource adequacy import capability

The ISO has established the maximum RA import capability to be used in year 2017 in accordance with ISO tariff section 40.4.6.2.1. These data can be found on the ISO website[83]. The entire import allocation process[84] is posted on the ISO website.

[83] http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2017.pdf

[84] http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

The ISO also confirms that all import branch groups or sum of branch groups have enough maximum import capability (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 2026.

The future outlook for all remaining branch groups can be accessed at the following link:

http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2017-2026.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2021 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.

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.

5.2 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

5.2.1 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.

5.2.2 Data Preparation and Assumptions

The 2016 LT CRR study leveraged the base case network topology used for the annual 2016 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 2016-2017 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). All applicable constraints that were applied during the running of the original LT CRR market 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, since they were awarded with the system capacity already reduced to 60 percent. For the study year, the market run was set up for four seasons (with season 1 being January through March, season 2 April through June etc.) 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.

5.2.3 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.

5.2.4 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 2016 that there are no existing released LT CRRs at-risk" that require further analysis. Thus, the transmission projects and elements approved in the 2016-2017 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.

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Chapter 6

6 Special Reliability Studies and Results

In addition to the mandated analysis framework set out in the ISO's tariff described above, the ISO has also pursued a number of additional "special studies" in parallel with the tariff-specified study processes, to help prepare for future planning cycles that reach further into the issues emerging through the transformation of the California electricity grid. These studies are provided on an informational basis only and are not the basis for identifying needs or mitigations for ISO Board of Governor approval in this planning cycle. The special studies undertaken in this planning cycle and the issues driving those studies are discussed in the following sections and are listed below:

- Risks of early economic retirement of gas fleet (section 6.1)
- Continuation of frequency response efforts through improved modeling (section 6.2)
- Gas/electric reliability coordination (section 6.3)
- 50 Percent Renewable Generation and Interregional Coordination (section 6.4)
- Large scale storage benefits (section 6.5)
- Slow response resources in local capacity areas (section 6.6)

The special studies discussed in this chapter have not been addressed elsewhere in the transmission plan.

6.1 Risks of early economic retirement of gas fleet

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – and use of coastal water for once-through-cooling at thermal generating stations continues to be phased out, the generation fleet is dealing with profound changes in the dynamics of market performance.

Increased quantities of grid connected renewable generation, including higher than previously expected levels of behind-the-meter solar generation, are producing new and more complex operating paradigms for which the ISO must consider in planning the grid. Increased renewable generation and state policies phasing out reliance on coastal waters for once-through cooling has accelerated the retirement of gas-fired generation in these areas. Further, the retirement of the San Onofre Nuclear Generating Station has materially affected California's generation fleet and the historical loading patterns on California's interconnected transmission network, as will the planned retirement of Diablo Canyon Nuclear Generating Station in 2024. These changes cumulatively drive increased reliance on the gas generation fleet and other resources for dynamic performance to support the operational needs of California's energy infrastructure but at the same time, reduce the need for overall energy production from those resources. These changes, among others such as the issues associated with the Aliso Canyon gas storage facility have and will continue to increase the need for effective gas/electric coordination.

The significant amount of new renewable generation being added to the grid is also putting economic pressure on the existing gas-fired generation fleet, especially for those generators not obtaining resource adequacy contracts. Further, the bulk of the grid-connected renewable generation developed to date has been "deliverable", e.g. capable of providing capacity towards the state's resource adequacy program, leaving more uncertainty as to the future of system resource adequacy compensation availability for the existing gas-fired generation fleet. Compensation for provision of flexibility services can also be uncertain, with the gas-fired generation fleet facing competition from other sources.

As generation owners are independently assessing market conditions and their own particular circumstances, the ISO has therefore undertaken this preliminary analysis of potential risks to system reliability if similarly economically-situated generators retire more or less simultaneously.

This analysis therefore focuses on two aspects of reliability:

- Are there localized areas of the grid transmission system where the retirement of a number of similarly situated generators would create reliability issues or other negative impacts on the operation of the transmission system, and,
- Are system-wide reliability requirements, e.g. load following, operating reserves and regulating reserve levels, unduly compromised?

In this analysis, it is assumed that local resource adequacy requirements continue to be met.

6.1.1 Study Scope

The scope of this study is to identify system resource and transmission reliability and market impacts (congestion/ramping issues etc.) as a result of potential economically-driven retirement of gas-fired generation, focusing on the evolution of the grid to meet a 50 percent renewables portfolio standard by 2030. Further, this study and the potential retirement scenarios were also utilized to identify any potential impacts on the transfer capability of existing bulk transmission system.

The development of mitigation for identified transmission issues are beyond the scope of this study and could be pursued in future transmission planning studies as the potential for retirement becomes clearer.

6.1.2 Risk to Transmission System Reliability

This section focuses on the transmission system issues that could be driven by the simultaneous retirement of a number of similarly situated gas-fired generators within material electrical proximity.

6.1.2.1 *Study Approach Methodology*

The ISO developed a framework for developing potential retirement scenarios using production cost and other publically available information such as expected retirement announcements or long-term operational viability concerns from generation owners. This framework and the associated list of units were then utilized to create two scenarios that were then analyzed to assess the impacts of the retirement of generation from the local transmission and bulk system perspective. Scenario 1 analyzed the potential retirement from the local transmission perspective which were defined based on the local capacity requirements (LCR) areas. Scenario 2 on the other hand analyzed the impacts from the bulk system perspective of the rest of the transmission grid. The following steps provide more information on the approach and the adopted methodology:

Study Approach

The ISO used the latest production cost model (PCM) from the 50 percent RPS special study conducted in the 2016-17 transmission planning process to identify the list of potentially retired units based on the methodology discussed in the next section. These units were then modeled retired (out of service) in the appropriate power flow and PCM cases to identify any potential reliability and market issues.

Methodology to identify the generation at risk of retirement that is needed for local reliability

The 2016-2017 PCM from the 50 percent RPS special study was the starting point for the identification of the list of the retired units. This initial list of potential retirements was based on comparing production cost simulation capacity factors to threshold capacity factors determined using typical historical values. The list was then modified by removing from the list generation based on the location of generators in the areas with LCR capacity deficits[85] in the 2020 LCR[86] requirements study. This modified list was utilized for scenario 1 analysis.

Scenario 2 involved retiring additional gas fired generation from LCR areas with excess available capacity from scenario 1 and selecting a different mix of generation to satisfy the local capacity requirements to assess the impacts on potential retirements of generation outside the local areas required for providing system capacity. In effect, this recognizes the need to preserve generation in the local capacity areas, but that the consequence may be to shift retirement risk to generators located outside of those areas.

The amount of potential retirement in Scenario 1 and Scenario 2 can be considered excessive, and so a ZP 26 sensitivity assuming the retirement of gas-fired generation in the zone between Path 15 and Path 26 (ZP26) was also developed for the power flow and production cost case analysis.

Study Database (Production and Power Flow Cases)

2016-17 PCM Cases from 50 percent RPS special study

2016-17 TPP Bulk and Local area cases as required.

Power Flow and Congestion Assessment

The ISO analyzed the impact for the three scenarios - scenario 1, 2 and ZP26 sensitivity - to identify any incremental congestion[87] issues using the PCM. Power flow analysis was not performed for scenario 1 and 2. Power flow analysis was conducted for the following:

- A ZP 26 sensitivity, which modeled retirement of a subset (2600 MW) of the Scenario 1 list focusing on gas generation in ZP 26; this generation was modeled out of service in the 2026 bulk system power flow case prepared for the 2016-2017 transmission planning reliability analysis.
- A southern California bulk system reliability assessment, with the 50% in-state full capacity deliverability status portfolio.

Furthermore, in order to assess the impact of the retirement on the transfer capabilities of the existing transmission system, two additional power flow cases were created:

- Heavy Path 15 and Path 26 south to north flow case
- Heavy Path 15 and Path 26 north to south flow case

[85] LCR areas with excess generation capacity were not modified for Scenario 1.

[86] For southern California area, the available information from the long-term 2025 LCR study results from the 2015-2016 Transmission Plan was utilized for this process.

[87] 50 percent RPS PCM results were used as a baseline to compare the incremental congestion.

This power flow analysis sensitivity scenario was also modeled in the PCM case to identify any incremental congestion on these transfer paths.

6.1.2.2 *Gas-fired Generation at Risk of Potential Retirement Assessment*

The generation at risk of retirement were developed for Scenario 1 and Scenario 2 by applying the methodology identified in section 6.1.2.1. The potential gas-fired generation at risk is summarized in summarized in

Table 6.1-1 and Table 6.1-2.

Table 6.1-1: Summary of Scenario 1 Potential Gas-fired Generation at Risk of Retirement

LCR area	Capacity [MW]
Gas-fired Generation Not Identified for Retirement for Local Capacity Requirement (LCR) Areas	
Big Creek/Ventura	1476
Fresno	152
Greater Bay Area	4211
Humboldt	81
Kern	106
LA Basin	7214
San Diego	3340
Sierra	60
Stockton	57
System	1772
Total	18469
Potential Gas-fired Generation at Risk of Retirement	
Big Creek/Ventura	197
Fresno	755
Greater Bay Area	1799
Humboldt	81
Kern	175
Sierra	524
Stockton	337
System	4396
Total	8265

Table 6.1-2: Summary of Scenario 2 Potential Gas-fired Generation at Risk of Retirement

LCR area	Capacity (MW)
Generation Not Identified for Retirement for Local Capacity Requirement (LCR) Areas	
Big Creek/Ventura	1476
Fresno	56
Greater Bay Area	4211
Humboldt	81
Kern	106
LA Basin	7214
San Diego	3340
Sierra	10
Stockton	57
System	524
	17075
Potential Generation at Risk of Retirement	
Big Creek/Ventura	197
Fresno	851
Greater Bay Area	1799
Humboldt	81
Kern	175
Sierra	574
Stockton	337
System	5643
	9659

6.1.2.3 *Transmission System Reliability Assessment*

The scope of the analysis for this special study was to identify any incremental reliability and congestion issues as compared to the other 2016-2017 transmission plan reliability, policy driven and economic analyses.

While the development of mitigation to any issues found will not be pursued in this study, there will be some consideration for possible transmission and non-transmission mitigation solutions to provide a high level context on the value of the retired generation. For more extensive and complicated issues, further detailed assessments may be required in subsequent transmission planning processes.

6.1.2.3.1 Northern and Central California bulk system impact assessment

Production cost modeling was used to develop the duration curves for Path 26 and Path 15 as shown in Figure 6.1-1. As can be seen in the that the duration curves the path flows are predominately in the south to north direction on both the paths for all the scenarios.

Figure 6.1-1: Path 15-26 Duration Curves

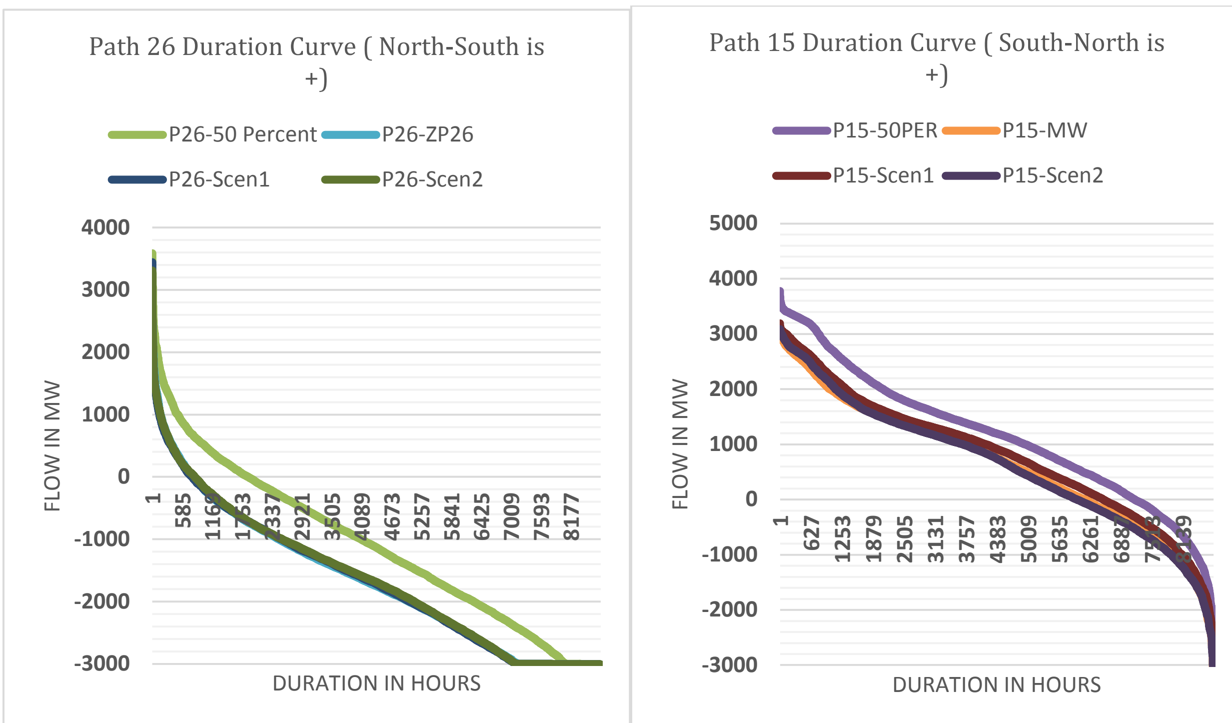


Table 6.1-3 illustrates the cumulative bidirectional congestion duration on the major norhernt California transfer paths.

Table 6.1-3: PCM Bidirectional Congestion Duration (Hours)

Transfer Paths	50 Percent Instate FC Portfolio	Scenario 1		Scenario 2	ZP 26 Scenario
COI	87	73		76	36
Path 15	67	31		29	33
Path 26	815	1881		1860	1829

The Path flow patterns and congestion duration can primarily be attributed to the loss of generation around Midway resulting in increased flows on Path 26 in the south to north direction to make up for the reduction in generation assumed in the various scenarios.

The high south to north flow snapshot was then simulated in the off-peak power flow case[88] used for the ZP 26 sensitivity analysis[89]. A selective contingency analysis (230 and 500 kV) did not result in any new thermal overloads on the PG&E system. Path 15 had sufficient available capacity with no foreseeable impacts expected on the current IRAS scheme in South to North direction.

The off-peak power flow case was then further utilized to develop a high north to south flow (major transfer paths) scenario. The modeled loss of 2600 MW of gas-fired generation in the Midway area resulted in reduced Path 26 north to south flow as compared to the initial off-peak power flow case. Generation north of Midway substation (located in ZP26) was increased to makeup for the lost generation in order to increase the north to south flow on Path 26. However, in this scenario, a selective contingency analysis did result in overloads on the underlying 230 kV system for the loss of 500 kV lines south of Los Banos (LBS) and north of Midway (MWN) 500 kV substations. This scenario could potentially result in some modifications to the existing IRAS scheme in order to achieve the pre ZP 26 sensitivity flows and the associated path ratings for the transfer paths.

6.1.2.3.2 Southern California bulk system impact assessment

Table 6.1-4 provides a summary of the total amount of potential generation retirement using the screening results from Section 6.1.2.2. Additionally inputs from generation owners regarding their concerns for long-term viability for their generating facilities without a power purchase contract were included.

Table 6.1-4: Summary of Potential Gas-fired Generation at Risk of Retirement in Southern California

Area	Sub-area	Number of Units	Type of Generating Units	Maximum Capacity (MW)	Notes
LA Basin	Eastern LA Basin	6	Combustion Turbines	125	Earlier screening results for Scenario 2[90]
System	N/A	N/A	Combined Cycle	560	Earlier screening results for Scenario 2

[88] 50 percent instate EO power flow case was the starting point for the cases that were used in the gas sensitivity study.

[89] Power flow analysis was only performed for the ZP26 sensitivity in the 2016-2017 planning cycle.

[90] The screening results were based on the previous 2015-2016 transmission planning process 50% RPS in-state full capacity deliverability status production cost model due to the need to stay on schedule for completing the special study.

System	N/A	N/A	Combined Cycle	830	Supplemental to the screening list due to generation owner expressing long-term viability concerns
LA Basin	Eastern LA Basin	2	Combustion Turbines	89	Supplemental to the screening list due to remaining peaking units located at the same site of the unit assumed to be impacted in the screening assessment
Total				1,604	

Reliability assessment results for southern California bulk transmission system

The ISO modeled the potential economic driven generation retirement in the 2026 summer peak power flow study to evaluate potential reliability impact to southern California transmission system. A 50% RPS in-state full capacity deliverability status portfolio was prepared for the starting study case. In addition, the ISO-Board approved transmission upgrades, as well as the CPUC-approved long-term procurement plan for local capacity requirement in the LA Basin and San Diego, are implemented for the retirement of once-through-cooled generation and SONGS in the study.

The reliability assessment identified two potential reliability concerns with potential solutions discussed in the previous transmission planning process:

- Thermal loading concerns were identified on the Lugo – Victorville 500 kV line due to the overlapping P6 (N-1-1) contingency (Lugo – Mohave & Eldorado – Lugo 500 kV lines). The ISO identified upgrades for the Lugo – Victorville 500 kV line in the 2015-2016 transmission planning process and is recommending those upgrades be approved in the ISO 2016-2017 Transmission Plan.

- Potential thermal loading concerns were identified for the south of Mesa 230 kV line (i.e., Mesa – Laguna Bell 230 kV line) due to the overlapping P6 (N-1-1) contingency (Mesa – Lighthipe & Mesa – Redondo 230 kV line). The thermal loading concern could be mitigated by utilizing an existing 321 MW of 20-minute "fast" demand response in the LA Basin, or installing a small line series reactor (1 – 2 Ω) on the Mesa – Laguna Bell 230 kV line

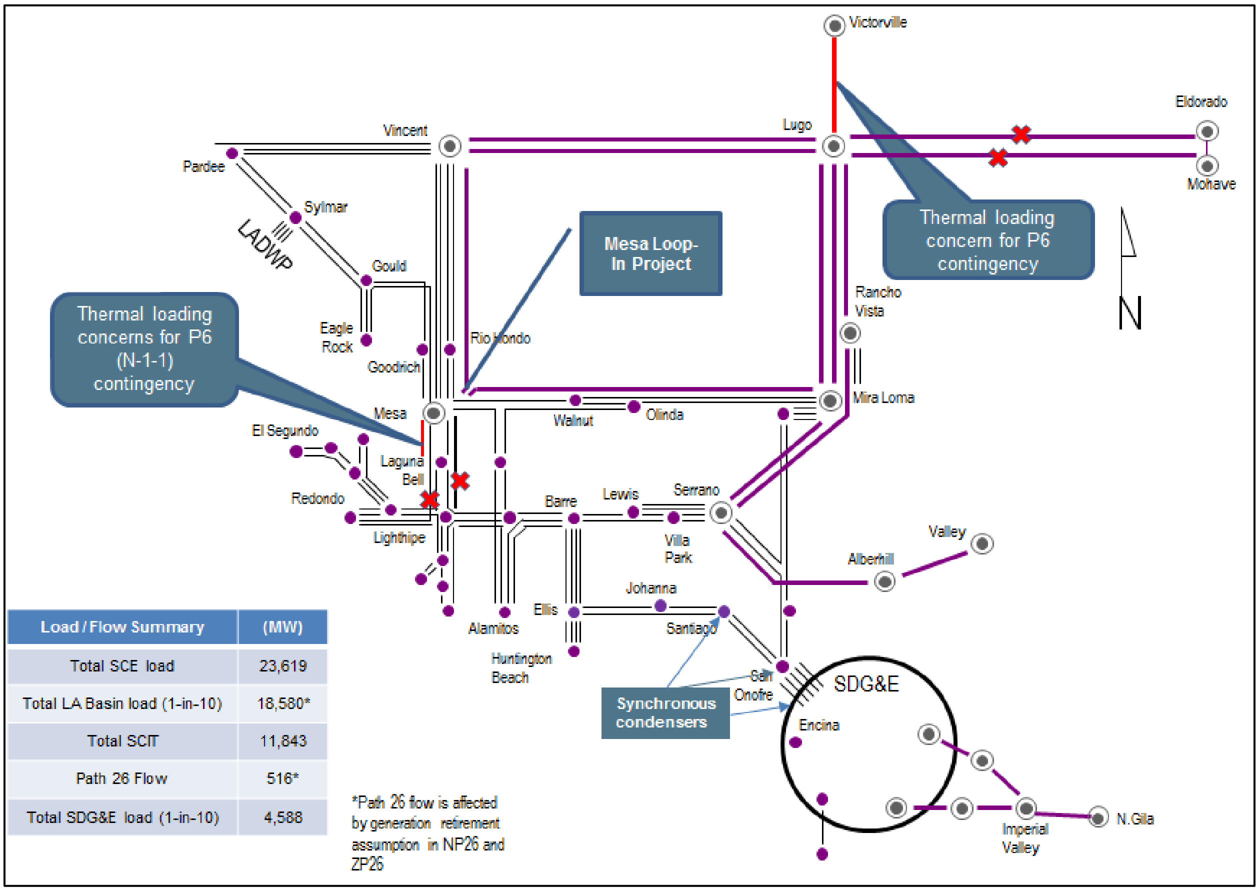
The following single line diagram provides an illustration of the transmission system in the LA Basin and San Diego area with the two unrelated critical contingencies as mentioned above. It is important to note that the Path 26 flow is low at peak load condition due to the planned shutdown of Diablo Canyon Nuclear Power Plant in 2025, as well as assumptions of early retirement of gas-fired generation in northern California. It is also important to note that the voltage instability concern has been largely mitigated with the addition of dynamic reactive supports in the Orange County and San Diego area.

Summary of Findings

In summary, the following are the potential reliability concerns due to early economic retirement of gas-fired generation retirement in southern California:

- Lower Path 26 (PG&E – SCE) flow due planned and potential gas-fired generation retirements in the NP26 and ZP26 based on the screening results of this special study.
- Potential thermal loading concerns for a 230 kV line under overlapping P6 contingency condition in the LA Basin
  - Utilization of the existing "fast" (i.e., 20-minute) demand response, or a small transmission upgrade (i.e., line series reactors), can mitigate this concern
- Potential thermal loading concerns on a previously identified 500 kV line connecting LADWP and ISO Balancing Authority Area under contingency condition
  - Previously identified and recently recommended transmission upgrades for LADWP and SCE-owned facilities can mitigate this loading concern.

Figure 6.1-2: Critical contingencies and transmission reliability concerns for the bulk transmission system in the LA Basin and San Diego areas under early economic retirement of gas generation special study



6.1.3 Risk to Overall System Resource Reliability

This section focuses on the overall system impacts of economically-driven gas-fired generation retirements, focusing on the sufficiency of capacity and flexibility of the generation fleet to meet load, load following, operating reserve and regulation reserve needs.

6.1.3.1 *Study Approach and Methodology*[91]

The study relied upon Energy Exemplar's PLEXOS production simulation package and approach consistent with the methodologies employed by the ISO in participating in the CPUC's LTPP proceedings. It used the Base Case that is discussed in section 6.5 "Benefits Analysis of Large Energy Storage" of this report.

[91] See http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf for details of the study approach.

Calculating Shortfalls

In the simulation, shortfalls occur when supply is insufficient to meet the combination of load, ancillary services, and load following requirements. If all available resources, including demand response and import capability, are depleted during these hours, the shortfalls are capacity shortfalls since there is no more capacity available for use. Alternatively, there are cases in which there is still unused capacity available but that capacity is not capable of following load ramp. These are referred to flexibility shortfalls.

A shortfall may occur either in meeting ancillary service or load following requirements, or in meeting load. The model sets a priority order for the shortfall, similar to that in the ISO market scarcity pricing mechanism. The order from high to low is energy, regulation-up, spinning, non-spinning, and load following-up on the upward side, and dump power, regulation-down, and load following-down on the downward side. That means when there is an upward shortfall, the shortfall occurs first in load following-up. If the shortfall is large enough, it will spill over to non-spinning, spinning, regulation-up and finally to unserved energy (loss of load).

Flexibility shortfalls occur mostly when the system net load has fast ramping in either upward or downward direction. The fast ramping is usually caused by the intermittencies and special patterns of renewable generation. If the renewable generation is dispatchable (or curtailable) the net load curve may be balanced. The requirement for system flexibility is significantly reduced and a flexibility shortfall may not occur at all, depending on the level of renewable generation that can be curtailed. Thus, there is a trade-off between the dispatchability of renewable generation and requirements for system flexibility.

In this study, it is assumed that all the California RPS solar and wind generation is curtailable at a cost lower than that of shortfall of load-following and ancillary services.[92] Therefore the production simulation is not intended to capture flexibility shortfalls, but capacity shortfalls.

The model has a zonal setup. It enforces transmission constraints on the paths among the zones. It also enforces an ISO maximum net export limit at 2,000 MW. The 2,000 MW maximum net export limit is from the CPUC Assumptions and Scenarios for the ISO 2016-17 TPP. It was decided in the CPUC LTPP proceedings.

6.1.3.2 *Study Cases*

Six cases of gas genertion resource retirement were analyzed in this study, as shown in Table 6.1-5 below.

[92] "Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for Use in the California Independent System Operator's 2016-17 Transmission Planning Process and Future Commission Proceedings", R.13-12-010, May 17, 2016.

Table 6.1-5: The Six Cases Analyzed in the Study

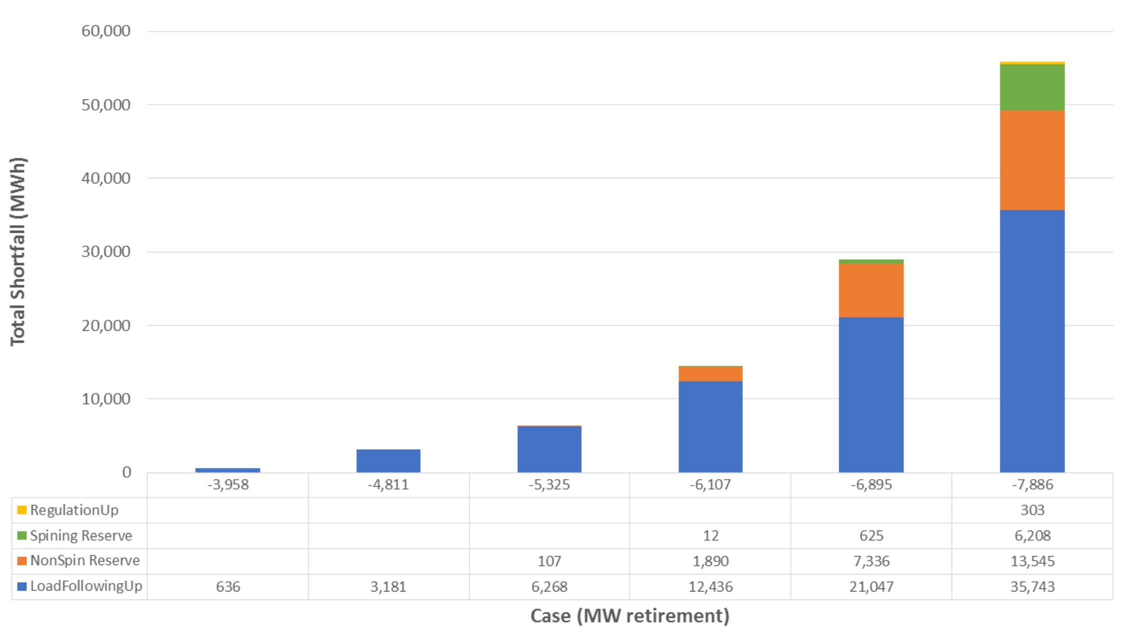
Retirement by Technology (MW)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CCGT	-3,739	-4,325	-4,325	-5,107	-5,107	-5,107
CHP	-219	-286	-751	-751	-840	-1,138
GT	0	-200	-250	-250	-939	-1,632
ST	0	0	0	0	-10	-10
Total	**-3,958**	**-4,811**	**-5,325**	**-6,107**	**-6,895**	**-7,886**

In the six cases the generation resources for retirement were selected from a list of candidate generation resources that were created in the "Risk to Transmission System Reliability" assessement as discussed in Section 6.1.2. The six cases were incremental. For example, Case 2 has all the generation resources retired in Case 1 plus some additional resources. the study used the six cases to identify the trend of impacts on the system reliability cased by capacity shortfalls.

6.1.3.3 *Study Results*

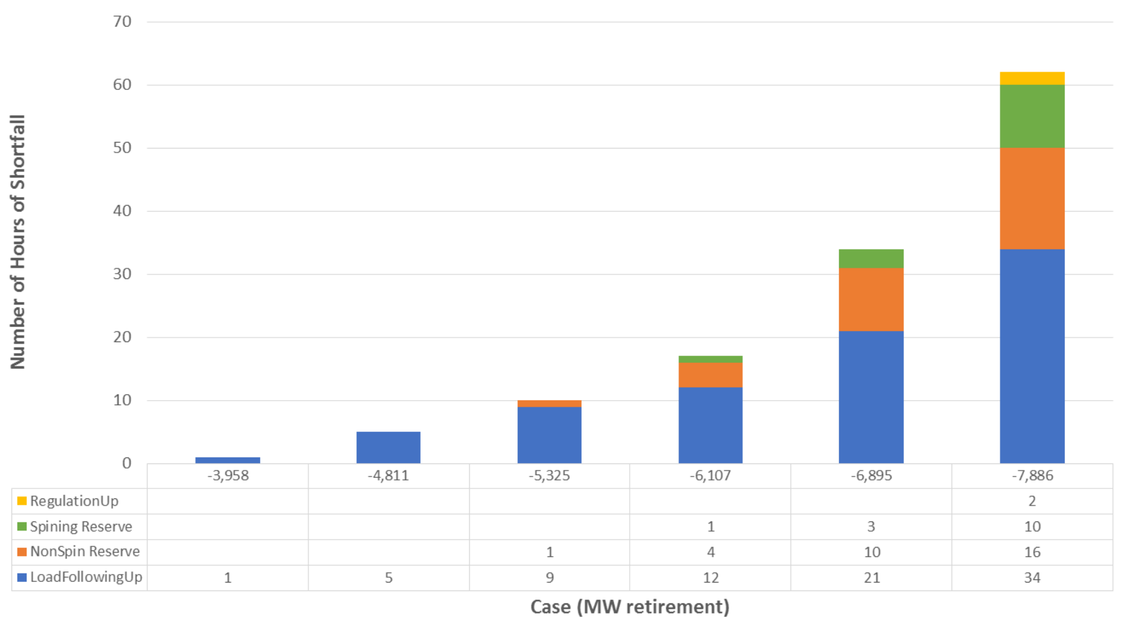
As discussed in Section 6.1.3.1, when there is sufficient capacity to meet load, ancillary service and load-following requirements, shortfalls in load-following and ancillary services will occur. As shown in Figure 6.1-3: Total Load-Following and Ancillary Service Shortfall by Case, shortfalls in load-following occurred in Case 1, which has generation resource retirement of 3,958 MW. Non-spinning Reserve had shortfalls in Case 2; in such situations the ISO could declare Stage 1 Emergency. When Spinning Reserve had shortfalls in Case 4, the ISO could start to shed load in order to restore the Spinning Reserve.

Figure 6.1-3: Total Load-Following and Ancillary Service Shortfall by Case



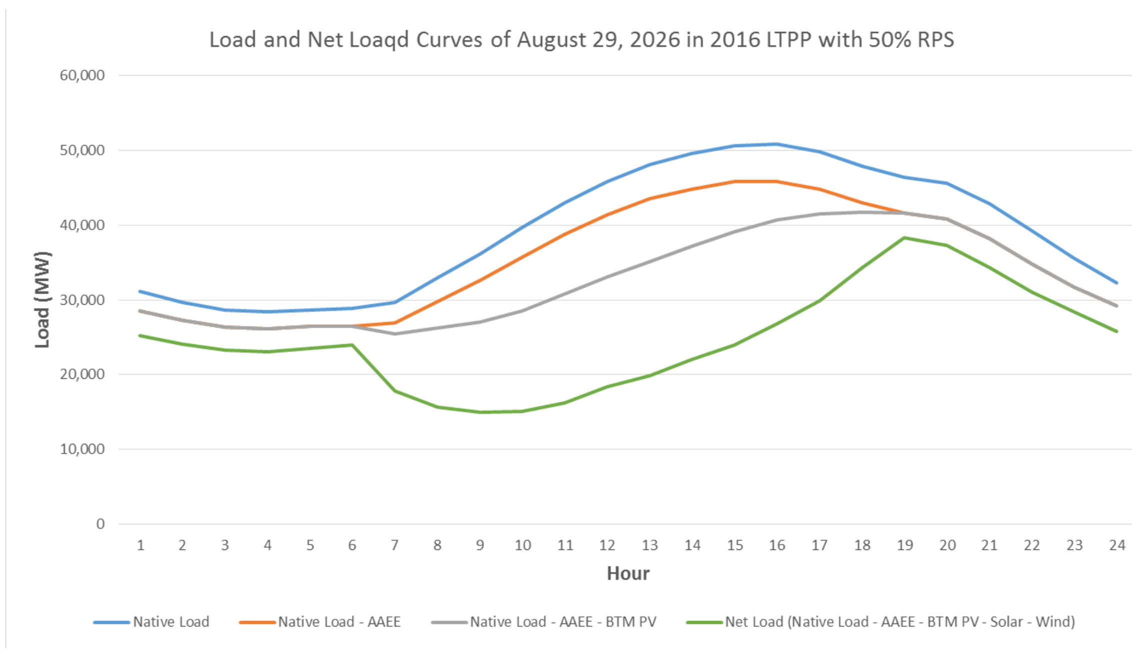
The frequency of load-following and ancillary service shortfalls are presented in Figure 6.1-4. The frequency of shortfalls increases quickly with the volume of generation resource retirement.

Figure 6.1-4: Total Number of Hours with Load-Following and Ancillary Service Shortfall by Case



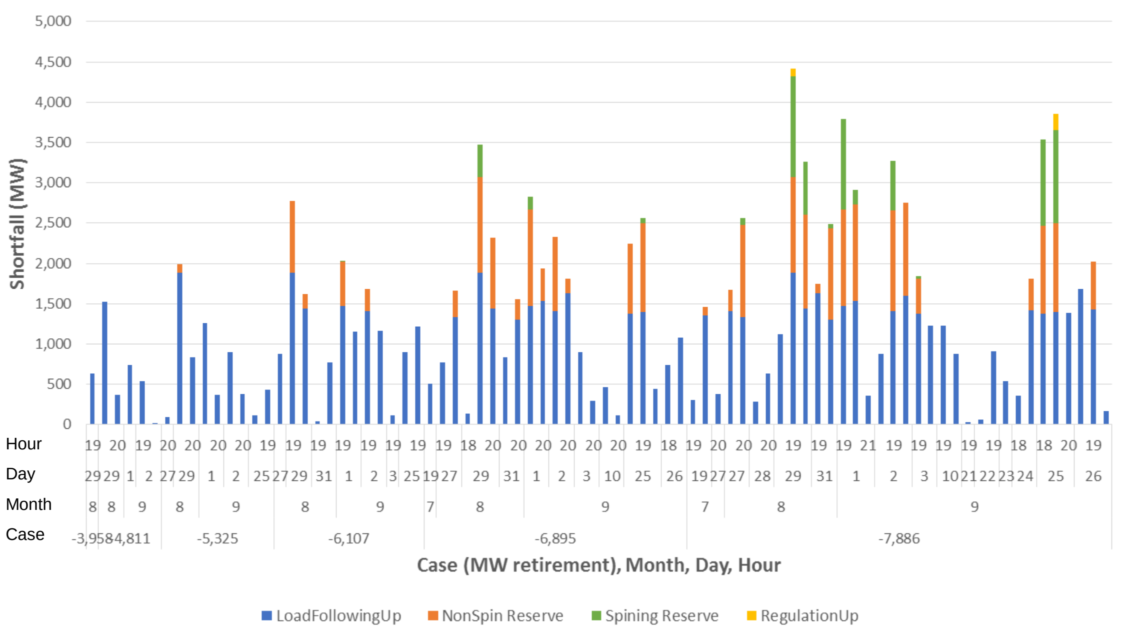
In the 50 percent RPS portfolio, solar was 55 percent installed capacity and wind was 32 percent. A larger volume of solar generation pushes the peak net load, which is load minus AAEE, distributed solar PV, RPS solar and wind generation, to the evening. Figure 6.1-5 shows the shift.

Figure 6.1-5: Shift of Peak of Net Load on the Annual Peak Load Day



With the shift of the peak of net load, the shortfalls of load-following and ancillary services occurred all in hour 18 to 21 in this study. This is not the time that the traditional Loss of Load Probability (LOLP) method measures.

Figure 6.1-6: Houry Load-Following and Ancillary Service Shortfall by Case



6.1.3.4 *Conclusions*

From the study, it can be concluded that:

- Unlimited renewable curtailment masks the need for flexible capacity during downward ramping in the morning and upward ramping in the afternoon;
- The shortfalls in load-following and reserves reflect the insufficiencies of capacity;
- Capacity insufficiencies occur in early evening after sunset, which is the new peak (net) load time; and
- Capacity insufficiency start to emerge between 4,000 to 6,000 MW of retirement, considering some uncertainties in the modeling assumptions.

6.2 Frequency Response Assessment – Generation Modeling

6.2.1 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.

The frequency response studies documented in the 2015-2016 ISO Transmission Plan built on the analysis commenced in the 2014-2015 transmission planning cycle. 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 began 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 and in 2015-2016 transmission planning processes the potential risk of oversupply conditions – a surplus of renewable generation that needs to be managed - in the 2020-2021 timeframe under the 33 percent renewables portfolio standard (RPS) and evaluated frequency response during light load conditions and high renewable production. Those studies also assessed factors affecting frequency response and evaluated mitigation measures for operating conditions during which the FRO couldn't be met.

The ISO 2014-2015 Transmission Plan[93] in section 3.3 and the ISO 2015-2016 Transmission Plan[94] in section 3.2 discuss reliability issues that can occur during oversupply conditions and also describe frequency performance metrics and study results.

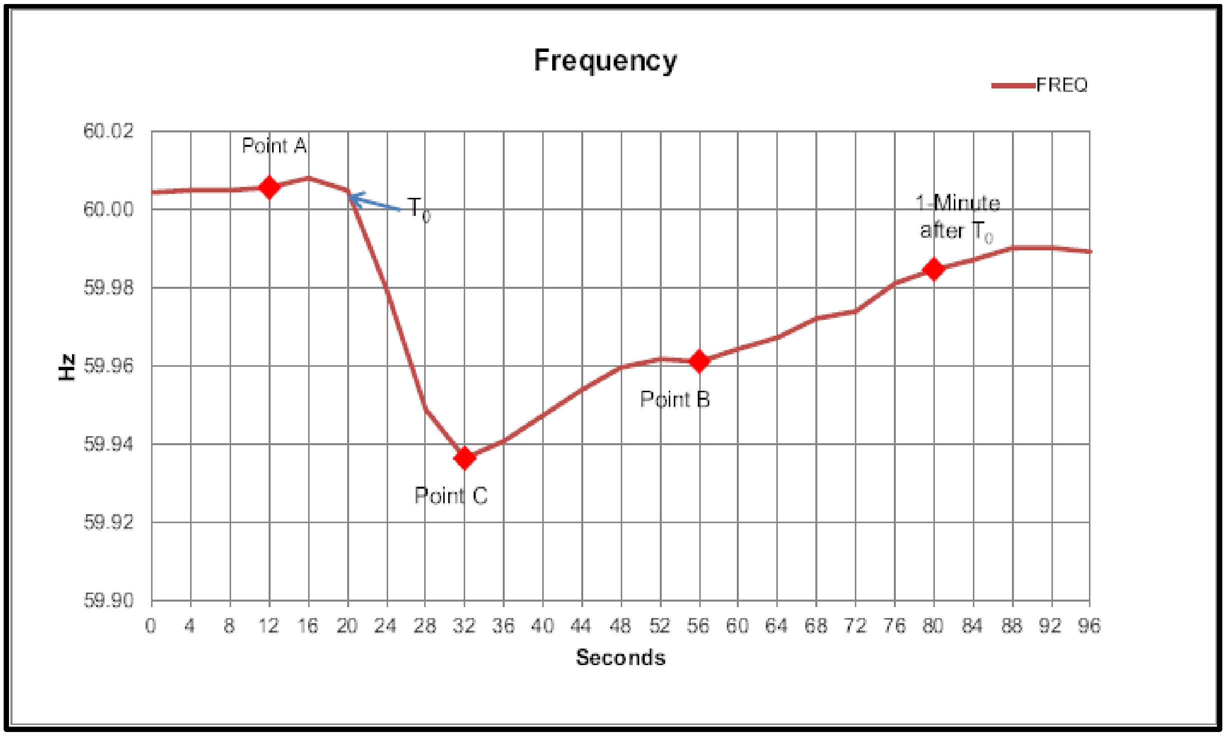
The studies of the 2014-2015 and 2015-2016 transmission planning processes concentrated on the primary frequency response. Figure 6.2-1 illustrates a generic system disturbance that results in frequency decline, such as a loss of a large generating facility. Pre-event period (Point A) represents the 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

[93] http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf

[94] http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf

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 6.2-1: 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. The studies performed by the ISO in 2015 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. It remained the same for 2017.

The NERC frequency response annual analysis report that specifies Frequency Response Obligations of each interconnection can be found on the NERC website[95].

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 the ISO studies, it was 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.

[95] http://www.nerc.com/comm/oc/documents/2016_fraa_report_2016-09-30.pdf

6.2.2 Need for additional studies

Studies performed in the previous transmission planning processes showed that the total frequency response from WECC was above the interconnection's frequency response obligation, but the ISO had insufficient frequency response when the amount of dispatched renewable generation was significant. When the study results and, in particular, response of some individual generation units was compared with the real time measurements during frequency disturbances, the results of the simulations did not match the actual measurements showing higher response to frequency deviations. Thus, the study results appeared to be too optimistic, and the actual frequency response deficiency may be higher than the studies showed.

Therefore, the studies of the 2016-2017 transmission planning process concentrated on the modeling issues rather than on frequency response studies. Having accurate models is important also in order to be compliant with the NERC standards MOD- 032 and MOD -033.

According to the NERC Standard MOD-32, each Balancing Authority, Planning Authority and Planning Coordinator should establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. The NERC MOD-32 standard is related to the NERC Standard MOD-33. The MOD-32 Standard requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area. The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by FERC recommendations and directives.

Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner and Planning Coordinator according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner. If the Planning Coordinator or Transmission Planner has technical concerns regarding the data, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall either provide the updated data or explain the technical basis for maintaining the current data. Each Planning Coordinator shall make available models for its planning area reflecting the provided data to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide cases that include the Planning Coordinator's planning area. For the ISO PTOs, generation owners are responsible for providing the data, and the ISO is responsible for the model validation.

