2019-2020 TRANSMISSION PLAN

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California ISO

January 31, 2020
DRAFT

Foreword to Draft 2019-2020 Transmission Plan

Thank you for your participation in the ISO transmission planning process, and your review of this draft transmission plan. The draft transmission plan represents the ISO's current thinking on system needs over the next 10-years and is an opportunity for stakeholder input before final recommendations are advanced to the ISO Board of Governors in March.

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

The ISO's objective each year is to provide a comprehensive review and assessment of the ISO transmission grid needs and draft recommendations on all decisions we expect to make in the course of the planning cycle.

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Executive Summary

The California Independent System Operator Corporation's 2019-2020 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to address grid reliability requirements, identify upgrades needed to successfully meet California's policy goals, and explore projects that can bring economic benefits to consumers. In doing so, the plan relies heavily on key inputs from state agencies in translating legislative policy into actionable policy-driven inputs.

This plan is updated annually, and culminates in an ISO Board of Governors (Board) approved transmission plan that identifies the needed transmission solutions and authorizes cost recovery through ISO transmission rates, subject to regulatory approval, as well as identifying non-transmission solutions that will be pursued in other venues as an alternative to building additional transmission facilities. It is prepared in the larger context of supporting important energy and environmental policies while maintaining reliability through a resilient electric system.

The transmission plan is developed through a comprehensive stakeholder process and relies heavily on coordination with key energy state agencies – the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) – for key inputs and assumptions regarding electricity demand side forecast assumptions as well as supply side development expectations. Both remain critical, building on past transmission planning efforts, as integrated resource planning considerations need to focus not only on accessing renewable generation but also accessing the necessary integration resources to effectively operate the grid in a future of high volumes of renewable generation, and distributed energy resources and shifting customer needs necessitate a high degree of coordination in supply side and demand side forecasting.

The aggressive pace of the electric power industry transformation in California continues to set the context for the ISO's annual transmission plan, where the focus is recalibrated each year to reflect the status of a range of issues at that time. This year's transmission plan continues to reflect those changing circumstances and the specific needs emerging at this particular point in time, with a noticeable shift in study efforts in some – but not all - of areas reflecting those emerging needs. Key trends in this year's transmission plan include the following:

- Load forecast growth continues to remain relatively flat, resulting in part from continued statewide emphasis on energy efficiency and behind-the-meter generation. Also, there has been no material increase in the pace of retirement of non-renewable generation as these resources continue to play a role in renewable integration and overall supply sufficiency in periods of low renewable generation output. As a result, transmission expansion planning needs continue to remain relatively modest overall. Despite these factors, new reliability challenges have emerged driving the need for system reinforcements on a case-by-case basis, however;
- Sustained emphasis on minimizing environmental impacts of the electricity industry and reducing greenhouse gas emissions continue to drive more integrated solutions to emerging needs that rely on combinations of preferred and conventional resources, as

well as transmission, although the relatively modest requirements of the 2019-2020 transmission plan afforded few opportunities for these solutions;

- The ISO's policy-driven transmission studies were based on a 60 percent RPS policy base portfolio provided by the CPUC, together with sensitivity portfolios based on higher approximately 71 percent – RPS levels. Consistent with past informational studies exploring levels at 50 percent and beyond, this transmission planning cycle did not reveal the need for major transmission expansion to achieve the 60 percent RPS goal set out in SB 100 for 2030. Sensitivities performed at higher – approximately 71 percent – RPS levels are demonstrating increased likelihood for reinforcement needs, with specifics depending upon the ultimate portfolio development in future CPUC integrated resource planning efforts;
- Through the course of the 2019-2020 planning cycle, the ISO also advanced a number of major study and process changes, including criteria and model refinements, to address emerging issues as well as issues identified through the extensive core and special study work undertaken in the 2018-219 planning cycle. These changes included refinements to renewable generation pricing and curtailment models, energy storage dispatch modeling, local capacity technical study criteria, deliverability criteria for system and local resources, and a methodology for ensuring adequacy of transmission availability for resources providing flexible capacity needs. The significant progress on these foundational issues better positioned the ISO for future challenges, and resulted in less focus on simply undertaking a large volume of "special studies" such as those undertaken in the 2018-2019 planning cycle. This year's transmission plan also contains fewer studies documented as "special studies" compared to recent previous transmission plans, as higher RPS levels beyond legislated targets were studied as policy portfolio sensitivities, and other potential topics of special studies have been migrated into the "other studies" category, recognizing the need for the studies to be performed annual into the foreseeable future. This latter category includes frequency response studies and the newly adopted flexible generation capacity deliverability analysis.
- The ISO continued its more extensive comprehensive analysis of potential mitigations to eliminate or materially reduce local capacity requirement dependence on gas-fired generation, completed as an extension of the 2018-2019 transmission planning cycle. As with the 2018-2019 transmission planning cycle, a subset of those alternatives were fed into the economic study process as potential economic-driven transmission;
- The longer term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined in the CPUC integrated resource planning process as well as in ISO studies conducted outside of the annual transmission planning process for purposes of supporting CPUC efforts. The uncertainty regarding the extent to which gas-fired generation will be needed to meet system and flexible capacity requirements necessitated continuing the conservative approach adopted in the 2018-2019 transmission planning cycle into this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements;