The purpose of the NERC Standard MOD-033-1 is to establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

The focus of validation in this standard is not Interconnection-wide phenomena, but events on the Planning Coordinator's portion of the existing system, although system-wide disturbances can also be used for model validation. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

The MOD-033-1 Standard requirements include comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other real-time data sources. Such model validation has to be done at least once in the 24 months. The standard includes guidelines needed to be used to determine unacceptable difference in the model's performance. The Standard states that each Reliability Coordinator and Transmission Operator shall provide actual system behavior data to any Planning Coordinator performing validation such as, state estimator case or other real-time data necessary for actual system response validation.

The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. According with the MOD-033, the ISO developed Power System Model Validation Process that includes guidelines on how to perform model validation. It also includes methodology of comparison of the ISO performance in planning power system model and dynamic stability response simulations to actual system behavior. These guidelines explain how to determine unacceptable differences in the evaluated performances for the planning power flow and dynamic model and how to resolve them. The ISO will make this system model validation process available to: Peak Reliability (Peak RC), ISO TOP, and the Participating Transmission Owners (PTOs) TP/TOPs in the ISO Planning Coordinator Area and ISO Balancing Authority Area (BAA).

6.2.3 Generator Modeling Issues in the ISO studies

While performing power flow and dynamic stability studies in past processes, the CAISO encountered the following potential generator modeling issues that are being resolved in this Generator Modeling Upgrades and Validation Study.

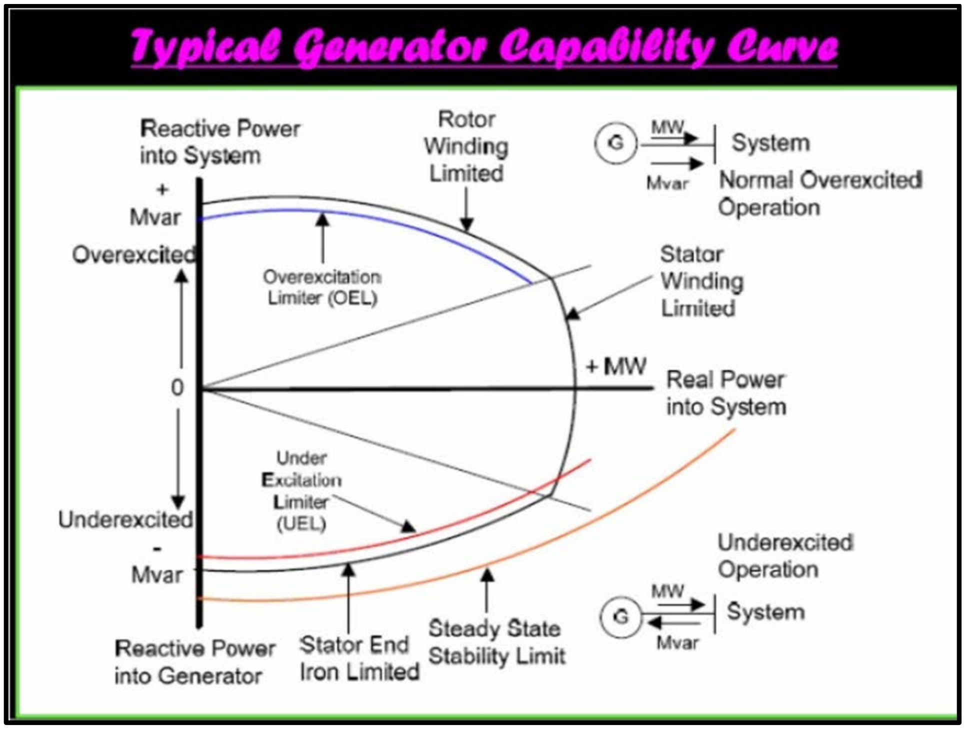
- Possible inadequate reactive capability modeling

This issue is more applicable to the new renewable units, when it is not clear if the unit is capable of regulating voltage. Thus, power flow model may not match dynamic stability model. Generation owners of inverter-based and induction generation units need to provide accurate data of their units' reactive capability, and it needs to be modeled consistently both in power flow and dynamic stability. Accurate data is needed, since reactive capability of inverter-based generation may have significant impact on the system performance.

Generation owners of synchronous units need to provide reactive capability curves for their units, and these curves should be adequately modeled. The latest version of the GE PSLF program allows to model the whole reactive capability curves, and not just maximum and minimum reactive capability. Having the whole reactive capability curve modeled, will allow to get more accurate results in voltage stability and reactive margin studies.

Figure 6.2-2 illustrates typical reactive capability curve of a synchronous generator.

Figure 6.2-2: Reactive Capability Curve of a Synchronous Generator



Absence of models

Often in the new generation interconnections of renewable generation, the generation owners haven't determined yet, which type of inverters will be used and what will be the generator's and control system settings. Therefore, in the generation interconnection studies, generic models with typical parameters are often used. Although WECC requires generation testing prior to the start of commercial operation, often this is not done, and the typical generic data included in the dynamic database is not being updated. Also, some models of new and of existing generation in the dynamic database have missing components, such as control systems, governors, or generation protection.

Errors in dynamic models

As it appeared, the dynamic database contains some errors, which are not obvious and may be difficult to identify. These errors can lead to incorrect study results. Among such errors are, for example, some existing wind generators modeled as thermal, or renewable units modeled as a wrong type, such as solar PV units modeled as wind, or induction generators modeled as inverters. Also, there some erroneous values or inadequate tuning of parameters, that in dynamic stability simulations may result in oscillations or criteria violations, for example, due to excessively high gains of exciters or inadequately tuned power system stabilizers. In these cases, oscillations and criteria violations observed in dynamic stability simulations, are results of model errors, and they are not indicators of the problems in the system performance.

Missing models of collector systems and step-up transformer for solar and wind farms

In the power flow cases, some solar PV or wind power plants are modeled as one or several aggregated units connected to a high voltage bus at the Point of Interconnection. At the same time, collector systems and step-up transformers between individual units and the collector system, and between the collector system and high voltage buses are not modeled. Such simplified modeling may provide inaccurate results in voltage stability, as well as in dynamic stability studies.

Figure 6.2-3 illustrates a schematic of a collector system of a wind farm or solar photovoltaic plant and Figure 6.2-4 shows a correct equivalent model of such generation project.

Figure 6.2-3: Configuration of a Wind Farm (or solar PV plant)

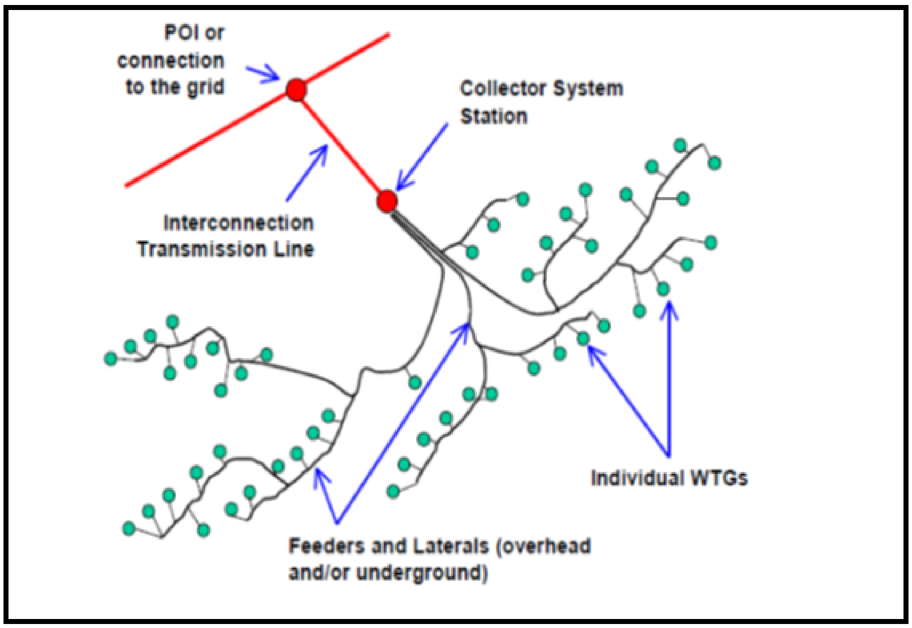
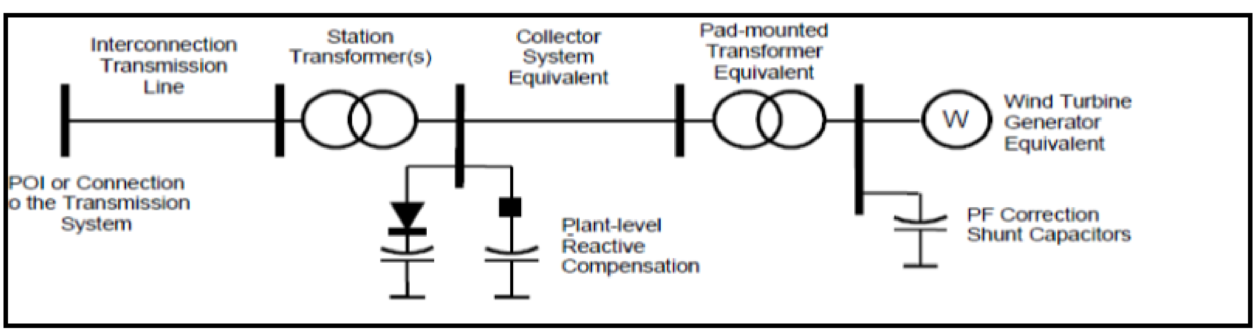


Figure 6.2-4: Equivalent model of a wind farm or solar PV plant for use in power flow and dynamic stability studies.



Inadequate models of frequency response

The frequency response studies performed by the ISO showed higher frequency response from the ISO than the one that was actually observed during disturbances. The reasons for these discrepancies may be, among others, blocked governors on some units that are not modeled as blocked in the simulations, errors in governor models when the models show higher response than the response during actual disturbances, or actual governor withdrawal that is not reflected in the models.

Mismatch between simulation results and real-time measurements

Since the studies and real time measurements showed discrepancies in the system performance, especially in the generation output, these discrepancies need to be investigated. More detailed analysis of the measurements and the simulation results will allow to obtain more accurate models.

6.2.4 Study Plan and Methodology

Given the potential generator modeling issues that have been previously encountered, the following goals were developed for this Generator Modeling Upgrades and Validation Study:

- identify missing models or missing model components
- identify models that have deficiencies and require upgrades
- point to generators that are modeled with generic models with typical parameters and obtain more accurate models of the units

The models that have deficiencies would be identified by comparison of the real time measurements and the simulation results. Where real time measurements are not available, model deficiencies would be identified based on assessments of unrealistic performance of the models in the dynamic stability simulations.

The ISO would inform the PTOs who in turn would contact those generation owners where the models were missing, had deficiencies, or were presented with only typical generic parameters, and requested generation owners to provide the updates. The updated models will be tested in dynamic stability simulations and compared with the real-time measurements.

For the wind and solar PV farms, where the models of collector systems and step-up transformers are missing, the ISO would inform the PTOs who would then request these models from the generation owners.

Updated models will be reported to WECC to be included in the dynamic stability model database. The updated models will be available for the 2017-2018 Transmission Planning cycle.

6.2.5 Study Results

6.2.5.1 *Model Validation with the WECC Dynamic Stability Masterfile*

As discussed in the study plan and methodology, the ISO reviewed the ISO portion of the WECC Dynamic Stability Masterfile, which is the database containing dynamic stability models of all WECC existing and future generation units, including renewable generation. The Masterfile also includes models of protection relays, but it does not include load models. Load models depend on the system conditions, such as season and hour of the day, therefore, they are added to the Masterfile in the course of dynamic stability studies and they are different depending on which case is studied. The WECC Dynamic Stability Masterfile is renewed periodically when new information becomes available. The new information includes updated models of existing generators and models of new generators coming into service in the future.

The ISO sent the list of generators that had missing models or models that needed updates to the PTOs with the explanations of what exactly was missing and which data seemed to be incorrect. This list included missing or seemingly incorrect models identified from the review of the Masterfile and also the models that caused issues in the dynamic stability studies previously performed by the ISO. The list of missing models included models of the components that were not represented in the Masterfile, for example, excitation systems of synchronous machines, or control systems of inverter-based generation, or speed governors of synchronous generators, or protection relays on both synchronous and inverter-based units.

The models that needed updates included the following:

- Generators represented in the Masterfile according to the ISO knowledge as a wrong type, for example, wind farms modeled as thermal units, or existing wind plants modeled not as the their actual type, such as induction generators modeled as inverter-based, and also solar plants modeled as wind and vice versa,

- Existing generators modeled with typical generic parameters instead of being modeled with parameters based on testing,

- Generators modeled with obsolete models that are not used and not approved by WECC anymore, and,

- Models with parameters that needed to be checked, such as models of control systems of the inverters and renewable projects that had conflicting control settings, or models of excitation systems with unusually high gains, or governors of the synchronous machines with unusually high or low droop settings, or conflicting parameters of the synchronous generators' saturation.

Other dynamic stability models included in the list of the models that seemed to be incorrect were the ones that showed unexpected performance in dynamic stability simulations previously performed by the ISO. These models included governors that showed unusually high frequency response, control systems of the renewable generation that showed spikes in voltage or frequency and as a result were tripped by frequency or voltage protection, and also models that were the cause of undamped oscillations with faults where such oscillations were not expected.

The ISO initially identified more than 400 generators with suspicious dynamic model. In coordination with the PTOs, the list was reduced as some generating units have retired or been cancelled.

All generators that needed updated models have been issued a model request letter from the PTO and the ISO, except for a few small QF units. These small units, owners of which were not known, were left to be modeled with typical data, the way they were modeled before. SCE and the ISO also issued model requests to all other generators in SCE area to confirm the currently being used power flow and dynamic models are accurate. According to the Standard MOD-032, generation owners have 90 days to respond. The PTOs have already received responses from several generation owners. Some models were updated, others are undergoing testing. The updated models were tested in dynamic stability simulations to ensure that the performance of the unit was adequate.

This work is ongoing and will be completed in 2017.

6.2.5.2 *Model Validation with Online Dynamic Security Assessment*

The ISO is involved in a continuous model validation effort using real-time snapshots from ISO's online DSA (Dynamic Security Assessment). Voltage, frequencies and flows are compared with those observed in PMU and SCADA data. Model validation efforts have led to correction of baseload flags in the input dynamic data for DSA and modification of initialization rules to accommodate wind and solar models that are at very low or zero output in the state estimation solutions. Model validation is a continuous effort that is being conducted in collaboration with Peak Reliability.

The ISO also performed dynamic stability analysis of the disturbance that occurred on March 3, 2016. This analysis is described below.

6.2.5.3 *March 3, 2016 Event Analysis*

A large frequency disturbance event occurred on March 3, 2016 that caused the WECC–wide frequency to drop to about 59.84Hz. The event sequence is listed in Table 6.2-1 below.

Table 6.2-1: March 3, 2016 Event Sequence

Time (sec)	Event
3.32915	ASHE - SLATT 500kV line tripped
4.29997	ASHE - SLATT 500kV line restored
5.29996	ASHE - SLATT 500kV line tripped
22.78897	Switch SVD at MARION 500.00 s D
23.25157	Open line - BUCKLEY 500.0 SLATT 500.0 1
23.90171	Restore line - BUCKLEY 500.0SLATT 500.0 1
26.23137	Open line - BUCKLEY 500.0 SLATT 500.0 1; CHJ and WELLS generators tripping
54.13924	Trip Navajo units

Simulation data, including the power flow base case representing pre-disturbance system conditions, dynamic models, PMU measurement data, and switching data, were obtained from Peak Reliability Coordinator. With some calibration to the power flow and dynamic models, the transient stability simulation was performed and compared to the PMU measurements. Figure 6.2-5 shows the comparison of bus voltages and Figure 6.2-6 shows the comparison of bus frequencies.

Figure 6.2-5: Comparison of Bus Voltage

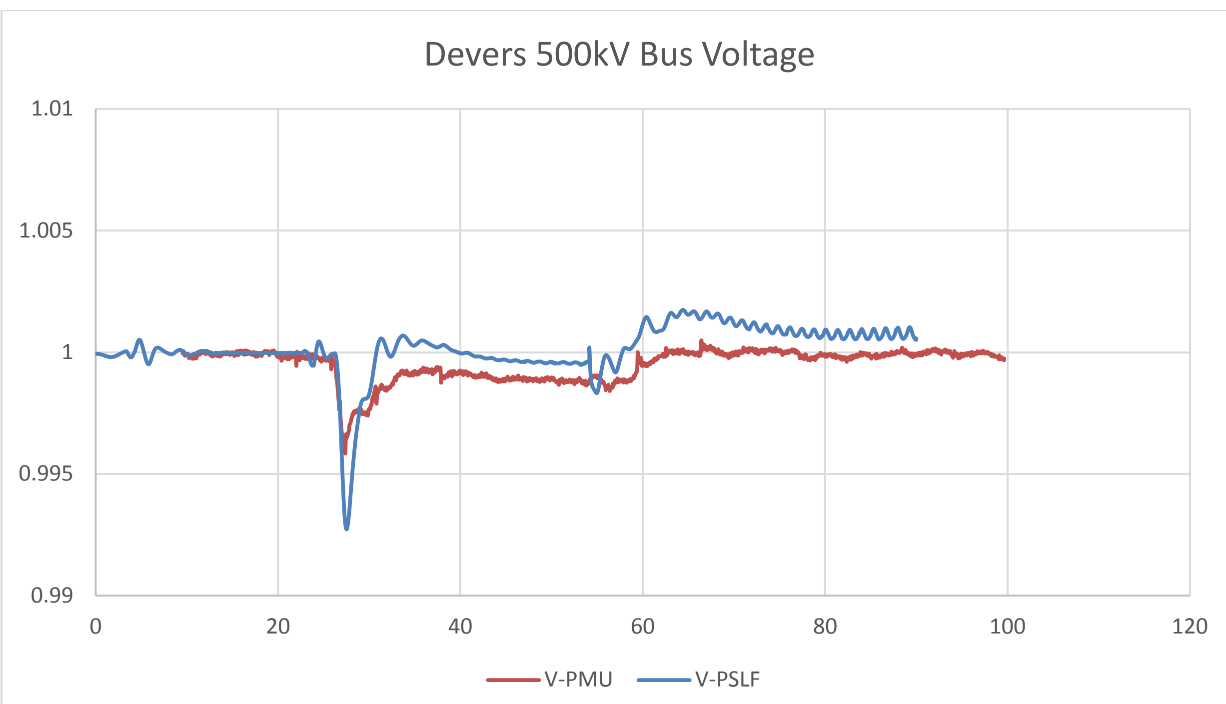
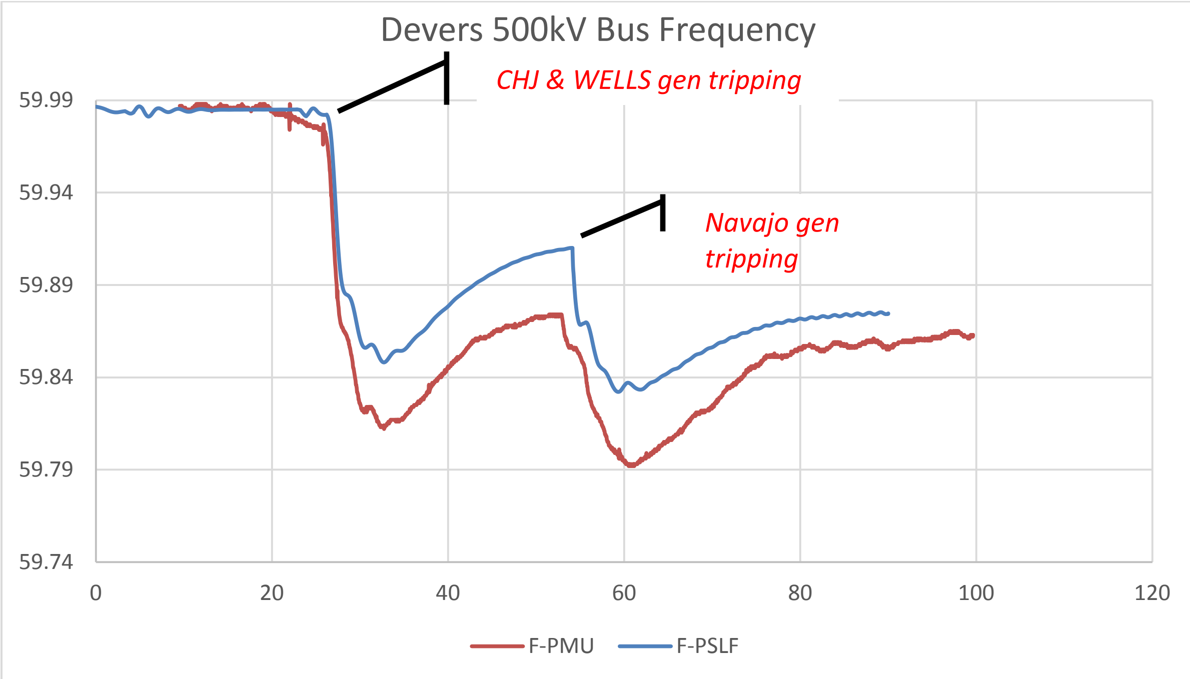


Figure 6.2-6: Comparison of Bus Frequency



The simulation results generally matched the measurements. The simulated frequency nadir was higher than the measured, which indicates that the simulated frequency response of the generators is too optimistic. Due to lack of measurements at generating plants, it can't be detected which generator models cause the discrepancy between the simulation and actual performance. The results demonstrated the need to perform field testing to verify generator dynamic models, and installing PMU at the generating plant would greatly improve the model validation.Next Steps and Conclusions

After all the responses from the generation owners are received, the dynamic database will be updated. The ISO and the PTOs will perform dynamic stability simulations to ensure that the updated models demonstrate adequate dynamic stability performance. After the models are validated, they will be sent to WECC so that the WECC Dynamic Masterfile can be updated, and the correct models will be used in the future.

Future work will include validation of models based on real-time contingencies and studies with modeling of behind the meter generation.

Further work will also investigate measures to improve the ISO frequency response post contingency. Other contingencies may also need to be studied, as well as other cases that may be critical for frequency response.

From the work performed by the ISO on the update and validation of dynamic stability models, the following conclusions can be made.

- Due to the discrepancies between dynamic stability simulations and actual system performance, dynamic stability models need to be updated and validated.
- The ISO successfully identified which models need update and is working with the PTOs on the update of the models
- Not having PMU with high resolution on the generating plants appears to be a significant obstacle in validating dynamic stability models and in obtaining correct models. Installing more PMUs will improve the validation process.
- The ISO needs to continue the work on model validation and on updating dynamic stability models.

6.3 Gas/Electric Coordination Special Study

6.3.1 Gas/Electric Coordination Transmission Planning Studies for Southern California

Section 7.3 of the California ISO 2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan[96] included 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. In the 2015-2016 Transmission Planning Process, the ISO explored and performed preliminary transmission planning related studies for the LA Basin and San Diego areas for the scenarios involving gas curtailments under adverse winter conditions as well as examining conditions involving a major gas transmission line extended outage. 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. The ISO is considering expanding the scope of the study to include other local areas."

In this planning cycle, transmission planning assessments were performed to evaluate the reliability of the southern California transmission system under various gas curtailment scenarios with the Aliso Canyon gas storage outage. The study was performed similar to the studies documented in the Aliso Canyon Risk Assessment Technical Report[97] that was prepared and posted in April 2016 by the Reliability Task Force, comprising of the California Energy Commission, the California Public Utility Commission, the ISO and the Los Angeles Department of Water & Power with participation from the Southern California Gas Company. The Reliability Task Force's report quantified the potential impacts to electric generation under various gas curtailment scenarios with the Aliso Canyon gas storage outage constraint for the summer 2016 timeframe.

The planning assessments conducted in this transmission planning cycle included reliability assessments for the summer 2017 and 2026 timeframe for four gas curtailment scenarios related

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[96] https://www.caiso.com/Documents/Final2016-2017StudyPlan.pdf

[97] http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf

to the Aliso Canyon gas storage outage constraint. The study results were presented to the stakeholders at the ISO 2016-2017 transmission planning process stakeholder meetings # 2 and #3.[98] This section summarizes the results of these studies.

6.3.1.1 *Overview of Southern California's Gas Storage System*

Natural gas in southern California is delivered by a network of major gas pipelines and gas storage facilities. There are four major gas storage facilities in the Southern California Gas system as briefly described in the following:

- Aliso Canyon, with 86 billion cubic feet (Bcf) maximum storage capability, is located in the Santa Susana Mountains in the Los Angeles County north of Porter Ranch neighborhood of the City of Los Angeles;
- Honor Rancho, with 26 Bcf maximum storage capability, is located in the Los Angeles County near the foothills of Valencia;
- La Goleta, 12 Bcf maximum storage capability, is located in Santa Barbara County;
- Playa Del Rey, with 2.6 Bcf maximum storage capability, is located near Balloma Wetlands between Marina Del Rey and Los Angeles International Airport (LAX) in Los Angeles County. Playa Del Rey is operated as operational gas reserve.

Of the four gas storage facilities, Aliso Canyon is the largest gas storage field. With a maximum inventory capacity of 86.2 Bcf, it has withdrawal capacity at 1,860 million cubic feet per day (Mmcfpd). It is typically used during summer time to provide hourly peak electric generation demands throughout the day, which cannot be met with pipeline supplies because of the magnitude and speed that these peak demands require. The Aliso Canyon gas storage field directly affects seventeen gas-fired power plants with a total combined 9,800 MW of electric generation in the western Los Angeles area and indirectly affects forty eight plants with a total combined 20,120 MW of electric generation in southern California. Figure 6.3-1 (courtesy of SoCalGas) and Figure 6.3-2 show the locations of the four gas storage facilities and backbone gas transmission pipelines in southern California and the Aliso Canyon delivery area.

[98] http://www.caiso.com/Documents/Day2Presentation-2016-2017TransmissionPlanningProcess-PreliminaryReliabilityResults.pdf, and http://www.caiso.com/Documents/Presentation_2016-2017TransmissionPlanningProcessStakeholderMeetingNov16_2016.pdf

Figure 6.3-1: SoCalGas System Map

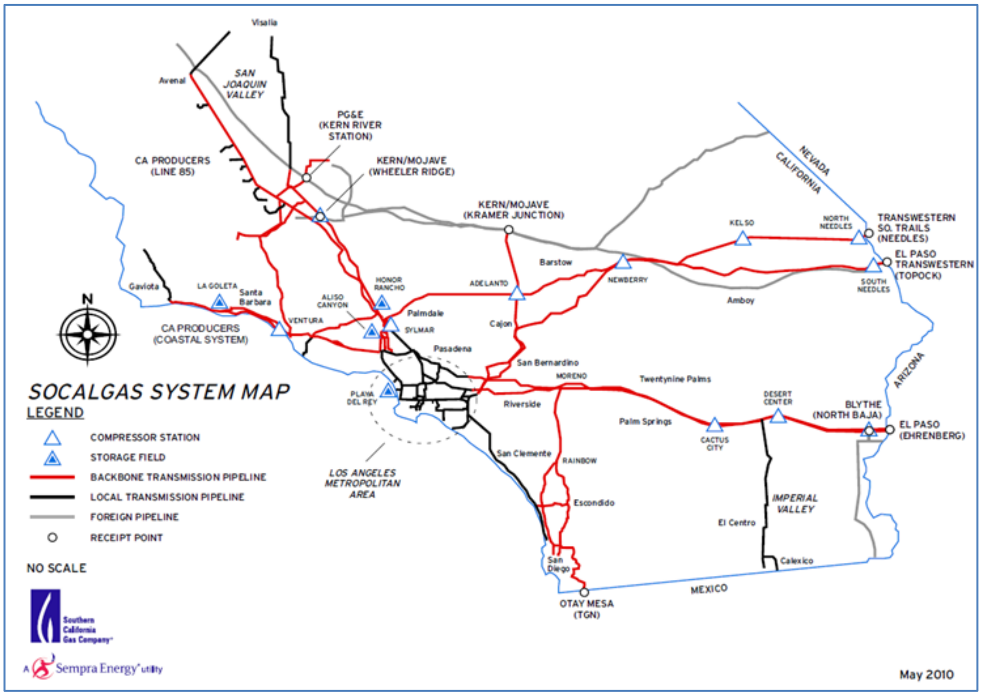

Figure 6.3-2: Aliso Canyon Delivery Area

T:\Projects\Special Requests 2\Roger Johnson\AlisoCanyon\AlisoCanyon_AffectedCities_SelectPowerPlantsV2.mxd

Current Status

In a January 21, 2016 letter[99] to SoCalGas, the CPUC directed SoCalGas to reduce stored gas to 15 Bcf with no new injections. SoCalGas must also retain enough wells to withdraw 420 Mmcfpd through summer. On January 24, 2017, SoCalGas resumed withdrawing natural gas from its Aliso Canyon storage facility on Tuesday in the northwest San Fernando Valley because of higher demand due to colder weather.[100] It was the first time natural gas has been withdrawn from the Aliso Canyon gas storage field since January 2016.

There were twenty one mitigation measures that were implemented for the summer, ranging from prudent use of Aliso Canyon gas storage, tariff changes, operational coordination, to reducing natural gas and electricity use and market monitoring.[101] In the summer 2016, heat events in June and July did not result in any gas-related loss of service on the gas or electric system due to a combination of good planning with implementation of mitigation measures and with better than expected weather.

On January 17, 2017, the Department of Conservation's Division of Oil, Gas, and Geothermal Resources (DOGGR) announced that it has completed its comprehensive safety review at the Aliso Canyon Storage Facility. A total of 114 wells have been ordered to be thoroughly tested. Thirty four wells have passed all tests as of January 23, 2017. Seventy nine wells have been taken out of operation. There is one pending test results. A decision about whether injection of gas into the storage facility can resume will not occur until a public meeting is held and the public has an opportunity to comment on the findings of the comprehensive safety review. Two public meetings in February 2017 have been scheduled to receive public input on the safety review.[102] Details can be found in the public notice.[103] The CPUC will make a decision whether to reopen the field following analysis of public comment.

Summer 2017 Transmission Planning Assessment

The study was performed similar to the Reliability Task Force technical assessment for summer 2016. The ISO evaluated minimum generation in the LA Basin and San Diego areas that are needed to maintain operational reliability for the normal conditions and for the next contingency. The NERC P0 (all facilities in service) and P1 (single-element contingencies) reliability criteria categories of events were studied in the Reliability Task Force technical assessment[104]. It is noted that the technical assessment is based operational reliability requirement and therefore was evaluated with specific reliability criteria (i.e., P0 and P1) for meeting operational needs. As the Aliso Canyon gas field storage outage is considered an operational constraint issue at this time,

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[99] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/01-21-16%20Aliso%20Canyon%20Draw%20Down%20Levels.pdf%20-%20Adobe%20Acrobat%20Pro.pdf

[100] http://www.dailynews.com/business/20170124/socalgas-withdraws-natural-gas-from-aliso-canyon-field-citing-high-demand-after-storm

[101] http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN211671_20160527T164305_Aliso_Canyon_Update.pdf

[102] http://www.conservation.ca.gov/dog

[103] http://www.conservation.ca.gov/dog/Documents/Aliso/2017.1.17_Aliso_Canyon_Storage_Facility_Public_Notice.pdf

[104] This analysis does not take into account the recently released "Aliso Canyon Working Gas Inventory, Production Capaicty, Injection Capacity and Well Availabiity for Reliability – Revised Report – Public Utilities Code 715, Energy Division, dated 1/17/2017. That report will be reviewed and considered in future analysis.

the use of operational reliability criteria is appropriate to address operational reliability concerns. With the Aliso Canyon gas storage field unavailable, the ISO does not expect to meet all of the NERC long-term planning reliability criteria (i.e., overlapping or double-element transmission contingency conditions), nor is the ISO attempting to do so at this time.

The gas burns required for meeting minimum generation were compared with net amount of actual gas burns that occurred on Sept. 9, 2015, minus gas curtailment amount due to the following major gas facility outage scenarios:

- **Scenario 1** – Aliso Canyon gas storage unavailable; supply shortfall of 150 MMcfpd of gas between scheduled and actual gas flows (without balancing rules)[105]
- **Scenario 2** – Scenario 1 plus a non-Aliso Canyon gas storage outage, reducing 400 MMcfd of system capacity (without balancing rules)
- **Scenario 3** – Scenario 1 plus a major gas pipeline outage reducing 500 MMcfd of system capacity (without balancing rules)
- **Scenario 4** – Combination of Scenarios 1, 2 and 3 resulting in an overall reduction of 900 MMcfd of system capacity (without balancing rules)

Summer 2017 Study Results

The following Table 6.3-1 provides a summary of the reliability assessments with identified reliability constraints under NERC P1 reliability criteria for the LA Basin and San Diego areas. The transmission constraints are ranked by severity – from the most limiting to the least limiting. A minimum generation requirement of 7,487 MW was identified for the most critical – most limiting - transmission constraint, which is voltage instability due to a single line contingency of the Imperial Valley – North Gila 500 kV line.

[105] Balancing rules reflect a benefit of 150 MMcfd for each scenario

Table 6.3-1: Identified Transmission Reliability Concerns

Constraint Ranking (1=most constraint)	Identified constraints	Contingency	Planned and approved transmission projects	Estimated gas-fired generation need reduction[106]	Notes
1	Post-transient voltage instability	N-1: Imperial Valley – N.Gila 500kV line	Synchronous condensers at the following locations: - San Luis Rey (2x225 Mvar) - San Onofre (225 Mvar) - Santiago (225 Mvar)	About 500 MW	These projects are under construction and have planned in-service date by December 2017 at the earliest. The study also assumed operation of both Huntington Beach synchronous condensers (i.e., Units 3 & 4)
2	Barre-Lewis 230 kV line thermal loading concern	N-1: Barre-Villa Park 230 kV line	Mesa 500 kV Loop-In project	About 500 MW*. Once #2 is mitigated, constraints 3 - 5 closely follow. Notes: *The 500 MW benefits are for the minimum generation condition associated with Aliso Canyon constraint for the P1 reliability criteria. For normal local capacity requirement assessment, the benefits of the Mesa Loop-In project can bring about 700 MW of gas-fired generation	The Mesa Loop-In project is currently under environmental review process by the CPUC.

[106] Gas-fired generation need reduction is associated with implementation of ISO-approved transmission projects

				reduction for the P6 reliability criteria (source: the ISO 2015-2016 Transmission Plan).	
3	Barre-Villa Park 230 kV line thermal loading concern	N-1: Barre-Lewis 230 kV line	See above		
4	Serrano-Villa Park #2 230 kV line thermal loading concern	N-1: Serrano-Villa Park #1 230kV line	See above		
5	Sylmar-Eagle Rock 230kV line thermal loading concern	N-1: Sylmar-Gould 230kV line	See above		

Table 6.3-2 provides an estimate of the potential electric generation impact due to gas curtailments under various gas outage scenarios for the most critical transmission reliability concern that was identified in Table 6.3-1. Potential gas burn shortages that could impact electric generation and customers served were identified for study scenarios 2 (Aliso Canyon gas field storage outage with another gas field outage), 3 (Aliso Canyon gas field storage outage with a major transmission pipeline outage) and 4 (Aliso Canyon gas field storage outage with another storage and major pipeline outage) without the benefit of balancing rules. These results are similar to the operational study results for summer 2016 by the Reliability Task Force.

- The ISO updated Table 6.3-2 with the benefit of having balancing rules implemented. With balancing rules, it is estimated that the amount of gas shortfall would be reduced by about 150 Mmcfpd or about 70 Mmcf per 8 hours. Incorporating this benefit into Table 6.3-2, the ISO observed a gas burn shortfall would have occurred for Scenario 4 only. However, it is important to note that the ISO has not incorporated the potential impact of tubing flow only operations for other gas storage fields (i.e., Goleta, Honor Rancho and Playa Del Rey) into the study results. The ISO will need to undertake additional study to understand the tubing only production limitation.

Table 6.3-2: Estimate of Potential Electric Generation Impacts (for the first most limiting transmission constraint)

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf) **for the most critical transmission constraint**	7487 MW*8 hours/103 MWh/MMcf	582	582	582	582
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	706	706	706	706
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410
11A	ISO + LADWP Gas Burn Short/Surplus (Delta)	Row 10 - Row 6	133	-7	-63	-296

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
	(MMcf) – without balancing rules benefit					
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	13,749	-671	-6,439	-30,472
13A	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW) – without balancing rules benefit	Row 12/Row 2	1,719	-84	-805	-3,809
14	Estimated customer impacted	Row 13*700	0	58,713	563,413	2,666,329
11B	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf) – with 150 MMcfd adjustment for balancing rules (70 Mmcf / 8 hours)	Row 11A+70	203	63	7	-226
13B	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	(Row 13A / Row 11A)*Row 11B	2,624	756	89	-2,908

Additional analyses were performed to evaluate the potential electric generation impact for the second most limiting transmission constraint (i.e., thermal loading constraint for the Barre-Lewis 230 kV line), after the most limiting constraint is mitigated (i.e., by implementing the remaining of the ISO-approved dynamic reactive supports at San Luis Rey, San Onofre and Santiago substations).[107] Table 6.3-3 shows the generation impact with the minimum generation required (i.e., 6,997 MW) to mitigate the second most limiting reliability concern, in the same format as Table 6.3-2. With the implementation of dynamic reactive support projects, the most limiting transmission constraint will be mitigated, and the potential generation need is reduced by 500 MW when the limiting condition shifts from the currently most limiting contingency to the second most limiting contingency that the dynamic support projects do not help mitigate. The lower generation need due to implementation of these dynamic reactive supports potentially removes

[107] These dynamic reactive supports are scheduled to be in service by the summer 2018 timeframe.

the gas burn shortage for scenario 2, leaving only two remaining gas outage scenarios (i.e., 3 and 4) as having gas burn shortage for electric generation with potential customer impact.

Similarly to Table 6.3-2, the ISO updated Table 6.3-3 with the benefit of having balancing rules implemented. With balancing rules, it is estimated that the amount of gas shortfall would be reduced by about 150 Mmcfpd or about 70 Mmcf per 8 hours. Incorporating this benefit into Table 6.3-3, the ISO observed a gas burn shortfall would have occurred for Scenario 4 only. It is also important to note that the ISO has not incorporated the potential impact of tubing flow only operations for other gas storage fields (i.e., Goleta, Honor Rancho and Playa Del Rey) into the study results. The ISO will need to undertake additional study to understand the tubing only production limitation.

Table 6.3-3: Potential Electric Generation Impact (for the second transmission constraint)

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)(	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf)	6997 MW*8 hours/103 MWh/MMcf	543	543	543	543
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	667	667	667	667
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410
11A	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	172	32	-24	-258
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	17,669	3,249	-2,519	-26,552
13A	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	2,209	406	-315	-3,319
14	Customer Impacted	Row 13*700	0	0	220,413	2,323,329
11B	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf) – with 150 MMcfd adjustment for balancing rules (70 Mmcf / 8 hours)	Row 11A+70	242	102	46	-188
13B	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	(Row 13A / Row 11A)*Row 11B	3108	1294	604	-2418

Summary of Findings for the summer 2017

The following is the summary of findings for the summer 2017 assessments:

- The potential impacts to electric generation due to various gas curtailment scenarios for summer 2017 exhibit similar trends as was evaluated for summer 2016
    - o Gas burn shortfall is observed for three gas curtailment scenarios (i.e., #2 through #4), similar to the Joint Agency Task Force findings
- Both Huntington Beach synchronous condensers Units #3 and 4 are needed to maintain post-transient voltage stability for the minimum gas generation condition for the P1 reliability criteria for the 2017 summer timeframe.
- Without balancing rules benefit, the gas burn for minimum generation requirement would be reduced by 543 MMcf (about 500 MW of generation) if the most critical reliability concern (i.e., post transient voltage instability) can be mitigated by the timely addition of planned dynamic reactive supports. With this reduction, a gas burn shortfall would occur for two gas curtailment scenarios instead of three (i.e., Scenarios #3 and 4). These planned transmission projects, however, are under construction and cannot be placed in service until December 2017 at the earliest.
- The ISO updated the analyses for potential generation impact with the benefit of having balancing rules implemented. With balancing rules, it is estimated that the amount of gas shortfall would be reduced by about 150 Mmcfpd or about 70 Mmcf per 8 hours. Incorporating this benefit into Tables 6.3-2 and 6.3-3, the ISO observed a gas burn shortfall would have occurred for Scenario 4 only. It is also important to note that the ISO has not incorporated the potential impact of tubing flow only operations for other gas storage fields (i.e., Goleta, Honor Rancho and Playa Del Rey) into the study results. The ISO will need to undertake additional study to understand the tubing only production limitation.
- The next reliability concern, after the post-transient stability issue is mitigated, is thermal loading concern for a number of 230 kV lines in the Orange County and Los Angeles County areas:
    - o The Mesa Loop-In project, which was approved by the ISO Board and is currently in the CPUC's permitting process, will be able to mitigate these various thermal loading concerns.
    - o This project, however, is not expected to be in service until December 2020 at the earliest, with the timing dependent on the CPUC permitting process.
- The ISO has also evaluated other options for potential interim solutions for mitigating thermal loading constraints (i.e., flow controlling devices). However, high capacity transmission lines in the LA Basin (due to bundled conductor construction), coupled with congested real estate conditions, pose a significant challenge in implementing interim solution in a timely manner for summer 2017. Additionally, since the primary transmission constraint is related to the

post transient voltage stability concern, mitigating this issue with planned dynamic reactive support projects would be needed before potential benefits for thermal loading mitigation can be realized. These may therefore need more consideration for the summer of 2018 and beyond if there are concerns that Aliso Canyon storage may be impacted in the longer term.

Summer 2026 (Long-Term) Transmission Planning Assessment

Similar to the summer 2017 transmission planning assessment, the same four gas outage scenarios were evaluated for the summer 2026 peak load conditions. For the 2026 long-term study, the Mesa Loop-In project, dynamic reactive support devices (at all four substations)[108] and the Sycamore-Penasquitos 230 kV transmission line are assumed to be in service.

The need for long-term transmission planning assessment was based on the Provision 14 of the Governor's Proclamation of a State of Emergency, which was issued on January 6, 2016, and stated that:

> *The Division of Oil, Gas and Geothermal Resources, the California Public Utilities Commission, the California Air Resources Board and the California Energy Commission shall submit to the Governor's Office a report that assesses the long-term viability of natural gas storage facilities in California. The report should address operational safety and potential health risks, methane emissions, supply reliability for gas and electricity demand in California, and the role of storage facilities and natural gas infrastructure in the State's long-term greenhouse gas reduction strategies.*

In addition, the CEC 2016 Integrated Energy Policy Report (IEPR) Update Final Scoping Order also identified the need:

- Assessment of long-term solutions to provide reliable natural gas and electricity service in the Los Angeles Basin if Aliso Canyon is not available or has limited availability.

Due to assumptions of significant penetration of the behind-the-meter photovoltaic distributed generation (BTM PVDG) for the ten-year horizon, the ISO also evaluated a sensitivity scenario in which the utilities' peak loads are shifted to early evening hours (i.e., 6 p.m.) when solar generation contribution is considerably reduced and modeled at zero output in this analysis.[109] This scenario is described as the "with peak shift" scenario in this analysis, versus the "without peak shift" scenario that considers the mid-afternoon load levels.