- The ISO continued to receive storage project proposals proposed as transmission mitigations, as well as considering on its own the potential for storage, as part of the larger basket of preferred resource options, to meet reliability needs. The ISO's stakeholder initiative regarding how storage procured as a regulated cost of service transmission asset (or SATA) could also access market revenues when not needed for reliability remains on hold to consider further refinements to the ISO's storage participation model. The ISO nonetheless continues to assess storage projects – where selected for detailed study - assuming that if appropriate, procurement could also be investigated as market-based local capacity resources through CPUC procurement processes;
- The ISO and respective neighboring planning regions received six Interregional Transmission Project submissions for consideration in the 2018-2019 transmission planning cycle, which was the first year of the biennial interregional coordination process the ISO has established with our neighboring planning regions. None of the projects were selected through the interregional coordination process with the ISO's neighboring planning regions for further review in the second year of the process. Several interregional projects were also submitted into economic study request windows or other request windows, and no further action was taken on those projects in this planning cycle. The 2020-2021 planning cycle will be the first year, *e.g.* the "intake" year, in the next round of biennial interregional coordination process and the ISO expects interregional transmission projects will be revisited in that process; and,
- Overall, the 2019-2020 Transmission Plan includes a modest increase in new reliability needs, continued refinement of modeling and study capabilities for meeting future challenges and issues, and study methodology refinements to inform future transmission planning processes, including CPUC integrated resource planning issues. The ISO's continuing efforts to increase opportunity for non-transmission alternatives, particularly preferred resources and storage, will remain a key focus of the transmission planning analysis.

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

- The ISO identified 9 transmission projects with an estimated cost of approximately $141.7 million as needed to maintain transmission system reliability, with one of the projects being advanced for economic benefit purposes from when it would otherwise be needed for reliability purposes;
- In reviewing previously approved projects in the PG&E service territory that were identified in the last planning cycle as needing more review, one other project will continue to be on hold pending reassessment in future cycles.
- 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 the

timing of other conventional mitigations, the situation is being continually monitored in case additional measures are needed;

- Consistent with past studies of transmission system capabilities to achieve RPS levels beyond 33 percent, no policy-driven transmission was considered for approval in this planning cycle to achieve 60 percent RPS goal established in SB 100, and sensitivities have been undertaken at higher, 71 percent RPS levels, identifying potential reinforcement needs subject to resource location considerations in future CPUC integrated resource planning efforts;
- No economic-driven transmission projects are recommended for approval in this planning cycle;
- The ISO tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the plan. No transmission projects in this transmission plan include facilities eligible for competitive solicitation through the ISO's competitive solicitation process.

Progress also continued in this planning cycle, continuing and completing the work initiated in the 2018-2019 Transmission Plan, in exploring issues emerging as the generation fleet continues to transform as the state pursues greenhouse gas reduction goals.

Unlike other recent transmission plans, the 2019-2020 Transmission Plan has not provided a summary of ISO resource sufficiency analysis input into the CPUC's integrated resource planning process, as timelines of resource sufficiency ISO analysis did not reasonably align with the transmission plan cycle.

Summaries of the transmission planning process and some of the key collaborative activities with the CPUC and the CEC are provided below. This is followed by additional details on each of the key study areas and associated findings described above.

The Transmission Planning Process

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 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 begins in January of each year, with the development of the study plan – phase 1. Phase 2, which includes the technical analysis, selection of solutions and development of the transmission plan for approval by the ISO Board of Governors, extends beyond a single year and concludes in March of the following year. If Phase 3 is required, engagement in a competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan, it takes place after the March approval of the plan. This results in the initial development of the study plan and assumptions for one cycle to be well underway before the preceding cycle has concluded, and each transmission plan being referred to by both the year it commenced and the year it concluded. The 2018-2019 planning cycle, for example, began in January 2018 and the 2018-2019 Transmission Plan was approved in March 2019.

Planning Assumptions and State Agency Coordination

The 2019-2020 planning assumptions and scenarios were developed through the annual agency coordination process the ISO, CEC and CPUC have in place and performed 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 integrated resource planning (IRP) proceedings conducted by the CPUC, replacing the previous long term procurement plan (LTPP) proceedings, and
- Annual transmission planning processes performed by the ISO.

In this coordination effort, the agencies considered assumptions such as demand, supply and system infrastructure elements, and the RPS generation portfolios proposed by the CPUC.

The CPUC's input was communicated via a decision[1] on May 1, 2019 at the end of the 2017-2018 Integrated Resource Planning cycle, adopting a preferred system portfolio designed to ensure that the electric sector is on track to help the State achieve its statewide 2030 greenhouse gas (GHG) reduction target established through SB 350 at least cost while maintaining electric service reliability and meeting other State goals, and also meeting 60 percent electric industry-specific RPS goals established in the more recent SB 100. This portfolio, based on a statewide electricity sector target of 42 MMT in 2030, was also used for economic study purposes. Anticipating higher renewable generation requirements going forward, the CPUC communicated sensitivity portfolios achieving higher – 71 percent – RPS levels that were tied to a statewide electricity sector target of 32 MMT in 2030.

[1] CPUC Decision 19-04-040 dated April 25, 2019, issued May 1, 2019, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

These assumptions were further vetted by stakeholders through the ISO's stakeholder process which resulted in this year's study plan.[2]

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.

Beyond coordinating study assumptions, the ISO also undertook a major informational special study in the 2018-2019 transmission planning cycle in response to a request from Robert B. Weisenmiller, Chair of the CEC and Michael Picker, President of the CPUC. Please refer to the Informational Study discussion below.

Key Reliability Study Findings

During the 2018-2019 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with applicable NERC reliability standards and ISO planning standards and tariff requirements. The analysis was performed across a 10-year planning horizon and modeled a range of 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 existed, the ISO identified transmission solutions to address these concerns or assessed the ability of previously approved projects to meet those needs. This plan proposes approving 9 reliability-driven transmission projects representing an investment of approximately $141.7 million in infrastructure additions to the ISO controlled grid, seven of which are located in the PG&E service territory, one in the GLW/VEA serviced territory, and one in the SCE service territory.