The following is a summary of the potential peak load impact values of the behind-the-meter photovoltaic distributed generation[110] for the 2026 timeframe.

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[108] These four substations are: Santiago, San Onofre, Talega and San Luis Rey.

[109] This peak shift assumption was modeled for the study prior to having the peak shift forecast being made available from the CEC in December 2016.

[110] Forms 1.4 for respective SCE and SDG&E for Mid Demand Case (http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_mid_case_final_baseline_demand_forecast.php). The behind-the-meter PV DG peak impact from these forms were used prior to peak shift calculation was made available by the CEC at

- Total for SCE service area: 1,739 MW
- Total for SDG&E service area: 504 MW

The CEC demand forecast for 2026 is less than its demand forecast for 2017 timeframe:

- 1100 MW less for the LA Basin
- 280 MW less for San Diego area

In addition to the CPUC-approved long term procurement for the LA Basin and San Diego local capacity requirement (LCR) areas, the ISO also included expedited battery energy storage system (BESS) that were approved recently by the CPUC related to the Aliso Canyon gas constraint as well as battery storage from the long-term procurement plan:

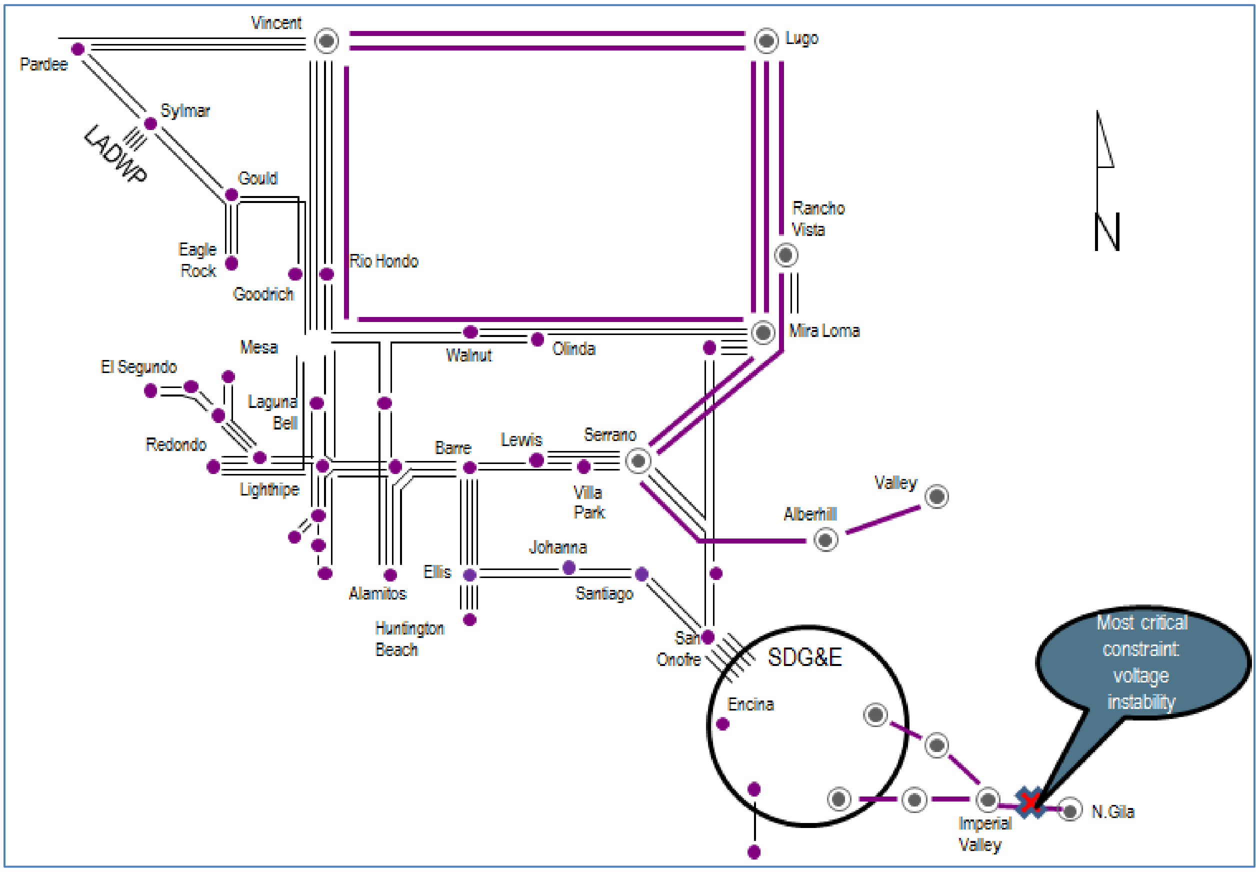
- 72 MW (expedited) and 264 MW (LTPP) for SCE service area
- 37.5 MW (expedited) for SDG&E service area

2026 Study Results without Peak Shift (Using CEC 2015 IEPR Mid Base Case with Low AAEE without adjustment for peak shift)

Without considering peak shift, the most critical constraint is the voltage instability concern that is caused by an N-1 (P1) contingency of the Imperial Valley-North Gila 500 kV line. Figure 6.3-3 provides a visual illustration of this transmission constraint impacting the LA Basin and San Diego areas.

the end of November 2016 timeframe. For simplicity in referencing in this chapter, when "peak shift" scenario is mentioned it means that the peak demand impact due to BTM PV DG is not modeled in the study.

Figure 6.3-3: Transmission constraint identified for the LA Basin and San Diego areas (No peak shift modeled for the study)



The following Table 6.3-4 provides a summary of potential electric generation impacts for four gas outage scenarios, similar to the transmission planning assessment that was performed for the summer 2017. The results indicated that the implementation of the ISO-approved Mesa Loop-In project, dynamic reactive support projects (at Santiago, San Onofre, Talega and San Luis Rey substations) and the Sycamore-Penasquitos 230 kV line, coupled with lower demand CEC demand forecasts, help mitigate gas burn shortages at the electric generation facilities for the NERC P1 reliability contingencies.

Table 6.3-4: Potential Generation Impacts for summer 2026 Transmission Planning Assessment (No peak shift)

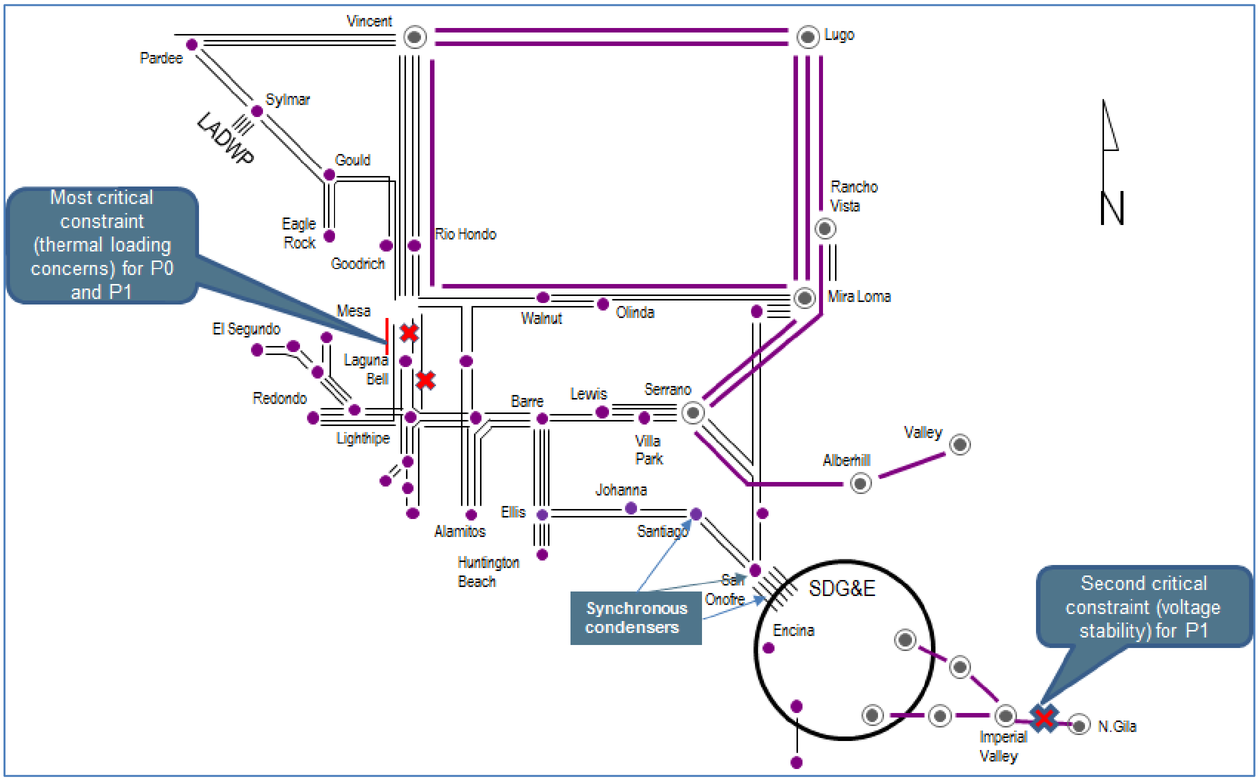
			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf) **for the most critical transmission constraint**	3505 MW*8 hours/103 MWh/MMcf	272	272	272	272
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	396	396	396	396
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
11A	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	443	303	247	13
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	45,607	31,187	25,419	1,386
13A	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	5,701	3,898	3,177	173
14	Customer Impacted	Row 13*700	0	0	0	0
11B	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf) – with 150 MMcfd adjustment for balancing rules (70 Mmcf / 8 hours)	Row 11A+70	513	373	317	83
13B	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	(Row 13A / Row 11A)*Row 11B	6602	4799	4077	1105

2026 Study Results with Peak Shift

With consideration of peak shift, the most critical constraint is the thermal loading concern affecting Mesa-Laguna Bell 230 kV line under P0 (all lines and transformers in service) as well as P1 (single-element contingency) conditions. The second constraint is voltage instability due to P1 contingency of the Imperial Valley-North Gila 500 kV line. Figure 6.3-4 provides a visual illustration of this transmission constraint impacting the LA Basin and San Diego areas.

Figure 6.3-4: Transmission constraint identified for the LA Basin and San Diego areas (with peak shift modeled for the study)



The following Table 6.3-5 provides a summary of potential electric generation impacts for four gas outage scenarios, similar to the transmission planning assessment that was performed for the summer 2017 for the reliability assessment modeled with peak shift. The results indicated that with peak shift modeled for the study, the gas burn shortage for electric generation occurs for the gas outage scenario #4.

Table 6.3-5: Potential Generation Impacts for summer 2026 Transmission Planning Assessment (with peak shift)

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf) **for the most critical transmission constraint**	4380 MW*8 hours/103 MWh/MMcf	340	340	340	340
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	464	464	464	464
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	**Description**	**Formula**	**Scenario 1: Aliso Canyon Gas Storage Outage**	**Scenario 2: With Other Storage Outage**	**Scenario 3: With Major Pipeline Outage**	**Scenario 4: Overlapping Outages (1+2+3)**
11A	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	375	235	179	-55
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	38,602	24,182	18,414	-5,620
13A	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	4,825	3,023	2,302	-702
14	Customer Impacted	Row 13*700	0	0	0	491,709
11B	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf) – with 150 MMcfd adjustment for balancing rules (70 Mmcf / 8 hours)	Row 11A+70	445	305	249	-15
13B	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	(Row 13A / Row 11A)*Row 11B	5726	3923	3202	-124

Summary of Findings for the summer 2026

The potential impact to electric generation due to various gas curtailment scenarios for summer 2026 exhibits the following:

- ISO Board-approved transmission projects (i.e., Mesa Loop-In and synchronous condensers in Orange County and San Diego areas), coupled with the CEC lower demand forecast, help mitigate reliability concerns due to various gas outage scenarios related to Aliso Canyon gas storage outage.
- Using the CEC demand forecast without peak shift modeled, coupled with the implementation of the above transmission projects, resulted in no gas burn deficiency for all four considered gas outage scenarios.

- Scenarios with peak demand shifted to early evening hours without contribution from behind-the-meter photovoltaic generation indicated thermal loading and voltage stability concerns. This could cause gas burn deficiency for the extreme gas outage scenario (i.e., Scenario 4).

- Similar to the 2017 study results, the ISO also updated the 2026 long-term analyses for potential generation impact with the benefit of having balancing rules implemented. With balancing rules, it is estimated that the amount of gas shortfall would be reduced by about 150 Mmcfpd or about 70 Mmcf per 8 hours. It is also important to note that the ISO has not incorporated the potential impact of tubing flow only operations for other gas storage fields (i.e., Goleta, Honor Rancho and Playa Del Rey) into the study results. The ISO will need to undertake additional study to understand the tubing only production limitation.

6.3.2 Gas/Electric Coordination Transmission Planning Studies for Northern California

The ISO expanded the analysis of the gas-electric coordination special study in the 2016-2017 transmission planning process to include and assessment of the gas system in northern California and assess if there is any issues or concerns with respect to the electric transmission system.

6.3.2.1 *Study Scope*

The scope of Northern California gas-electric reliability coordination study was conducted in the following three stages:

- gather information about gas system, capacity and supply network to gas-fired power plant in Northern California;
- investigate plausible conditions which could result in gas curtailment to power plant resulting in significant reduction in electric generation; and
- perform studies to identify any adverse impact to electric system reliability, if such conditions are identified.

6.3.2.1 *Overview of Northern California's Gas Transmission System*[111]

Most of the gas supplies that serve Northern California are sourced from out of state with only a small portion originating in California. This mix is due to the increasing gas demand in California over the years and the limited amount of native California supply available.

GAS SUPPLY

California-Sourced Gas

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley.

U.S. Southwest Gas

Gas from three major U.S. Southwest gas producing basins—Permian, San Juan, and Anadarko— are accessed via the El Paso, Southern Trails, and Transwestern pipeline systems. Gas in these basins are transported to California via interstate pipelines.

Canadian Gas

Gas Transmission Northwest Pipeline transports gas from western Canada (British Columbia and Alberta) to California.

Rocky Mountain Gas

Gas from Rocky Mountain area are accessed via the Kern River Pipeline, the Ruby Pipeline and via the Gas Transmission Northwest Pipeline interconnect at Stanfield, Oregon. The Ruby Pipeline brings up to 1.5 billion cubic feet per day (bcf/d) of Rocky Mountain gas to Malin, Oregon.

[111] Source: 2016 California Gas Report

With Ruby pipeline, the share of Canadian gas to PG&E's system has been reduced somewhat while the Redwood path from Malin to PG&E Citygate has run at a higher utilization rate.

Storage

Northern California is served by several gas storage facilities in addition to the long-standing PG&E fields at McDonald Island, Pleasant Creek, and Los Medanos. Other storage providers include Gill Ranch Storage, LLC (the 20 bcf facility was co-developed with PG&E, which owns 25 percent of the capacity), Wild Goose Storage, Inc., Lodi Gas Storage, LLC, and Central Valley Storage, LLC. These facilities have total working gas capacity of roughly 105 billion cubic feet and peak withdrawal capacity of 2.1 bcf/d.

In addition to storage services offered by PG&E, there are four other storage providers in Northern California—Wild Goose Storage, Inc., Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. As of 2015, these facilities had total working gas capacity of roughly 133 billion cubic feet and peak withdrawal capacity of 2.5 bcf/d.

Figure 6.3-5 and Figure 6.3-6 show backbone gas pipeline system and storage facilities in Northern California along with their capacity.

Figure 6.3-5: Northern California backbone gas pipeline and capacity

INTERCONNECT SUPPLY CAPACITY (mmcfd)	
Redwood Path	
From Gas Transmission Northwest	2,180
From Ruby	1,500
Baja Path	
From KRGT - HDL	282
From KRGT - Daggett	375
From Southern Trails	120
From El Paso Natural Gas	1,140
From Transwestern	365

Figure 6.3-6: Northern California gas storage facilities and capacity

PG&E Storage Capacity

	Working Inventory	Supply
	Bcf	MMscf/d
Total 2016	**105**	**2,105**
McDonald Island	82	1,580
Los Medanos	16	355
Pleasant Creek	2	70
Gill Ranch	5	100

Independent Storage Providers (ISPs)

	Working Inventory	Supply
	Bcf	MMscf/d
Total 2016	**133**	**2,300**
Wild Goose	75	950
Lodi Storage	32	750
Central Valley Storage	11	300
Gill Ranch Storage (75%)	15	300

Gas-fired Power Plants

The aggregated capacity of power plants served from line 400/401backbone pipeline is roughly 5,900 MW. Figure 6.3-7 shows view of the backbone line 400/401, sub-transmission pipelines and rough location of gas-fired power plants.

The aggregated capacity of power plants served from line 300 backbone pipeline is roughly 5,500 MW. Figure 6.3-8 shows view of the backbone line 300, sub-transmission pipelines and rough location of gas-fired power plants.

Figure 6.3-7: Line 400/401 view

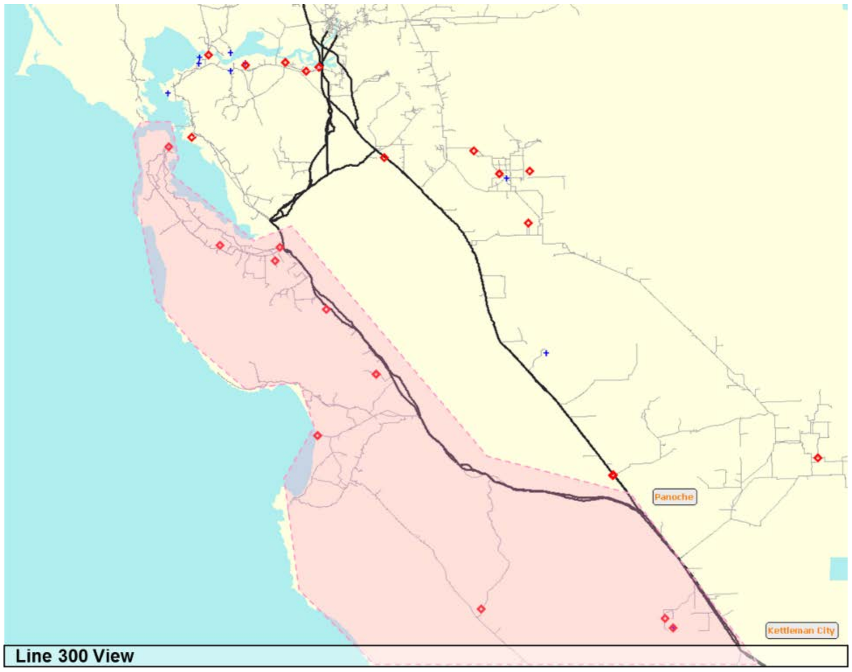
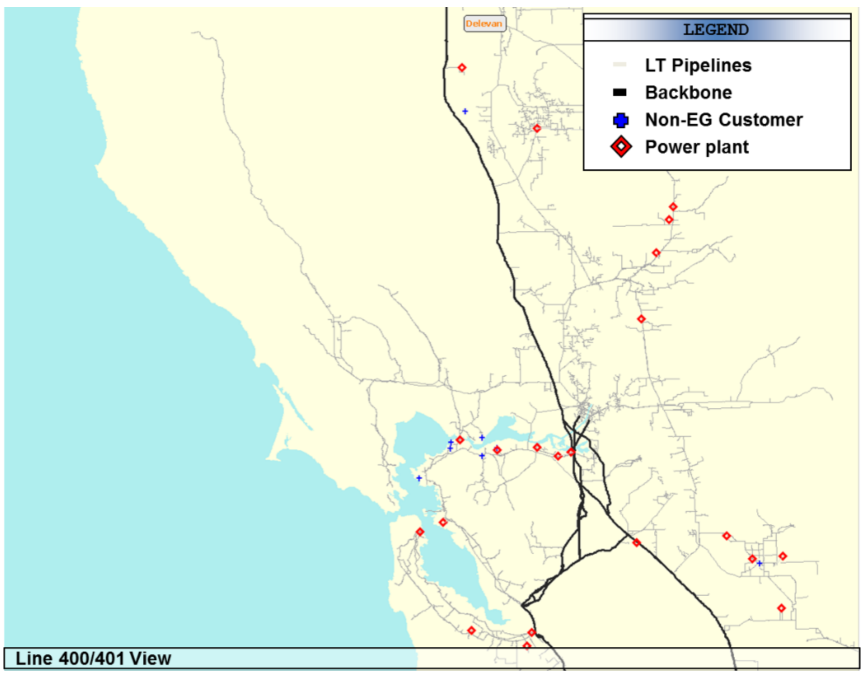


Figure 6.3-8: Line 300 View



The aggregated capacity of power plants served from Kern River-Mojave gas system is roughly 3,800 MW of which 2,200 MW is in PG&E service territory and 1,600 MW is in SCE territory.

Figure 6.3-9 shows general location of Kern River-Mojave gas system within Northern California.

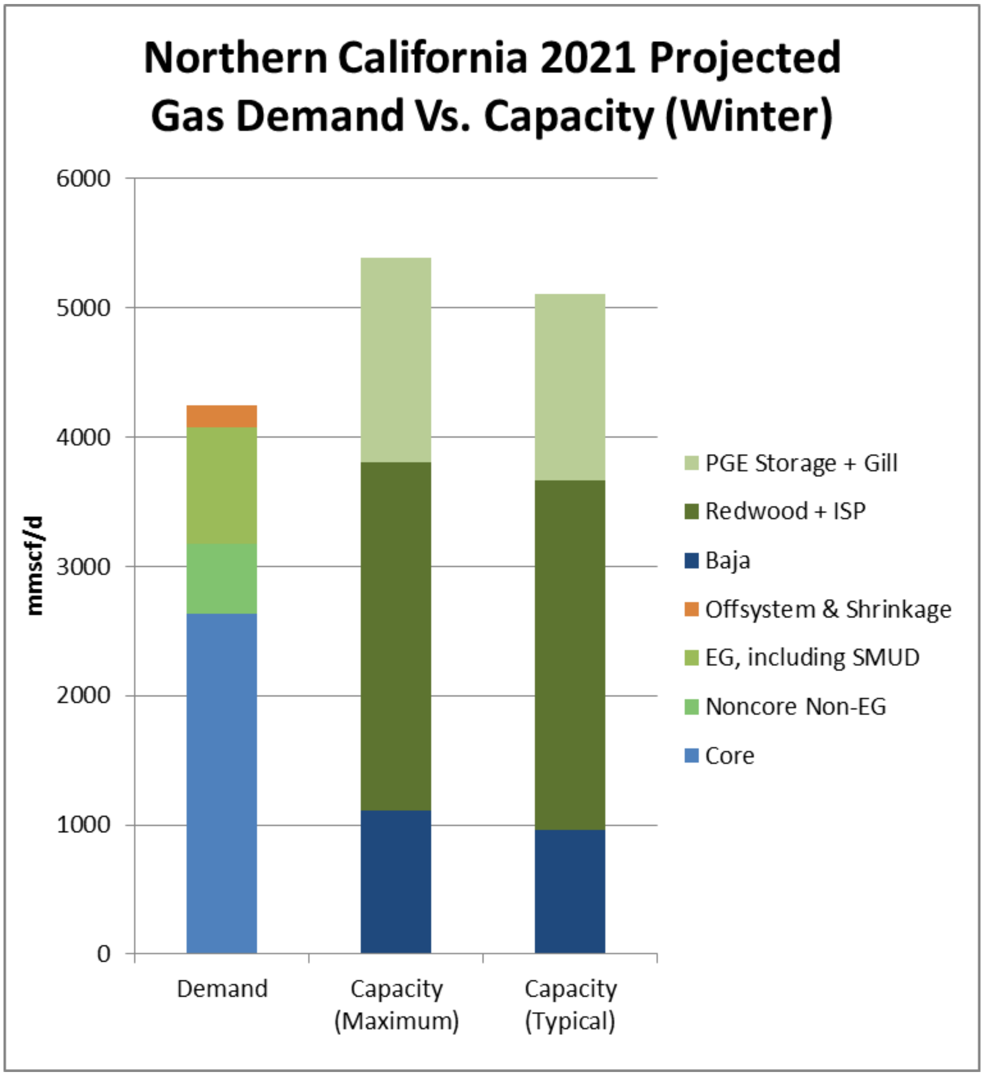
Figure 6.3-9: Kern River-Mojave gas system

6.3.2.2 *Gas Demand Verses Capacity*

One of the approaches taken in investigating plausible conditions which could result in gas curtailment to power plant is to compare projected peak winter and summer gas demands with corresponding pipeline and storage facility capacities. Figure 6.3-10 below shows the projected winter peak gas demand for 2021 based on the 2016 California Gas Report along with corresponding maximum and typical combined pipeline/storage capacities, including any pipeline delivery constraints. The maximum capacity is based on the pipelines and storage fields being at full capacity. The typical capacity considers that the pipeline may have day to day limitations and storage fields may not be full. The gas storage capacities do not reflect any impact from new Division of Oil, Gas, & Geothermal Resources (DOGGR) regulations. The extent of the potential impact from new regulations cannot be determined until final regulations are adopted.

As seen in Figure 6.3-10 the combined pipeline and storage facilities provide sufficient capacity to serve demand under normal and typical constrained conditions. Furthermore, it should also be noted that there is no direct relationship between gas-fired power plants and storage facilities in terms of gas supply and dependency.

Figure 6.3-10: Gas demand vs capacity (winter)

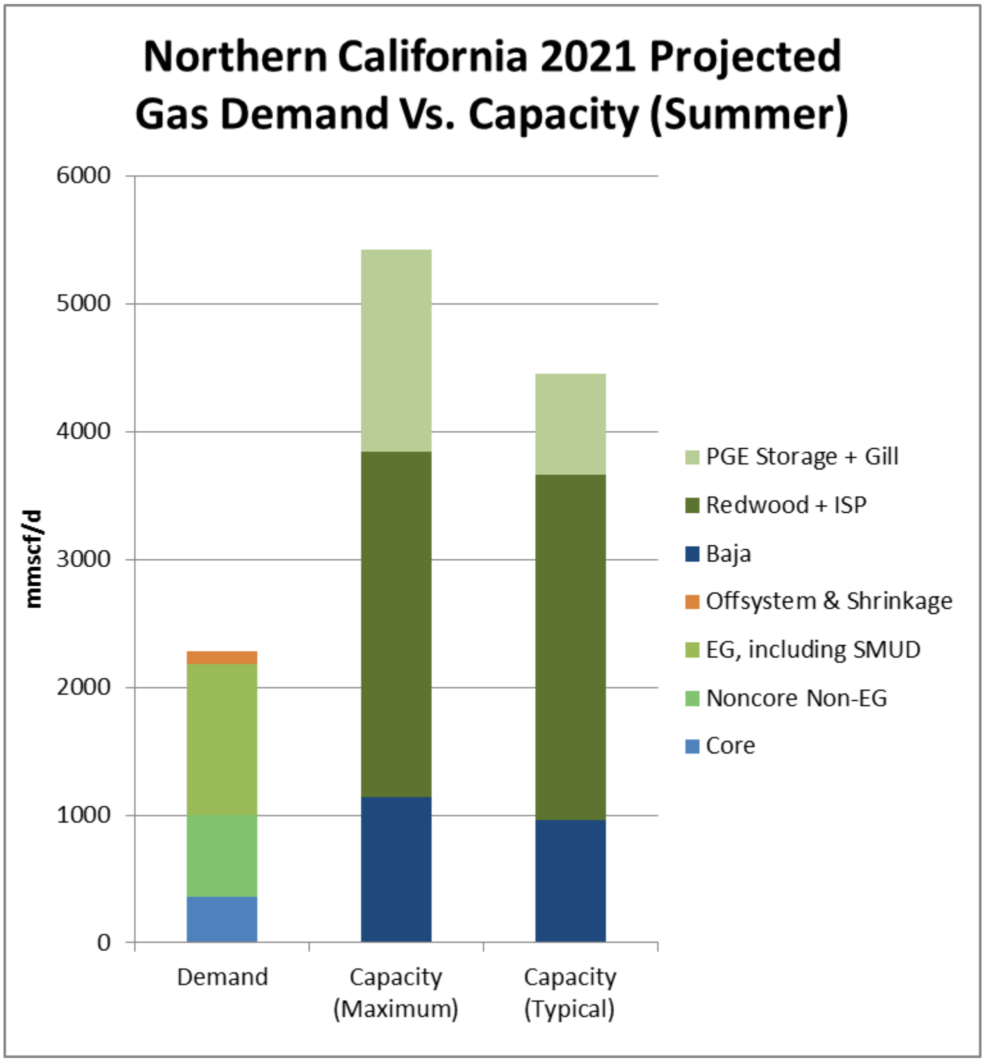


Notes:
1) Demands are primarily from 2016 California Gas Report - Winter Peak Day Demand
2) Redwood + ISP Capacity is restricted by Redwood Northern pipeline constraint. The pipeline constraint may vary depending on system conditions
3) Typical Capacity scenario assumes Storage Capacity based on lower storage field inventories.
4) Highest historical daily demand (winter) was 4975 mmscf/d.

The chart below shows the projected summer peak gas demand for 2021 based on the 2016 California Gas Report along with corresponding maximum and typical pipeline/storage facility capacities. The maximum capacity is based on the pipeline and storage fields being at full capability. The typical capacity considers that the pipeline may have day to day limitations and storage fields may have limitations primarily due to maintenance.

As seen in Figure 6.3-11 the combined pipeline and storage facilities provide sufficient capacity to serve demand under normal and typical constrained conditions.

Figure 6.3-11: Gas demand vs capacity (summer)



Notes:

1) Demands are primarily from 2016 California Gas Report - Summer Peak Day Demand
2) Redwood + ISP Capacity is restricted by Redwood Northern pipeline constraint.
3) The pipeline constraint may vary depending on system conditions.
4) Typical Capacity scenario assumes PG&E Storage + Gill capacity is half of max due to maintenance.

It should be noted that the capacities in the above assessments for peak winter and summer demands reflect possible limitations due to pipeline delivery capacity. These limitations can vary depending on system operating conditions.

6.3.2.3 *Critical Areas and Local Capacity Requirements*

The other approach taken in investigating plausible conditions which could result in gas curtailment to power plant is to compare the minimum local generation required for reliability (local capacity requirement, LCR), reliance on local thermal generation fleet to meet LCR and risk of not meeting LCR in each local capacity area due to plausible curtailment to local gas-fired power plants.

Humboldt LCR Area

Based on the ISO's 2017 local capacity requirement study, total generation in Humboldt LCR area is 218 MW. Out of which the aggregated maximum output from gas-fired power plants is 163 MW. The category P1/P3 requirement for Humboldt is 110 MW. Assuming all non-thermal generation is available, the minimum thermal generation needed to meet LCR in Humboldt is 55 MW.

The thermal power plant in Humboldt has dual fuel capability and that the curtailment of gas supply doesn't impact electric generation. As such, it is determined that there is no risk of not meeting LCR in Humboldt LCR area due to gas constrained conditions.

Sierra LCR Area (Pease subarea)

Based on the ISO's 2017 local capacity requirement study, total generation in Pease subarea is 106 MW, of which the aggregated maximum output from gas-fired power plants is 105 MW. The category P1/P3 requirement for Pease subarea is 100 MW. Assuming all non-thermal generation is available, the minimum thermal generation needed to meet LCR in Pease subarea is 99 MW.

The three thermal power plants in Pease subarea are primarily fed from same gas transmission line. If the upstream pipeline feeding these power plants is unavailable to supply gas, the downstream feed will not have enough capacity to serve the three plants. There will be sufficient supply to run one of the plants from the downstream in summer. As such, it is determined that there is risk of not meeting LCR in Pease LCR subarea due to gas constrained conditions.

Greater Bay Area LCR Area

Based on the ISO's 2017 local capacity requirement study, total generation in Greater Bay Area LCR area is 9,862 MW. Out of which the aggregated maximum output from gas-fired power plants is 9,500 MW. The category P1/P3 requirement for Greater Bay Area is 4,260 MW. Assuming all non-thermal generation is available, the minimum thermal generation needed to meet LCR in Pease subarea is 3,898 MW.

There are many thermal power plants in Greater Bay Area connected to many different gas pipelines. There will be enough gas supply for minimum local generation under an abnormal demand and plausible facility outage conditions due to redundancy in the system. As such, it is determined that there is no significant risk of not meeting LCR in Greater Bay Area LCR area due to gas constrained conditions.

Fresno LCR Area

Based on the ISO's 2017 local capacity requirement study, total generation in Fresno LCR area is 3,303 MW. Out of which the aggregated maximum output from gas-fired power plants is 914 MW. The category P1/P3 requirement for Fresno is 1,760 MW. Assuming all non-thermal generation is available, the minimum thermal generation needed to meet LCR in Pease subarea is 0 MW.

There is enough non-thermal generation in Fresno to meet LCR requirement. As such, it is determined that there is no significant risk of not meeting LCR in Fresno LCR area due to gas constrained conditions.

Stockton LCR Area

Based on the ISO's 2017 local capacity requirement study, total generation in Stockton LCR area is 598 MW, of which the aggregated maximum output from gas-fired power plants is 390 MW. The category P1/P3 requirement for Stockton is 340 MW. Assuming all non-thermal generation is available, the minimum thermal generation needed to meet LCR in Pease subarea is 132 MW.

The thermal power plant in Stockton LCR area is fed off of transmission line which can be fed from both directions, so an outage in on either side will most likely not have an impact. However, a severe outage right at the power plant location, the plant could lose its feed. As such, it is determined that there is no significant risk of not meeting LCR in Stockton LCR area due to gas constrained conditions.

6.3.2.4 *Conclusion*

Based on the assessment comparing forecasted gas demand and gas facility capacities, the gas system in Northern California seems to have adequate capacity to supply peak winter and summer forecasted demands under both normal and plausible constrained conditions. The high capacity doubly built backbone pipelines and storage facilities – which are scattered but located close to the backbone pipelines - add redundancy and flexibility in supplying gas to power plants in the area. The assessment based on local capacity requirements for critical local capacity areas and its dependency on local thermal fleet for meeting LCR identified all critical local capacity areas, except for the Pease subarea, with no significant risk of not meeting its local capacity requirement due to plausible gas constrained conditions. The ISO will continue to work with the PG&E gas operation group and other stakeholders in future cycles to identify plausible gas constrained condition, including the impact of new DOGGR regulation that could significantly impact generation from gas-fired power plants in Northern California. To the point such conditions are identified, the ISO will perform studies to identify if such conditions impose any adverse impact to electric system reliability.

6.4 50 Percent RPS Special Study

During the 2016-2017 planning cycle the ISO undertook information-only study work to provide information regarding the potential need for public policy-driven transmission additions or upgrades to support a state 50 percent renewable energy goal by 2030. The ISO and CPUC both believed there would be value in performing this study to anticipate potential transmission needs to meet the 50 percent renewable energy goal and to help inform the process by which the policy direction to achieve 50 percent RPS is set.

In framing the context of the 50 percent renewable energy study, the ISO and CPUC contemplated that a continued reliance on full capacity deliverability status (FCDS) for future renewable generation and alternatively, assessing transmission needs through an "energy only" assumption would provide reasonable bookends on establishing transmission related needs to mitigate congestion and deliver additional renewable resources to California's aggregate of load.

The ISO's assessment also focused on evaluating the impact of out-of-state renewable resources on the general reliability performance of the western interconnection and curtailment of renewables in Wyoming and New Mexico that were targeted to meet California's out-of-state renewable requirements. This effort provided a framework for ISO and other western planning regions to coordinate their consideration of those Interregional Transmission Projects that were submitted through the FERC Order No. 1000 interregional coordination process.

While there is considerable interest in exploring how the benefits of interregional transmission projects could help California move beyond 33 percent RPS towards a 50 percent RPS goal, the policy direction is not in place at this time to consider interregional transmission projects as policy-driven transmission. However, recognizing California's interest in examining different possibilities to achieve a 50 percent RPS goal, the ISO chose to consider an interregional coordination effort as an extension of the 50 percent RPS special studies that were being conducted inside the 2016-2017 transmission planning cycle. This capitalized on the first opportunity to employ the biennial interregional coordination process developed by the ISO and neighboring planning regions in compliance with FERC Order No. 1000, which always commences on even-numbered years. As such, during the 2016-2017 planning cycle the ISO worked with the other western planning regions to coordinate an assessment of the interregional project proposals as a means to connect out-of-state renewable resources with California.

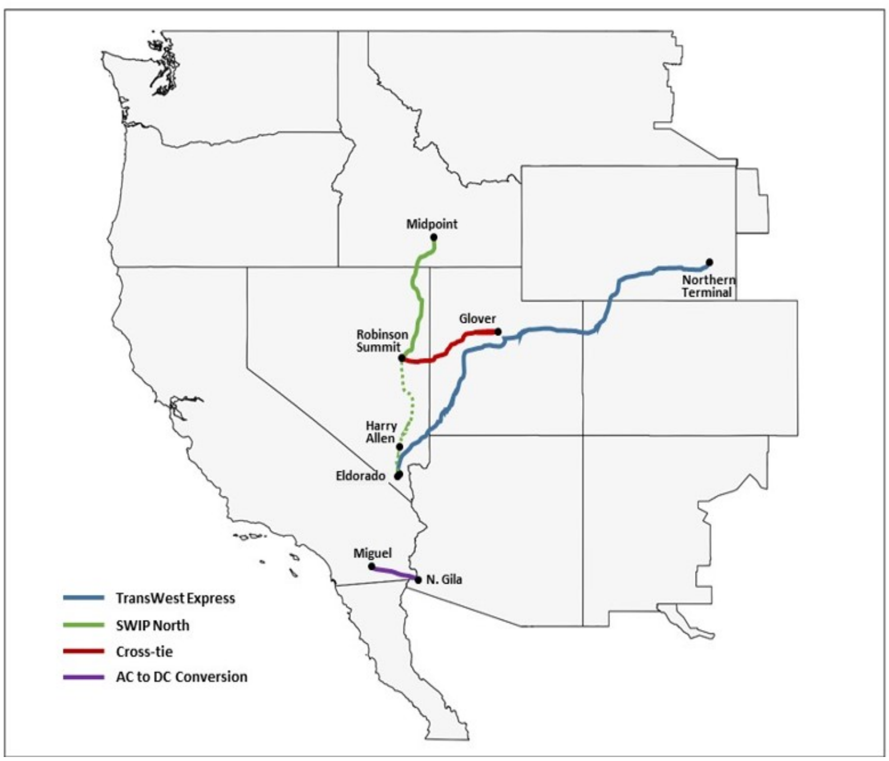
The following sections describe the study methodology, assessment, and conclusions of the 50 Percent RPS Special Study assessment as well as information on how interregional coordination has supported the ISO's assessment in this particular special study. As stated earlier, this assessment is but one of the possible sources of information which California may consider in its determination of meeting California's 50 percent RPS goal.

6.4.1 Interregional Coordination Background

During the ISO's 2016-2017 planning cycle, the ISO continued to participate and advance interregional transmission coordination along with the other western planning regions within the broader landscape of the western interconnection. As discussed in chapter 1, January 1, 2016 marked the initiation of the 2016-2017 western planning region interregional coordination cycle. During the earlier part of 2016 the western planning regions continued to refine aspects of their regional processes that resulted in the development of guiding principles that provided a common framework for an annual exchange and coordination of planning data and information.

As defined by the Common Interregional Tariff Language[112] among the western planning regions, the ISO hosted its interregional transmission project submission period during the first quarter of 2016. Four interregional transmission projects were submitted to the ISO, NTTG, and WestConnect in the submission window. The general location of the projects are shown in Figure 6.4-1 and generally described in Table 6.4-1.

Figure 6.4-1: Interregional Transmission Projects Submitted to the ISO



[112] http://www.caiso.com/Documents/May10_2013TariffAmendment-Order1000Phase2%20InterregionalER13-1470-000.pdf

Table 6.4-1: Interregional Transmission Project Descriptions

Proposed Project	Description
TransWest Express Transmission Project	The TransWest Express Transmission Project (TWE Project) is a proposed 730-mile, phased 1,500/3,000 MW, ±600 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and southeastern Nevada. The Relevant Planning Regions are the ISO, NTTG, and WestConnect.
Southwest Intertie Project North	The Southwest Intertie Project (SWIP) is a proposed 275 mile 500kV single circuit AC line that connects the Midpoint 500 kV substation to the Robinson Summit 500 kV substation. The SWIP is expected to have a bi-directional WECC-approved path rating of approximately 2000 MW. The Relevant Planning Regions are NTTG and WestConnect. (Note that this project was also submitted into the ISO's regional planning process as a potential regional – e.g. ISO – economic driven project.)
Cross-Tie Project	The Cross-Tie Transmission Line (Cross-Tie) project is a 213 mile 500 kV HVAC transmission project that will be constructed between central Utah and east-central Nevada. The Cross-Tie Project is expected to have a rating of approximately 1500 MW. The Relevant Planning Regions are NTTG and WestConnect.
AC to DC Conversion Project	The AC to DC Conversion Project proposes to convert a portion of the 500 kV Southwest Powerlink (SWPL) to a multi-terminal, multi-polar HVDC system with terminals at North Gila (500 kV), Imperial Valley (500 kV), and Miguel Substations (230 kV). The Relevant Planning Regions are the ISO and WestConnect.

All four project proposals met the screening requirements of the ISO, NTTG, and WestConnect and were included in the regional planning processes of these regions. Subsequent to meeting the screening requirements the ISO coordinated the development of project evaluation process plans with the other relevant planning regions. These process plans were shared with the project sponsors and ISO stakeholders[113].

A common theme among all projects was a possible role in providing access to out-of-state renewable generation to move California beyond the 33 percent RPS toward a 50 percent RPS goal. As Relevant Planning Regions the ISO, NTTG, and WestConnect were required to develop to coordinate planning data and information related to the interregional transmission projects to

[113] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=EAEBC2EA-AE8D-4F8D-A7A6-E477B2ACD085

ensure that this information was common in all of the regional studies being conducted by the planning regions. As part of this coordination effort, the ISO worked with NTTG and WestConnect to develop a common methodology for scheduling renewable resources in Wyoming and New Mexico to California. The ISO provided NTTG and WestConnect specific details on how these resources should be sinked to California. Alternatively, NTTG and WestConnect provided the ISO with renewable resource information in Wyoming and New Mexico that was modeled in the ISO's studies. While the out-of-state RPS studies will continue beyond the 2016-2017 planning cycle, the ISO will share its results with and consider any input received from NTTG and WestConnect in future ISO planning studies.