Renewables Portfolio Standard Policy-driven Transmission Assessment

As noted above, the CPUC's input was set out via a decision[3] at the end of the 2017-2018 Integrated Resource Planning cycle, which adopted the integrated resource planning process and also provided resource planning assumptions to the ISO. The CPUC communicated a base portfolio based on its "42 MMT scenario" that results in approximately a 60 percent RPS, and sensitivity portfolios for policy-driven planning efforts.

The ISO has accordingly performed policy-driven study assessments of the 42 MMT scenario and did not identify any new Category 1 policy-driven transmission needs. The ISO is not recommending any new transmission solutions at this time for policy purposes.

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[2] The 2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan, April 3, 2019, is available at: http://www.caiso.com/Documents/Final2019-2020StudyPlan.pdf

[3] Initially provided in a Proposed Decision released on March 18, 2019 (as referenced in the ISO's 2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan document finalized on April 3, 2019), and subsequently confirmed in Decision 19-04-040, April 25, 2019, page 123, Table 6, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

A summary of the various transmission elements already underway for supporting California's renewables portfolio standard is shown in Table 1.1-1. 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 major transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the permit approval process; and
- Major transmission projects that have been previously approved by the ISO but are not yet permitted.

Table 1.1-1: Elements of 2019-2020 ISO Transmission Plan Supporting 60 Percent Renewable Energy Goals

Transmission Facility	In-Service Date
Transmission Facilities Approved, Permitted and Under Construction	
West of Devers Reconductoring	2021
Additional Major Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
None at this time	
Policy-Driven Transmission Elements Approved but not Permitted	
Lugo – Eldorado series cap and terminal equipment upgrade	2021
Warnerville-Bellota 230 kV line reconductoring	2024
Wilson-Le Grand 115 kV line reconductoring	2021
Lugo-Mohave series capacitors	2021
Additional Policy-Driven Transmission Elements Recommend for Approval	
None identified in 2019-2020 Transmission Plan	

Key Economic Study Findings

The ISO's economic planning study is an integral part of the ISO's transmission planning process and complements the reliability-driven and policy-driven analysis by exploring economic-driven network upgrades that may create opportunities to reduce ratepayer costs within the ISO. The studies used a production cost simulation as the primary tool to identify potential economic development opportunities and in assessing those opportunities. 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 which is a key input in identifying potential study areas, prioritizing study efforts, and assessing benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load, and 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. Other end-use ratepayer cost saving benefits such as reducing local capacity requirements in transmission-constrained areas can also provide material benefits. Note that other benefits and risks – which cannot always be quantified – must also be taken into account in the ultimate decision to proceed with an economic-driven project.

In the economic planning analysis performed as part of this transmission planning cycle in accordance with the unified planning assumptions and study plan, approved reliability and policy network upgrades and those recommended for approval in this plan 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.

Beyond screening congestion results to select key focus areas for detailed economic studies, the ISO:

- Received a number of economic study requests, which included projects that would more reasonably be categorized as interregional transmission projects;
- Received several proposed reliability projects that cited material economic benefits;
- Completed the expanded 10-year local capacity technical study initiated in the 2018-2019 planning cycle, examining not only the need and the characteristics of the need but alternatives to reduce local gas-fired generation capacity requirements, and selected a subset of local capacity areas for detailed economic analysis where options appeared potentially viable.

A number of the above proposals and submissions overlapped, enabling them to be studied in single study areas.

The ISO's studies were impacted by certain conditions existing in this planning cycle:

- The longer term requirements for gas-fired generation for system and flexible capacity requirements continues to be examined, both in the CPUC integrated resource planning process as well as ISO studies – studies conducted outside of the annual transmission planning process for purposes of supporting CPUC efforts. As no actionable direction has yet been set regarding the future of the existing gas-fired generation fleet beyond known retirements, the uncertainty necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements;

- A number of project sponsors requesting economic studies proposed projects that were proposed and considered in the 2018-2019 planning cycle.

While the ISO tariff allows the ISO to limit the number of economic evaluations to five or less, the ISO studied proposals in 10 study areas in this year's planning cycle.

In summary, no new projects were found to be needed as economic-driven projects in the 2019-2020 planning cycle, and one project already found to be needed for reliability needs is recommended to be advanced for economic benefit reasons.

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 60 percent renewable energy goals.

Interregional Transmission Coordination Process

The ISO's 2019-2020 transmission planning cycle marks the beginning of the second biennial cycle since these coordination processes were put in place addressing the requirements of FERC Order No. 1000.

Six interregional transmission projects were submitted into the biennial process. Of those, three were screened out, and the remaining three were fed into the ISO's economic study process for further analysis in the 2018-2019 planning cycle. This aligns with the requirement to examine if proposed interregional transmission projects that may provide more economic and cost-effective solutions than regional proposals for meeting identified needs. As such, the remaining three projects studied in detail but were not found to be more economic and/or cost-effective solutions than regional proposals for meeting identified needs.

Consistent with the Order No. 1000 Common Interregional Tariff, no further consideration of the submitted ITPs was required in the 2019-2020 TPP.

Non-Transmission Alternatives and Preferred Resources

The ISO has routinely emphasized exploring preferred resources[4] and other non-transmission alternatives to conventional transmission to meet emerging reliability needs. Through reliance on existing resources as a matter of course as potential mitigations for identified needs, area-specific studies[5] and continued efforts to refine understanding of the necessary characteristics for resources such as slow response demand response to provide local capacity[6], the ISO's applications have expanded beyond the ISO's original methodology[7] set in place some years ago. Further, in this 10-Year Local Capacity Technical Study developed over the 2018-2019 and 2019-2020 transmission planning cycles, the ISO provided detailed information regarding the characteristics of the local capacity area needs that are the basis for assessing non-transmission and preferred resource solutions. The ISO is also continuing to support the implementation of solutions for transmission needs consisting of combinations of transmission reinforcements and procurement of preferred resources in the LA Basin, in Oakland, and the Moorpark sub-area. A number of storage proposals have also been studied in this year's transmission planning process, although none were found to be needed given the limited transmission system reinforcement requirements in this year's cycle, and the conservative approaches taken in this planning cycle in assessing the value of resources that would be focused on replacing existing gas-fired generation. Please refer to section 8.2.