6.4.2 Objective

The 50 percent special study focused on broader investigation into the feasibility and implications of moving beyond 33 percent RPS from a transmission system perspective. To date, in identifying needed transmission for 33 percent RPS the ISO has sought to provide full capacity deliverability status to the renewable resources, based on the CPUC's stated direction and the load serving entities' desire to obtain resource adequacy capacity from the same resources that provide renewable energy. The 50 percent special study conducted in the 2015-2016 planning cycle assessed the ability of the transmission system to accommodate incremental renewable resources on an energy-only basis. The special study in this planning cycle builds on that work by performing a deliverability assessment of 50 percent RPS portfolios in addition to the assessment of energy only portfolios. The objectives of this 2016-2017 50 percent special study are:

- to continue investigating the transmission impacts of moving beyond 33 percent RPS assuming procurement based on
  - Deliverability Status – Energy Only (EO) or Full Capacity (FC)
  - Resource location – In-state or Out-of-state
- to test the transmission capability estimates used in RPS calculator v6.2 and update these for the next release of RPS calculator
- to examine the transmission implications of meeting part of the 50 percent RPS obligation by relying on renewable resources outside of California and foster a higher degree of coordination with regional planning entities for the out-of-state portfolio modeling and assessment

This special study is strictly for informational purposes and should not be relied upon as reflecting the direction of future renewable generation development or policy direction in the state. The study:

- does not provide basis for procurement/build decisions in 2016-17 TPP cycle;
- is intended to be used to develop portfolios for consideration by ISO in future TPP cycles; and,
- explores potential policy direction on various related issues but does not attempt to predict how those issues will ultimately be addressed.

6.4.3 Portfolios

The CPUC staff produced portfolios using the RPS Calculator v6.2a for the ISO to use in these studies. The following four portfolios were selected for the 50 percent special studies:

- In-state portfolio with full capacity deliverability status (In-state FCDS)
- In-state portfolio with energy only deliverability status (In-state EODS)
- Out-of-state (OOS) portfolio with full capacity deliverability status (OOS FCDS)
- Out-of-state (OOS) portfolio with energy only deliverability status (OOS EODS)

The in-state portfolios were selected from resources located within California and either directly connected to the ISO controlled grid or scheduled to the ISO balancing authority area. Out-of-state portfolios included a substantial amount of in-state resources, but also included a material but reasonable amount of out-of-state resources scheduled to the ISO balancing authority area with a focus on wind resources from Wyoming and New Mexico. All the portfolios represent the total resources necessary for the California loads within the ISO balancing authority area to meet 50 percent of the annual energy demand with renewable resources. Note that the portfolio resources, whether connected directly to the ISO controlled grid or dynamically scheduled or pseudo-tied into the ISO balancing authority area are considered “inside” the ISO balancing authority area and are not considered imports. Also, any transfer out of the ISO balancing authority area, whether to an in-state or out-of-state balancing authority area, is considered export.

The out-of-state portfolios were used to test the ability of the transmission system within California to deliver the renewable energy from intertie injection points bordering the system to the load centers within California. The out-of-state portfolios are also being used as an input into an informational evaluation of interregional transmission projects.

In-state FCDS portfolio

Renewable Net Short (RNS) is filled only by FCDS resources located within California. Figure 6.4-2 shows the resource selection for the top 20 zones in the in-state FCDS portfolio. Table 6.4-2 shows a detailed breakdown of renewable zones and renewable resources selected in these zones by technology.

Figure 6.4-2: In-state FCDS portfolio

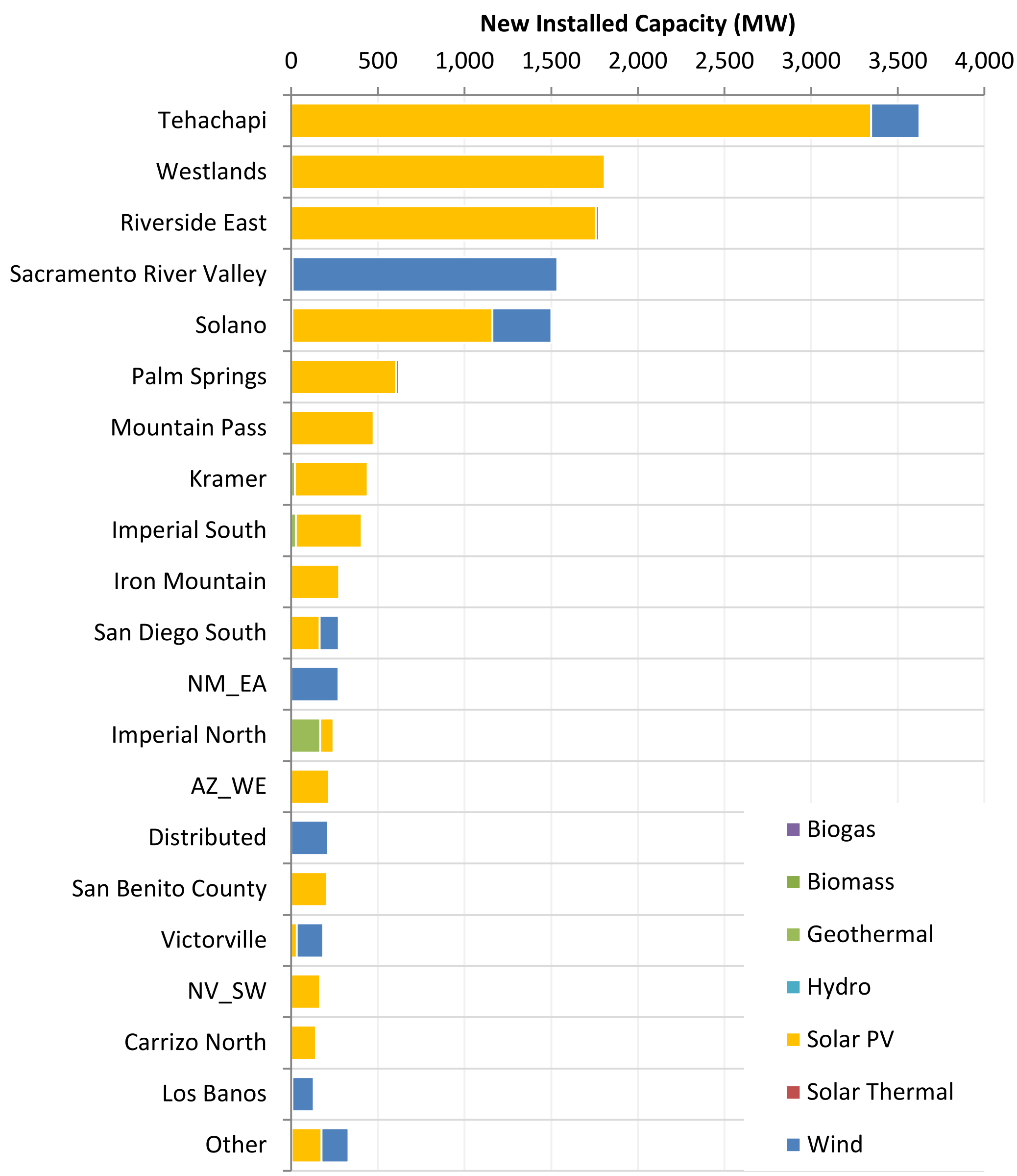


Table 6.4-2: 50 percent In-state FCDS portfolio – Top 20 zones

No.	CREZ	Biogas	Bio-mass	Geo-thermal	Hydro	Solar PV	Solar Thermal	Wind	Total
1	Tehachapi	0	0	0	0	3346	0	279	**3625**
2	Westlands	0	0	0	2	1806	0	0	**1808**
3	Riverside East	0	0	0	0	1757	0	17	**1774**
4	Sacramento River Valley	0	0	0	5	4	0	1527	**1536**
5	Solano	7	0	0	0	1154	0	339	**1500**
6	Palm Springs	0	0	0	0	604	0	17	**621**
7	Mountain Pass	0	0	0	0	475	0	0	**475**
8	Kramer	0	0	20	0	421	0	0	**441**
9	Imperial South	0	0	27	0	379	0	0	**406**
10	Iron Mountain	0	0	0	0	276	0	0	**276**
11	San Diego South	0	0	0	0	164	0	111	**275**
12	NM_EA	0	0	0	0	0	0	272	**272**
13	Imperial North	0	0	168	0	76	0	0	**244**
14	AZ_WE	0	0	0	0	219	0	0	**219**
15	Distributed	0	0	0	0	0	0	213	**213**
16	San Benito County	0	0	0	0	207	0	0	**207**
17	Victorville	0	0	0	0	31	0	152	**183**
18	NV_SW	0	0	0	0	166	0	0	**166**
19	Carrizo North	0	0	0	0	143	0	0	**143**
20	Los Banos	0	0	0	0	7	0	123	**130**
	Other	0	0	0	3	172	0	155	**330**
	Total	**7**	**0**	**215**	**9**	**11407**	**0**	**3205**	**14842**

In-state EODS portfolio

Renewable Net Short (RNS) is filled by resources located within California regardless of their deliverability status. Figure 6.4-3 shows the resource selection for the top 20 zones in the in-state FCDS portfolio. Table 6.4-3 shows a detailed breakdown of renewable zones and renewable resources selected in these zones by technology.

Figure 6.4-3: 50 percent In-state EODS portfolio – Top 20 zones

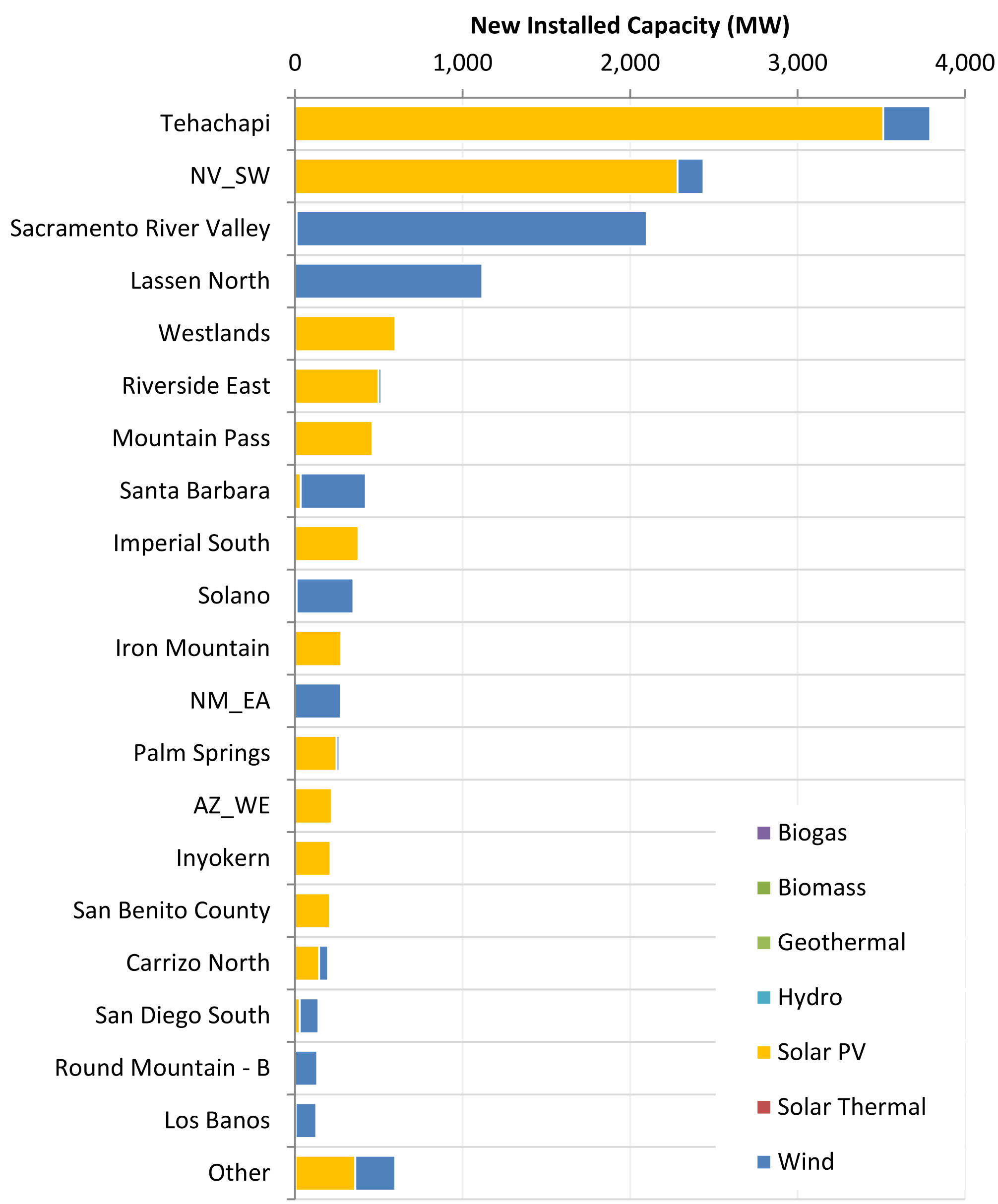


Table 6.4-3: In-state EODS portfolio – Top 20 zones

No.	CREZ	Biogas	Biomass	Geothermal	Hydro	Solar PV	Solar Thermal	Wind	Total
1	Tehachapi	0	0	0	0	3512	0	279	**3791**
2	NV_SW	0	0	0	0	2283	0	156	**2439**
3	Sacramento River Valley	0	0	0	5	4	0	2090	**2099**
4	Lassen North	0	0	0	0	0	0	1117	**1117**
5	Westlands	0	0	0	2	597	0	0	**599**
6	Riverside East	0	0	0	0	497	0	17	**514**
7	Mountain Pass	0	0	0	0	462	0	0	**462**
8	Santa Barbara	0	0	0	0	34	0	389	**423**
9	Imperial South	0	0	0	0	379	0	0	**379**
10	Solano	7	0	0	0	2	0	339	**348**
11	Iron Mountain	0	0	0	0	276	0	0	**276**
12	NM_EA	0	0	0	0	0	0	272	**272**
13	Palm Springs	0	0	0	0	248	0	17	**264**
14	AZ_WE	0	0	0	0	219	0	0	**219**
15	Inyokern	0	0	0	0	211	0	0	**211**
16	San Benito County	0	0	0	0	207	0	0	**207**
17	Carrizo North	0	0	0	0	143	0	55	**197**
18	San Diego South	0	0	0	0	28	0	111	**139**
19	Round Mountain - B	0	0	0	0	0	0	133	**133**
20	Los Banos	0	0	0	0	3	0	123	**126**
	Other	0	0	0	3	357	0	239	**599**
	Total	**7**	**0**	**0**	**9**	**9462**	**0**	**5335**	**14814**

Out-of-state portfolio (FCDS and EODS)

The CPUC provided two out-of-state portfolios:

RNS is filled by FCDS resources within California and wind resources in Wyoming and New Mexico assuming that the out-of-state resources are also fully deliverable. Figure 6.4-4 shows the resource selection for the top 20 zones in out-of-state portfolio.

- RNS is filled by resources within California regardless of their deliverability status and wind resources in Wyoming and New Mexico assuming that the out-of-state resources are fully deliverable.

Both these portfolios turned out to be very similar in terms of resource selection within California. Since there was no material difference in these two portfolios, the ISO decided to create a common model for these two portfolios for the study purpose.

shows the resource selection for the top 20 zones in the out-of-state FCDS portfolio. Table 6.4-4 shows a detailed breakdown of renewable zones and renewable resources selected in these zones by technology.

Figure 6.4-4: Out-of-state portfolio (FCDS and EODS)

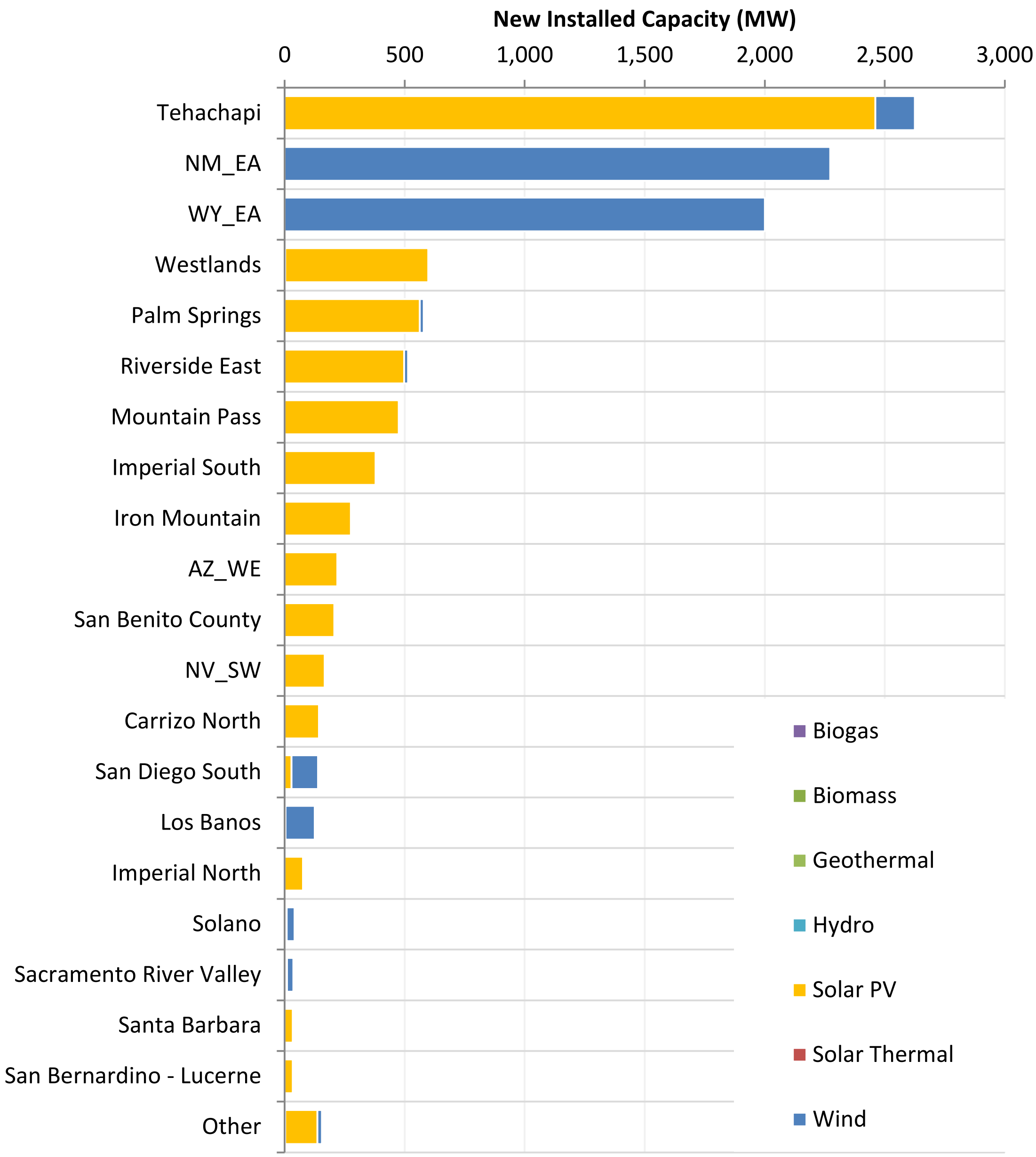


Table 6.4-4: Out-of-state portfolio (FCDS and EODS) – Top 20 zones

No.	CREZ	Biogas	Biomass	Geothermal	Hydro	Solar PV	Solar Thermal	Wind	Total
1	Tehachapi	0	0	0	0	2461	0	164	**2625**
2	NM_EA	0	0	0	0	0	0	2272	**2272**
3	WY_EA	0	0	0	0	0	0	2000	**2000**
4	Westlands	0	0	0	2	597	0	0	**599**
5	Palm Springs	0	0	0	0	563	0	17	**580**
6	Riverside East	0	0	0	0	497	0	17	**514**
7	Mountain Pass	0	0	0	0	475	0	0	**475**
8	Imperial South	0	0	0	0	379	0	0	**379**
9	Iron Mountain	0	0	0	0	276	0	0	**276**
10	AZ_WE	0	0	0	0	219	0	0	**219**
11	San Benito County	0	0	0	0	207	0	0	**207**
12	NV_SW	0	0	0	0	166	0	0	**166**
13	Carrizo North	0	0	0	0	143	0	0	**143**
14	San Diego South	0	0	0	0	28	0	111	**139**
15	Los Banos	0	0	0	0	3	0	123	**126**
16	Imperial North	0	0	0	0	76	0	0	**76**
17	Solano	7	0	0	0	2	0	32	**41**
18	Sacramento River Valley	0	0	0	5	4	0	27	**36**
19	Santa Barbara	0	0	0	0	34	0	0	**34**
20	San Bernardino - Lucerne	0	0	0	0	34	0	0	**34**
	Other	0	0	0	3	134	0	19	**155**
	Total	**7**	**0**	**0**	**9**	**6296**	**0**	**4780**	**11093**

An important differentiating factor compared to 2015-2016 50 percent special studies is the size of these portfolios. Taking cognizance of this size reduction will help interpret the results in comparison to the findings of the previous 50 percent special study. Table 6.4-5 summarizes the total MW amounts in the portfolios studied in 2016-2017 TPP compared to those studied in 2015-2016 TPP.

Table 6.4-5: Comparison of 50 percent portfolios (2015-2016 TPP vs 2016-2017 TPP)

Portfolio	2015-2016 TPP		2016-2017 TPP		
	In-state EODS	Out-of-state EODS	In-state FCDS	In-state EODS	Out-of-state
MW Capacity	21,567	19,174	14,842	14,814	11,093

It is evident that the total MW capacity selected in the in-state EODS portfolio is less by 6,753 MW and the MW capacity selected in the out-of-state portfolio is less by 7,181 MW compared to the portfolios used in the 2015-2016 transmission planning cycle. This reduction in portfolio size is a function of several factors including but not limited to:

- a lower load forecast was used compared to the one used in 2015-2016 transmission planning process;
- a higher level of behind-the-meter generation was assumed; and
- new renewable generation achieving commercial operation by January 2016 was not included in the new resource portfolios.

The transmission capability estimate numbers which were refined as a result of 2015-2016 50 percent special study, were used as an input to the RPS calculator v.6.2 in order to generate the four portfolios being used in this 50 percent special study. Table 6.4-6 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 6.4-6: Summary of transmission capability estimates and capability utilization in portfolios[114]

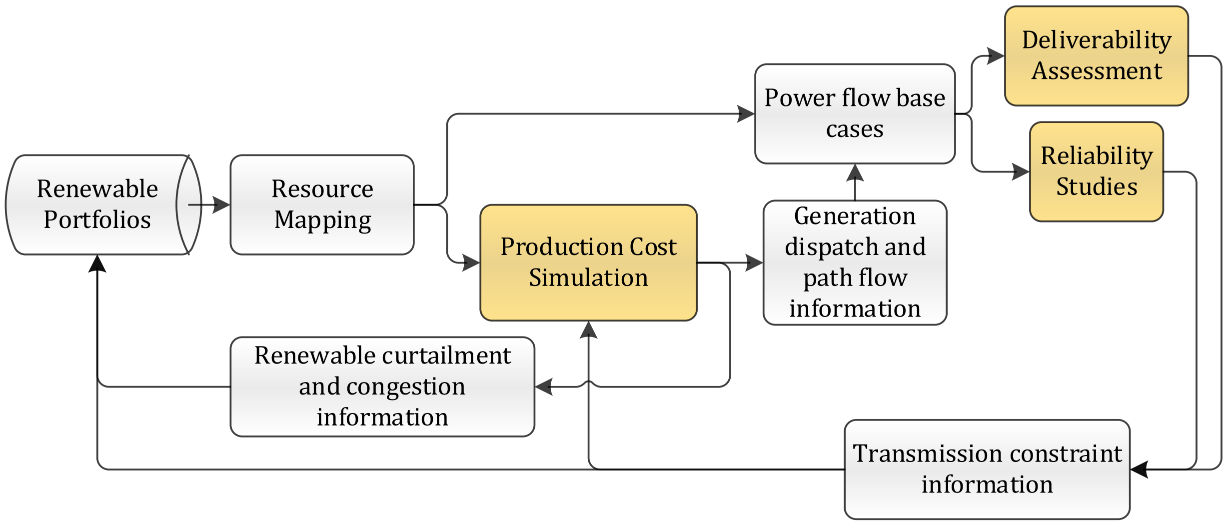
Renewable Zones	Transmission Capability Estimate (MW)		New renewable resources modeled (MW)		
	FCDS	EODS	In-State FCDS	In-State EODS	Out-of-state
Central Valley North and Los Banos	130	1,889	130	126	126
El Dorado and Mountain Pass	535	2,735	916	3,177	916
Greater Carrizo	Unknown	590	143	197	143
Greater Imperial	523	1,849	649	379	454
Kramer & Inyokern	0	412	624	211	0
Lassen and Round Mountain	Unknown	1,250	0	1,250	0
Riverside East & Palm Springs	2,450	4,754	2,395	779	1,094
Sacramento River Valley	36	2,099	1,536	2,099	36
Solano	Unknown	879	1,500	348	41
Tehachapi	2,628	3,794	3,625	3,791	2,625
Westlands	1,823	3,121	2,015	1,228	839

6.4.4 Study Components

A combination of production cost simulation, reliability assessment and deliverability assessment was used to test 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 6.4-5 shows a simplified study process of the 50 percent special study.

[114] This table does not include some resources that do not exactly map to the zones considered for estimating transmission capability. So the numbers will not add up to match the exact portfolio amount.

Figure 6.4-5: 50 percent 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. Resource mapping information was used to build power flow models and production cost simulation models.

6.4.4.1 *Production Cost Simulations*

Production cost simulations were performed using the updated models to identify renewable curtailment and transmission congestion in the ISO's system. Renewable curtailment can be caused by system constraints, such as system ramping, or by transmission constraints. Two scenarios with different ISO export limitations were developed and simulated. One was to assume 2000 MW maximum net export from the ISO, which was the base case, the other was to assume no export limit from the ISO. The second scenario was used as a proxy for the scenario that there was no system constraints with assuming that the entire WECC system can provide additional ramping capability to absorb the intermittency of renewable. The difference of renewable curtailment between the first and the second scenarios was assumed to approximate the renewable curtailment related to system constraints. It should be noted, however, that the "no export limit" scenario may still have some renewable curtailment due to system constraints, but this should be relatively small. Production cost simulations were used to create hourly snapshots of the system with 50 percent RPS resources.

6.4.4.2 *Reliability Assessment*

A reliability assessment was performed in order to identify transmission system limitations above and beyond the constraints monitored in the production cost simulations. The 8,760 hours of snapshots created during production cost simulations were used to identify high transmission system usage patterns to be tested using the power flow models for reliability assessment. For the purpose of identifying the renewable dispatch, the production cost simulation results and resource profiles from 2015-2016 transmission planning cycle were used in the interest of time. Power flow contingency analysis, post transient voltage stability analysis, and transient stability analysis were performed as part of reliability assessment. The intent was to capture any additional area-wide constraints that need to be modeled in the production cost simulations in order to more accurately capture the renewable curtailment caused by transmission congestion.

6.4.4.3 *Deliverability Assessment*

The deliverability test is designed to identify if there is sufficient transmission capability to transfer generation from a given sub-area to the aggregate of ISO control area load when the generation is needed most. The first step in the 50 percent RPS deliverability assessment was to review the study methodology in anticipation of expected resource counting changes for resource adequacy purposes. As the forecasted amount of behind-the-meter solar PV resources are developed between now and 2030, the ISO aggregate peak sales (gross load utility customer consumption minus behind-the-meter generation) is expected to occur later in the day than it currently does. This forecasted development is expected to broaden the consideration of when the grid-connected generation is needed most for resource adequacy purposes. The ISO requested and received information from CPUC staff that could help the ISO understand this change and begin consideration of potential adjustments to the input assumptions to the study on a preliminary basis. This information was utilized in this special study to gain insight into potential adjustments that may be needed to the input assumptions for future deliverability assessments. This experimental work is intended to directionally evaluate the incremental transmission needs beyond 33 percent renewable. It is based on preliminary information which was utilized to explore a preliminary methodology and is not intended to be used for making any transmission planning project approval decisions and is focused only on moving beyond 33 percent RPS to 50 percent RPS.

Two FCDS portfolios were received as part of this 50 percent special study. A deliverability assessment was performed on the In-state FCDS portfolio. The impact of delivering the additional wind resources from Wyoming and New Mexico into California on the existing and expanded maximum import capability (MIC) was examined for the out-of-state portfolio. It was assumed that the additional ~2,000 MW of wind resources from Wyoming would arrive through intertie lines in the Eldorado area and the additional ~2,000 MW of wind resources from New Mexico would arrive through the Palo Verde corridor.

6.4.5 Base Case Assumptions

6.4.5.1 *Production cost simulation base case*

The ISO economic planning database for 2026 described in chapter 4 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 2026 load level used in the TEPPC model was used for the 50 percent special study. Contingency and RAS modeling is also updated to reflect the potential impact of the new resources in the 50 percent portfolios. Because of the reduced expected net 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 2026 to 2030 time frame.

6.4.5.2 *Power flow and stability base cases*

Starting base cases

Base cases for the year 2026 developed for 2016-2017 ISO annual reliability assessment 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 hours 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.

6.4.5.3 *Deliverability assessment base cases*

Starting base cases

Summer peak base cases for the year 2026 developed for 2016-2017 ISO annual reliability assessment were used as a starting point for building the deliverability assessment 50 percent portfolio models.

Load Assumptions

The deliverability assessment modeled the same 2026 peak load levels (1-in-5 years summer peak) that were modeled in the bulk cases used for the 2016-2017 ISO annual reliability assessment.

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.

Import Assumptions

The deliverability assessment modeled the 2017 Maximum Import Capability (MIC) for each branch group plus the approved MIC expansion on IID-SCE and IID-SDGE branch groups[115]. The target flows on the branch groups are shown in Table 6.4-7.

[115] This 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.

Table 6.4-7: Peak Deliverability Assessment Import Targets

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville_BG	N-S	1109	13
COI_BG	N-S	4567	68
BLYTHE_BG	E-W	29	0
CASCADE_BG	N-S	76	0
CFE_BG	S-N	-35	0
ELDORADO_MSL	E-W	300	0
IID-SCE_BG	E-W	702	0
IID-SDGE_BG	E-W		0
LAUGHLIN_BG	E-W	-38	0
MCCULLGH_MSL	E-W	0	316
MEAD_MSL	E-W	831	606
NGILABK4_BG	E-W	-155	168
NOB_BG	N-S	1283	0
PALOVRDE_MSL	E-W	3139	115
PARKER_BG	E-W	76	25
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	13	0
SYLMAR-AC_MSL	E-W	111	337
Total		12008	1648

Generation Assumptions

The deliverability assessment used qualified capacity as Pmax in the base case. The highest summer month NQC in the most recent 3 years was used as Pmax for existing non-intermittent generating units. For new non-intermittent generating units, Pmax was based on the installed capacity.

According to the deliverability assessment methodology, wind and solar generation Pmax data are set to 20 percent exceedance production level during summer peak load hours initially. If the study identifies 20 or more non-intermittent generating units contributing to a deliverability constraint or a mix of wind and solar generators, wind and solar generations were assessed for maximum output of 50 percent exceedance production level for the deliverability constraint. This guideline typically results in local deliverability constraints studied with 20 percent exceedance level and area deliverability constraints with 50 percent exceedance level. The 50 percent RPS deliverability study focused on area deliverability constraints, therefore 50 percent exceedance production level was used.

The current deliverability methodology used summer month production data from hour ending 1pm to 6pm to calculate the wind and solar exceedance production levels. As described above, given that the peak sale may shift to after 6 pm, a preliminary modification to the production window was explored in this special study.

CPUC staff provided the ISO with preliminary forecasts of hourly load, capacity and hourly output of behind-the-meter generating resources, and capacity and hourly output of renewable resources from 2017 through 2026. The forecast data showed that the ISO coincident peak sale shifted from hour ending 18 in 2025 to hour ending 19 in 2026. After some brainstorming discussion between the ISO and CPUC it was preliminarily decided as a starting point for the CPUC staff to calculate renewable output percentiles in the 3 hour window centered at the ISO coincident peak sale from May through September for 2017 ~ 2026 by region and by technology, and provide the result to the ISO. The ISO then used the highest 50 percentile from May through September as the exceedance production level for that year. In the numbers provided, there are three technologies for solar resources: PV Fixed (photovoltaic with fixed tilt), PV Single (photovoltaic with tracking) and solar thermal.

6.4.6 Results of Production Cost Simulations

Six scenarios with different assumptions about the ISO net export limitation were simulated for both in-state and out-of-state portfolios

1. In-state FCDS portfolio with maximum 2,000 MW net export from the ISO controlled grid
2. In-state FCDS portfolio with no net export limit from the ISO controlled grid
3. In-state EODS portfolio with maximum 2,000 MW net export from the ISO controlled grid
4. In-state EODS portfolio with no net export limit from the ISO controlled grid
5. Out-of-state (OOS) portfolio with maximum 2,000 MW net export from the ISO controlled grid
6. Out-of-state (OOS) portfolio with no net export limit from the ISO controlled grid

Curtailments of wind and solar generation within the ISO controlled grid and the transmission congestions were analyzed for the first four scenarios. For scenario 5 and 6, along with the renewable curtailment and transmission congestion within California, major transmission congestion outside of California was also captured. For the export assumption purposes, non-ISO BAAs within California were considered to be outside of the net export boundary.

Export modeling

Net export in the production cost models is defined as follows:

Net export = Sum of Line flow of all lines from the ISO to other BAAs + Sum of Generation output of out of state resources with dynamic schedule to the ISO

The net export limit sensitivities were tested by limiting this term to 2,000 MW and then by removing the limit on this term during the course of the simulation.

6.4.6.1 *Summary of renewable curtailment*

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. Figure 6.4-6 shows the total wind and solar curtailment in the six scenarios described above. The 2,000 MW export scenarios show a higher level of renewable curtailement compared to the corresponding scenarios with no limit on the net ISO exports. The percentage values on the plot are calculated as the curtailment of wind and solar divided by the total potential (dispatch + spillage) wind and solar energy within the ISO controlled grid.

Figure 6.4-6: Total wind and solar curtailment – all portfolios

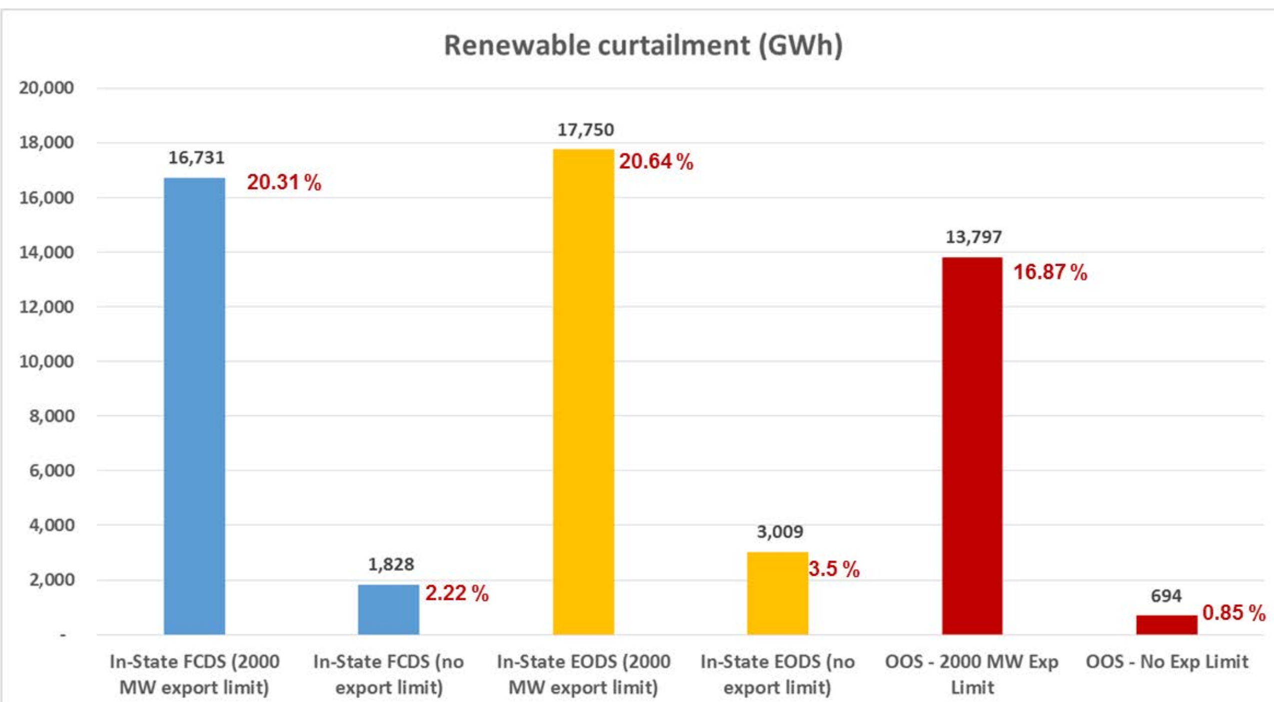
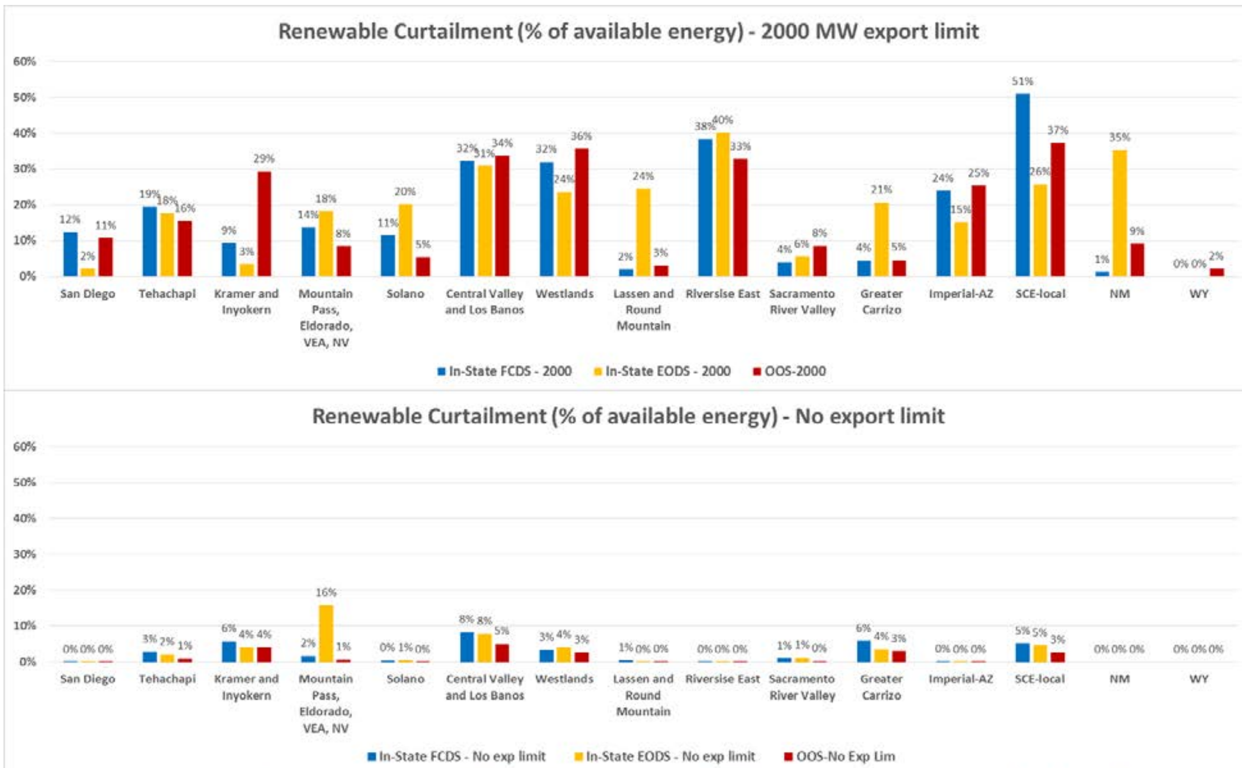


Figure 6.4-6 shows that the export limit assumptions have a significant impact on the extent of renewable curtailment.The large diference between curtailment observed with an export limit and without an export limit indicates that most of the renewable curtailment is related to over-supply

and a small component is related to transmission congestion, regardless of the portfolio being studied.

Figure 6.4-7 breaks down of the total renewable curtailment into specific zones and also presents a more granular impact of export limit assumptions on individual renewable zones. Again, the percentage values on the plot are calculated as the curtailment of wind and solar divided by the total potential (dispatch + spillage) wind and solar energy within the respective renewable zone.

Figure 6.4-7: Wind and solar curtailment by renewable zones (% of available energy)



It is evident that renewable curtailment across all the renewable zones is predominantly triggered by over-supply. Renewable curtailment observed in the renewable zones comprising of Mountain Pass, Eldorado, VEA and parts of Nevada areas in the "No export limit" scenario is due to a local issue on a radial line connecting resources to Eldorado 230 kV substation. This renewable curtailment could be potentially eliminated by mapping the resources to a different location in this zone. The renewable curtailment plot without any export limitation shows that the curtailment of resources within California is consistently lower in the out-of-state portfolio case than the in-state portfolio cases.

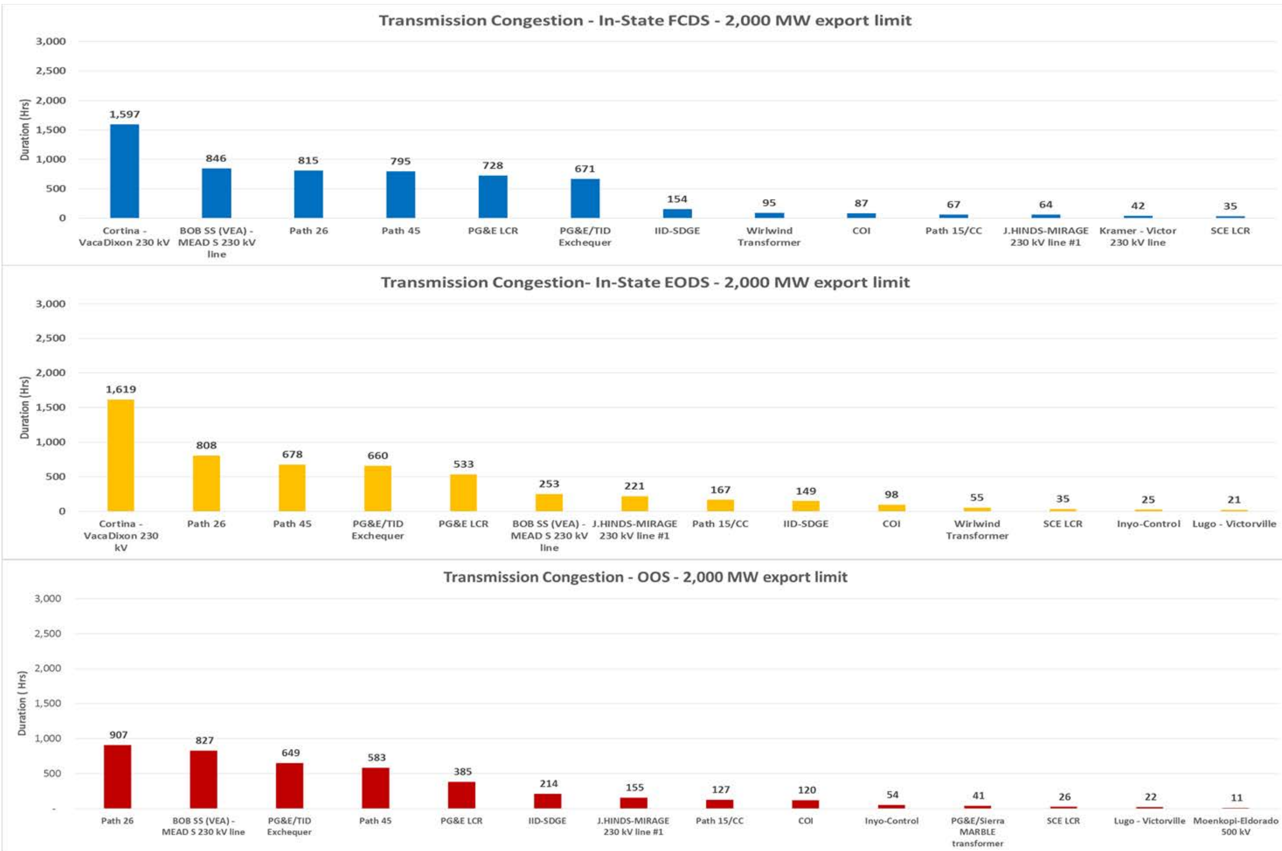
6.4.6.2 *Summary of transmission congestion*

In order to gain more insights into renewable curtailment that may have been caused due to transmission congestion, major transmission constraints that experienced a high number of hours of congestion were identified through production cost simulation studies.