Informational Studies

As in past transmission planning cycles, the ISO undertook additional informational studies to help inform future transmission planning or resource procurement processes. The ISO has identified the need to perform a number of these studies on an ongoing basis, at least for the foreseeable future, and has therefore documented these studies in the "other studies" in chapter 6, instead of categorizing them as "special studies". Noteworthy changes are set out below.

Frequency Response and Dynamic System Modeling

Consistent with the 2018-2019 transmission planning cycle, the ISO undertook frequency response studies and reported on associated modeling improvement efforts as an ongoing study process inside the annual planning cycle despite not being a tariff-based obligation.

[4] 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.

[5] See generally CEC Docket No. 15-AFC-001, and see "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

[6] Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC. See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

[7] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf.

Within this cycle, the ISO has also examined the benefits of potential modifications to frequency response settings for grid-connected inverter-based resources.

Reliance on Gas-fired Generation in Local Capacity Areas

The ISO undertook to conduct additional analysis of local capacity requirements in local capacity areas over the 2018-2019 and 2019-2020 transmission planning cycles, to help inform resource planning issues. First, the 10-Year Local Capacity Study conducted as part of the 2018-2019 planning cycle was expanded to include detailed information regarding the characteristics of the local capacity area needs that are the basis for assessing non-transmission and preferred resource solutions. Second, transmission or other hybrid alternatives were developed for half of the area and sub-area needs, selected on a prioritized basis. These first two steps were considered to be of use in future resource procurement processes. Third, a subset of those areas and sub-areas were fed into the ISO's economic study process to assess the viability of moving forward with some level of local capacity requirement reduction on the economic basis used to assess transmission development. In the 2019-2020 planning cycle, the ISO repeated steps 2 and 3, relating to exploring alternatives, for those areas with local capacity requirements for gas-fired generation that were not already studied as well as reviewing several specific areas from the preceding where it was warranted.

Flexible Capacity Deliverability Requirements

The ISO developed a methodology and tested the deliverability of flexible capacity in the 2019-2020 transmission planning cycle, recognizing that the tests applied to ensure deliverability of system capacity may not reflect the conditions and limitations that could constrain the ability of flexible capacity resources to provide ramping when most needed.

The flexible deliverability test relies on the deliverability assessment and adds new tests to address scenarios not already covered in the deliverability assessment. A testing procedure was developed to monitor the generation pockets for flexible deliverability. However, no study and requirements will be proposed to be considered for enforcement on new generators in the generation interconnection study procedure until 1) it becomes clear how the flexible capacity will be counted, especially for the wind and solar capacity through the FRACMOO2 or follow-up initiative, 2) the revised on-peak and off-peak deliverability methodologies are approved and adopted, and 3) the transmission planning process analysis identifies flexible deliverability constraints. The assessment did not identify any flexible deliverability concerns. However, future work is needed to improve the assessment methodology.

Conclusions and Recommendations

The 2019-2020 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 9 transmission projects, estimated to cost a total of approximately $141.7 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 identified that for one of those projects, an earlier in-service date than would otherwise be needed for reliability purposes was warranted to capture economic benefits.

The ISO has also conducted sensitivity studies regarding 2030 RPS levels exceeding current SB 100 requirements, that will be used to inform future CPUC integrated resource planning and portfolio development processes.

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 2019-2020 planning cycle.

The ISO has prepared this plan in the larger context of continuing to support important energy and environmental policies and assisting the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system. This entails not only transitioning to lower emission sources of electricity, but also considering evolving forecasts and expectations being set for transitions in how and when electricity is used. While each year's transmission plan is based on the best available forecast information at the time the plan is prepared, the ISO considers and adapts to changing forecasts to ensure a cost effective and reliable transmission system meeting the demands placed on it in these rapidly changing times.

In this regard, the transmission plan continues to be 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. It also reflects the need to adapt plans as circumstances change and new inroads are made on the broader electricity context in California – and energy footprint overall.

Each year's transmission plan is a product of timing, reflecting the particular status of various initiatives and industry changes in the year the plan is developed, as well as the progress in parallel processes to address future needs. The 2019-2020 Transmission Plan is heavily influenced by the success in past transmission planning cycles to address historical reliability issues and greenhouse gas emissions reductions goals as well various state agency processes and proceedings to meet renewable energy targets.

The emerging issues and challenges are discussed in more detail in section 1.2 below, Impacts of the Industry Transformation.

Within this context, the transmission plan's primary purpose is to identify – based on the best available information at the time this plan was prepared – needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy, and economic needs. The CAISO may also identify in the transmission plan 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. 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.

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 2018-2019 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 a range of peak, off-peak, and partial-peak conditions. The ISO assessed the transmission facilities under ISO operational control, ranging in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns considering upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and examining the potential for conventional and non-conventional resources (preferred resources including storage) to meet these needs. 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 and work with the relevant parties and agencies to seek their implementation.

This transmission plan documents ISO analyses, results, and mitigation plans.[8] 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. In recent transmission planning cycles, the focus of public policy analysis has been predominantly 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 essentially been achieved, and this plan focuses on the greenhouse gas emissions reductions objectives set out in Senate Bill (SB) 350[9] and, in particular, the 60 percent RPS by 2030 objective in Senate Bill (SB) 100[10] that became

[8] 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 and subsequent transmission plans, the ISO has not included in this year's plan the 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.

[9] 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. Among other provisions, the law established clean energy, clean air, and greenhouse gas (GHG) reduction goals, including reducing GHG to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030, that have now been superseded by the provisions of Senate Bill 100.