Transmission congestion within California

Figure 6.4-8 shows a comparison of transmission congestion hours for the most severe constraints observed within California under a 2,000 MW net export limit for the ISO.

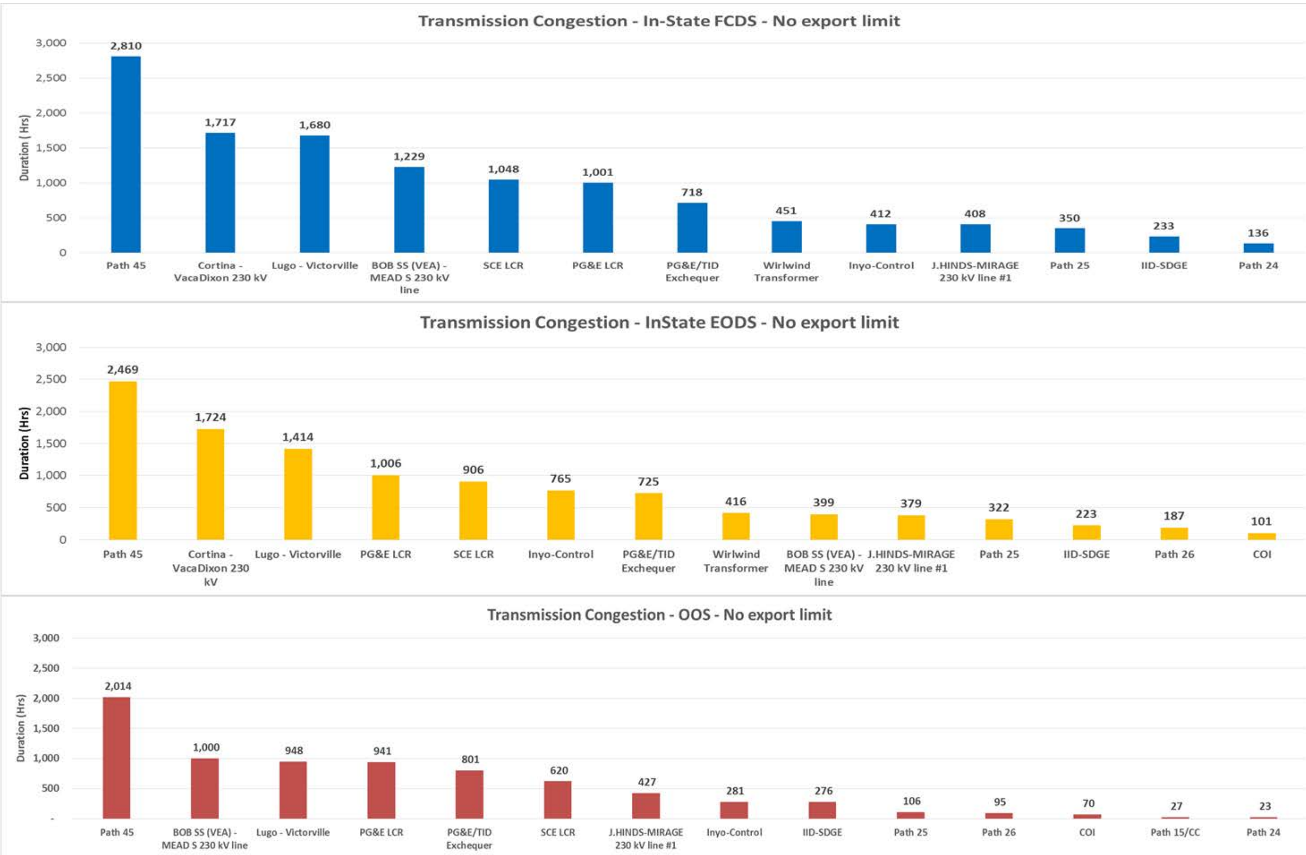
Figure 6.4-8: Congestion hours within California – 2,000 MW net export limit for the ISO



Out of these constraints, the ‘Cortina – VacaDixon 230 kV’, ‘Path 26’ and ‘BOB SS (VEA) – MEAD S 230 kV line’ constraints were also observed in the power flow snapshots that were studied as part of the reliability assessment of portfolios. The Out-of-state portfolio is the least severe in terms of transmission congestion within California. The In-state EODS portfolio shows an increase in transmission congestion when compared against the same constraints in the In-state FCDS portfolio. This increase in congestion can be explained by the fact that the resource selection in the EODS portfolio in some zones exceeded the transmission system capability estimates for connecting FCDS resources, thus increasing the chances of more severe transmission loading on facilities in those zones.

Figure 6.4-9 shows transmission congestion hours within California under a no net export limit assumption. While the overall renewable curtailment under a relaxed export scenario is much lower than the renewable curtailment under a restricted net export limit scenario, transmission congestion hours were increased under a relaxed export scenario. One plausible reason behind this result is that when the export limit is relaxed, some of the generation which was already curtailed under a restricted export scenario is now available for dispatch and it now runs into the next limitation which could be transmission constraints in certain zones. Under the no net export limit sensitivity, the out-of-state portfolio is the least severe in terms of transmission congestion within California. The In-state EODS portfolio shows an increase in transmission congestion on the same constraints when compared against the In-state FCDS portfolio.

Figure 6.4-9: Congestion hours within California – No net export limit for the ISO

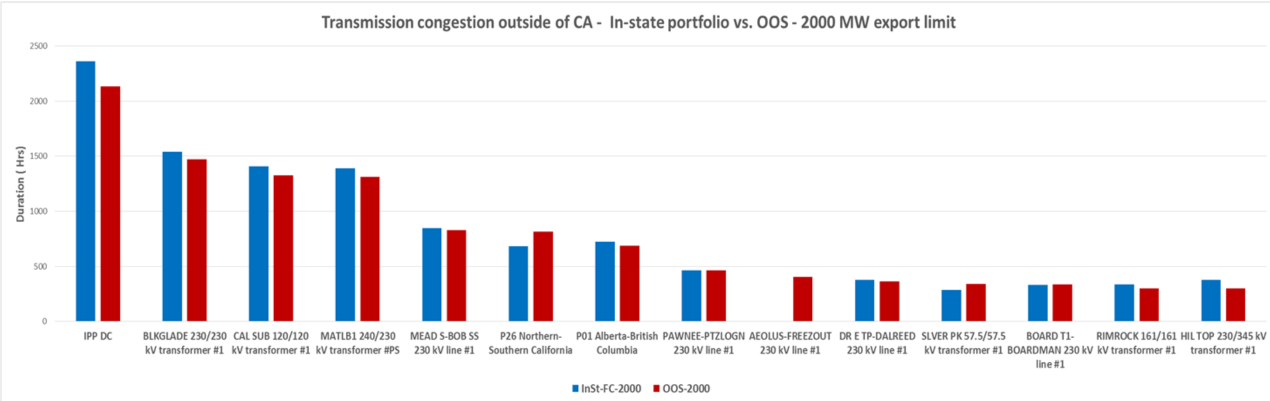


Transmission congestion outside of California

In addition to identifying transmission congestion within California, major transmission constraints outside of California were analyzed to get a sense of the impact of additional wind resources modeled in Wyoming and New Mexico as part of the out-of-state portfolio. Transmission congestion outside of California observed in the out-of-state portfolios was compared with the congestion outside of California observed in the in-state FCDS portfolio under 2,000 MW net ISO export limitation. This comparison gives a sense of what the incremental congestion outside of California would be if more than 4,000 MW of wind resources were added in Wyoming and New Mexico.

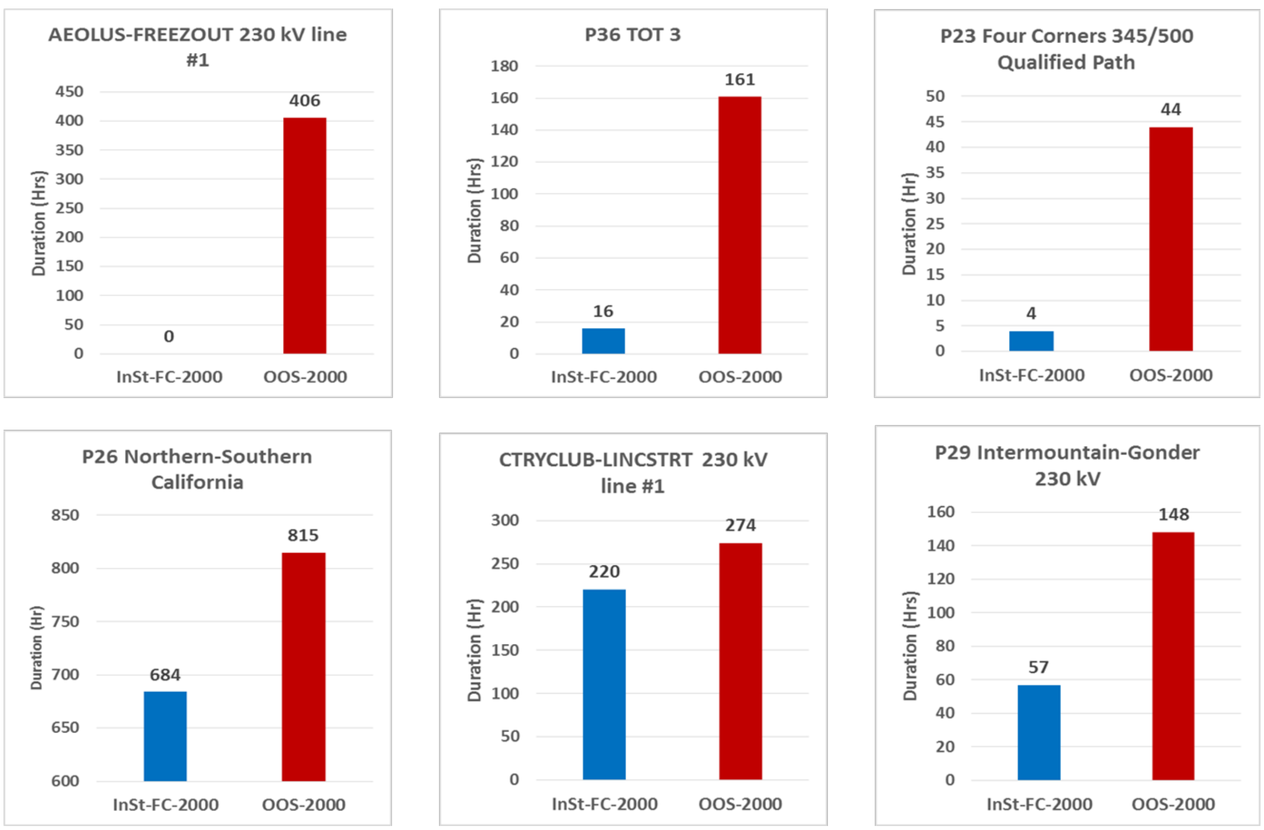
Figure 6.4-10 shows the comparison of the major constraints found to be congested in the production cost simulations. Barring a few constraints, no major changes were observed in the congestion duration outside of California when the In-state portfolio was compared to the out-of-state portfolio.

Figure 6.4-10: Congestion hours outside of California



While most of the significantly congested constraints do not show much change, certain constraints that demonstrated a significant percentage change in congestion duration between the In-state portfolio and the out-of-state portfolio were identified. Figure 6.4-11 summarized the constraints that experienced a noticeable jump in number of hours of congestion.

Figure 6.4-11: Constraints that experienced significant increase in congestion (In-State vs OOS portfolio)



6.4.7 Reliability Assessment of Portfolios

6.4.7.1 *Power flow modeling and reactive power capability*

50 percent renewable portfolios provided by the CPUC have assigned renewable resources geographically by technology to renewable zones. 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.

6.4.7.2 *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 settings for the under- and over-voltage and frequency relays for the new units were assumed according to the NERC standard PRC-024-2.

The dynamic data set used for transient stability simulations also included 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.

For the battery storage projects, dynamic stability models included models for the generator/converter (regc_a), inverter electrical control models applicable to battery storage plants (reec_c) and centralized plant control model (repc_a) for the large projects. Protection models for the battery storage were the same as for the wind and solar plants.

Load in the whole WECC system, including the ISO was modeled with composite load model for the selected conditions (Off-peak).

6.4.7.3 *Power flow and stability snapshots 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. Since the study timeline did not allow for the latest production cost simulation models released by TEPPC, the stressed patterns were identified based on the production cost simulations performed during 2015-2016 TPP. The following critical factors were considered in selecting the stressed patterns:

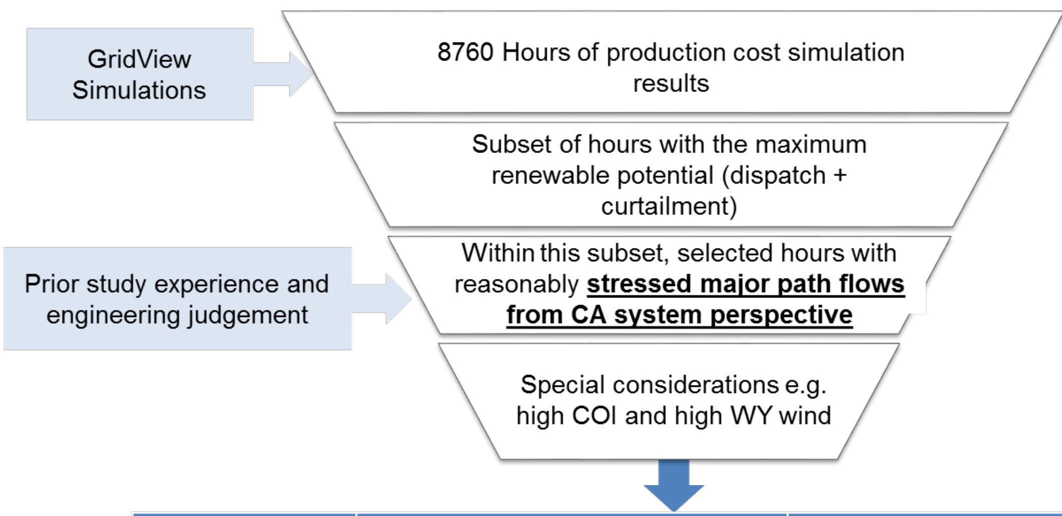
- renewable generation potential system-wide and within renewable study areas

- power flow on the major transfer paths in California and especially in the study area

For example, hours that were selected for reference purposes in Southern CA 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.

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 6.4-12 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 6.4-12: Snapshot selection for reliability assessment of portfolios



Scenario	Northern CA	Southern CA
In-state FCDS	None (focus was on deliverability assessment)	March 18 – Hr 13
In-state EODS	March 19 – Hr 19	March 18 – Hr 13
Out-of-state FCDS/EODS	June 15 – Hr 05 (High COI and high WY wind)	November 29 – Hr 12

6.4.7.4 *Summary of Northern CA reliability assessment*

For the Northern CA reliability assessment, primary focus was on the In-State EODS portfolio because this portfolio contains significant amount of wind resources (>3,000 MW) selected in the Northern CA region. Due to this large amount of wind resources, the stressed snapshot for Northern CA case was an hour 19 snapshot. Any reliability issues associated with solar resources selected in the In-state FCDS portfolio are expected to be captured in the deliverability assessment since deliverability assessment is performed for the peak hour. For the out-of-state portfolio, a snapshot hour with high Wyoming wind and high COI flows was identified. As shown in Figure 6.4-12, Hour 05 snapshot was selected for the out-of-state portfolio assessment.

Table 6.4-8 presents a summary of resource nameplate amounts selected in Northern CA zones. These values were modeled in the respective base cases for the purpose of reliability assessment.

Table 6.4-8: Summary of portfolio resources in Northern CA[116]

Renewable Zones	In-state FCDS (MW)	In-state EODS (MW)	Out-of-state (MW)
Central Valley North and Los Banos	130	126	126
Greater Carrizo	143	197	143
Lassen and Round Mountain	0	1,250	0
Sacramento River Valley	1,536	2,099	36
Solano	1,500	348	41
Westlands	2,015	1,228	839

Key findings from the Northern CA reliability assessment are as follows:

- No area-wide issues were noticed for the selected snapshots
- Some local overloads were observed in Central Valley area which can be reasonably assumed to be addressed through GIDAP (Generation Interconnection and Deliverability Allocation Procedures)
- Overloads observed during the 50 percent RPS special study performed as part of 2015-2016 TPP were eliminated due to refinement of location selection for resources as recommended during 2015-2016 TPP
- Transient stability simulation studies indicated a potential need for dynamic reactive power absorption capability due to high voltages in certain local areas; these were not area-wide issues

[116] This table does not include some resources that do not exactly map to the zones considered for estimating transmission capability. So the numbers will not add up to match the exact portfolio amount.

- Out-of-state portfolio was less severe than the In-state portfolio with regards to transmission issues within California

Potential mitigations for the issues noticed during this snapshot assessment may include – (i) local upgrades triggered through GIDAP, (ii) pre-contingency generation dispatch and/or remedial action schemes (RAS). No area wide-transmission issue that would limit significant amount of generation from interconnecting to the ISO controlled grid was identified as part of the reliability assessment.

6.4.7.5 *Summary of Southern CA reliability assessment*

As shown in Figure 6.4-12, three reliability snapshots were studied for evaluating the impact on the Southern CA system. All three snapshots are daytime hours as a result of predominantly solar resources being selected in renewable zones in Southern CA in all portfolios.

Table 6.4-9 presents a summary of resource nameplate amounts selected in Southern CA zones. These values were modeled in the respective base cases for the purpose of reliability assessment.

Table 6.4-9: Summary of portfolio resources in Southern CA[117]

Renewable Zones	In-state FCDS (MW)	In-state EODS (MW)	Out-of-state (MW)
El Dorado and Mountain Pass	916	3,177	916
Greater Imperial	649	379	454
Kramer & Inyokern	624	211	0
Riverside East & Palm Springs	2,395	779	1,094
Tehachapi	3,625	3,791	2,625

Reliability issues were observed in Tehachapi, Mountain Pass, Eldorado and VEA zones.

Tehachapi zone reliability issues

The transmission capability estimate and the resources selected in in-state and out-of-state portfolios in this zone are listed in Table 6.4-10.

Table 6.4-10: Transmission capability estimates and portfolio MW – Tehachapi zone

Zone	In-state FCDS (MW)	In-state EODS (MW)	Out-of-state (MW)	Transmission capability estimates (MW)
Tehachapi	3,625	3,791	2,625	2,628 (FCDS) 3,794 (EODS)

[117] This table does not include some resources that do not exactly map to the zones considered for estimating transmission capability. So the numbers will not add up to match the exact portfolio amount.

Table 6.4-11 shows major overloads observed in Tehachapi zone. The percentage overloads shown in the table are the most severe overloads observed amongst all the portfolios. The most severe overloads were observed in the In-state EODS portfolio.

Table 6.4-11: Reliability issues observed in Tehachapi zone

Scenario	Limiting Element	Contingency	Type	Overload (%)
In-State-EODS, In-State-FCDS, OOS	MIDWAY- WIRLWIND 500kV (Path 26)	Base Case	N-0	119%
In-State-EODS, In-State-FCDS	ANTELOPE-VINCENT 500kV 1	ANTELOPE- VINCENT 500kV 2 & MIDWAY - WIRLWIND 500kV	N-1-1	100.87%
In-State-EODS, In-State-FCDS	ANTELOPE-VINCENT 500kV 2	ANTELOPE- VINCENT 500kV 1 & MIDWAY - WIRLWIND 500kV	N-1-1	100.91%
In-State-EODS, In-State-FCDS	ANTELOPE-WIRLWIND 500kV	MIDWAY - WIRLWIND 500kV & WIRLWIND - VINCENT 500kV	N-1-1	122.40%
In-State-EODS, In-State-FCDS	ANTELOPE-WIRLWIND 500kV	VINCENT - WIRLWIND 500kV & ANTELOPE - WINDHUB 500kV	N-1-1	130.75%
In-State-EODS, In-State-FCDS	ANTELOPE-WIRLWIND 500kV	ANTELOPE - WINDHUB 500kV & MIDWAY - WIRLWIND 500kV	N-1-1	131.00%
In-State-EODS, OOS	MAGUNDEN-ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & ANTELOPE - PARDEE 230kV 1	N-1-1	123.50%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & BAILEY - PARDEE 230kV 1	N-1-1	106.10%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & BAILEY - PASTORIA 230kV 1	N-1-1	107.20%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & PARDEE-PASTORIA-WARNETAP 230kV	N-1-1	107.50%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	PARDEE - VINCENT 230kV & MAGUNDEN - ANTELOPE 230kV 2	N-1-1	103.50%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	MIDWAY - WIRLWIND 500kV & MAGUNDEN - ANTELOPE 230kV 3	N-1-1	101.20%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	WIRLWIND - VINCENT 500kV & MAGUNDEN - ANTELOPE 230kV 4	N-1-1	100.50%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	ANTELOPE - VINCENT 500kV 1 & MAGUNDEN - ANTELOPE 230kV 5	N-1-1	101.60%
In-State-EODS	MAGUNDEN-ANTELOPE 230kV 1	ANTELOPE - VINCENT 500kV 2 & MAGUNDEN - ANTELOPE 230kV 5	N-1-1	101.70%

A summary of reliability issues in Tehachapi area is as follows –

- Midway – Whirlwind 500 kV overload was observed due to very high South to North flows on Path 26. This overload indicates a need to review the series compensation balance during heavy South to North flows on Path 26. Without any other mitigation, more than 1,000 MW generation may be curtailed due to this overload.
- Antelope – Vincent/Whirlwind 500 kV overloads observed under N-1-1 contingencies may require up to ~1,300 MW of curtailment after the first N-1 contingency. 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. This indicates that under long-term outage conditions (planned or unplanned) there is a risk of significant amount of curtailment in this area.
- Magunden – Antelope 220 kV overloads under N-1-1 contingency conditions could result in up to 2,500 MW curtailment after the N-1 contingency if Big Creek generation is unavailable. If Big Creek generation is available, the curtailment would still be of the order of 1,000 MW. This indicates that under long-term outage conditions (planned or unplanned) there is a risk of significant amount of curtailment in this area.

Mountain Pass, Eldorado and VEA zone reliability issues

The transmission capability estimate and the resources selected in the in-state and out-of-state portfolios in this zone are listed in Table 6.4-12 .

Table 6.4-12: Transmission capability estimates and portfolio MW – Mountain Pass, Eldorado and VEA zone

Zone	In-state FCDS (MW)	In-state EODS (MW)	Out-of-state (MW)	Transmission capability estimates (MW)
Mountain Pass, Eldorado and VEA	916	3,177	916	535 (FCDS) 2,375 (EODS)

Table 6.4-13 shows major overloads observed in this renewable zone. The most severe overloads were observed in the In-state EODS portfolio. The percentage overload shown in the table is the most severe overloads observed amongst all the portfolios which is the In-state EODS portfolio.

Table 6.4-13: Reliability issues observed in Mountain Pass, Eldorado and VEA zone

Scenario	Limiting Element	Contingency	Type	Overload (%)
In-State & OOS	Mead - Bob SS 230kV Line	Eldorado 500/230kV Bank 5	T-1	344%

Mead – Bob 230 kV line overloading is very severe since the contingency was tested without a pre-existing RAS that drops generation in Eldorado area. With the portfolio generation, the RAS won't be adequate since the required generation drop would exceed the maximum allowable generation tripping (1,150 MW) criteria for N-1 contingencies specified in the ISO planning standards. The most severe overload occurred in the In-state EODS portfolio and it indicates that generation development in this zone beyond a certain level could be susceptible to more than 1,000 MW of pre-contingency curtailment. In addition to this internal generation dispatch, a reduction in import into Eldorado area may also be required which in turn can result in some renewable curtailment in zones outside of California.

6.4.7.6 *Transient stabilty assessment*

The study methodology for transient stability assessment and the dynamic models for the new renewable resources are described in section 6.4.7.2. 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 identified tripping of some renewable generators following three-phase faults close to these generators' points of interconnection. 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 has been and will continue to 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. Some existing or future wind and solar PV power plants were modeled in the Dynamic Master File with old models that were no longer supported by WECC. Several units were tripped with faults for high or low voltage or high frequency. Most likely, this was an issue of incorrect models rather than unacceptable transient stability performance. These models need to be discussed with the generator owners and the models need to be updated.

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 due to high and low voltages, potentially caused by overly simplistic modeling.

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.

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 major dynamic stability issues related to the large amount of renewable resources under the snapshots that were selected for studies, but they identified some 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:

- High voltages in the base cases
- 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. These level of details would typically be available in future as more generation shows up in the interconnection queue. 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.

Addition of fictitious synchronous condensers at certain nearby buses resolved the issue of tripping due to high voltages. This indicates a potential need for a higher level of dynamic reactive power absorption capability.

6.4.7.7 *Out-of-state (OOS) portfolio reliability assessment*

The reliability snapshots for assessing the impacts of out-of-state portfolio on transmission system were identified based on the methodology described in section 6.4.7.3. Figure 6.4-12 shows the two snapshots selected for modeling in the power flow cases – (i) June 15, Hour 05 (high COI and high Wyoming wind sensitivity case for Norhtern CA) and (ii) November 25, Hour 12 (Southern CA case).

Due to the timing limitations and unavailability of updated TEPPC models, the two snapshots were based on the production cost simulations run during 2015-2016 TPP and the path flows were selected based on stressed conditions from the California transmission system perspective. The latest production cost simulations were being run in parallel to this effort; hence could not be used for the purpose of snapshot identification during the 2016-2017 TPP cycle.

The out-of-state reliability assessment can be divided into two parts – (i) evaluation of CA transmission and (ii) evaluation of transmission outside of CA.

Evaluation of CA transmission system for the OOS portfolio

The OOS portfolio compared to the In-state portfolios contains a much smaller amount of resources within California. This results in less severe loadings on the transmission system within California. Consequently, the reliability snapshots tested for the implication on the CA transmission demonstrated very few issues. These issues are summarized in Table 6.4-14.

Table 6.4-14: Major overloads observed as part of OOS portfolios assessment of CA transmission

Scenario	Limiting Element	Contingency	Type
In-State & **OOS**	Mead - Bob SS 230kV Line	Eldorado 500/230kV Bank 5	T-1
In-State-EODS, In-State-FCDS, **OOS**	MIDWAY-WIRLWIND 500kV (Path 26)	Base Case	N-0
In-State-EODS, **OOS**	MAGUNDEN - ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & ANTELOPE - PARDEE 230kV 1	N-1-1

All of the aforementioned overloads were observed in the In-state portfolio results. The loading on these facilities was much lower in the OOS portfolio assessment. So the key findings discussed in section 6.4.7.5 with regards to these overloads also apply to the OOS portfolio results.

There were no issues identified in Northern CA system for the OOS portfolio. Given that the resources selected in Northern CA in the OOS portfolio were much smaller compared to other portfolios, this was not an unexpected outcome.

Evaluation of the transmission system outside of CA for the OOS portfolio

As part of the inter-regional coordination with the Western Planning Regions, Northern Tier Transmission Group (NTTG) provided a list of contingencies to be tested for the system outside of California to primarily test the impact of additional wind resources modeled in Wyoming. The snapshots described above were tested against these contingencies. Due to lack of additional information about the rest of the system outside of California, the ISO tested some contingencies by relying on observations from other related studies and engineering judgment. Key findings from this effort are as follows:

- Some 230 KV transmission lines in Southern Wyoming were observed to be overloaded. These facilities were in the electrical vicinity of the portfolios resources modeled in Wyoming.
- As described above, the snapshots studied for the OOS portfolios were based on production cost simulations which were run during 2015-2016 TPP and path flow modeling was focused on California’s transmission system. As a result the ISO was unable to identify the most stressed snapshots for paths outside of CA using this data.
- Production cost simulation results obtained as part of 2016-2017 TPP will help refine the snapshot identification for evaluating the impact on transmission system outside of California.

The ISO will continue to work with the western planning regions and stakeholders in order to identify the additional scenarios and assumptions to be taken into account so that the most stressed conditions for the system outside of California can be identified for the purpose of evaluation of out of state transmission needs, including consideration of the Inter-regional Transmission Projects (ITPs) submitted.

6.4.8 Results of 50 Percent RPS Portfolio Deliverability Assessment

An exploratory deliverability assessment of the 50% RPS portfolios was performed by the ISO during the 2016-2017 TPP cycle. The investigation was divided into two parts:

(i) identifying the impact of potential peak-shift on the underlying assumptions of exceedance values for deliverability assessment and

(ii) identifying deliverability constraints in Northern CA and Southern CA systems under the deliverability assumptions discussed in section 6.4.5.3

6.4.8.1 *Impact of potential peak-shift on exceedance value assumptions*

As explained in section 6.4.5.3, analysis of the data provided by CPUC staff indicated that the ISO coincident peak sale would shift from hour ending 18 in 2025 to hour ending 19 in 2026. The CPUC staff provided renewable output percentiles in the 3 hour window centered at the ISO coincident peak sale hour from May through September for 2017 ~ 2026 by region and by technology. The highest 50th percentile from May through September was used as the 50 percent exceedance level for the study year to test deliverability of resources. The 50 percent exceedance levels derived from the analysis are shown in Figure 6.4-13, Figure 6.4-14, Figure 6.4-15 and Figure 6.4-16.

Figure 6.4-13: 50% Exceedance Levels for PV Fixed (photovoltaics with fixed tilt)

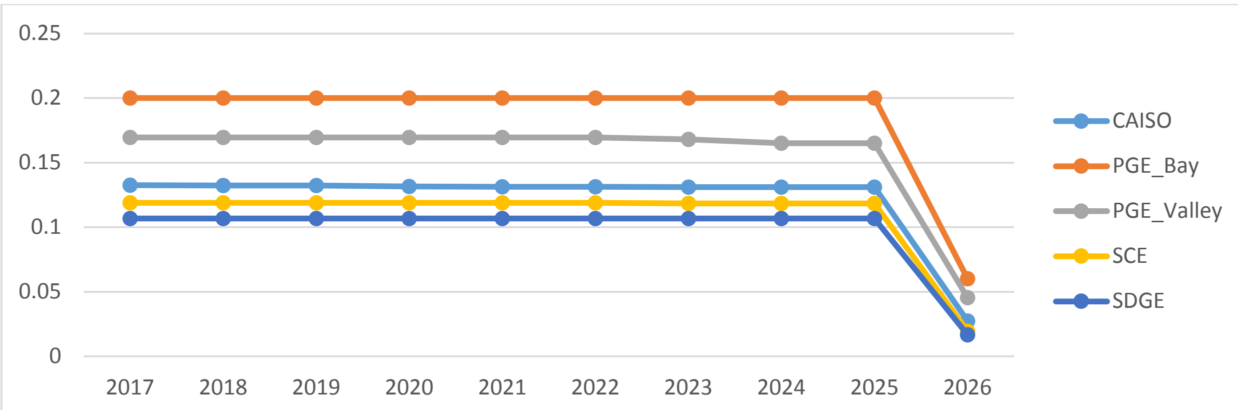


Figure 6.4-14: 50% Exceedance Levels for PV Single (photovoltaics with tracking

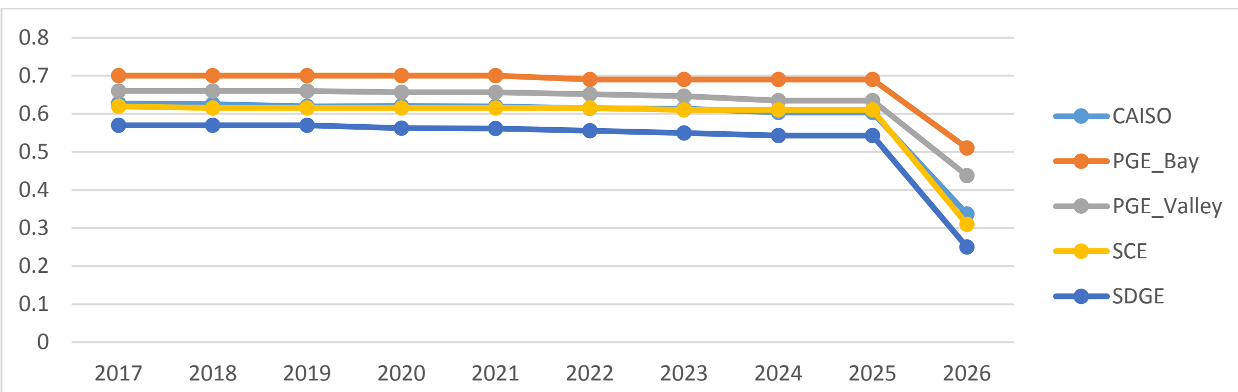


Figure 6.4-15: 50% Exceedance Levels for Solar Thermal

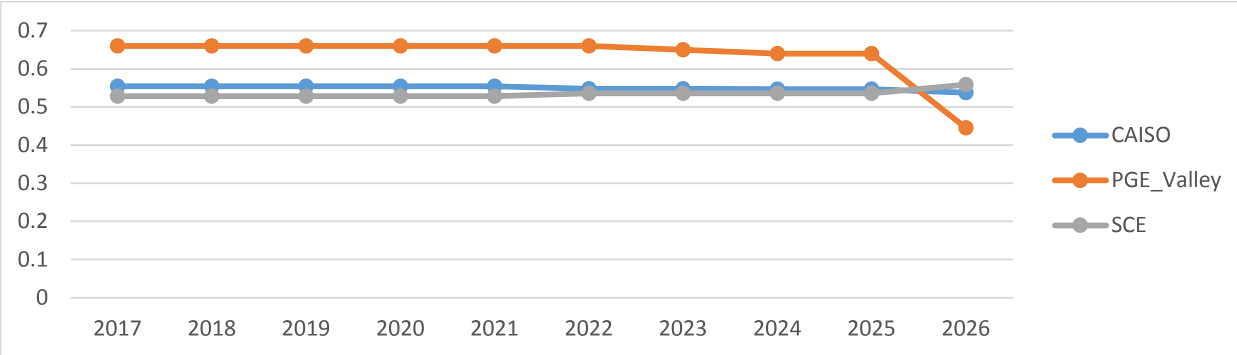
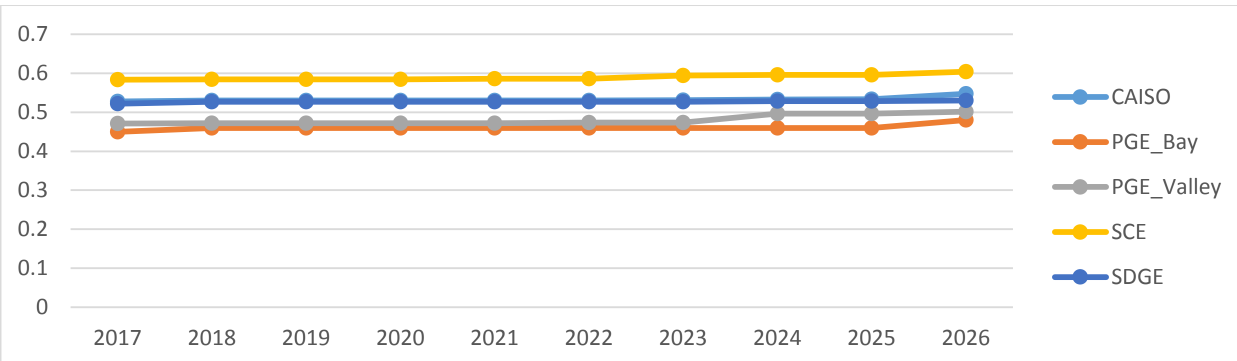


Figure 6.4-16: 50% Exceedance Levels for Wind



The exceedance levels dropped significantly for PV Fixed and PV Single from 2025 to 2026 due to the peak sale time shift. Table 6.4-15 shows based on the preliminary data and methodology, directionally the 2025 and 2026 exceedance factors reduce for solar and increase for wind compared to what are currently being used in deliverability studies.

Table 6.4-15: Wind and Solar 50% Exceedance Levels

Area	Technology	Current	2025	2026
PG&E	Wind	32% / 37% / 47%	46% / 50%	48% / 50%
	PV Single	92%	63% / 69%	44% / 51%
SCE	Wind	38% / 47%	60%	60%
	PV Single	92% / 93%	61%	31%
SDG&E	Wind	37%	53%	53%
	PV Single	87%	54%	25%

By examining the installed capacity and preliminary exceedance levels, it can be observed that the highest deliverability need (installed capacity multiplied by the 50% exceedance level) may be expected in 2025 for southern California and 2026 for northern California. The overall ISO need was higher in 2025 than 2026. Two generation scenarios were studied. The main study was performed for 50% RPS portfolio with the preliminary 2026 exceedance factors. A sensitivity study was performed for the southern California with 41.5% RPS portfolio and preliminary 2025 exceedance factors.

6.4.8.2 *Northern CA deliverability assessment*

Portfolio resources in Northern CA in the In-state FCDS portfolio contain a mix of solar and wind resources. Table 6.4-16 shows the MW amounts in the zones that impact deliverability in Northern CA region.

Table 6.4-16: Major renewable zones that impact deliverability in Northern CA

Renewable Zone	In-State FCDS Portfolio MW
Sacramento River valley	1,536
Solano	1,500
Westlands	2,015
Los Banos	130
Carizzo	143

The focus of the 50% RPS portfolio deliverability assessment was on identifying constraints that could affect large amounts of generation across one or more renewable zones. For the zones potentially impacted by deliverability issues in Northern CA, the Sacramento River Valley and Solano zones did encounter deliverability limitations. Assessment of other zones resulted in minor overloads on the lower voltage system (<230 kV) which can be assumed to be addressed through the Generation Interconnection and Deliverability Allocation Procedures (GIDAP) as more generation enters the interconnection queue in these zones.

Deliverability results for Sacramento River Valley

Using the preliminary exceedance value assumptions presented in section 6.4.8.1, the deliverability assessment in Sacramento River Valley resulted in one deliverability constraint comprising of two overloaded facilities as shown in Table 6.4-17.

Table 6.4-17: Deliverability constraints in Sacramento River Valley zone

Contingency	Overloaded Facility	Flow & Undeliverable MW	Affected renewable zones
Delevan-Vaca Dixon No.2 and No.3 230 kV Lines	Cortina - Vaca 230 kV Line	102% ~1,000 MW	Sacramento River Valley
Cortina 230/115 kV transformer #4	Cortina 230/115/60 kV Transformer No. 1	149% ~500 MW	Sacramento River Valley

The worst constraint would result in ~1000 MW resources being undeliverable from this zone under the preliminary exceedance value assumptions used in this study.

Deliverability results for Solano zone

Using the preliminary exceedance value assumptions presented in section 6.4.8.1, the deliverability assessment in Sacramento River Valley resulted in one deliverability constraint comprising of two overloaded facilities as shown in Table 6.4-18.

Table 6.4-18: Deliverability constraints in Solano zone

Contingency	Overloaded Facility	Flow & Undeliverable MW	Affected renewable zones
Contra Costa – Moraga #1 and #3 230 kV lines	Las Positas – Newark 230 kV line	105% ~300 MW	Sacramento River Valley

The deliverability constraint would result in ~300 MW resources being undeliverable from this zone under the preliminary exceedance value assumptions used in this study.

6.4.8.3 *Southern CA deliverability assessment*

Portfolio resources selected in Southern CA in the In-state FCDS portfolio were predominantly solar. Table 6.4-19 shows MW amounts in the zones that could be impacted by potential deliverability issues in the Southern CA region.

Table 6.4-19: Major renewable zones that impact deliverability in Southern CA

Renewable Zone	In-State FCDS Portfolio MW
Tehachapi	3,635
Riverside East	1,774
Palm Springs	621
Mountain Pass and Eldorado	475
NV_SW	166
Kramer	441
Victorville	183
Iron Mountain	276
Imperial South	406
Imperial North	244
San Diego South	275
AZ_WE	219
NM_EA	272

As explained in section 6.4.8.1, two generation scenarios were studied in Southern CA – (i) a 50% RPS scenario with the preliminary 2026 exceedance factors and (ii) a 41.5% RPS scenario with the preliminary 2025 exceedance factors. The focus of 50% RPS portfolio deliverability assessment was on identifying constraints that could affect large amounts of generation across one or more renewable zones.

Deliverability results for SCE and VEA areas

Using the preliminary exceedance value assumptions presented in section 6.4.8.1, the deliverability assessment in SCE and VEA areas resulted in two area-wide deliverability constraints. Table 6.4-20 shows the deliverability constraints observed in SCE and VEA areas.

Table 6.4-20: Deliverability constraints in SCE and VEA areas

Contingency	Overloaded Facility	Flow & Undeliverable MW		Affected renewable zones
		50% renewable with 2026 Factor	41.5% renewable with 2025 Factor	
McCullough - Victorville 500kV No. 1 & No. 2	Adelanto - Market Place 500KV	100.85% ~400 MW	101.96% ~850 MW	Arizona, Greater Imperial, Riverside East, Palm Springs Mountain Pass and Eldorado, Nevada
Coachella - Mirage 230kV & Ramon - Mirage 230kV with RAS	Imperial Valley-El Centro 230 kV line	100.77%	<100%	Riverside East (Blythe 161kV), greater Imperial

Note that the Imperial Valley – El Centro 230 kV constraint will limit resources in SCE as well as greater Imperial zone. In case of the Adelanto – Marketplace 500 kV constraint, out of the total portfolio resources in these zone, ~850 MW resources spread across multiple zones were found to be undeliverable under the preliminary exceedance value assumptions used in this study.

Deliverability results for SDG&E area

Using the preliminary exceedance value assumptions presented in section 6.4.8.1, the deliverability assessment in SDG&E area resulted in two area wide deliverability constraints. Table 6.4-21 shows these constraints in SDG&E area.

Table 6.4-21: Deliverability constraints in SDG&E area

Contingency	Overloaded Facility	Flow & Undeliverable MW		Affected renewable zones
		50% renewable with 2026 Factor	41.5% renewable with 2025 Factor	
Imperial Valley-North Gila 500 kV line	Imperial Valley-El Centro 230 kV line	106% ~150 MW	100%	Imperial - IID
Miguel 500/230 kV #1	Miguel 500/230 kV #2	-	103% (mitigation is SPS and/or 30min rating)	Arizona, Baja, greater Imperial
Miguel 500/230 kV #2	Miguel 500/230 kV #1	-	105%(mitigation is SPS and/or 30min rating)	Arizona, Baja, greater Imperial

In case of the Imperial Valley – El Centro 230 kV constraint, out of the total portfolio resources in Imperial zone, ~150 MW resources were found to be undeliverable under the preliminary exceedance value assumptions used in this study. The Miguel bank constraint was observed only in the 41.5% RPS scenario with 2025 exceedance value assumptions, but was relieved in the 50% RPS scenario with the preliminary 2026 exceedance value assumptions.

6.4.8.4 *Deliverability of out-of-state resources from CAISO injection point to CAISO loads*

Deliverability of the out-of-state resources was preliminarily evaluated from the perspective of the transmission system within California. In order to evaluate the capability of CA transmission system to deliver out-of-state resources from the scheduling point into CAISO BAA to CAISO loads, MIC (Maximum Import Capability) expansion need was evaluated. The scheduling points specified in Table 6.4-22 were used to evaluate the import of wind resources from Wyoming and New Mexico respectively. This table shows that adequate import capacity exists for importing these resources via the selected scheduling points. For Wyoming wind resources it was determined that ~886 MW of MIC would be needed and 1,821 MW is available. Similarly for New Mexico wind, it was determined that ~815 MW of MIC would be needed and 925 MW is available. In-state resources connecting in the vicinity of scheduling points would not increase the needed

MIC since while preliminarily testing the deliverability of the In-state FCDS portfolio the MIC was already modeled and held constant.

Table 6.4-22: Out-of-state import deliverability evaluation

	New Mexico Wind	Wyoming Wind
50% exceedance factor	40.27%	40.76%
Wind Capacity	2200	2000
MIC Need	885.94	815.20
Scheduling Point	PVWEST	ELDORADO500 & MEAD230 & WILLOWBEACH
Remaining Import Capacity after ETC and Pre-RA in 2026	1821	925
MIC Expansion	0	0
Current MIC	3254	1753
Total Target MIC	3254	1753

The transmission system outside of California was not evaluated for deliverability or availability of firm transmission service for out-of-state resources. The available MIC import capacity and the deliverability constraints identified for the In-state FCDS portfolio indicate that there are no major deliverability issues between assumed CAISO scheduling points and CAISO loads for the resources selected outside of California in the out-of-state portfolio.

6.4.9 Conclusions and Next Steps

6.4.9.1 *Summary of key findings*

The 50 percent RPS portfolios provided by the CPUC staff were tested for renewable curtailment, transmission congestion, reliability issues with interconnecting the portfolio resource and deliverability constraints for the FCDS portfolio resources.

Production cost simulation summary –

- The net export limit assumption had a significant impact on the amount of total renewable curtailment. The drastic reduction in renewable curtailment once the export limitation is relaxed, indicates that a very small fraction of the total renewable curtailment is related to transmission congestion.

- The in-state EODS portfolio experienced the maximum renewable curtailment amongst all the portfolios. Since the In-state EODS portfolio had exceeded the FCDS transmission capability estimates in several areas, additional renewable curtailment was expected for this portfolio.

- The out-of-state portfolio showed the least amount of curtailment (total GWh curtailment and percentage of renewable potential) amongst all portfolios. This portfolio resulted in slight increase in congestion outside of California. Some constraints presented in section 6.4.6.2 Figure 6.4-11 experienced a drastic increase in congestion duration.

Reliability assessment summary –

- The in-state EODS portfolio was the most severe portfolio showing reliability issues affecting resources in Tehachapi, Mountain Pass, Eldorado, VEA and Southwest Nevada. Resources in these zones may expect significant renewable curtailment (>1,000 MW) under contingency conditions or pre-contingency conditions.

- The in-state FCDS portfolio experience fewer reliability issues compared to the In-state EODS portfolio because portfolio resource amounts in most of the zones were less than the FCDS transmission capability amounts provided to the CPUC as part of 2015-2016 TPP.

- The out-of-state portfolio was the least severe portfolio for transmission system within California. For evaluating the impact on transmission system outside of California, the ISO needs to consider additional snapshots that take into account sensitivities of resource assumptions outside of California and how these impact the transmission system outside of the state.

Deliverability assessment summary –

- The exploratory deliverability assessment of In-state FCDS portfolio identified deliverability constraints on Cortina – Vaca 230 kV line, Cortina 230/115 kV bank and Las Positoas – Newark 230 kV line. These constraints would limit the deliverability out of Sacramento River Valley and Solano zones.

- In Southern California, several zones were identified to be adversely affected by constraints on Adelanto – Market place 500 kV line, Imperial Valley – El Centro 230 kV line and Miguel 500/230 kV transformer banks. The impacted zones include Arizona, greater Imperial, Riverside East, Palm Springs, Mountain Pass, Eldorado, VEA and Southwest Nevada.

- The deliverability of out-of-state portfolio resources into California BAA was evaluated only at the expected scheduling points. Expected available MIC (Maximum Import Capability) at these scheduling points was evaluated to ensure that resources from outside of California can be delivered from these scheduling points. The transmission system between the out-of-state resource locations and the assumed scheduling points into CAISO BA was not evaluated for availability of firm transmission service. With the assumption that all the wind resources from Wyoming will be scheduled into California through Eldorado area and all the New Mexico wind resources will be scheduled into California using Palo Verde corridor, the expected available MIC was found to be adequate. No major deliverability issues were identified between the CAISO injection points and CAISO loads for the resources selected outside of California in the out-of-state portfolio.

Figure 6.4-17 summarizes the key takeaways of different assessments by each zone in the Northern CA system.

Figure 6.4-17: Summary of 50 Percent RPS portfolio evaluation for Northern CA zones

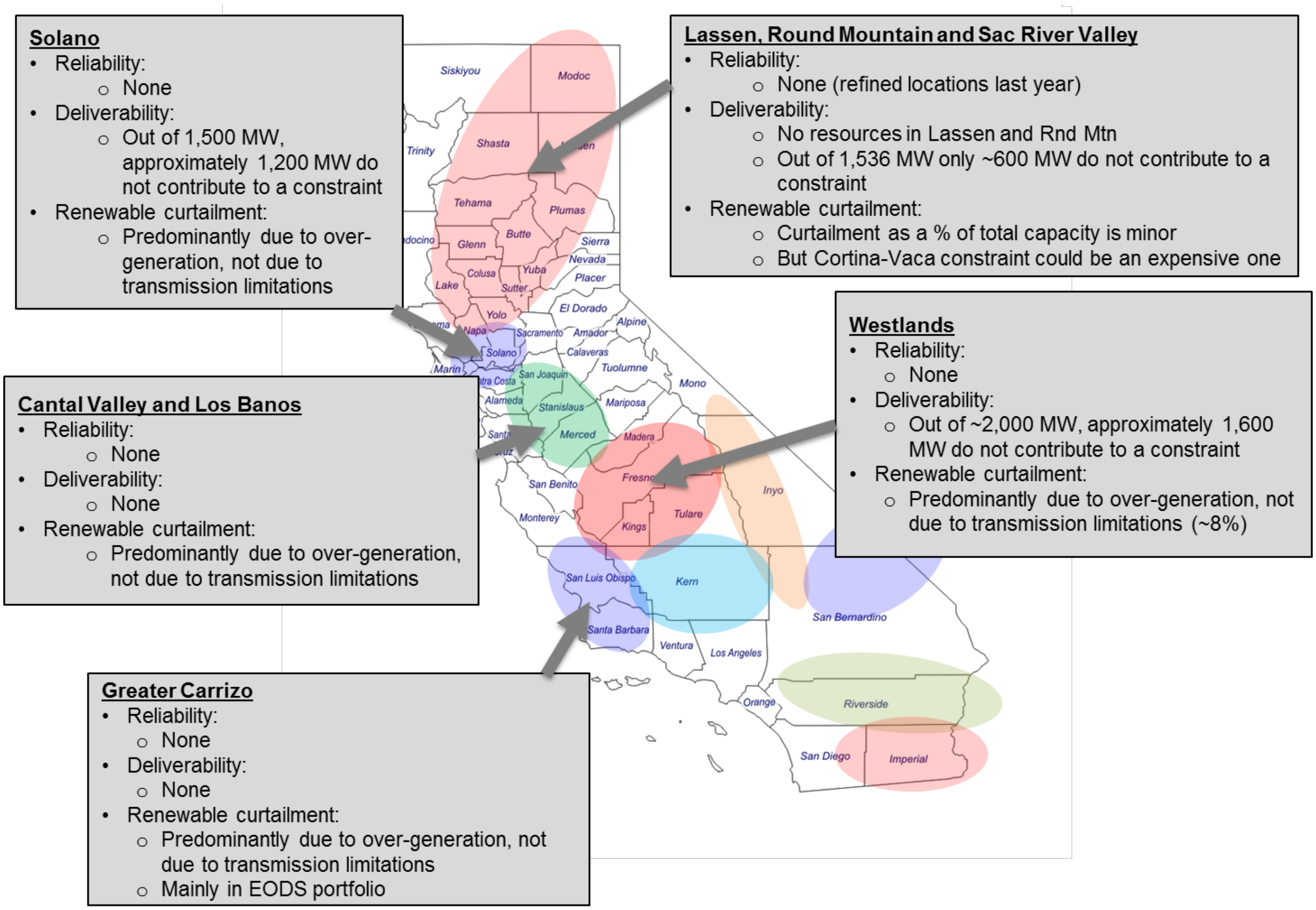
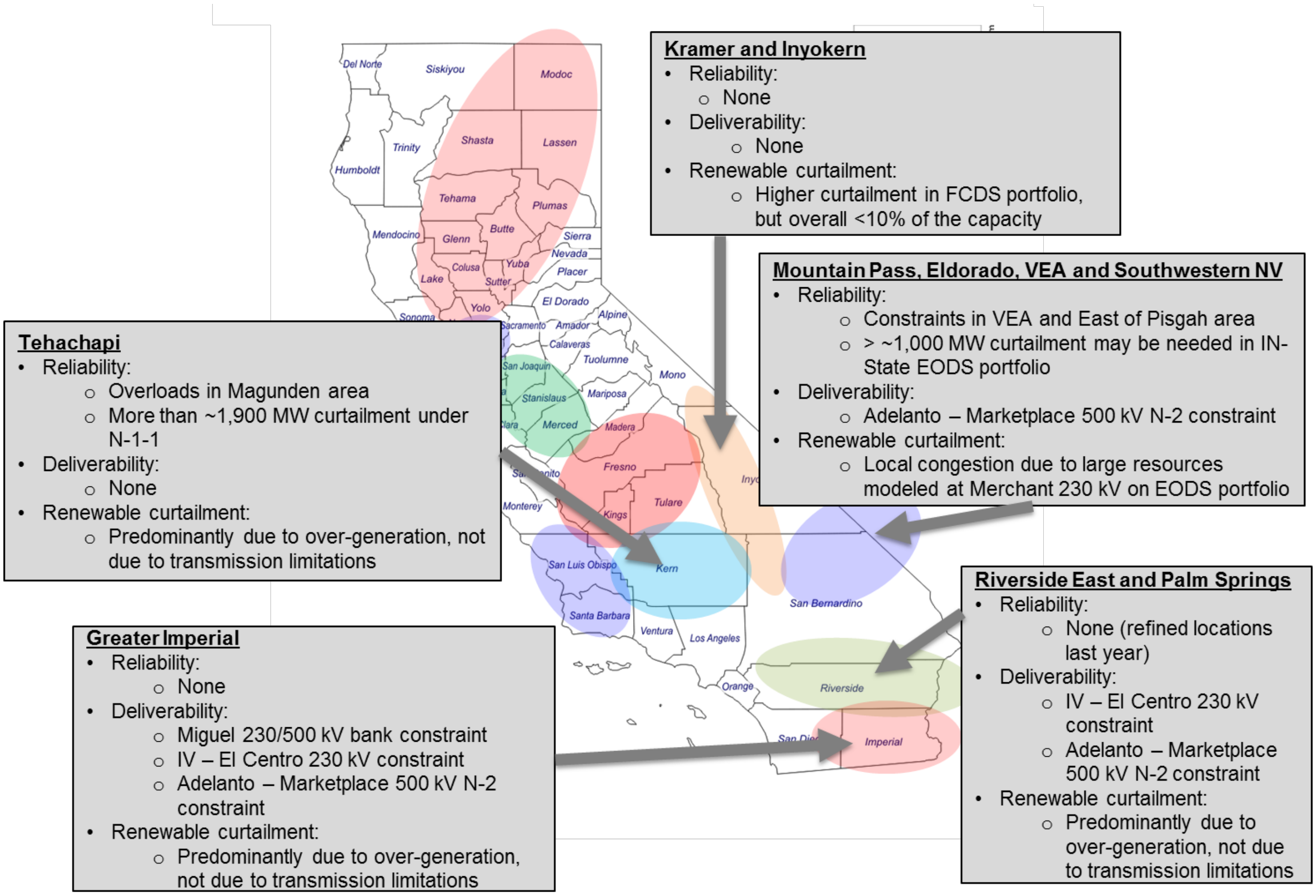


Figure 6.4-18 summarizes the key takeaways of different assessments by each zone in the Southern CA system.

Figure 6.4-18: Summary of 50 percent RPS portfolio evaluation for Southern CA zones



The ISO will work with the CPUC and the CEC to incorporate the findings and conclusions into future portfolio development.

6.4.9.2 *Next steps regarding an informational study to evaluate ITPs*

The out-of-state portfolio assessment from the California system perspective was completed and the conclusions are presented in the section 6.4.9.1 above. The next steps involve leveraging this out-of-state portfolio assessment to inform the informational evaluation of ITPs. To this effect, the ISO plans to work with the western planning regions to identify additional assumptions and scenarios to be considered in order to make the ITP evaluation more comprehensive.

ITP evaluation will take place as an effort independent of the 2017-2018 TPP. The ISO plans to engage the western planning regions in developing a timeline for the ITP evaluation activities outlined below –

- The ISO will share with the western planning regions, the results of evaluation of transmission system outside of California along with the scenarios that were considered in order to identify stressed snapshots for evaluating the system outside of California.
- Depending on the input from the western planning regions, additional production cost analysis will be performed to capture any sensitivities which may result in stressed conditions for the system outside of California.
- The ISO plans to work with the western planning regions to identify important contingencies to test the out-of-state portfolio on the affected part of the western planning regions areas.
- Once major transmission issues are identified using stressed scenarios and snapshots for the system outside of California, The ISO will test the effectiveness of ITPs in mitigating these issues.
- The ISO will coordinate with WestConnect and NTTG on the key assumptions and findings of their respective renewable scenario assessments that model the entire or California 50% out-of-state portfolio.

6.5 Benefits Analysis of Large Energy Storage

6.5.1 Introduction

In this 2016-2017 transmission planning cycle, the ISO undertook further study of the benefits large scale energy storage projects may provide to ratepayers in the ISO footprint as the state moves from the 33 percent RPS to a 50 percent RPS. This analysis began in the 2015-2016 transmission planning cycle with a 40 percent RPS-based analysis that was later updated to a 50 percent RPS-based analysis.[118] This study uses the same methodology as the previous ones and provides a further update using the latest assumptions and load forecasts, and 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 ISO also expanded the study scope to consider potential locational benefits.

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, and this study further explores the benefits large energy storage can provide. This work is in addition to considering energy storage as part of the overall preferred resource umbrella in transmission planning, and the ISO is engaged in a number of parallel activities to facilitate energy storage development overall, including past efforts refining the generator interconnection process to better address the needs of energy storage developers.

The study was provided on an information-only basis and the results are dependent on the assumptions made in the study. The methodology, assumptions, and results of the study are set out in this section.

6.5.2 Study Approach

This study was conducted based on the 50 percent RPS "in-state portfolio with full capacity deliverability" portfolio the CPUC provided for the ISO 2016-2017 50 percent RPS special studies.

Two new bulk energy storage resources – a 500 MW and a 1400 MW resource - were added in turn to the 50 percent 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

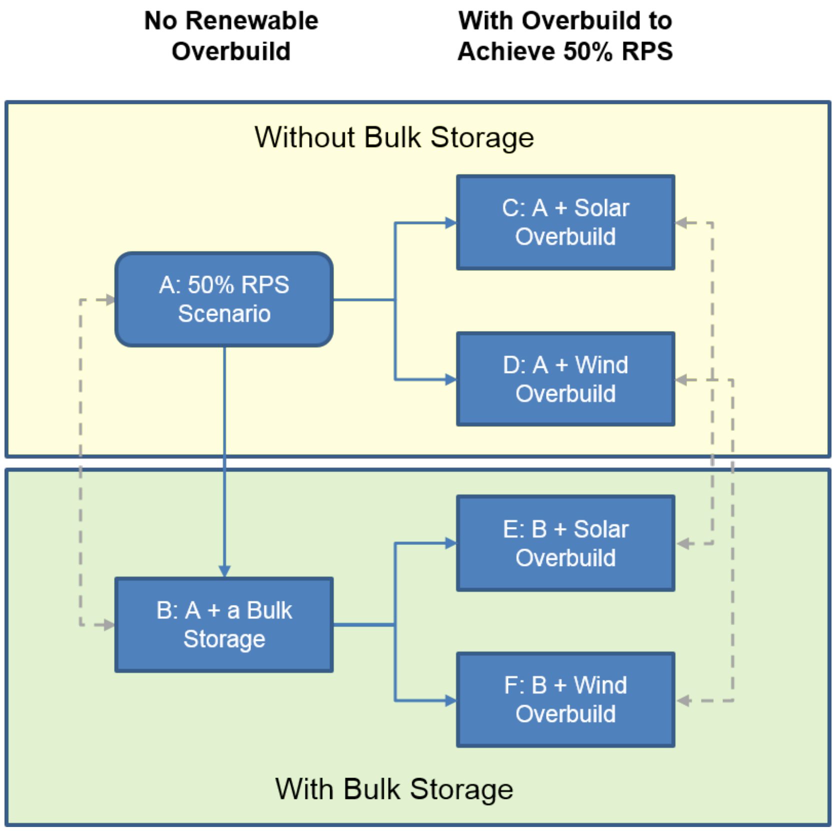
[118] See http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf and http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf

presence of the storage resource may lead to different levels of success of various resource mixes in achieving the 50 percent RPS target.

Consistent with the studies the ISO did in the 2015-2016 transmission planning process, the study was therefore based on production simulations – for each size of resource - of the original case and five new cases, as shown in Figure 6.5-1. The five cases are all derived from the 50 percent RPS scenario Base Case, which was designated as case **A** in this study. In all cases, renewable curtailment remains unlimited. Case **B** is case **A** with the new bulk energy storage resource added. As expected, the actual renewable generation did not initially meet the state's 50 percent renewable portfolio standard (RPS) goal in the production simulations due to the amount of curtailment. In case **B** the 50 percent 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 50 percent RPS requirement despite the curtailment. The additional renewable resources are in effect the renewable overbuild needed to achieve the 50 percent 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 50 percent RPS scenario (case **A**), installed solar capacity was 55% of the total RPS portfolio and wind was 32%, excluding the distributed solar PV. 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 6.5-1, 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 6.5-1: 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 50 percent 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 50 percent 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. Table 6.5-1 has the list and definitions of all cases of this study.

Table 6.5-1: Study Case Definition

Case	Definition
A	50% RPS Base Case, no pumped storage and no renewable overbuild
B500	Base Case plus a 500 MW pumped storage resource
B1400	Base Case plus a 1,400 MW pumped storage resource
C	Base Case with solar overbuild
D	Base Case with wind overbuild
E500	Base Case with solar overbuild and a 500 MW pumped storage resource
E1400	Base Case with solar overbuild and a 1,400 MW pumped storage resource
F500	Base Case with wind overbuild and a 500 MW pumped storage resource
F1400	Base Case with wind overbuild and a 1,400 MW pumped storage resource

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 6.5-5).

Locational benefits – Gridview and powerflow analysis

Further to the above analysis employing the PLEXOS software, the ISO also undertook additional analysis using the same tools employed in the annual transmission planning cycle economic assessment of the potential locational benefits of the large energy storage, considering:

- Known potential sites: Lake Elsinore, Eagle Mountain, San Vicente
- Local resource adequacy capacity benefits using local capacity requirements study concepts; the local capacity benefits would depend on the projects' proposed point of interconnection and relative electrical effectiveness in an LCR area.
- Transmission line loss benefits through Gridview or powerflow analysis
- Congestion management benefits through Gridview production simulation analysis
- Potential gaps between assumptions of system-wide analysis and location-constrained analysis

6.5.3 Study Assumptions

Assumptions of the 50 percent RPS Base Case

The 50 percent RPS Base Case was developed based on the Default Scenario of the CPUC 2016 LTPP/TPP Assumptions and Scenarios.[119] The assumptions have some major changes compared to that of the last 50 percent RPS based bulk energy storage study in the 2015-2016 transmission planning cycle. The changes are mostly in the following areas:

- The retirement of of non-dispatchable generation resources;
- Dispatchability of CHP resources;
- Energy forecast and Additional Achievable Energy Efficiency (AAEE);
- Renewable energy needed to achieve the 50 percent RPS target (not curtailment included); and
- The prices for renewable curtailment.

Table 6.5-2 below has the comparison of these changes.

[119] See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF

Table 6.5-2: Comparison of Assumptions with Major Changes

Assumption	This Study	2015-2016 TPP 50% RPS Study
Changes in non-dispatchable generation resources	Diablo Canyon nuclear plant (2,300 MW) is retired 2,786 MW CHP in operation	Diablo Canyon in operation 4,684 MW CHP in operation
Dispatchability of CHP resources	50% of the 2,786 MW CHP is dispatchable	All 4,684 MW CHP is non-dispatchable
California load forecast	64,009 MW 1-in-2 No AAEE non-coincident peak load 301,480 GWh energy	70,763 MW 1-in-2 No AAEE non-coincident peak load 322,218 GWh energy
California AAEE	9,418 MW non-coincident peak impact 39,779 GWh energy CEC provided hourly profiles that usually have higher values in the late afternoon and early evening	5,713 MW non-coincident peak impact 24,535 GWh energy No hourly profile, offsetting load proportionally to the hourly load values
California RPS Portfolio	36,776 MW installed capacity 110,288 GWh energy	40,986 MW installed capacity 125,307 GWh energy
Price of renewable generation curtailment	-$15/MWh for the first 200 GWh, -$25/MWh for additional 12,400 GWh and -$300/MWh thereafter	-$300/MWh for all curtailment
Hydro condition	2005 hydro generation	2005 hydro generation
ISO maximum net export capability	2,000 MW	2,000 MW

The Base Case assumptions generally lean to underestimate the value the pumped storage is reasonably able to provide provide. They provide a starting point of the studies, however, to help focus further study. The ISO will analyze additional sensitivity cases to assess the costs and benefits of the bulk energy storage resource in supporting integration of high penetration renewable energy in the ISO market.

Assumptions for New Pumped Storage Resources

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 6.5-3 and Table 6.5-4 show the assumptions for the 500 and 1,400 MW pumped storage resources. The ISO made the assumptions based on a review of publically available information.

Table 6.5-3: Assumptions of the New 500 MW (Gen) 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

Table 6.5-4: Assumptions of the New 1,400 MW (Gen) Pumped Storage Resource

Item	Assumption
Number of units	4
Max pumping capacity per unit (MW)	422
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	350
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)	18.8
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 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 calculating the revenue requirements of the solar and wind overbuild and the new pumped storage resources, the assumptions in Table 6.5-5 were used. Revenue requirements included capital cost, taxes, tax credits, insurance, etc. NQC Peak Factor is the percentage of installed capacity that is counted as net qualifying capacity (NQC). NQC is the capacity of the resource that be counted toward California's Resource Adequacy (RA) capacity requirements and receive resource adequacy capacity revenue.

The assumptions come from several sources that are listed in the footnotes of Table 6.5-5.

Table 6.5-5: Assumptions of Revenue Requirements and RA Revenue of the New Resources[120]

Item	Revenue Requirement (2016$/kW-year)[121]	NQC Peak Factor[122]	RA Revenue (2016$/kW-year)[123]
Large Solar In-State	242.19	47%	16.53
Large Solar Out-State	183.17	47%	16.53
Small Solar In-State	334.80	47%	16.53
Solar Thermal In-State	551.55	90%	31.66
Wind In-State	239.14	17%	5.98
Wind Out-State	223.88	45%	15.83
Pumped Storage In-State	407.91	100%	35.18

The revenue requirements include both the generation resource and transmission upgrade costs. The values are adjusted to 2016 dollars using the CEC GDP Deflators.

[120] All revenue requirements and RA revenue are in 2014 dollars.

[121] Solar and wind cost - *Draft2017 IRP Assumptions* at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/DRAFT_RESOLVE_Inputs_2016-12-21.xlsx; others see https://www.wecc.biz/Reliability/2014_TEPPC_GenCapCostCalculator.xlsm, https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf, and http://www.transwestexpress.net/scoping/docs/TWE-what.pdf and the CAISO assumptions

[122] References https://www.caiso.com/Documents/2012TACAreaSolar-WindFactors.xls and https://www.wecc.biz/Reliability/2024-Common-Case.zip

[123] *CPUC 2015 RA Report* at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452221

6.5.4 Study Results - System Benefits

Table 6.5-6 summarizes the simulation results and the calculated levelized annual revenue requirements of the solar and wind overbuild and the new pumped storage resources. The results are analyzed in more detail in the sections below.

Table 6.5-6: Simulation Results and Calculated Revenue Requirements[124]

	No Pumped Storage			500 MW Pumped Storage			1,400 MW Pumped Storage		
Case	**A**	**C**	**D**	**B500**	**E500**	**F500**	**B1400**	**E1400**	**F1400**
Renewable Curtailment (GWh)	737	793	743	601	646	612	466	496	474
Curtailment Frequency (hours)	292	320	305	251	268	253	211	219	207
CA CO2 Emission (MM-ton)	26.83	26.75	26.72	26.39	26.33	26.34	25.91	25.89	25.88
CA CO2 Emission ($million)	606	604	604	596	595	595	585	585	585
Production Cost ($million)									
WECC	14,541	14,519	14,514	14,525	14,503	14,502	14,499	14,484	14,483
CA	2,999	2,989	2,986	2,952	2,945	2,946	2,900	2,898	2,897
Renewable Overbuild and Pumped Storage Capacity (MW)									
Solar		275			231			179	
Wind			257			220			166
Pumped Storage				500	500	500	1,400	1,400	1,400
Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($million/year)									
Solar		62.11			52.17			40.43	
Wind			58.89			50.41			38.04
Pumped Storage				186.37	186.37	186.37	407.61	407.61	407.61
Sum		*62.11*	*58.89*	*186.37*	*238.54*	*236.78*	*407.61*	*448.04*	*445.65*
Pumped Storage Net Market Revenue ($million)				48.91	49.35	49.03	92.47	93.81	93.20

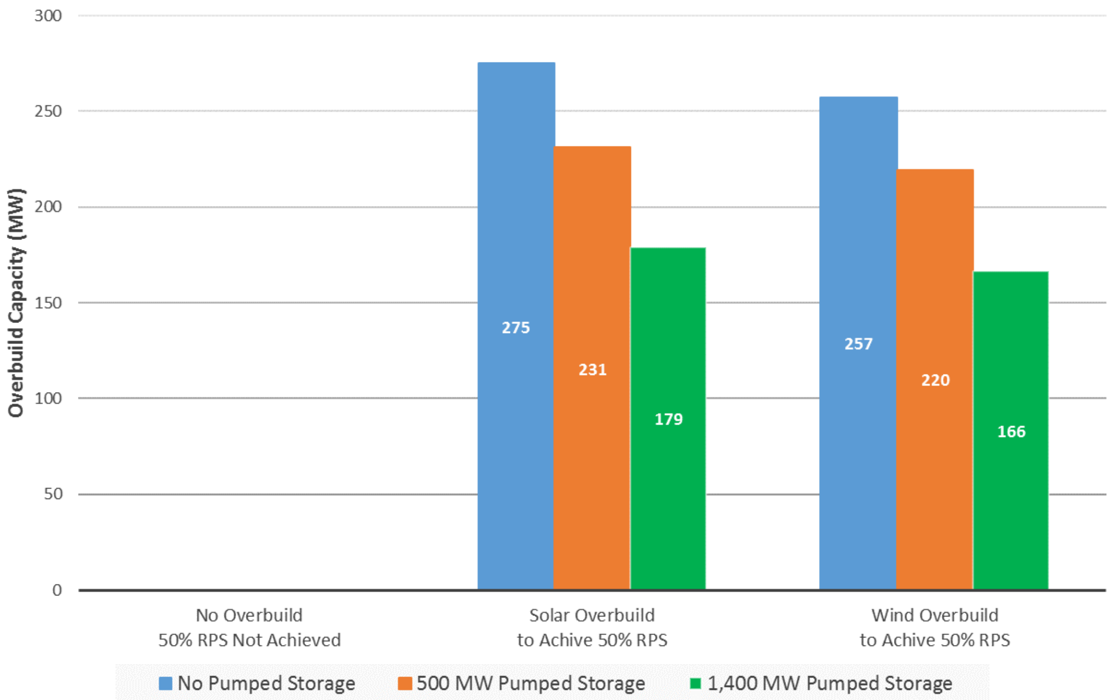
Renewable Overbuild

The volume (MW) of solar and wind overbuild needed to achieve the 50 percent 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 6.5-2.

Without the new pumped storage resource, 275 MW of solar overbuild or 257 MW of wind overbuild was required in order to achieve the 50% RPS target. As expected, wind was more effective in terms of reducing the capacity amount of overbuild needed. The RPS portfolio in the Base Case (Case A) has 55 percent solar and 32 percent wind. With solar overbuild in case C, the RPS portfolio has an even higher solar concentration. As a result, more renewable generation was curtailed and more overbuild was needed (see Figure 6.5-3). 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 of the hours, resulting in less curtailment than case C.

[124] CA CO2 Emission includes the CO2 emission from net import; CO2 cost is $22.59/M-ton (in 2016 dollars); Production Cost includes start-up, fuel and VOM cost, but not CO2 cost; and Net Market Revenue the pumped storage resource is its revenue from providing energy, reserves and load following minus its cost of pumping and operation.

Figure 6.5-2: Capacity of Solar and Wind Overbuild



With the new pumped storage resource added to the system, the overbuild needed to achieve the 50% RPS target was reduced. The 1,400 MW pumped storage resource reduced more overbuild than the 500 MW pumped storage resource.

These established the cases for further evaluation, and the societal benefit of reducing overbuild requirements is discussed below. Cost savings have to be considered in two ways – societal benefits that can be considered at a policy level, and benefits that can be captured directly by the pumped storage.

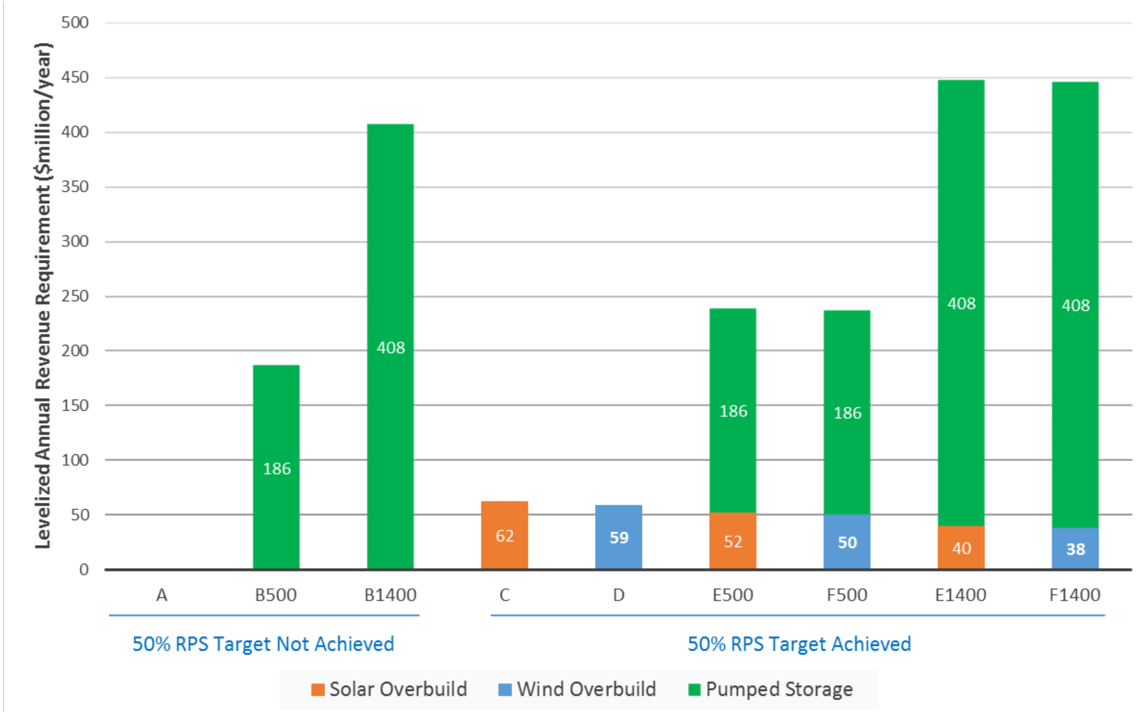
Societal Benefits

Levelized Annual Revenue Requirement of Capacity Overbuild

In Figure 6.5-6 are the levelized net annual revenue requirements of the renewable overbuild scenarios. The levelized net annual revenue requirements of the new pumped storage resources are also provided for comparison purposes. (The levelized net annual revenue requirement credits the construction cost with the resource adequacy capacity benefit.)

The calculated results show that the annual revenue requirement of wind overbuild was lower than that of solar overbuild. This was because less overbuild with wind was needed to achieve the 50% RPS target than with solar and wind per unit cost was also lower than solar (see Table 6.5-5).

Figure 6.5-3: Levelized Annual Revenue Requirement



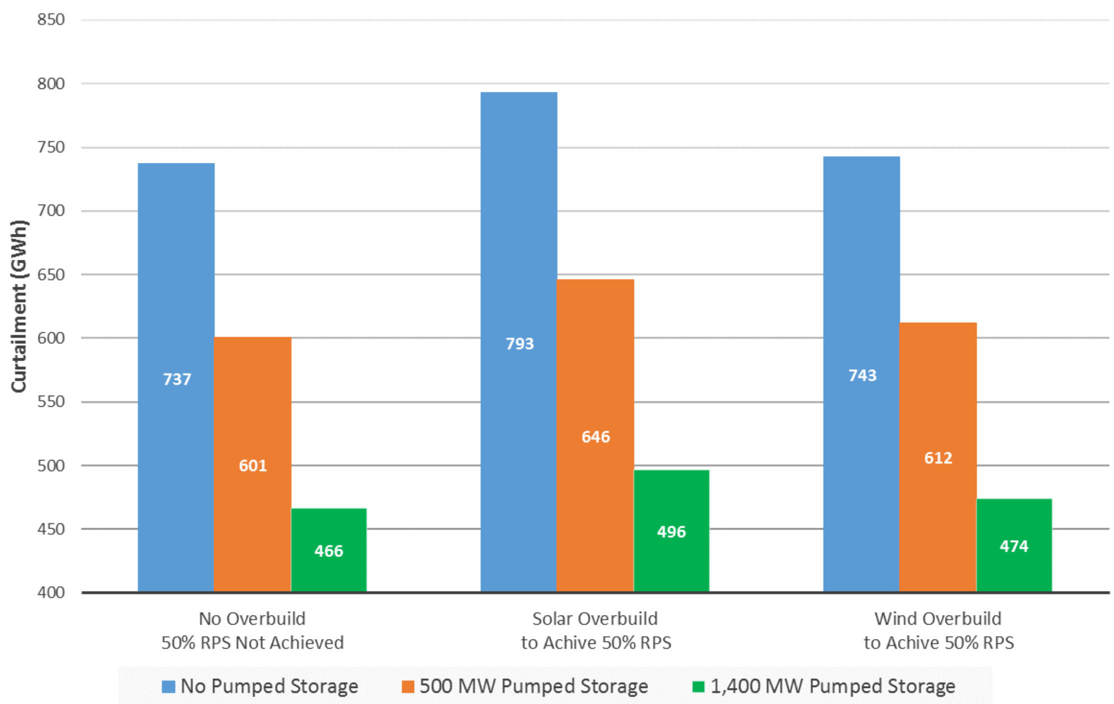
The avoided capacity overbuild savings was found to be relatively small compared to the net capital cost of the pumped storage. This is because of the capital cost of the pumped storage relative to the renewable generation, and the relatively small amount of overbuild that the pumped storage eliminated. (The 500 MW pumped storage reduced the overbuild by 44 MW of solar or 37 MW of wind, and the 1400 MW pumped storage reduced the overbuild by 96 MW of solar or 91 MW of wind.) The overbuild results were in part due to the very low level of renewable curtailment found in the study which was due to the conservative assumptions used in the study. As noted earlier, the ISO will conduct additional sensitivity analyses of the key assumptions.

Renewable Generation Curtailment

Figure 6.5-3 shows the renewable generation curtailment from all nine cases. In the study the first 200 GWh of renewable generation was curtailed when the energy price (MCP) dropped to -$15/MWh, then additional 12,400 GWh when MCP dropped to -$25/MWh, and -$300/MWh for curtailment more than 12,600 GWh. The assumption mimics the CAISO market mechanism to curtail renewable generation with economic bids and self-schedules.

The most effective use of a large pumped storage resource is to move large volumes of energy from the hours with low generation cost to other hours with high generation cost. It matches with the solar generation pattern that that drive down energy prices or even causes curtailment in midday and has no generation before sunrise and after sunset, during which other higher cost generation is needed to meet the load. It. The new pumped storage resource was more effective in reducing curtailment with solar overbuild than with wind overbuild due to this pattern.

Figure 6.5-4: Renewable Generation Curtailment by Case



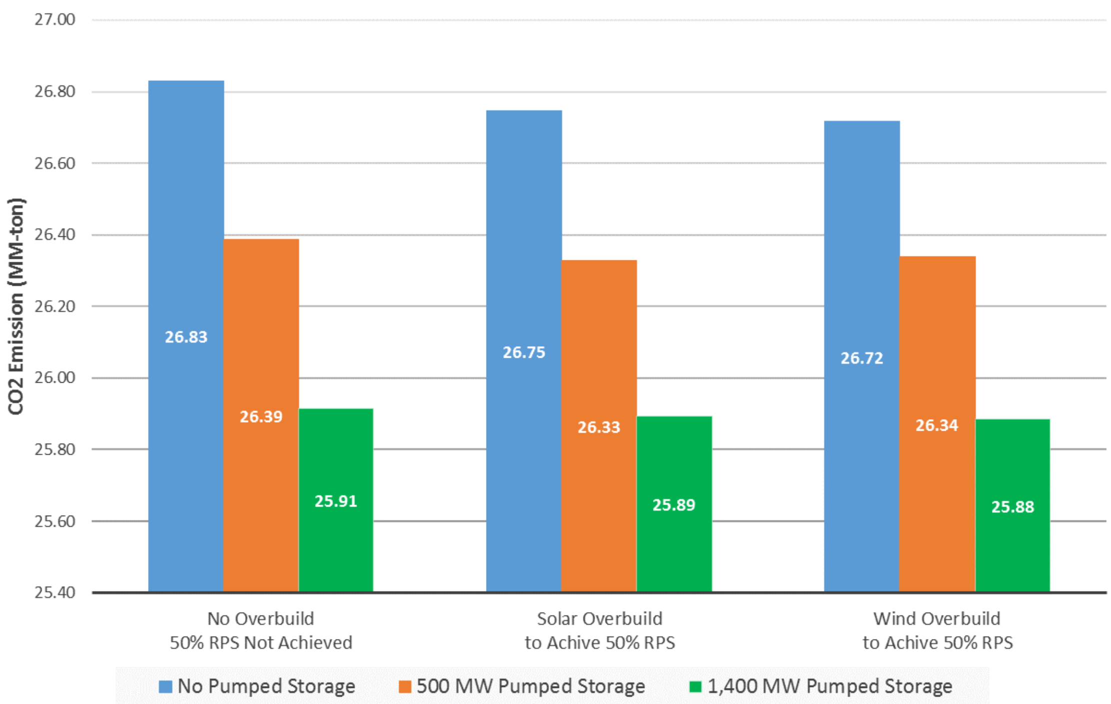
On the other hand, the effectiveness of the new pumped storage resource is limited by its maximum capacity relative to the volume of potential renewable generation curtailment. In the case with 500 MW punped storage resource, it can convert a maximum of 600 MW of pumping load to 500 MW maximum generation, 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 E500 or F500 cannot store all the energy and use it in later hours. The portion of energy exceeding 600 MW is still curtailed. The 1,400 MW pumped storage resource, therefore, can store more curtailed energy and use it in later hours. It can reduce more curtailment and the amount of overbuild than the 500 MW pumped storage resource.

CO2 Emissions

Figure 6.5-3 and Figure 6.5-4 demonstrate high correlation between California CO2 emission results and renewable generation curtailment. The renewable energy recovered from curtailment by the pumped storage resource was used in later hours to displace generation of non-renewable resources and reduced CO2 emission. It is one of the benefits that the pumped storage brought to the system.

The California CO2 emission costs of the cases can be calculated by multiplying the CO2 emission amount by the CO2 emission price of $22.59/metric-ton.