[10] SB 100, the 100 Percent Clean Energy Act of 2018, also authored by Senator Kevin De León, was signed into law by Governor Jerry Brown on September 10, 2018. Among other provisions, SB 100 built on existing legislation including SB 350 and revised the previously established goals to achieve the 50 percent renewable resources target by December 31, 2026, and to achieve a 60 percent target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

law in September, 2018. Accordingly, the CPUC provided to the ISO renewable generation portfolios reflecting approximately 60 percent RPS[11] for reliability, base policy and economic study purposes, and higher sensitivity portfolios representing approximately a 71 percent RPS objective[12] for further policy-driven analysis. The ISO expects that the results of these sensitivity studies will be helpful in future CPUC integrated resource planning efforts that will also take into account more aggressive goals aligned with broader GHG reductions.

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. As renewable generation continues to be added to the grid, with the inevitable economic pressure on other existing resources, economic benefits will also have to take into account cost effective mitigations of renewable integration challenges as well as potential reductions to the generation fleet located in local capacity areas. To assist future CPUC resource planning processes, the ISO completed a more in-depth analysis of local capacity requirements that began in the 2018-2019 transmission planning cycle, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs.

Accordingly, the 2019-2020 Transmission Plan, and the scope of policy and economic studies in particular, were largely influenced by:

1. Inclusion of a new “policy-driven” base case with a 60 percent RPS objective and two sensitivity portfolios from the first two-year cycle of the CPUC’s integrated resource planning process. The previous “policy-driven” base cases from the CPUC only reached a 33% RPS objective.
2. Completing the two year detailed study of local capacity technical requirements – and scoping mitigations that could reduce or eliminate gas-fired generation requirements in those areas – that was commenced in the 2018-2019 transmission plan.
3. The 2019-2020 Transmission Plan being the second year of the two-year interregional coordination planning process, with the first year being the “intake year” in which interregional projects can be proposed by stakeholders for consideration.

Through the course of the 2019-2020 planning cycle, the ISO also advanced a number of major study and process changes, including criteria and model refinements, to address emerging issues as well as issues identified through the extensive core and special study work undertaken in the 2018-219 planning cycle. These changes included refinements to renewable generation pricing and curtailment models, energy storage dispatch modeling, local capacity technical study criteria, deliverability criteria for system and local resources, and a methodology for ensuring adequacy of transmission availability for resources providing flexible capacity needs. The significant progress on these foundational issues better positioned the ISO for future

[11] Initially provided in a Proposed Decision released on March 18, 2019 (as referenced in the ISO’s 2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan document finalized on April 3, 2019), and subsequently confirmed in Decision 19-04-040, April 25, 2019, page 123, Table 6, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

[12] id.

challenges, and resulted in less focus on the volume of studies such as those undertaken in the 2018-2019 planning cycle. The 2019-2020 Transmission Plan also continues with the migration of special studies into a more permanent category of “other studies” in the plan itself, once the need as been identified to perform these analyses on an annual basis, such as frequency response studies and now flexible capacity deliverablity analysis.

1.2 Structure of the Transmission Planning Process

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. For example, the 2018-2019 planning cycle began in January 2018 and concluded in March 2019.

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.

1.1.1 Phase 1

Phase 1 generally consists of developing and completing the annual unified planning assumptions and study plan.

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 the ongoing 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 forecasts of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR);
- Biennial Integrated Resource Planning (IRP) proceedings conducted by the CPUC; and,
- The 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, and are discussed in more detail in section 1.3.

The results of that annual process fed into this 2019-2020 transmission planning process and was communicated via decisions[13, 14] in the 2017-2018 IRP process.

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. As discussed later in this section, the ISO's study work and resource requirements determination for reliably integrating renewable resources is continuing on a parallel track outside of the transmission planning process, but the ISO has continued 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 bulk of the supply

[13] As the 2019-2020 Transmission Plan was conducted in the second year of the CPUC's biennial IRP process, please refer to the Feb 20, 2018 Unified Resource Adequacy and IRP Inputs and Assumptions document: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/1Unified_IA_main_draft_20180220.pdf . that was also used in the 2018-2019 Transmission Plan as per Decision 18-02-018: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K771/209771632.PDF. Generation assumptions were subsequently modified in the CPUC's 2018 IRP process and the load forecast in the CEC 2018 IEPR process.

[14] Initially provided in a Proposed Decision released on March 18, 2019 (as referenced in the ISO's 2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan document finalized on April 3, 2019), and subsequently confirmed in Decision 19-04-040, April 25, 2019, page 123, Table 6, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

procurement activities 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 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 alternative resource development portfolios or scenarios are formulated through the processes described above, then the ISO identifies the needed transmission to support each portfolio and selects for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

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.

1.1.2 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;
- 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 integrated resource planning proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);
- Reassesses, as needed, significant transmission facilities starting with the 2011-2012 planning cycle that were in GIP phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;
- Performs a “least regrets” analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[15] which is 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

[15] 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 ISO tariff specifies the criteria considered in this evaluation.

the plan that require Board approval.[16] As indicated above, the ISO solicits and accepts 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 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.[17]

1.1.3 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.

This requires one clarification in the consideration of storage that may be found to be needed as a transmission asset. Note that the determination of eligibility is made at the end of Phase 2, and before the competition is held. Transmission connected resources are resources that are connected to the ISO controlled grid, with Regional resources being greater than 200 kV, and Local resources being lower than 200 kV. Storage as a transmission asset may be connected to the transmission system at a level that differs from the transmission issue it has been identified to resolve, just like other transmission assets. For example, the ISO may identify a Regional need, but identify storage – as a transmission asset - connecting at a Local level as the best solution or as a possible solution. Notwithstanding the treatment for allocation to transmission access charges, the ISO has consistently interpreted eligibility criteria to be more, not less supportive of competition, and therefore considers a “greenfield” solution such as a storage transmission asset to be eligible for competition if it can be met equally well by a local or regional facility, but is not eligible for competition if only a local facility will meet the need.

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

[16] 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.

[17] These details are set forth in the BPM for Transmission Planning, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission%20Planning%20Process.

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.

1.3 Key Inputs and Other Influences

Section 1.3 provides background and detail on key inputs into the 2019-2020 transmission planning process, as described in section 1.2 above. In addition to the key study plan inputs received from state agencies described in section 1.2.1 above, the ISO must address a growing range of considerations to ensure those objectives are enabled and ensure overall safe, reliable, and efficient operation through its planning process. These efforts include the continued growth of renewable generation on the ISO system, whether grid-connected or behind-the-meter at end customer sites, the phase out of using coastal water for once-through-cooling at thermal generating stations, and a growing range of strategies, policy priority areas, emerging technologies and risks and opportunities to either achieve energy use reductions or impacts on energy consumption. Many of these are no longer stand-alone solutions – they can achieve great outcomes if properly planned and implemented in concert with the right volumes of other mitigations, or fail to provide the expected benefits if implemented in isolation or carelessly.

These trends, including the continued rapid expansion of behind-the-meter solar generation, have created new and more complex operating paradigms for which the ISO must consider in planning the grid, as discussed in the 2017-2018 Transmission Plan. In its transmission planning processes, the ISO therefore considers factors and trends reaching beyond the more specific and well-defined challenges of the past, such as the phasing out of gas-fired generation relying on coastal waters for once-through cooling as well as the early retirement of the San Onofre Nuclear Generating Station and the planned retirement of Diablo Canyon Nuclear Generating Station commencing in 2024.

These new challenges and potential solutions must also consider the emergence of new policy and operating frameworks that will be relied upon to develop and coordinate the supply of, and demand for, electricity in the future.

The changing generation resource fleet inside California and the continued exploration of regionalism as a means to 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 continued growth in participation in the ISO's energy imbalance market is resulting in more dynamic import and export conditions.

The rest of this subsection discusses the key inputs as well as a number of the emerging issues and other actions being taken to advance the understanding or implementation of those issues in the future — whether special study activities, ISO policy initiatives or regulatory proceedings.

1.1.4 Load Forecasting and Distributed Energy Resources Growth Scenarios

1.1.4.1 Base Forecasts

As discussed earlier, the ISO continues to rely on load forecasts and load modifier forecasts prepared by the California Energy Commission (CEC) through its Integrated Energy Policy Report (IEPR) processes. The combined effects of flat or declining gross load forecasts and reductions in those net load forecasts due to behind-the-meter generation and energy efficiency programs continue to significantly impact the planning process:

The increasing variable loading on the transmission system is resulting in more widely varying voltage profiles, resulting in an increased need for reactive control devices to maintain acceptable system voltages.

The rapid deployment of behind-the-meter generation is driving changes in forecasting, planning and operating frameworks for both the transmission system and generation fleet. The rapid acceleration of behind-the-meter rooftop solar generation installations in particular has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to shift to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted out of the window when grid-connected solar generation is available.

These efforts have now resulted in the development of the California Energy Demand Forecast 2018-2030 (CED 2018) that the ISO is using in the 2019-2020 transmission planning process. This forecast includes full hourly load forecasting models for both consumption and load modifiers, and this information will play a key role in the more complex analysis of emerging system needs and the effectiveness of use-limited preferred resources as part of meeting those needs.

1.1.4.2 Further Drivers

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 is emphasizing the role and integration of DERs into the planning and procurement framework of its jurisdictional utilities. These issues are being considered both in the CPUC's current Distribution Resources Plan proceeding, and identified in the 2017-2018 Integrated Resource Planning proceeding as an issue for future optimization in the subsequent 2019-2020 proceeding, as discussed in more detail below.

Further consideration of a range of industry trends and needs also drive an increased range of uncertainty about future requirements—with current energy efficiency programs driving demand down, but decarbonizing other sectors such as transportation potentially causing increased demand in new and previously unseen consumption patterns. In the future, fuel substitution, as a subset of energy efficiency, may increase demand as well.

Also, the ISO will continue to explore the possibility for demand-side management tools to play a role in mitigating local reliability needs; those processes are considered as part of the resource planning processes discussed in the next subsection.

1.1.5 Resource Planning and Portfolio Development

Resource planning has informed past planning cycles by focusing primarily on informing policy-driven transmission needs to support state policy objectives on the development of renewable generation, and the role local resources—whether conventional or preferred resources—can play in meeting local reliability needs.

Facilitating the coordination of the three major processes discussed earlier – the CPUC's IRP process, the CEC's IEPR process, and the ISO's transmission planning process – and addressing renewable generation requirements specifically, the ISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for ISO to analyze in the ISO's annual transmission planning process. The portfolio development has transitioned from the CPUC's previous long term procurement plan proceedings to the current IRP proceedings.

1.1.5.1 Integrated Resource Planning Process and Renewable Portfolio Development

The CPUC issued a decision[18] on May 1, 2019 at the end of the 2017-2018 Integrated Resource Planning cycle, adopting a preferred system portfolio designed to ensure that the electric sector is on track to help the state achieve its statewide 2030 greenhouse gas (GHG) reduction target established through SB 350 at least cost while maintaining electric service reliability and meeting other State goals, and also meeting the electric industry-specific RPS goals established in the more recent SB 100. While the CPUC's focus was on the more aggressive goals related to GHG reductions from the electricity sector taking into account input from the California Air Resources Board (CARB)[19], the effectiveness of meeting RPS goals were also assessed in the adoption of the preferred system portfolio. In effect, the RPS goals have become more of a floor in CPUC consideration of portfolios that are targeting more aggressive reductions for the electricity sector to align with statewide GHG reduction goals.