Figure 6.5-5: California CO2 Emission by Case



Production Costs

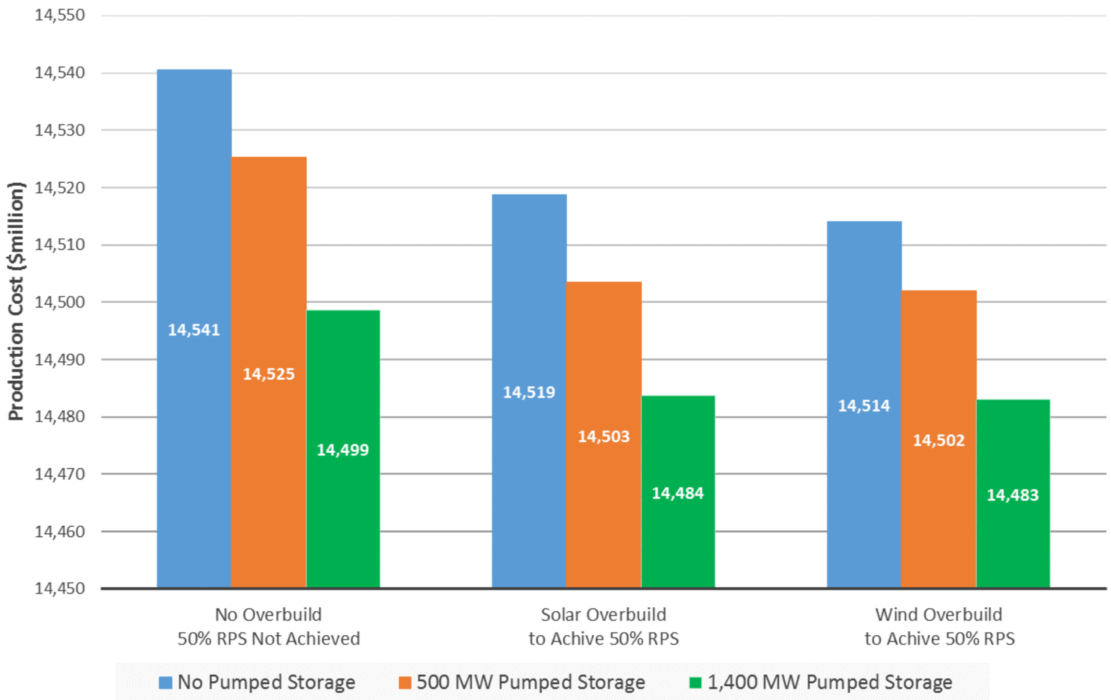
In Figure 6.5-5 are the annual production costs of the whole western interconnect for all the cases.

The production cost in Figure 6.5-5 includes generator start-up cost, variable operation and maintenance (VOM) cost, fuel and charging costs, but not CO2 emission costs. In this study the renewable generation had negative curtailment prices, but the production cost of renewable generation is assumed to be $0/MWh.

Even though all the cases with renewable overbuild had the same amount of renewable generation, production costs were different. Generally the cases with wind overbuild had lower production costs than the comparable cases with solar overbuild as the latter required more support of conventional resource in the morning and evening ramping periods than the former, as discussed in the CO2 emissions section above. That is a benefit of a more diversified RPS portfolio.

The new pumped storage resource helped further reduce production costs 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, further confirming that the new pumped storage resource was more effective with higher solar volumes in the RPS portfolio.

Figure 6.5-6: WECC Total Annual Production Cost

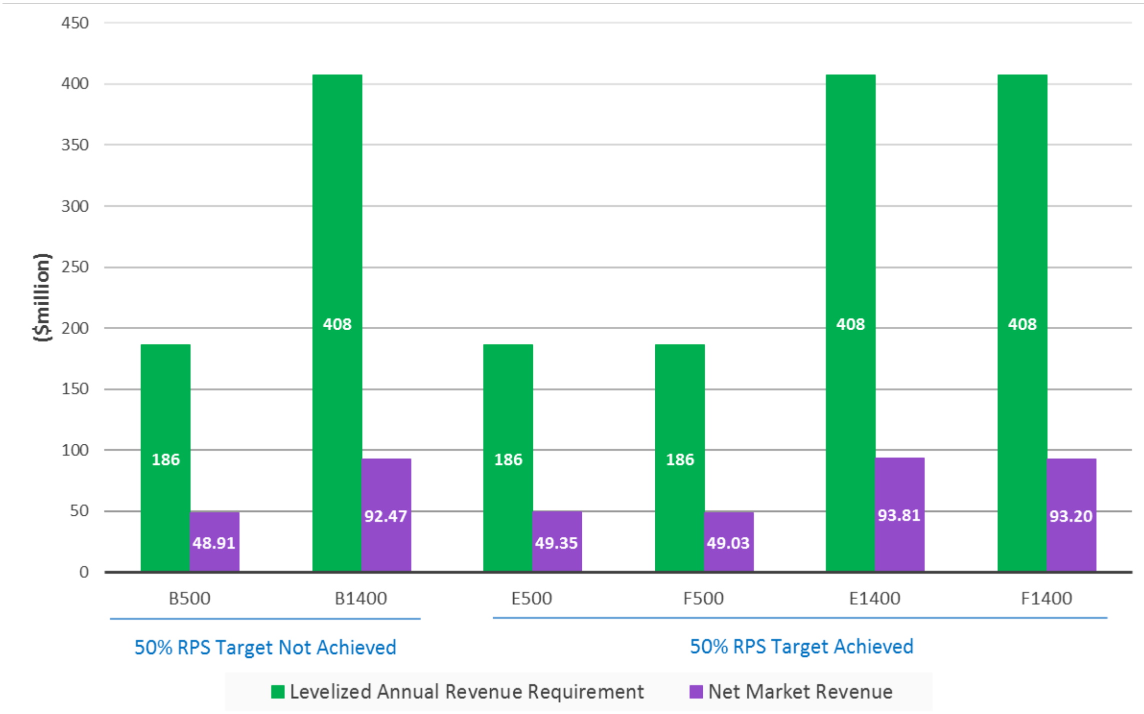


Revenue Requirement and Net Market Revenue of the New Pumped Storage Resource

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 resource adequacy capacity revenues and net revenue from the market barring other revenue streams. Figure 6.5-7 shows the comparison of levelized net annual revenue requirement with the net market revenue of the new pumped storage resource. As noted earlier, the levelized net annual revenue requirement credits the construction cost with the resource adequacy capacity benefit.

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 (negative energy prices) 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 frequency and volume, and curtailment prices.

Figure 6.5-7: Levelized Annual Revenue Requirement and Net Market Revenue of the New Pumped Storage Resource in 2026



This study found low renewable curtailment frequency and volume and relatively high renewable curtailment prices. The net market revenue provided only a portion of the levelized net revenue requirement of the new pumped storage resource for the assumptions used in this study. Developing pumped storage resources would need other sources of revenue streams, which could be developed through policy decisions to access the other benefits the pumped storage provides such as those set out below.

The analyses above show that the new pumped storage brought benefits to the system in reducing overbuild requirements, CO2 emissions, and production costs, as shown in Table 6.5-7. These benefits may be attributed to the new pumped storage resource.

Table 6.5-7: Reduction of System Costs by the Pumped Storage Resource

	500 MW Pumped Storage		1,400 MW Pumped Storage	
Case	**E500**	**F500**	**E1400**	**F1400**
CA CO2 Emission ($million)	-9.45	-8.50	-19.25	-18.79
Production Cost ($million)				
WECC	-15.30	-11.96	-35.03	-30.96
CA	-44.05	-39.59	-91.49	-89.01
Levelized Annual Revenue Requirement of Renewable Overbuild ($million/year)				
Solar	-9.94		-21.68	
Wind		-8.48		-20.85

6.5.5 Study Conclusions

Based on the results of the study, it can be concluded that:

- The new pumped storage resources brought significant benefits to the system, including
  - reduced renewable curtailment and reduced renewable overbuild needed to meet the 50% 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.
- 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.
- Compared to the study with 50% RPS in 2015-2016 TPP, results of this study show significantly lower renewable curtailment, mainly due to the following assumptions:
  - Retirement of Diablo Canyon and non-dispatchable CHP resources;
  - Dispatchability of 50% of CHP resources; and
  - Lower load forecast together with higher AAEE, and the resulted lower renewable energy needed to achieve the 50% RPS target
- Because of low renewable curtailment, the effectiveness of the pumped storage resources in reducing renewable curtailment, CO2 emission and production costs was limited in this study.
- Besides lower curtailment, the net market revenues of the pumped storages were also affected by the higher renewable curtailment prices.
- The net market revenue of the pumped storage resources provided only a portion of the levelized annual revenue requirements. Developing pumped storage resources would need other sources of revenue streams, which could be developed through policy decisions.
- The annual system cost reductions (benefits), shown in Table 6.5-7, are not included in the net market revenue, but may be attributed to the pumped storage resources.
- The results of the study are sensitive to the assumptions, especially those listed in Table 6.5-2. There are uncertainties in some of these assumptions and the assumptions generally lead to conservative curtailment results understating the benefits of the pumped storage. The conclusions about the benefits and costs of the pumped storage resources will change

should the assumptions change. The ISO will conduct additional sensitivity analyses on the various assumptions to frame the range of potential resultsincluding:

- o Dispatchability of CHP resource;
- o Level of AAEE; and
- o Prices of renewable curtailment.

- The additional studies will be conducted as an extension of the 2016-2017 transmission planning cycle.

6.5.6 Locational benefits – Gridview and powerflow analysis

The ISO undertook additional analysis to assess the locational benefits of large energy storage. This assessment considered known potential sites; Lake Elsinore, Eagle Mountain, and San Vicente

The analysis approach for each site was designed to capture the expected locational benefits for that particular site. Eagle Mountain is located in the Riverside renewable zone, and renewable generation from that zone must be transmitted over 100 miles across major transmission paths to the coastal load areas to the west. The Riverside renewable zone could be potentially congested due to a large amount of renewable development in the area. Preliminarily screening to identify congestion benefits of locating the Eagle Mountain storage project in the Riverside Renewable zone was performed using the ISO's 2016-2017 production cost models with 50% renewable portfolios. The Eagle Mountain storage project was modeled into the following production cost models:

- In-state FCDS
- In-state EODS
- Out-of-state FCDS/EODS

The amount of congestion in these models affecting the Riverside renewable generation was minimal, and the Eagle Mountain storage project did not materially reduce any of the identified congestion. However, the ISO also utilized the models to perform a loss benefit analysis. Based on this analysis, a marginal transmission line loss improvement was observed as a result of adding the Eagle Mountain storage project to the model.

The Lake Elsinore and San Vicente storage projects are located in the San Diego load center, and this area requires local generation capacity to reliability serve the San Diego area load. The San Vicente storage projects would be interconnected at a location that would be effective providing local resource adequacy capacity into San Diego. The Lake Elsinore project has several interconnection configurations that have been considered, but for the purposes of this study it was assumed that this project would be connected to the San Diego area because this configuration would be capable of providing local capacity benefits. Using the production cost models, a sensitivity study was performed to assess the transmission line loss benefits from a pumped storage project in the San Diego area. However this analysis showed that there were no line loss benefits. It is thought that this result was observed because the pumped storage generation appeared to displace local gas-fired generation and this resource tradeoff did not produce any line loss benefits. However, the pumped storage still needed to consume energy to pump and this resulted in incrementally increasing transmission line losses. As a result, the only local benefits observed for the San Diego located storage projects was the local capacity benefits. However, further analysis to quantify this benefit was not performed because the financial value of these local capacity benefits would be subject to future procurement decisions.

6.6 Characteristics of Slow Response Local Capacity Resources

6.6.1 Introduction

Historically, the necessary characteristics for demand response resources to meet local capacity performance requirements have not been consistently applied across the industry. Over the last several years, especially stemming from the more detailed analysis in addressing the early retirement of the San Onofre Nuclear Generating Station, there is a more urgent need for greater alignment between reliability requirements, the procurement rules for local resource adequacy capacity developed by the CPUC, and how the ISO can rely on demand response resources to meet reliability requirements and comply with NERC mandatory standards. This is especially true for energy-limited slow-response resources – those resources that cannot respond quickly enough after a contingency to allow the ISO to prepare the system for the "next" contingency – and how the ISO can plan and operate these resources to meet NERC mandatory standards.

Stemming from stakeholder concerns expressed with the changes the ISO proposed to the ISO's business practice manual for reliability requirements (PRR854) to provide greater clarity on current technical needs, the ISO initiated a new stakeholder process to address implementation issues and outstanding stakeholder questions related to the pre-contingency dispatch of resources for local reliability needs, and provide broader visibility of the analysis being conducted inside the transmission planning process that was already underway.

ISO staff were encouraged to focus on developing creative solutions to allow energy-limited, slower responding demand response resources to count toward local capacity requirements by enabling the ISO to use the resources prior to a first contingency, rather than relying only on those resources capable of fast response after a first contingency event.

As part of this new stakeholder process, the ISO conducted a joint workshop with the CPUC to address how energy-limited, slow response demand response resources can help the ISO effectively address NERC, WECC and ISO reliability standards applicable to local areas. The ISO encouraged participation from all stakeholders involved, and believes that collaboration with the Commission is fundamental to advancing our shared interests in integrating preferred resources and ensuring electric system reliability.

As noted earlier, the stakeholder process was expected to rely on and carry forward with the special study work to examine resource requirements already underway as part of this special study being conducted in the 2016-2017 transmission planning process. The ISO conducted a conference call on April 26, 2016 to begin scoping the technical study work necessary to establish energy requirements for resources dispatched pre-Contingency for local reliability requirements. The preliminary results were presented at a joint ISO/CPUC workshop on October 3, 2016 and in the transmission planning process stakeholder session 2 held on September 21st and 22nd, 2016.

The ISO has received comments that will lead to additional analysis. In particular, the IOUs raised concerns with the methodology they employed to scale their load shapes. This is being reviewed by the IOUs. The preliminary results presented in those sessions is presented here.

Local capacity resources must enable the ISO to readjust the system within 30 minutes following a first contingency to prepare the system for a potential second contingency pursuant to Section 40.3.1.1(1) of the ISO tariff, California ISO Planning Standards and NERC standards for stability limits. Resources can provide this capability by either (1) responding with sufficient speed, allowing the operator the necessary time to assess and re-dispatch resources to effectively reposition the system within 30 minutes after the first contingency as illustrated in Figure 6.6-1 or (2) having sufficient energy available for frequent dispatch on a pre-Contingency basis to ensure the operator can meet minimum online commitment constraints to reposition the system within 30 minutes after the first contingency occurs as illustrated in Figure 6.6-2. The number of dispatches in the latter case is anticipated to be materially higher than in the former case.

Figure 6.6-1: Post-contingency Dispatch of Fast-response Resources

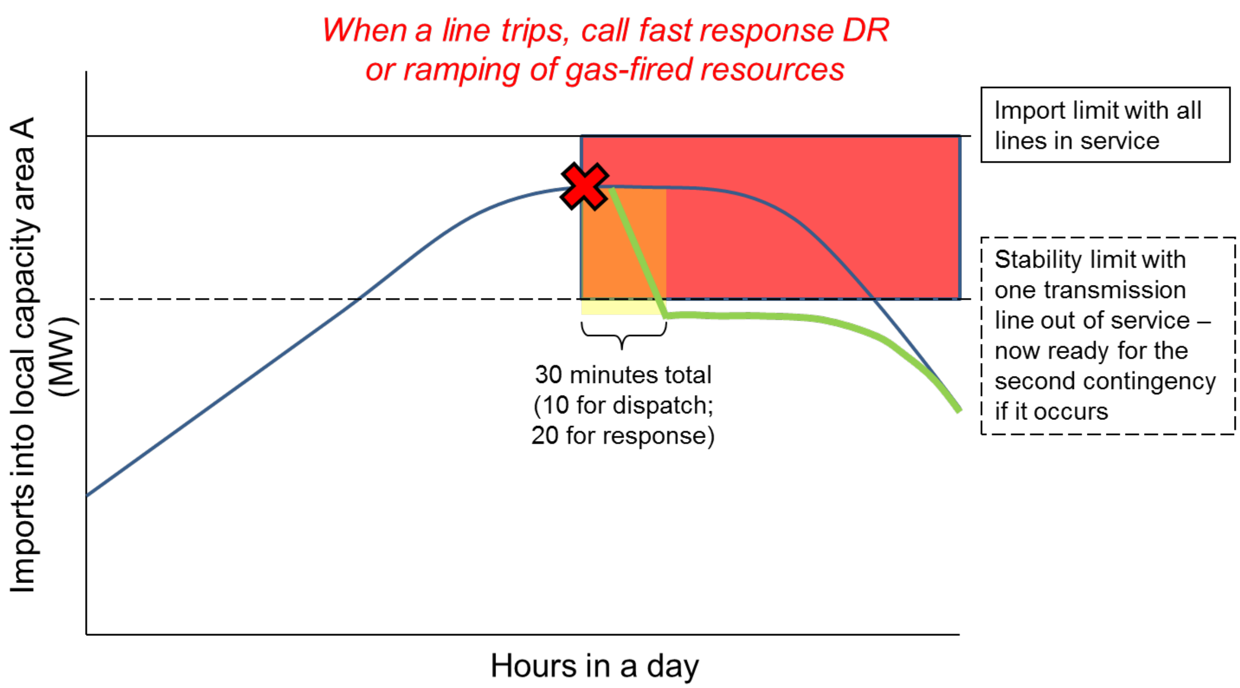
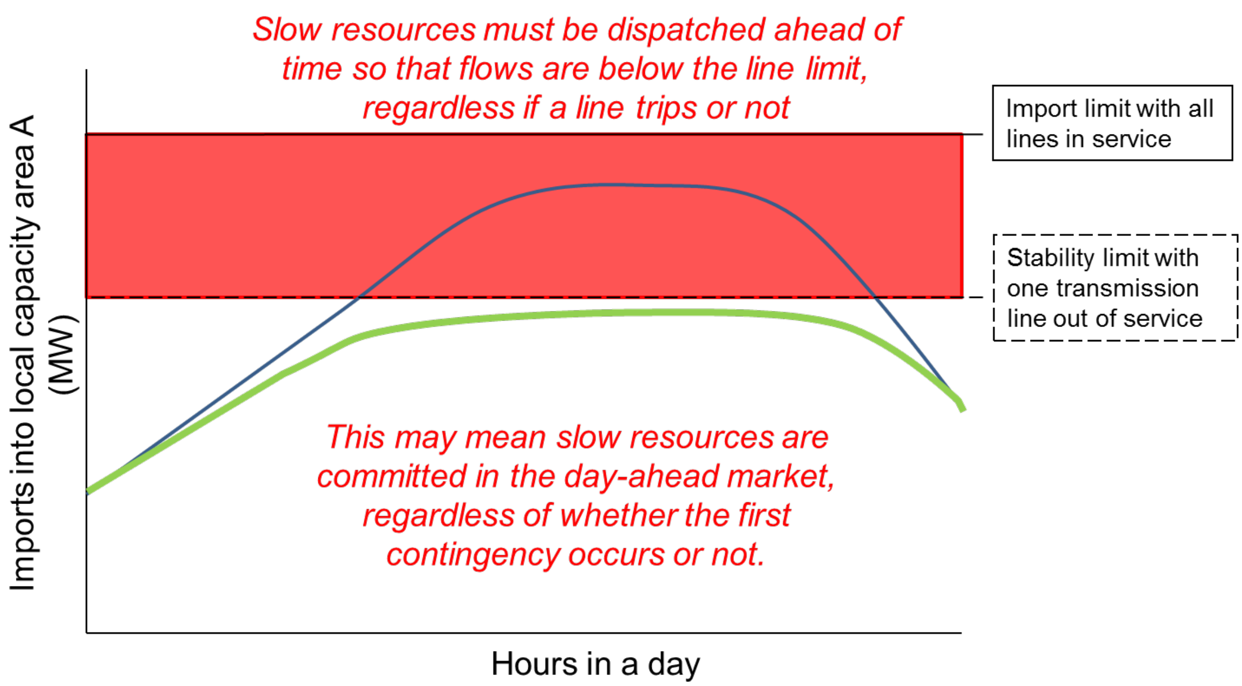


Figure 6.6-2: Pre-contingency dispatch of slow-response resources



This special study examines the required availability for slower response resources to be considered for local resource adequacy on the basis of pre-contingency dispatch. While the study also evaluates increased amounts of generic slow-response resources, the focus of the study is existing slow-response demand response (DR) resources.

The availability characteristics evaluated are based on the characteristics of existing slow-response DR programs and include:

- annual, monthly and daily event hours
- number of events per month, day and consecutive days
- operating times (time of year, days of the week, hours of the day, etc.)

The study was jointly performed by the ISO and the three investor-owned utilities (IOUs) Southern California Edison (SCE), San Diego Gas and Electric (SDG&E) and Pacific Gas and Electric (PG&E).

The study did not consider other factors that could require upward availability adjustments to the requirements for local reliability resources, and it is expected that these, if necessary, will be addressed in future efforts:

- Responses to prices or triggers other than local capacity related reliability events
- System events or by PTOs for distribution system issues
- Planned outages and unforeseen events

6.6.2 Demand response participation in the ISO market and operations

CAISO has introduced two products to enable wholesale demand response resource participation in the ISO market and operations. Reliability Demand Response Resource or RDRR allows emergency responsive demand response resources to integrate into the ISO market. Proxy Demand Resource or PDR participates in the CAISO comparable to a supply resource. Table 6.6-1 provides some of the characteristics of RDRR and PDR that are relevant to this study.

Table 6.6-1: RDRR and PDR characteristics

Market model	Services	Market dispatch	Maximum response time	Maximum run time	Minimum availability (for reliability-only use)
RDRR	Energy	Economic day-ahead, reliability real-time (any remaining uncommitted capacity)	≤ 40 minutes	>4 hours	15 events and /or 48 hours per term[125] (June –September & October – May)
PDR	Energy, non-spin, residual unit commitment (RUC)	Economic day-ahead and real-time	N/A	N/A	N/A

Demand response resource aggregations are required to be within a single sub-Load Aggregation Point (LAP) which were developed initially for congestion revenue rights (CRRs). A sub-LAP is an ISO-defined subset of pricing nodes (Pnodes) within a default LAP. The 24 sub-LAPs shown in Figure 6.6-3 were created to reflect major transmission constraints within each utility service territory. Each sub-LAP is designed to fall entirely within a single Local Capacity Area (LCA). However, multiple sub-LAPs can reside within a LCA which may not be aligned with local capacity sub-areas.

[125] Economic participation of RDRR in the day-ahead market will not reduce availability limits for the term. Real-time RDRR dispatches in the event of imminent or actual system or transmission emergency are counted against total RDRR eligible availability limits.

Figure 6.6-3: Sub-LAPS

Note that the sub-laps were updated on January 1 and restructured into 25 sub-laps as of January 1.

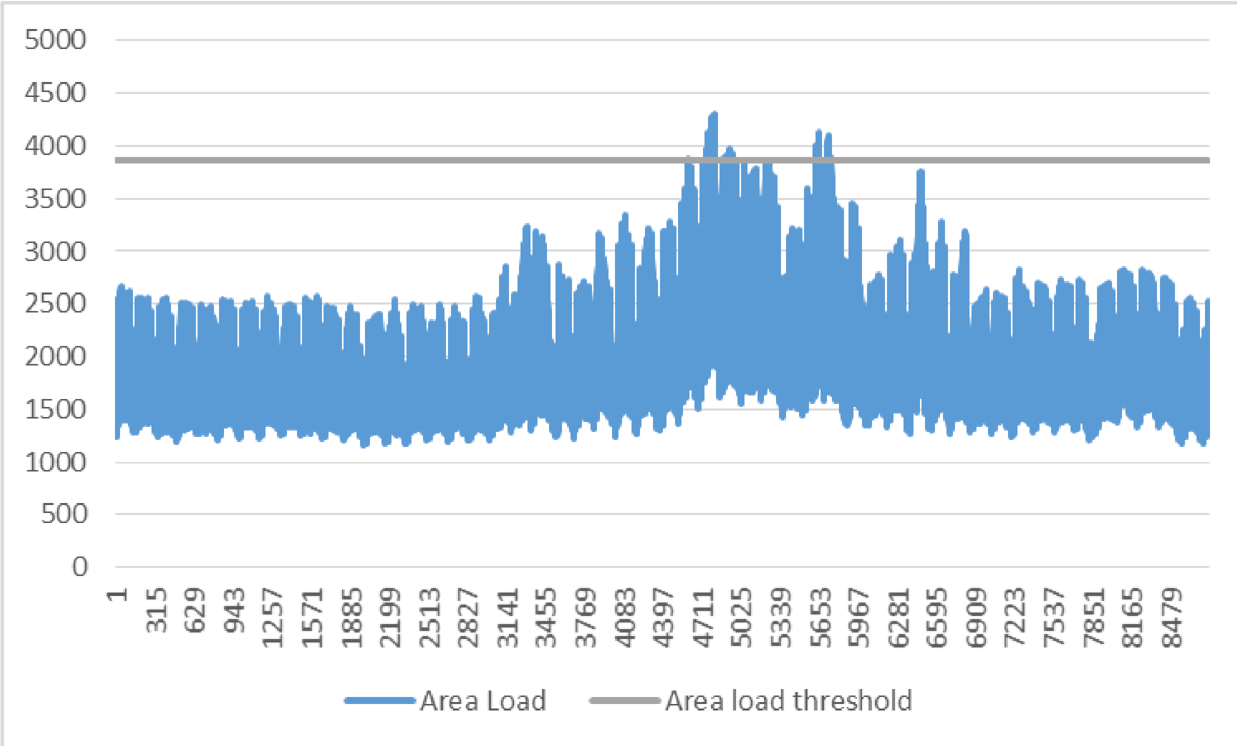
6.6.3 Study Methodology and Assumptions

The basic study methodology involves determining an area load threshold, which is shown as a grey line in Figure 6.6-4 which slow-response local capacity resources must be dispatched to maintain reliability of the transmission system, and then identifying the hours where the forecast hourly load, which is shown in blue, exceeds the threshold.

Study steps

- Develop hourly forecast load data for the LCR area or sub-area under consideration
- Determine the area load threshold as described below
- Using a spreadsheet, identify instances where the forecast hourly load for the area exceeds the area load threshold obtained in step 2 and record relevant data.
- Repeat the above steps for the slow-response resource amounts and study areas to be assessed

Figure 6.6-4: Study Methodology



Determination of area load threshold

Two approaches were used in this study to determine the area load threshold. The first approach ("Method 1" or "Step 1") is a simplified approach which assumes active power from all resources within the study area are equally effective and neglects reactive power capability impacts. In this approach the area load threshold is calculated as the difference between the forecast area peak load and the slow response resource amount.

The second approach ("Method 2" or "Step 2") tests locational and reactive power impacts and is more reliable compared to Method 1 in particular for voltage stability limited areas. In this approach the area load threshold is determined as follows:

- Starting from the final marginal 2017 LCR base case for the study area reduce online generation in the LCR area by the amount of slow response resource
- Apply the limiting contingency, which should cause loading, voltage, etc. violation
- Reduce area load proportionally until the loading, voltage, etc. is acceptable. Record the resulting area load as the area load threshold.

Assumptions

The study assumes:

- slow-response resources are called last and therefore have the lightest possible duty.
- slow response resources that are the subject of this study will not be utilized for events beyond the planning standards such as unavailability of multiple generating units which can occur during non-peak load hours
- demand response capacity value is assumed to be constant throughout the 8760 hours of the year
- perfect forecast and dispatch capabilities to call resources only when and where they are needed.
- DR availability in not impacted by dispatch frequency.
- The local area or sub-area is not resource-deficient.

The study assesses dispatch calls related to local resource adequacy and does not account for other non-coincident uses such as:

- in response to price or triggers other than local capacity related reliability events
- for system events or by PTOs for distribution system issues
- due to planned outages and unforeseen events
- for program evaluation

Projected hourly load data

Hourly load data for each local capacity study area for year 2017 was developed by the respective load serving entity (LSE) from recorded hourly load data for the area. In the absence of better hourly load forecast, hourly load values for 2017 were obtained by multiplying recorded load for the hour by the ratio of the 2017 forecast 1-in-10 peak load to the recorded peak load for the historical year. Three sets of 2017 hourly data produced using recorded data for 2013 to 2015 were used in the study.

This approach has the following short comings:

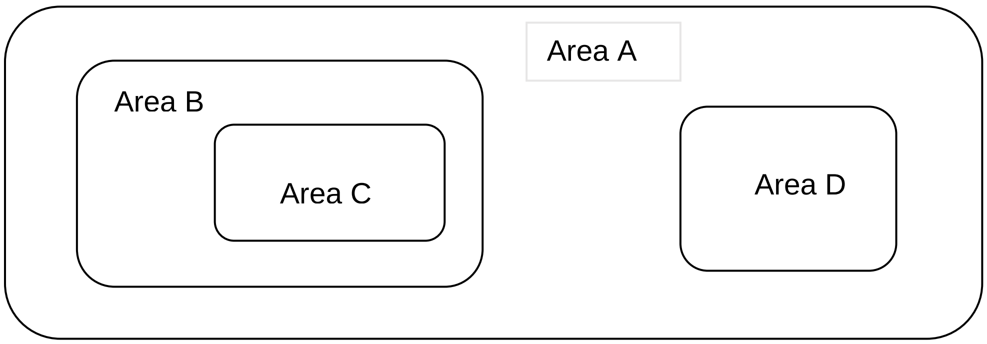
- all load hours are scaled in proportion to the forecast 1-in-10 peak load.
- since the forecast is based on simply scaling historical load profiles, it does not capture future changes in load shape due to increasing DER such as BTM PV.

The study may be updated when improved hourly forecasts are available.

Non-coincident dispatch calls among overlapping areas

A resource located in a sub-area can be called to address local capacity need in the sub-area or in overlapping areas. Non-coincident calls in overlapping areas must be included in the sub-area results. For example in Figure 6.6-5 below non-coincident dispatch calls for Area A and Area B must be included in the results for Area C in addition to dispatch calls for Area C itself. Similarly, non-coincident calls for Area A must be included in the results for Area B and Area C.

Figure 6.6-5: Dispatch calls in overlapping areas



Local capacity areas and resource amounts assessed

Table 6.6-2 summarizes the local capacity areas and resource amounts assessed. The study areas were selected by the respective LSE. The ISO expects availability studies will be performed for those local capacity areas and sub-areas not covered by the current study before slow-response DR and other similarly use-limited resources can be counted for local resource adequacy in those areas. In addition to current slow-response DR amounts, additional amounts of generic slow-response resources were studied as shown as a percentage of study area load.

Table 6.6-2: Local Capacity Areas and Resource Amounts Assessed

Load Serving Entity	Areas studied	Slow-response resource amounts studied
Method 1		
SCE	- All LCAs, - All sub-areas	- Existing DR (Slow Response) - 2% of study area load - 5% of study area load - 10% of study area load
PG&E	- All LCAs	- Existing DR (Slow Response) - 2% of study area load - 5% of study area load - 10% of study area load
SDG&E	- San Diego sub-area	- Existing DR (Slow Response) - 1% of study area load - 3% of study area load
Method 2		
ISO	- Main local capacity areas and voltage stability limited sub-areas in southern California	- Existing DR (Slow Response)

6.6.4 SCE Area Assessment

Existing SCE supply resource DR programs

Table 6.6-3 provides demand response MW by LCR area of existing supply resource DR including fast-response resources, i.e. resources with a response time of 20 minutes or less, and slow-response resources, i.e. resources with a response time greater than 20 minutes. The table does not include DR programs such as PTR-PCT and CPP that are accounted for in the CEC load forecast. As noted earlier the slow-response DR programs are the focus of this study.

Table 6.6-3: Existing SCE Supply Resource DR Programs

Region ↓ Program →	Response time ≤ 20 minutes (MW)					Response time > 20 minutes (MW)				Grand total (MW)
	API	BIP15	SDP-C	SDP-R	Total	BIP30	CBP	AMP	Total	
El Nido	0.2	3.7	2.4	2.2	8.4	26.0	3.3	5.0	34.3	42.7
West of Devers	0.0	-	1.8	8.6	10.3	2.8	1.2	5.4	9.4	19.8
Valley-Devers	1.3	7.8	4.0	34.7	47.8	5.4	5.0	8.5	18.8	66.6
Western LA Basin	2.1	26.9	22.6	61.2	112.8	297.7	21.9	35.3	354.9	467.6
LA Basin	3.9	44.3	36.0	141.1	225.3	469.3	34.5	62.8	566.7	792.0
Rector	30.3	6.2	2.0	6.8	45.4	12.5	1.7	2.4	16.6	62.0
Vestal	43.0	7.2	2.2	7.4	59.8	14.1	2.5	11.1	27.7	87.5
Santa Clara	0.8	0.3	1.9	1.8	4.8	24.2	2.7	3.3	30.1	35.0
Moorpark	0.9	1.2	3.0	7.4	12.5	28.5	3.9	5.1	37.5	50.0
Big Creek Ventura	45.6	39.1	7.7	30.0	122.5	46.5	10.1	23.1	79.7	202.2
Total (MW)	49.6	83.4	43.8	171.1	347.8	515.8	44.6	85.9	646.4	994.2

Existing slow-response DR program information

Table 6.6-4 summarizes the availability limitations and capacity values of existing SCE DR programs with >20 minute response time. Each of these availability limitations were evaluated in the study. Additional operational characteristics of these programs are provided in Table 6.6-5.

Table 6.6-4: Existing SCE DR Program availability characteristics

Program name	Hours per year	Days per month	Hours per month	Event duration in hours	Number of events per day	Additional availability restrictions	MW Capacity
BIP-30	180	10	N/A	6	1	N/A	516
CBP	N/A	N/A	30	4,6,8	1	Monday-Friday, 11 a.m. - 7 p.m.	86
AMP	N/A (varies by contract)						45

Table 6.6-5: Additional existing SCE DR program characteristics

Program name	Level of Dispatch	Notification Time	Triggers
BIP-30	System-wide, Sub-LAP, A-Bank	30 minutes	System, local, distribution reliability
CBP	System-wide, Sub-LAP	Day Of: 1 hour, Day Ahead by 3 p.m.	Economic criterion (15,000 Btu/kWh heat rate)
AMP		Day of: 1 hour	varies by contract

SCE slow-response resource amounts assessed

In addition to current slow-response DR amounts, generic slow-response resources amounts of 2%, 5% and 10% of area peak load were evaluated for each main local capacity area (LCA) and sub-area in the SCE area as shown in MW in Table 6.6-6 and as a percentage of the 2017 LCR in Table 6.6-7.

Table 6.6-6: Resource amounts assessed in MW

Area/Sub-area	Existing slow-response DR		2% of Peak (MW)	5% of Peak (MW)	10% of Peak (MW)
	MW	Percent of peak load			
El Nido	34.3	2.1%	33.2	83.0	165.9
West of Devers	9.4	1.3%	14.4	36.0	72.0
Valley-Devers	18.8	0.7%	52.7	131.8	263.6
Western LA Basin	354.9	3.1%	230.0	575.1	1150.1
LA Basin	566.7	3.0%	374.9	937.3	1874.6
Rector	16.6	1.5%	21.9	54.7	109.4
Vestal	27.7	2.2%	25.7	64.2	128.3
Santa Clara	30.1	3.7%	16.3	40.7	81.4
Moorpark	37.5	2.3%	32.0	80.1	160.1
Big Creek Ventura	79.7	1.8%	86.0	215.0	429.9
Total	646.4	--	460.9	1152.3	2304.5

Table 6.6-7: Resource amounts assessed as a percentage of 2017 LCR

Area/Sub-area	2017 LCR (MW)	Resource amounts as a percentage of 2017 LCR			
		Existing slow-response DR (MW)	2% of Peak (MW)	5% of Peak (MW)	10% of Peak (MW)
El Nido	318	10.8%	10.4%	26.1%	52.2%
West of Devers	261	3.6%	5.5%	13.8%	27.6%
Valley-Devers	1415	1.3%	3.7%	9.3%	18.6%
Western LA Basin	3871	9.2%	5.9%	14.9%	29.7%
LA Basin	7368	7.7%	5.1%	12.7%	25.4%
Rector	513	3.2%	4.3%	10.7%	21.3%
Vestal	715	3.9%	3.6%	9.0%	17.9%
Santa Clara	227	13.3%	7.2%	17.9%	35.9%
Moorpark	511	7.3%	6.3%	15.7%	31.3%
Big Creek Ventura	2057	3.9%	4.2%	10.5%	20.9%
Total	9425	6.9%	4.9%	12.2%	24.5%

Method 1 and Method 2 area load thresholds

As noted earlier, all SCE LCR areas and sub-areas and all slow-response resource amounts were assessed using Method 1 whereas only main LCR areas and voltage stability limited sub-areas were assessed for current levels of slow-response DR. Table 6.6-8 provides area load thresholds determined using Method 1 and Method 2.

Table 6.6-8: Area load thresholds based on current slow-DR amounts

Area	Limiting condition	Area load MW (A)	Method 1		Method 2	
			Existing Slow DR MW (B)	Area load threshold (A-B)	Required load reduction from power flow (C)	Area load threshold (A-C)
El Nido *	Voltage	1,659	34.3	1,625	34.3	1,625
West of Devers *	Voltage	720	9.4	711	9.4	711
Valley-Devers	Thermal	2,636	18.8	2,617	N/A	N/A
Western LA	Thermal	11,501	354.9	11,146	N/A	N/A
LA Basin	Thermal	18,746	566.7	18,179	N/A	N/A
San Diego	Thermal	4,838	10	4,828	N/A	N/A
Combined LA Basin/San Diego	Voltage stability[126]	23,584	577.7	N/A	1,085	22,499
Rector	Thermal	1,094	16.6	1,077	N/A	N/A
Vestal	Thermal	1,283	27.7	1,255	N/A	N/A
Santa Clara *	Voltage	814	30.1	784	34.9	779
Moorpark *	Voltage	1,601	37.5	1,564	38.6	1562
Big Creek	Thermal	4,299	79.7	4,219	79.7	4219
* Areas further assessed using Method 2.						

The Method 2 assessment for LA Basin and San Diego area is performed for the combined area since for one of the most limiting contingencies, the n-1-1 loss of Sunrise and SWPL, the combined area load is the load that causes the voltage collapse concern once the contingency has occurred. Thus, the combined load shape of the two areas was studied even if resource procurement responsibilities are split between the two areas[127].

[126] The 2017 LCR study analyzed two scenarios for the combined LA Basin/San Diego area to address concerns related to the potential of a peak shift issue associated with the impact of behind-the-meter solar generation which may be understating the local area peak, and concerns with the Aliso Canyon gas storage facility affecting the availability of LA Basin gas-fired generation. The former scenario in which the limiting condition is voltage instability was selected for the Method 2 assessment in this study in order to capture the reactive power impacts of replacing synchronous generators with demand response.

[127] This approach is consistent with the CPUC Track 4 scoping ruling which specifically recognized the electrical interdependence of the two areas and noted "Due to the interdependency of the LA Basin local area and San Diego sub-area on the SONGS facility, one comprehensive set of studies will be conducted. Collectively this area is referred to as the SONGS Study Area."

Assessment results

The following availability characteristics which are based on the characteristics for SCE's existing slow-response DR programs were evaluated for the SCE area.

- • annual, monthly and daily hours
- • number of dispatches per month and day
- • operating times (days of the week, hours of the day)

Annual dispatch hours

Table 6.6-9 provides the annual number of hours of slow-response resource dispatch for each area and resource amount studied. The columns labeled "Local" and "Overall" represent results without and with non-coincident calls in overlapping areas included in the sub-area results, respectively. In comparison, the BIP30 program has 180 hours per year maximum limit and the RDRR market model has 96 hours per year (48 hours per term) minimum limit.

Table 6.6-9: Annual dispatch hours (3-year max.)

	Existing DR*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	19	29(30)	19	22	45	47	223	223
West of Devers *	4	9 (13)	5	6	18	23	65	83
Valley-Devers	3	9 (14)	8	11	15	26	57	79
Western LA Basin	16	16(17)	7	7	23	23	49	52
LA Basin*	8(13)	8(13)	5	5	13	13	40	40
Rector	5	27	7	28	22	75	88	190
Vestal	6	27	6	28	31	73	100	189
Santa Clara*	21(24)	26(29)	13	26	26	65	86	184
Moorpark*	6(7)	23	6	24	19	61	37	146
Big Creek Ventura*	21	21	22	22	57	57	141	141
* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.								

Monthly dispatch hours

Table 6.6-10 provides the maximum number of hours per month of slow-response resource dispatch for each area and resource amount studied. The columns labeled "Local" and "Overall" represent results without and with non-coincident calls in overlapping areas included in the sub-area results, respectively. In comparison, CPB has a 30 hours per month maximum limit.

Table 6.6-10: Maximum monthly dispatch hours (3-year max.)

	Existing DR*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	16	23(24)	16	19	36	37	63	63
West of Devers*	4	9(12)	4	5	12	13	31	37
Valley-Devers	3	8(12)	8	8	14	16	29	33
Western LA Basin	13	13(14)	7	7	17	17	31	33
LA Basin*	8(12)	8(12)	5	5	12	12	26	26
Rector	5	9	7	11	14	28	52	81
Vestal	6	8	6	8	21	25	64	76
Santa Clara*	13 (14)	13(14)	9	10	17	21	42	50
Moorpark*	3 (4)	8(8)	3	8	13	20	24	47
Big Creek Ventura*	7	7	7	7	20	20	46	46
* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.								

Number of dispatches per month

Table 6.6-11 provides the maximum number of dispatches (days) per month for each area and resource amount studied. The columns labeled “Local” and “Overall” represent results without and with non-coincident calls in overlapping areas included in the sub-area results, respectively. In comparison, BIP30 has a 10 dispatch per month maximum limit.

Table 6.6-11: Maximum number of monthly dispatches (3-year max.)

	Existing DR*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	4	4	3	4	4	4	14	14
West of Devers*	2	3	2	3	6	6	9	11
Valley-Devers	3	4	3	3	5	6	7	8
Western LA Basin	4	4	3	3	4	4	4	5
LA Basin*	3	3	2	2	4	4	5	5
Rector	2	4	2	4	6	7	11	16
Vestal	2	3	2	3	7	7	13	16
Santa Clara*	3	3	3	3	4	4	6	12
Moorpark*	2(3)	3	2	3	4	4	4	12
Big Creek Ventura*	3	3	3	3	4	4	12	12
* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.								

Dispatch duration

Table 6.6-12 provides the maximum duration of a single dispatch for each area and resource amount studied. The columns labeled “Local” and “Overall” represent results without and with non-coincident calls in overlapping areas included in the sub-area results, respectively. In comparison, BIP30 has a 6 hour duration limit whereas the CPB limit 4, 6 or 8 hours depending on the product.

Table 6.6-12: Maximum dispatch duration (3-year max.)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	6	7	6	6	11	11	14	14
West of Devers*	2	4(5)	2	3	4	5	7	9
Valley-Devers	1	4(5)	3	3	4	5	7	9
Western LA Basin	4	4(5)	3	3	5	5	10	10
LA Basin*	4(5)	4(5)	3	3	5	5	9	9
Rector	3	4	4	4	6	6	9	9
Vestal	4	4	4	4	6	6	9	9
Santa Clara*	5	5	4	4	6	7	11	11
Moorpark*	3	4	3	4	5	6	9	9
Big Creek Ventura*	4	4	4	4	6	6	9	9

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

Yellow highlights indicate results that exceed the characteristics of one or more existing DR programs at current DR levels.

Weekend dispatch

Table 6.6-13 provides the number of weekend dispatches when CPB resources are not available. The columns labeled "Local" and "Overall" represent results without and with non-coincident calls in overlapping areas included in the sub-area results, respectively.