Accordingly, the adopted preferred system portfolio meets a state-wide GHG emission target of 42 million metric tons (MMT) by 2030, which represents a 50% reduction in electric sector GHG emissions from 2015 levels and a 61% reduction from 1990 levels. It was also assessed as achieving a 60 percent RPS target that meets the 2030 goal of SB 100 as discussed below,

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[18] CPUC Decision 19-04-040 dated April 25, 2019, issued May 1, 2019, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

[19] The CPUC chose to adopt a 2030 statewide electricity GHG emissions planning target of 42 MMT in Decision 18-02-018, taking into account the range of scenarios provided in the 2017 Climate Change Scoping Plan in draft form in January 20, 2017, and ultimately approved by CARB on December 14, 2017. The 2017 Climate Change Scoping Plan outlines the regulations, programs, and other mechanisms needed to reduce GHG emissions in California. The California Global Warming Solutions Act of 2006 - Assembly Bill 32 (AB 32) created a comprehensive, multi-year program to reduce greenhouse gas (GHG) emissions in California. AB 32 required CARB to develop a Scoping Plan that describes the approach California will take to reduce GHGs to achieve the goal of reducing emissions to 1990 levels by 2020. The Scoping Plan was first approved by the Board in 2008 and must be updated every five years. https://ww3.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf?_ga=2.185410026.2108179798.1578097422-1787807483.1523971494

which was established after the IRP process had commenced, but before the IRP process was completed. In addition, the CPUC also adopted two sensitivities with over 70% RPS targets to compare in-state versus out-of-state renewable development. The preferred system portfolio was provided to the ISO as the basis for reliability and policy analysis while the two sensitivities were provided as policy-driven sensitivities with an eye toward meeting the longer term post-2030 objectives of SB 100.

1.1.5.2 Market pressure on gas-fired generation fleet – and new expectations on the fleet

The significant amount of new renewable generation added to the grid continues to put downward economic pressure on the existing gas-fired generation fleet, and this is expected to be exacerbated as renewable generation is added in the future. Further, the long term requirements established by SB 100 moving to GHG-free electricity sets the direction for the eventual retirement of gas-fired generation and replacement with other non-GHG-emitting resources.

The initial 2017 results of the CPUC's 2017-2018 integrated resource planning process, set out in CPUC Decision 18-02-018[20] did not address potential gas-fired generation retirement beyond the known retirements and the retirement plans of the once-through-cooling generation fleet. In contrast, in developing the preferred system portfolio referenced above and set out in CPUC Decision 19-04-040, the CPUC adopted a 40-year life for fossil-fueled resources as a proxy for potential retirements. This also aligned with the ISO's planning assumptions in the 2018-2019 planning cycle – derived from the previous CPUC Long Term Procurement Plan processes – that gas-fired generation would retire at the end of a 40 year life, unless a power purchase arrangement extended that timeline. The 40 year life assumption has therefore been used in the 2019-2020 transmission planning process. However, it continues to be recognized that a transmission plan recommendation for a transmission project's approval based solely on 40-year life retirement assumptions would be unlikely, and such circumstances would need to be considered on a case-by-case basis.

Further, CPUC Decision 19-04-040 providing RPS portfolios into this planning cycle reiterated that in D.18-02-018, the Commission found that while no new natural gas-fired power plants are identified in the 2030 new resource mix, the modeling showed that existing gas-fired plants are needed in 2030 as operable and operating resources, providing a renewable integration service. It was recognized that eliminating natural gas-fueled resources altogether by 2030, while maintaining reliability, would require technological solutions well beyond any of those that have been surfaced or analyzed in the proceeding to date.[21]

Subsequently and during the course of the 2019-2020 transmission planning cycle, the CPUC launched a "procurement track" of the 2017-2018 integrated resource plan proceeding, based on CPUC staff analysis of available near-term supply for system resource adequacy. The CPUC staff analysis found a near-term capacity shortfall and, as a result, the CPUC issued Decision 19-11-016 on November 7, 2019 authorizing incremental procurement of system-level

[20] CPUC Decision 18-02-018: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K771/209771632.PDF.

[21] CPUC Decision 19-04-040, p. 132: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

resource adequacy capacity of 3,300 MW by all jurisdictional load-serving entities (LSEs). The incremental resources are required to come online at least 50 percent by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023. In addition to this incremental procurement, the CPUC also recommended that the State Water Resources Control Board (Water Board) extend the once-through-cooling (OTC) compliance deadlines for four units currently slated to retire by December 31, 2020, for periods of up to three years. The OTC resources can serve as a hedge against potential delays to the incremental builds and address near-term operational needs.

The ISO has taken these circumstances into account in considering the efficacy of transmission projects that could lower local requirements for the gas-fired generation fleet, given the apparent need to retain most if not all of the remaining fleet – past planned retirements – for supply adequacy over the transmission planning horizon.

Notwithstanding these strong indications that the gas-fired generation fleet will be needed into the foreseeable future, the ISO has conducted additional studies on a largely informational basis to provide better insights and understandings of the opportunities and issues associated with gas-fired generation retirement.

To understand the risk of a material amount of similarly situated generation retiring more or less simultaneously, ostensibly for economic reasons, the ISO initiated special studies in the 2016-2017 transmission planning cycle, with additional analysis extending into the 2017-2018 time frame, to assess the risks. Those studies did not find new geographic areas of concern exposed to local reliability risk if faced with retirements at levels that approached the limit of acceptable system capacity outside of the pre-existing local capacity areas.

As well, the ISO undertook in the 2018-2019 transmission planning cycle a more comprehensive study of local capacity areas examining both the load shapes and characteristics underpinning local capacity requirements, and evaluating alternatives for those needs even if it is unlikely that the economic benefits alone would outweigh the costs, with that effort being concluded in this planning cycle. Please refer to chapter 5 and chapter 6.