Table 6.6-13: number of weekend dispatches (3-year max.)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	0	0	0	0	0	0	1	1
West of Devers*	0	0	0	0	2	2	2	2
Valley-Devers	2	2	2	2	2	2	4	4
Western LA	0	0	0	0	0	0	0	1
LA Basin*	0	0	0	0	0	0	1	1
Rector	0	1	0	1	0	2	3	5
Vestal	0	1	0	1	0	2	3	5
Santa Clara*	1	1	1	1	1	2	1	4
Moorpark*	0	1	0	1	0	2	0	4
Big Creek	1	1	1	1	2	2	4	4

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

Yellow highlights indicate results that exceed the characteristics of one or more existing DR programs at current DR levels.

Weekday dispatch outside 11 a.m. -7 p.m.

Table 6.6-14 provides the number of dispatches 11 a.m. -7 p.m. weekdays when CPB resources are not available. The columns labeled "Local" and "Overall" represent results without and with non-coincident calls in overlapping areas included in the sub-area results, respectively.

Table 6.6-14: Number of Weekday Dispatches (3-year max)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	2	2	2	2	10	10	46	46
West of Devers*	0	0	0	0	0	0	0	0
Valley-Devers	0	0	0	0	0	0	0	0
Western LA Basin	0	0	0	0	0	0	1	1
LA Basin*	0	0	0	0	0	0	0	0
Rector	0	0	0	0	1	1	5	8
Vestal	0	0	0	0	1	1	8	8
Santa Clara*	0	0	0	0	0	0	10	12
Moorpark*	0	0	0	0	0	0	0	2
Big Creek Ventura*	0	0	0	0	0	0	2	2
* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA. Yellow highlights indicate results that exceed the characteristics of one or more existing DR programs at current DR levels.								

Multiple dispatches per day

Table 6.6-15 provides the number of multiple dispatches in a single day. The columns labeled "Local" and "Overall" represent results without and with non-coincident calls in overlapping areas included in the sub-area results, respectively. BIP30 and CPB have a 1 dispatch per day limit.

Table 6.6-15: Number of Multiple Dispatches in a Single Day (3-year max)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	0	0	0	0	2	2	6	6
West of Devers*	0	0	0	0	1	0	0	0
Valley-Devers	0	0	0	0	0	0	1	0
Western LA Basin	0	0	0	0	0	0	3	1
LA Basin*	0	0	0	0	0	0	0	0
Rector	1	0	0	0	1	0	1	2
Vestal	0	0	0	0	0	0	2	2
Santa Clara*	0	0	0	0	1	1	4	1
Moorpark*	0	0	0	0	0	0	1	0
Big Creek Ventura*	0	0	0	0	0	0	0	0
* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.								

6.6.5 SDG&E Area Assessment

Existing supply slow-response DR programs

Table 6.6-16 provides SDG&E's existing slow response demand response program MW and availability characteristics.

Table 6.6-16: Existing SDG&E DR > 20 minute response time

program name	Annual hours	Dispatches per month	Dispatch hours per month	Run time in hours	Dispatches per day	Consec. dispatch days	Other restrictions	MW Capacity
Summer Saver	72	18	72	4	1	3	May – October	10

SDG&E slow-response resource amounts assessed

In addition to current slow-response DR amounts, generic slow-response resources amounts of 1% and 3% of 2017 area peak load were evaluated for the San Diego local capacity area. The amounts are shown in MW and as a percentage of the 2017 LCR in Table 6.6-17.

Table 6.6-17: Resource Amounts Assessed

LCR Area	Resource amount	Existing (0.2% of peak) (MW)	1% of peak (MW)	3% of peak (MW)
San Diego (2017 LCR=2,915 MW)	In MW	10	40.4	145.1
	As a percentage of 2017 LCR	0.3%	1.4%	5.0%

Method 1 and Method 2 area load thresholds

For the San Diego area, all slow-response resource amounts were assessed using Method 1 whereas Method 2 was applied for the combined LA Basin and San Diego area due to the interdependence of the two areas for the Sunrise and SWPL N-1-1 outage even if resource procurement responsibilities are split between the two areas.

Table 6.6-18 provides area load thresholds determined using Method 1 and Method 2 based on current slow-DR amounts.

Table 6.6-18: Area Load Thresholds Based on Current /slow DR Amounts

Area	Limiting condition	Area load MW (A)	Method 1		Method 2	
			Existing Slow DR MW (B)	Area load threshold (A-B)	Required load reduction from power flow (C)	Area load threshold (A-C)
San Diego	Voltage stability[128]	4,838	10.0	4,828	--	--
Combined LA Basin/San Diego *		23,584	577.7	23,006	1,085	22,499
* Areas further assessed using Method 2.						

Assessment results

Table 6.6-19 provides the San Diego area results for each of the characteristics of SDG&E's existing slow-response DR programs.

Table 6.6-19: San Diego Area Assessment Results

	Slow resource amounts		
	Existing DR*	1% of Peak	3% of Peak
Annual dispatch (hours)	1 (13)	4	9
Dispatches per month (hours)	1(12)	2	9
Number of dispatches per month (days)	1(3)	1	3
Max. dispatch duration (hours)	1(5)	2	5
Number of events/day > 1	0	0	1
Max. consecutive events (days)	1 (3)	1	3
Dispatches during November – April (days)	0	0	0
* Slow-response resource levels further assessed using Method 2. Results are provided in parenthesis. Method 2 assessment is based on the combined LA Basin-San Diego LCA. Yellow highlights indicate results that exceed the characteristics of one or more existing DR programs at current DR levels.			

[128] The 2017 LCR study analyzed two scenarios for the combined LA Basin/San Diego area to address concerns related to the potential of a peak shift issue associated with the impact of behind-the-meter solar generation which may be understating the local area peak, and concerns with the Aliso Canyon gas storage facility affecting the availability of LA Basin gas-fired generation. The former scenario in which the limiting condition is voltage instability was selected for the Method 2 assessment in this study in order to capture the reactive power impacts of replacing synchronous generators with demand response.

6.6.6 PG&E Area Assessment

Existing slow-response DR program information - PG&E area.

Table 6.6-20 summarizes the availability limitations and capacity values of existing PG&E DR programs with >20 minute response time identified by PG&E as focus of this study. Each of these availability limitations were evaluated in the study.

Table 6.6-20: Existing PG&E DR Program Availability Characteristics

Program name	Notification time	Max annual hours	Period	Max monthly event days	Days	Max monthly hours	Hours of the day	Max event hours	Capacity MW
BIP	30 m	180	any	10	any	N/A	any	N/A	63.9
AMP	30 m	80	5/1-10/31	N/A	M-F	N/A	11:00-19:00	4-6	71.4
Smart AC	N/A	100	5/1-10/31	N/A	any	N/A	any	6	44.9

PGE slow-response resource amounts assessed:

In addition to current slow-response DR amounts, generic slow-response resources amounts of 2%, 5% and 10% of area peak load were evaluated for each local capacity area (LCA) in the PG&E area as shown in MW in Table 6.6-21 and as a percentage of the 2017 LCR in Table 6.6-22.

Attention: Sierra, Stockton and Kern process book definitions (used in this study) do not align with local capacity area definitions. Future DR Program assessments will have to proper align the two definitions for an informed conclusion and decision making process.

Table 6.6-21: Resource Amounts Assessed in MW

Area	Existing slow-response DR		2% of Peak (MW)	5% of Peak (MW)	10% of Peak (MW)
	MW	Percent of peak load			
Humboldt	6.8	3.62%	2.8	7.1	14.2
Sierra	18.5	1.05%	23.9	59.6	119.2
Stockton	22.0	1.90%	26.9	67.3	134.6
Greater Bay	48.5	0.46%	163.5	408.8	817.7
N Coast & N Bay	9.6	0.73%	28.3	70.7	141.5
Kern	42.4	3.72%	36.6	91.6	183.2
Fresno	32.3	1.09%	65.1	162.7	325.4
Total	180.2	0.95%	347.1	867.8	1735.7

Table 6.6-22: Resource Amounts Assessed as a Percentage of 2017 LCR

Area	2017 LCR (MW)	Resource amounts as a percentage of 2017 LCR			
		Existing slow-response DR (MW)	2% of Peak (MW)	5% of Peak (MW)	10% of Peak (MW)
Humboldt	157	4.33%	1.78%	4.52%	9.04%
Sierra	2043	0.91%	1.17%	2.92%	5.83%
Stockton	745	2.95%	3.61%	9.03%	18.07%
Greater Bay	5617	0.86%	2.91%	7.28%	14.56%
N Coast & N Bay	721	1.33%	3.93%	9.81%	19.63%
Kern	492	8.62%	7.44%	18.62%	37.24%
Fresno	1779	3.9%	1.82%	3.66%	9.15%
Total	11554	1.56%	3.00%	7.51%	15.02%

Assessment results

The following availability characteristics which are based on the characteristics for PG&E's existing slow-response DR programs were evaluated for the PG&E area.

- • annual, monthly and daily hours
- • number of dispatches per month and day
- • operating times (days of the week, hours of the day, weekends, days in a row)

Only the main LCR areas have been analyzed in PG&E therefore these results do not take into account observed non-coincidence of DR calls among areas and sub areas.

Humboldt

Table 6.6-23 provides the assessment data results for Humboldt area.

Table 6.6-23: Humboldt (3-year max.)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	20	4	22	149
Monthly # of hours	10	4	11	62
Monthly event days	6	2	6	19
Weekend Events	0	0	1	7
Events outside 11-7	2	1	2	9
Days in a row	4	2	4	13
Other	Need is November-March only	Need is November-March only	Need is November-March only	2 events/day or 8 hours/day with 6 hours break

Sierra

Table 6.6-24 provides the assessment data results for Sierra area.

Table 6.6-24: Sierra (3-year max.)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	3	4	10	32
Monthly # of hours	3	4	9	22
Monthly event days	2	2	3	5
Weekend Events	0	0	1	3
Events outside 11-7	0	0	0	0
Days in a row	2	2	3	6
Other	-	-	-	6 hours/day

Stockton

Table 6.6-25 provides the assessment data results for Stockton area.

Table 6.6-25: Stockton (3-year max.)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	6	6	18	49
Monthly # of hours	4	5	11	20
Monthly event days	1	1	3	4
Weekend Events	0	0	0	1
Events outside 11-7	0	0	0	0
Days in a row	1	1	3	3
Other	-	5 hours/day	6 hours/day	7 hours/day

Bay Area

Table 6.6-26 provides the assessment data results for Bay Area.

Table 6.6-26: Bay Area (3-year max.)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	5	18	50
Monthly # of hours	2	4	15	29
Monthly event days	2	2	4	6
Weekend Events	1	1	1	2
Events outside 11-7	0	0	0	0
Days in a row	2	2	3	4
Other	-	-	5 hours/day	8 hours/day

North Coast/North Bay

Table 6.6-27 provides the assessment data results for North Coast/North Bay area.

Table 6.6-27: North Coast/North Bay (3-year max.)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	2	14	50
Monthly # of hours	2	2	8	20
Monthly event days	1	1	3	5
Weekend Events	0	0	2	2
Events outside 11-7	0	0	0	0
Days in a row	1	1	2	6
Other	-	-	-	6 hours/day

Kern

Table 6.6-28 provides the assessment data results for Kern area.

Table 6.6-28: Kern (3-year max.)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	12	8	46	175
Monthly # of hours	8	7	34	110
Monthly event days	5	3	8	20
Weekend Events	0	0	2	10
Events outside 11-7	1	0	2	2
Days in a row	3	1	3	9
Other	-	-	8 hours/day	11 hours/day

Fresno

Table 6.6-29 provides the assessment data results for Fresno area.

Table 6.6-29: Fresno (3-year max.)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	11	14	37	133
Monthly # of hours	8	11	26	79
Monthly event days	3	4	7	14
Weekend Events	0	0	3	8
Events outside 11-7	0	0	0	0
Days in a row	2	2	4	8
Other	-	-	7 hours/day	9 hours/day

6.6.7 Conclusions

This special study examined the required availability for slower-response resources to be considered for local resource adequacy on the basis of pre-contingency dispatch. The following conclusions can be drawn based on the results of the study.

- The availability needs identified in this study are exclusively for local RA use. Additional provisions should be made for other non-coincident uses of slow-response resources such as to respond to planned outages, non-local and distribution system needs or price triggers.
- Requirements for voltage stability limited areas in particular must be established using Method 2 to account for reactive power impacts of replacing local RA generators with DR.
- Availability requirements increase as the amount of DR that counts for local RA increases. One possible approach to facilitate the establishment of availability criteria is to set a limit for the amount of DR that counts for local RA.
- At current levels, most existing slow-response DR resources appear to have adequate availability to count for local resource adequacy on the basis of pre-contingency dispatch. Exceptions are:
    - SCE BIP and CPB resources in the El Nido area where 7-hour run time and availability outside weekdays 11 a.m. – 7 p.m. were found to be needed.
    - SCE CPB resources in the Big Creek area and the Valley-Devers sub-area where availability outside weekdays 11 a.m. – 7 p.m. was found to be needed.

- o SCE CPB 4-hour and SDG&E Summer Saver resources in the LA Basin and San Diego area and Santa Clara sub-area where 5-hour run time was found to be needed.
- o The SCE AMP program was not evaluated against the availability results as its characteristics varies with contract and was not made available to the ISO.
- o DR programs in Humboldt due to season, time and length of need.
- o DR programs in Sierra, Stockton and Kern due to definition mismatch (additional studies with correct boundary is necessary before conclusions can be drawn).

- Note that the methodology is not applicable to any resource-deficient areas and sub-areas.
- Availability requirements vary among LCR areas and sub-areas as presented in the results due to differences in load profiles. Table 6.6-30 show the maximums for all areas per TAC based on current slow-response DR levels which can be considered if one set of TAC[129]-wide criteria is desired for ease of implementation. Studies using Method 2 need to be performed for voltage stability limited areas before availability criteria for higher slow response-DR levels can be established.

Table 6.6-30: Maximum Availability Requirements per TAC Area

Availability characteristics	TAC-wide minimum requirements based on current slow-DR levels			RDRR availability limits (for reliability-only use)
	SCE	SDG&E	PG&E	
Annual hours	30	13	20	96 (48 per term)
Monthly hours	24	12	10	--
Number of events per month	4	3	6	--
Number of events per year	10	4	12	30 (15 per term)
Run time in hours	7 (5 if El Nido sub-area is excluded)	5	4	4
Number of calls per day	1	1	1	--
Max. consecutive event days	N/A	3	4	--
Restrictions on seasonal, day-of-week and hour-of-day availability	Monday-Friday, 11 a.m. - 7 p.m. not OK	November – April unavailability OK	Eliminate all restrictions	--

[129] Transmission Access Charge (TAC)

- At current DR levels, the minimum reliability-only[130] availability requirements of the CAISO RDRR market model appears to adequately address local RA needs in all TAC areas with the exception of the 4 hour minimum run time. If the minimum run time for RDRR resources is increased to 5 or 6 hours, it could allow resources registered as RDRR to count for local RA in almost all ISO local areas.

- The study has identified significant occurrences of non-coincident DR calls among overlapping areas. Once a slow-response resource counts for local RA, it will be used in real time and transmission planning studies as a mitigation for all contingencies in an LCR area and its sub-areas not just for the critical contingency. As a result studies for main LCR areas as well as sub-areas need to be performed before specific availability criteria can be developed, as was done for the SCE area.

[130] Economic participation of RDRR resources in the day-ahead market does not reduce availability limits.

Chapter 7

7 Transmission Project List

7.1 Transmission Project Updates

Table 7.1-1 and Table 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	Trans Bay Cable Dead Bus Energization Project	TransBay Cable	Completed
2	Estrella Substation Project	NEET West	May-19
3	Almaden 60 kV Shunt Capacitor	PG&E	Canceled
4	Ashlan-Gregg and Ashlan-Herndon 230 kV Line Reconductor	PG&E	May-18
5	Borden 230 kV Voltage Support	PG&E	May-19
6	Caruthers – Kingsburg 70 kV Line Reconductor	PG&E	Apr-19
7	Cascade 115/60 kV No.2 Transformer Project and Cascade – Benton 60 kV Line Project	PG&E	May 19 and Nov-22
8	Cayucos 70 kV Shunt Capacitor	PG&E	May-21
9	Christie 115/60 kV Transformer No. 2	PG&E	Jan-2018
10	Clear Lake 60 kV System Reinforcement	PG&E	Feb-23
11	Contra Costa – Moraga 230 kV Line Reconductoring	PG&E	Completed
12	Contra Costa Sub 230 kV Switch Replacement	PG&E	Dec-17
13	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	May-2018

14	Cortina No.3 60 kV Line Reconductoring Project	PG&E	May-2019
15	Cressey – North Merced 115 kV Line Addition	PG&E	Canceled
16	Diablo Canyon Voltage Support Project	PG&E	Jul-19
17	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	Dec-2020
18	Estrella Substation Project	PG&E/NEET West[131]	May-19
19	Evergreen-Mabury Conversion to 115 kV *	PG&E	Jun-21
20	Fulton 230/115 kV Transformer	PG&E	May-22
21	Fulton-Fitch Mountain 60 kV Line Reconductor	PG&E	Aug-18
22	Glenn #1 60 kV Reconductoring	PG&E	Apr-21
23	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	Dec-2018
24	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	Mar-2018
25	Helm-Kerman 70 kV Line Reconductor	PG&E	May-17
26	Ignacio – Alto 60 kV Line Voltage Conversion	PG&E	Mar-23
27	Jefferson-Stanford #2 60 kV Line	PG&E	On hold
28	Kern – Old River 70 kV Line Reconductor Project	PG&E	Dec-16
29	Kern PP 230 kV Area Reinforcement	PG&E	Apr-23
30	Kearney-Caruthers 70 kV Line Reconductor	PG&E	Apr-2019
31	Kearney – Hearndon 230 kV Line Reconductoring	PG&E	Mar-2019

131 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.

32	Kearney-Kerman 70 kV Line Reconductor	PG&E	Canceled
33	Lemoore 70 kV Disconnect Switches Replacement	PG&E	Apr-2017
34	Lockheed No.1 115 kV Tap Reconductor	PG&E	Canceled
35	Lodi-Eight Mile 230 kV Line	PG&E	Sep-2019
36	Los Banos-Livingston Jct-Canal 70 kV Switch Replacement	PG&E	Jan-2018
37	Los Esteros-Montague 115 kV Substation Equipment Upgrade	PG&E	Mar-21
38	Maple Creek Reactive Support	PG&E	Jan-2020
39	McCall-Reedley #2 115 kV Line	PG&E	May-22
40	Menlo Area 60 kV System Upgrade	PG&E	Completed
41	Mesa-Sisquoc 115 kV Line Reconductoring	PG&E	Completed
42	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	May-19
43	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	Apr-22
44	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Nov-2026
45	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	Apr-2019
46	Missouri Flat – Gold Hill 115 kV Line	PG&E	Dec-18
47	Monta Vista – Los Gatos – Evergreen 60 kV Project	PG&E	Canceled
48	Monte Vista 230 kV Bus Upgrade	PG&E	Apr-2020
49	Moraga Transformers Capacity Increase	PG&E	Completed
50	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Mar-21
51	Moraga-Oakland "J" SPS Project	PG&E	Completed
52	Morro Bay 230/115 kV Transformer Addition Project	PG&E	Apr-2019
53	Mosher Transmission Project	PG&E	May2019

54	Mountain View/Whisman-Monta Vista 115 kV Reconductoring	PG&E	Canceled
55	Napa – Tulucay No. 1 60 kV Line Upgrades	PG&E	Jul-20
56	Navidad Substation Interconnection	PG&E	Canceled
57	North Tower 115 kV Looping Project	PG&E	Dec-21
58	NRS-Scott No. 1 115 kV Line Reconductor	PG&E	May-18
59	Oakhurst/Coarsegold UVLS	PG&E	May-17
60	Oro Loma – Mendota 115 kV Conversion Project	PG&E	May-19
61	Oro Loma 70 kV Area Reinforcement	PG&E	Apr-23
62	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	May-20
63	Pease-Marysville #2 60 kV Line	PG&E	Canceled
64	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	May-22
65	Pittsburg-Lakewood SPS Project	PG&E	Completed
66	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	May-21
67	Reedley 70 kV Reinforcement	PG&E	Feb-20
68	Reedley 115/70 kV Transformer Capacity Increase	PG&E	May-21
69	Reedley-Dinuba 70 kV Line Reconductor	PG&E	Mar-19
70	Reedley-Orosi 70 kV Line Reconductor	PG&E	Dec-18
71	Rio Oso – Atlantic 230 kV Line Project	PG&E	Dec-22
72	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Jul-21
73	Rio Oso Area 230 kV Voltage Support	PG&E	Feb-22
74	Ripon 115 kV Line	PG&E	Apr-22
75	San Bernard – Tejon 70 kV Line Reconductor	PG&E	Jan-18

76	San Mateo – Bair 60 kV Line Reconductor	PG&E	May-23
77	Semitropic – Midway 115 kV Line Reconductor	PG&E	Jan-19
78	Series Reactor on Warnerville-Wilson 230 kV Line	PG&E	Dec-17
79	Soledad 115/60 kV Transformer Capacity	PG&E	Canceled
80	South of San Mateo Capacity Increase *	PG&E	Feb-29
81	Spring 230/115 kV substation near Morgan Hill **	PG&E	May-21
82	Stagg – Hammer 60 kV Line	PG&E	Aug-22
83	Stockton ‘A’ –Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	Jun-19
84	Stone 115 kV Back-tie Reconductor	PG&E	Canceled
85	Table Mountain – Sycamore 115 kV Line	PG&E	Dec-25
86	Taft-Maricopa 70 kV Line Reconductor	PG&E	Canceled
87	Tesla 115 kV Capacity Increase	PG&E	Completed
88	Tesla-Newark 230 kV Path Upgrade	PG&E	Canceled
89	Vaca Dixon – Lakeville 230 kV Reconductoring	PG&E	Canceled
90	Vierra 115 kV Looping Project	PG&E	Feb-23
91	Warnerville-Bellota 230 kV line reconductoring	PG&E	Aug-22
92	Watsonville Voltage Conversion *	PG&E	Jun-21
93	Weber 230/60 kV Transformer Nos. 2 and 2A Replacement	PG&E	Completed
94	Weber-French Camp 60 kV Line Reconfiguration	PG&E	Completed
95	West Point – Valley Springs 60 kV Line	PG&E	May-19
96	Wheeler Ridge Voltage Support	PG&E	Mar-19
97	Wheeler Ridge-Weedpatch 70 kV Line Reconductor *	PG&E	Jan-19

98	Wilson 115 kV Area Reinforcement	PG&E	May-19
99	Wilson-Le Grand 115 kV line reconductoring	PG&E	Dec-20
100	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	Dec-20
101	Bellota 230 kV Substation Shunt Reactor	PG&E	Jan-19
102	Cottonwood 115 kV Substation Shunt Reactor	PG&E	Jan-19
103	Delevan 230 kV Substation Shunt Reactor	PG&E	Feb-19
104	Ignacio 230 kV Reactor	PG&E	Jun-20
105	Los Esteros 230 kV Substation Shunt Reactor	PG&E	May-19
106	Wilson 115 kV SVC	PG&E	Dec-20
107	2nd Escondido-San Marcos 69 kV T/L	SDG&E	Dec-20
108	2nd Pomerado - Poway 69kV Circuit	SDG&E	Jun-18
109	Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously approved New Sycamore - Bernardo 69 kV line)	SDG&E	Feb-19
110	Miguel 500 kV Voltage Support (aka Miguel VAR Support)	SDG&E	Apr-17
111	Miramar-Mesa Rim 69 kV System Reconfiguration	SDG&E	Jun-18
112	Mission Bank #51 and #52 replacement	SDG&E	Jun-18
113	Mission-Penasquitos 230 kV Circuit *	SDG&E	Jun-19
114	Reconductor TL663, Mission-Kearny	SDG&E	Jun-18
114	Reconductor TL676, Mission-Mesa Heights	SDG&E	Jun-18
116	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	Feb-21
117	Rose Canyon-La Jolia 69 kV T/L	SDG&E	Jun-18
118	Sweetwater Reliability Enhancement	SDG&E	Jun-20

119	TL626 Santa Ysabel – Descanso mitigation (TL625B loop-in, Loveland - Barrett Tap loop-in)	SDG&E	Dec-17
120	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Dec-20
121	TL633 Bernardo-Rancho Carmel Reconductor	SDG&E	Feb-19
122	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Jun-20
123	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	Dec-19
124	TL690A, San Luis Rey-Oceanside Tap	SDG&E	Completed
125	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	Jan-21
126	TL694A San Luis Rey-Morro Hills Tap: Reliability (Loop-in TL694A into Melrose)	SDG&E	Completed
127	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Dec-19
128	TL 13820, Sycamore-Chicarita Reconductor	SDG&E	Jun-18
129	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	Dec-21
130	Upgrade Los Coches 138/69 kV Bank 50	SDG&E	Dec-17
131	Upgrade Los Coches 138/69 kV bank 51	SDG&E	Completed
132	15 Mvar Capacitor at Basilone Substation	SDG&E	Jun-17
133	30 Mvar Capacitor at Pendleton Substation	SDG&E	Jun-17
134	Reconductor TL 605 Silvergate – Urban	SDG&E	Jun-18
135	Second Miguel – Bay Boulevard 230 kV Transmission Circuit	SDG&E	Jun-19
136	TL600: “Mesa Heights Loop-in + Reconductor	SDG&E	Jun-18
137	Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Swap	SCE	Jun-18
138	Kramer Reactors	SCE	Dec-17
139	Laguna Bell Corridor Upgrade	SCE	Dec-20

140	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-20
141	Method of Service for Wildlife 230/66 kV Substation	SCE	Jun-21
142	Path 42 and Devers – Mirage 230 kV Upgrades	SCE	Dec-16
143	Victor Loop-in	SCE	Jun-17
144	Eagle Mountain Shunt Reactors	SCE	Dec-18
145	CT Upgrade at Mead-Pahrump 230 kV Terminal	VEA	Completed

Notes:

* The project requires further evaluation in future planning cycles to reassess the need scope of the project. All development activities are recommended to be put on hold until a review is completed.

** The project requires further evaluation in future planning cycles to reassess the need scope of the project. The project is in the late stages of design, siting, and permitting, and continuing the design, siting and permitting activities will assist in the review. However, the ISO is recommending that the project sponsors do not proceed with filings for permitting and certificates of public convenience and necessity until the ISO completes the review.

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	May-17[132]
3	Atlantic-Placer 115 kV Line *	PG&E	Dec-21
4	Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project *	PG&E	Apr-24
5	Embarcadero-Potrero 230 kV Transmission Project	PG&E	Completed
6	Fresno Reliability Transmission Projects	PG&E	Completed
7	Gates #2 500/230 kV Transformer Addition	PG&E	Dec-22
8	Gates-Gregg 230 kV Line *	PG&E/MAT	Dec-22
9	Kern PP 115 kV Area Reinforcement *	PG&E	Jun-20
10	Lockeford-Lodi Area 230 kV Development **	PG&E	Dec-22
11	Martin 230 kV Bus Extension	PG&E	Apr-22
12	Midway-Andrew 230 kV Project **	PG&E	Jun-25
13	Midway – Kern PP #2 230 kV Line	PG&E	Jul-20
14	New Bridgeville – Garberville No. 2 115 kV Line *	PG&E	Jan-24
15	Northern Fresno 115 kV Area Reinforcement *	PG&E	Dec-22
16	South of Palermo 115 kV Reinforcement Project	PG&E	Feb-22
17	Vaca – Davis Voltage Conversion Project **	PG&E	Apr-25
18	Wheeler Ridge Junction Substation **	PG&E	May-20
19	San Luis Rey Synchronous Condensers (i.e., two 225 Mvar synchronous condensers)	SDG&E	Jun-17

[132] In service date to be revisited by project sponsor when Environmental Impact Report is completed

No	Project	PTO	Expected In-Service Date
20	Artesian 230 kV Sub & loop-in TL23051	SDG&E	Dec-20
21	Bay Boulevard 230/69 kV Substation Project	SDG&E	Completed
22	Imperial Valley Flow Controller (IV 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	Dec-21
24	Sycamore-Penasquitos 230 kV Line	SDG&E	Jun-18
25	South Orange County Dynamic Reactive Support – San Onofre (now 1-225 Mvar synchronous condenser)[133]	SDG&E	Apr-18
26	South Orange County Dynamic Reactive Support - Santiago Synchronous Condenser - SCE's component (1-225 Mvar synchronous condenser)[134]	SCE	Jun-18
27	Alberhill 500 kV Method of Service	SCE	Jun-21
28	Harry Allen-Eldorado 500 kV transmission project	DesertLink LLC	May-20
29	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	Jun-19
30	Lugo-Mohave series capacitor upgrade	SCE	Jun-19
31	Mesa 500 kV Substation Loop-In	SCE	Jun-21

[133] 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.

[134] Refer to the preceding footnote.

No	Project	PTO	Expected In-Service Date
32	Tehachapi Transmission Project	SCE	Completed

Notes:

* The project requires further evaluation in future planning cycles to reassess the need scope of the project. All development activities are recommended to be put on hold until a review is completed.

** The project requires further evaluation in future planning cycles to reassess the need scope of the project. The project is in the late stages of design, siting, and permitting, and continuing the design, siting and permitting activities will assist in the review. However, the ISO is recommending that the project sponsors do not proceed with filings for permitting and certificates of public convenience and necessity until the ISO completes the review.

7.2 Transmission Projects found to be needed in the 2016-2017 Planning Cycle

In the 2016-2017 transmission planning process, the ISO determined that 2 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 Table 7.2-1, Table 7.2-2, and Table 7.2-3.

A list of projects that came through the 2016 Request Window can be found in Appendix E.

Table 7.2-1: New Reliability Projects Found to be Needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Big Creek Rating Increase Project	SCE	Dec-18	$6 M
2	Lugo – Victorville 500 kV Upgrade (SCE portion)[135]	SCE	Dec-18	$18 M

Table 7.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
	No policy-driven projects identified in the 2016-2017 Transmission Plan			

Table 7.2-3: New Economic-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
	No economic-driven projects identified in the 2016-2017 Transmission Plan			

[135] Does not include LADWP's portion estimated at $16 million, that LADWP is addressing.

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 2016-2017 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:

7.3.1 Additional achievable energy efficiency (AAEE) in PG&E service territory

Sensitivity studies were conducted as a part of the 2016-2017 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:

Humboldt Area

- No new reliability concerns were identified in North Coast / North Bay area from the no-AAEE sensitivity studies.

North Coast and North Bay Area

- Several other overloads on lines that were seen to be overloaded in the base line scenario were seen to have worsened in the no-AAEE sensitivity study.

North Valley Area

- One new base case type P1 thermal overload was identified on Cottonwood-Anderson 60 kV line in the North Valley area in the no-AAEE sensitivity study.
- One new base case type P1 thermal overload was identified on Palermo-Big Bend 60 kV Line in the North Valley area in the no-AAEE sensitivity study.
- 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 scenario. Also, some facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE scenario.
- Four cases of 60kV voltages are slightly lower in the P3 type contingency scenario in the no-AAEE sensitivity study.

- For P6 contingencies there were 12 lines that are worse loaded in the no-AAEE, up to 20% higher loadings. For P6 type voltage 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.
- For P7 type contingencies the loading on most of the facilities overloaded in baseline scenario increased by about 10% to 20% in the no-AAEE sensitivity study. Also, some facilities overloaded in the baseline scenario were found to be overloaded from additional contingencies in the no-AAEE sensitivity study.

Central Valley Area

- No new reliability concerns were identified in in the no-AAEE sensitivity studies. In most cases the thermal overloads worsened under contingency conditions in the no-AAEE sensitivity study.

Greater Bay Area

- No new reliability concerns were identified in San Francisco area from the sensitivity studies. In some cases, thermal overloads were worsen by about 3% in the peak shift and about 4% in the no-AAEE sensitivity study.
- In Oakland area, new thermal overloads were identified on Grant-Oakland J 115 kV line in the no-AAEE sensitivity study. These results are captured in more detail in the East Bay area sensitivity study.
- In Metcalf 115 kV system, new thermal overloads were identified on Piercy-Metcalf and Swift-Metcalf 115 kV lines in the no-AAEE sensitivity study.
- In Oleum-Christie 115 kV system, new thermal overloads were identified on the Oleum-Martinez, Martinez-Sobrante and Sobrante-El Cerrito 115 kV lines in the no-AAEE sensitivity study. Also, the contingency loading on most of the facilities overloaded in baseline scenario increased by about 5% to 10% in the no-AAEE sensitivity study.
- In Peninsula 60 kV system, contingency loading on most of the facilities overloaded in baseline scenario increased by more than 10% in the no-AAEE sensitivity study.
- In San Jose 60 kV system, contingency loading on most of the facilities overloaded in baseline scenario increased by about 10% to 20% in the no-AAEE sensitivity study.

Fresno Area

- Two new P1 thermal overloads were identified in the 2021 Summer Peak no AAEE sensitivity study.
- For P7 type contingencies six new overloads were identified in the Kerckhoff-Chowchilla 115kV area in the no AAEE sensitivity study. The loading on the Woodward-Shepherd 115kV line worsens in the no AAEE sensitivity study.

Kern Area

- The Midway-Cymric #1 115 kV Line experienced up to 110% loading in the no-AAEE sensitivity study following a Category P6 of the Midway-Taft and Taft-Chalk Cliff 115 kV Lines.

Central Coast and Los Padres Area

- The Prundale Jct 1-Moss Landing 115 kV #1 Line was thermally loaded at 103% in the no-AAEE sensitivity study for the loss of Moss Landing-Salinas #1 & 2 kV Lines (Category P6).

7.3.2 Reliance on Aging Generation in the East Bay Area

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 2017-2018 transmission planning process the transmission, generation or non-transmission alternatives to address the needs of the area.

7.3.3 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; 1,313 MW in the LA Basin and 344 MW in the San Diego area. Grid connected distributed generation amounting to 340 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 37.5 MW forenergy storage (actual projects related to Aliso Canyon gas storage constraint), 22.4 MW of additional energy efficiency, and 33.6 MW of demand response for LTPP preferred resources and energy storage assumptions. Existing demand response, in the amount of 566 MW, was also assumed to be repurposed within the SCE and SDG&E areas 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 CEC load forecast.

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 2016-2017 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.

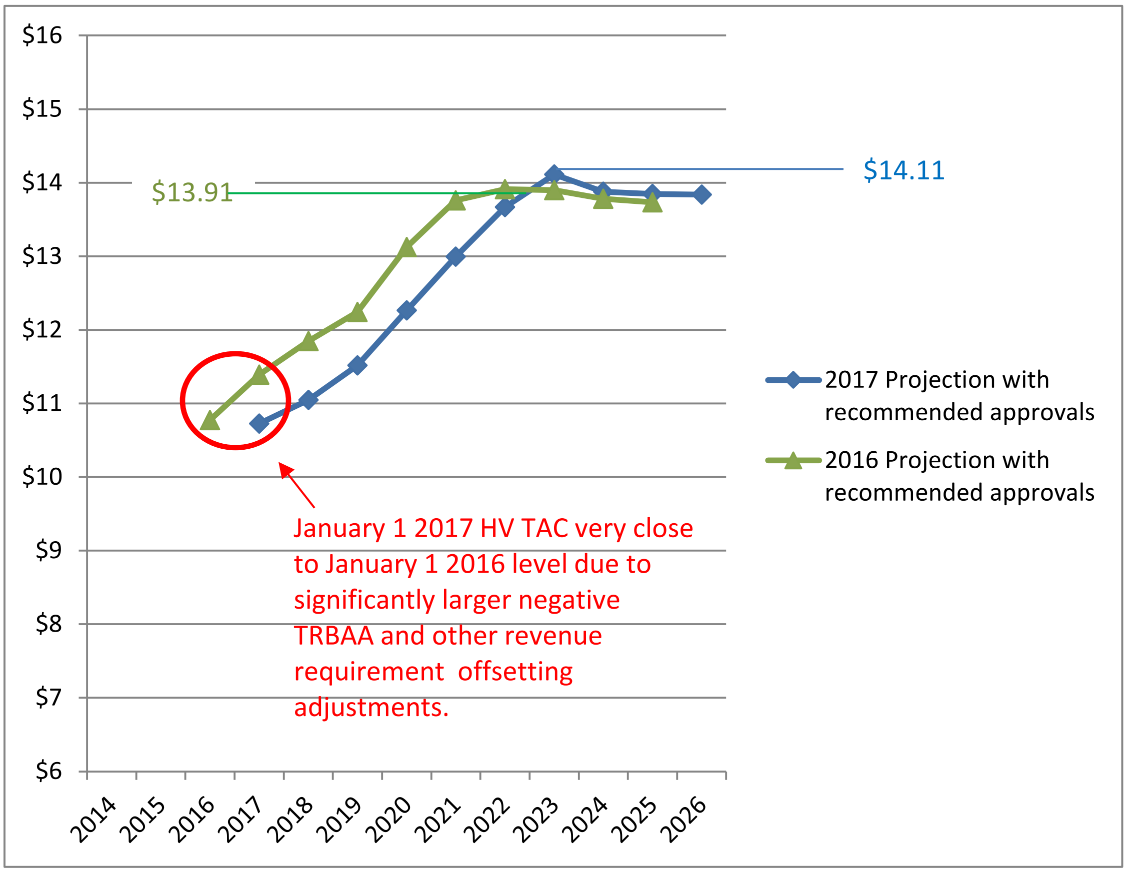
The tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

The ISO has also continued the trend commenced in the last planning cycle in adjusting the long term forecast return on equity assumptions downward. While stakeholders have suggested that a 10% return may be appropriate, the ISO has considered this as a lower bound, and continued to base this year's analysis of future transmission projects on a more conservative average of 11% in Figure 7.5-1. The overall return values for existing rate base assets are drawn from the PTO's actual approved revenue requirements. The estimate from the 2015-2016 Transmission Plan has also been provided for comparison.

The estimate provided below reflects the addition of the two projects recommended for approval in this cycle and the removal of the 13 projects recommended for cancellation in the 2016-2017 Transmission Plan – with only two of them having a high voltage component. No adjustments have been made to the 16 projects previously approved but recommended to be placed on hold pending further review in the 2017-2018 transmission planning cycle. Also, in past transmission plans, it was assumed that the level of transmission reliability driven project expenditures, once reaching levels above $250 million, would remain at or above that level but in this planning cycle, only the cost of approved transmission projects were included. The 2016-2017 results also reflect the addition of several projects previously approved by the CAISO but that had not been included in the 2015-2016 results.

As in past planning cycles, a 1% load growth was assumed in overall energy forecast over which the high voltage transmission revenue requirement is recovered.

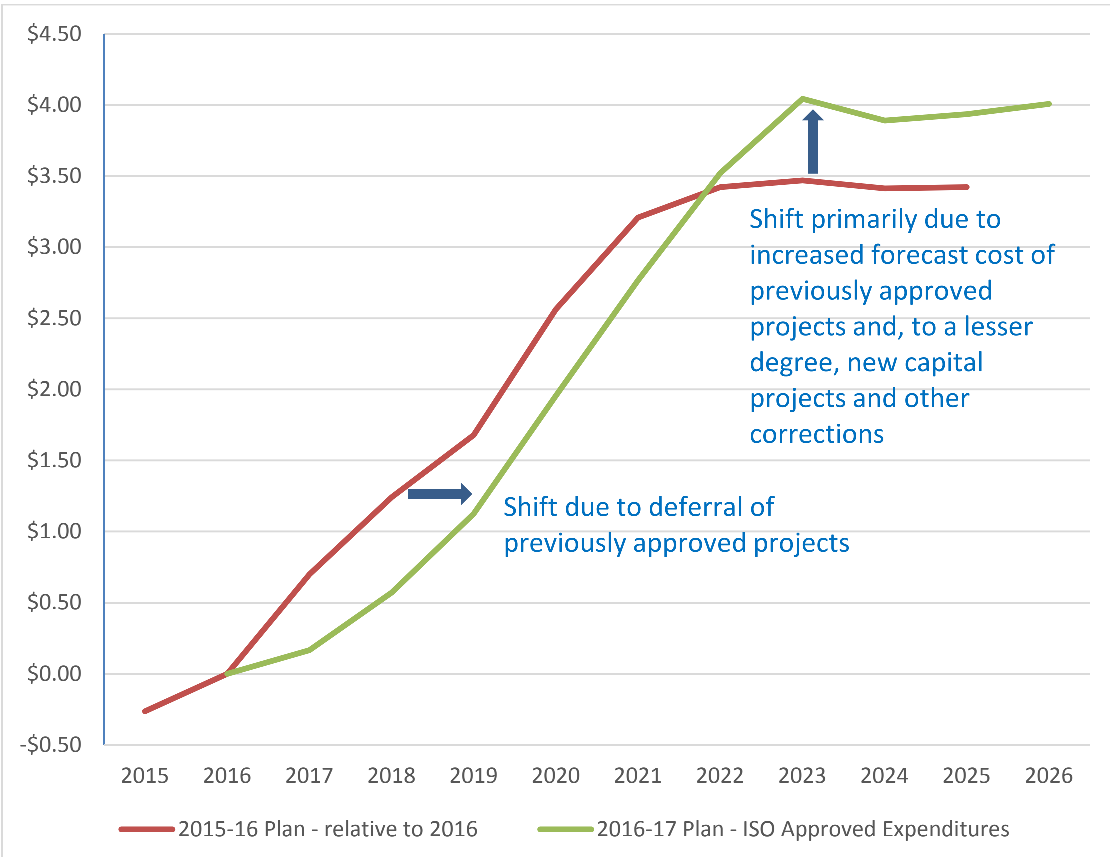
Figure 7.5-1: Forecast of ISO High Voltage Transmission Access Charge Trended from First Year of Transmission Plan



In addition to the uncertainty regarding projects being placed on hold pending further review, the January 2017 High Voltage (Regional) TAC reflects a significantly larger cumulative negative TRBAA values offsetting any other rate increase implications. This largely accounts for the similarity in the initial levels of both projections in Figure 7.4-1. Note that the posted High Voltage TAC rate for January 1, 2017 (as of February 23, 2017) was $10.5671/MWH and for January 1, 2016 (as of March 21, 2016) was $10.3893/MWH. Other credits and adjustments also contributed to the relatively small change in actual High Voltage TAC. As the ISO trends its TAC projection from the single High Voltage TAC as of January 1 of the first year of the 10 year planning horizon, any adjustments reflected in those values that are not sustained through the 10 year period lead to a distortion of the projection.

To provide a more meaningful representation of the impact of the ISO-approved transmission capital program Figure 7.5-2 is provided below providing a comparison of the incremental impact of post-2016 capital expenditures from ISO-approved transmission projects in this cycle and past cycles. Note that rate reductions resulting from depreciation on previously-approved capital that is already in service is not reflected in the graph.

Figure 7.5-2: Incremental Impact of post-2016 ISO-approved capital project expenditures on High Voltage Transmission Acccess Charge ($/MWH)



The higher and later peak in the incremental High Voltage TAC shows the impact of increased cost forecasts for previously approved projects (and inclusion of a small amount of new capital) and the deferral of a number of projects.