The CAISO has continued to support the CPUC process regarding exploration of sytem and flexible needs to ensure supply sufficiency. Study efforts focusing on reducing costs to consumers by reducing local capacity requirements and shifting away from reliance on gas-fired generation for those needs will need to take into account not only the current and future economics of existing local capacity resources, but also the renewable integration benefits the generation may provide and the system needs to retain that generation in prioritizing study efforts and in committing to alternatives to reduce local capacity needs.

1.1.5.3 Coordination with CPUC Resource Adequacy Activities

Along with other drivers, the shifting of the net sales peak to later hours – largely due to the rapid growth of behind-the-meter solar generation – combined with steadily increasing volumes of grid-connected solar generation has led to the need to broadly revisit resource planning assessments and certain ISO transmission assessment methodologies that underpin resource planning efforts. This has become most apparent in considering the alignment of long term integrated resource planning efforts with the CPUC's administration of the state's resource adequacy program. While longer term planning studies have focused on more granular approaches of studying comprehensive forecasts and load and resource profiles, the near term resource adequacy programs have focused on methodologies to tabulate resource characteristics to guide short term resource contracting of existing resources to meet near term needs. In this regard, evolving load shapes and increased dependence on use-limited resources require additional consideration of how various resource types contribute to meeting resource adequacy needs overall. An example of this consideration is the incorporation of effective load carrying capability methodologies used by the CPUC in assessing capacity benefits of new resources.

Along with other stakeholders, the ISO has supported and encouraged a broader review of the current resource adequacy framework in the CPUC's current resource adequacy proceeding. In the CPUC's "Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years", the Commission noted that:

> *"[g]iven the passage of time and the rapid changes occurring in California's energy markets, it may be worthwhile to re-examine the basic structure and processes of the Commission's [resource adequacy] program."*[22]

The ISO strongly supports this re-examination and provided several proposals to improve the fundamental structure of the CPUC's resource adequacy program especially in light of the transforming grid. To effectively and efficiently maintain grid reliability while incorporating greater amounts of preferred and intermittent clean, green resources, the resource adequacy program must ensure both procurement of the right resources in the right locations and with the right attributes, and the procurement of a resource adequacy portfolio that meets the system's energy needs all hours of the year. Simply stacking resource capacity values to meet an hourly forecast peak is no longer relevant and not a prudent long-term resource adequacy practice given the system's growing reliance on intermittent and availability limited resources.

To help reform and inform the resource adequacy provisions, the ISO launched its ongoing resource adequacy enhancements initiative. In this initiative, the ISO is investigating resource adequacy policy and design changes that incentivize and support transitioning to a clean, green grid that relies more on variable and energy-limited resources, awards resources that are the most reliable and dependable, and ensures that both peak capacity and system energy needs are met all hours of the year. The ISO continues to collaborate with the CPUC and participate in the CPUC's resource adequacy proceeding to ensure that a viable and coordinated resource adequacy framework is adopted to enure reliability and advance California's clean energy goals.

The ISO also conducted a review of existing ISO "backstop" procurement mechanisms. On September 27, 2019, the Federal Energy Regulatory Commission approved tariff amendments the CAISO filed to enhance and upgrade its reliability must run (RMR) and capacity

[22] *Order Instituting Rulekmaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2010 Compliance Years*, CPUC Proceeding No. R.17-09-020, at p. 3 (OIR), October 4, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747674.PDF.

procurement mechanism (CPM) processes, including the substantive issues relating to the Risk of Retirement (ROR) CPM process.

The amendments effected changes to the RMR and CPM paradigms, including review of the RMR tariff, agreement and process and clarifying and aligning the use of RMR and CPM procurement. Some of the key items include:

- Merging ROR CPM procurement and RMR procurement into one procurement mechanism under the RMR tariff and “modernize” the 20-year-old RMR contract and related tariff provisions to better align them with the CAISO’s current operating framework and needs;
- Eliminating the Condition 1 RMR option (under which RMR resources receive partial cost of service and also retain all market revenues). The revised RMR construct follows the same approach as today’s Condition 2 form of RMR (full cost of service recovery with market rents netted from cost of service payment);
- The ISO will no longer allocate RMR costs to Responsible Utilities or Participating Transmission Owners. Consistent with the practices of other ISOs and RTOs, the ISO will allocate RMR costs not recovered from market revenues to load, or, more specifically, to the scheduling coordinators of LSEs that serve load in the transmission access charge (TAC) areas(s) in which the need for the RMR arose;
- Providing flexible and system resource adequacy credits from RMR resources;
- Making RMR units subject to a must offer obligation like resource adequacy and CPM resources, subject to the rules in CAISO tariff Section 40.6;
- Updating the rate of return provisions for RMR resources; and
- Streamlining and automating RMR settlement process, and lowering banking costs for RMR invoicing.

On October 29, 2018, the FERC approved a limited interim change to the pro forma RMR agreement effective September 1, 2018, to be applied to new RMR designations. The approval also allowed the ISO to terminate the interim form of agreement effective at the end of the contract year and immediately re-designate RMR resources under the new substantive RMR agreement for the following contract year. No RMR agreements were put in place under the interim form of the agreement, and the interim arrangements have been subsumed into the larger amendments.

Impact of Evolving Resource Fleet on Transmission Deliverability Assessments Supporting Resource Adequacy Programs

The same drivers leading to the CPUC's development of effective load carrying capability (ELCC) methodologies in considering the usefulness of particular resources in meeting load requirements also affect the ISO transmission assessment methodologies that underpin resource planning efforts. The existing tariff requires the ISO to perform an on-peak deliverability study to ensure system needs are met at periods of greatest need. The methodology used to consider the deliverability of various resources, such that the resources can provide capacity into the state's resource adequacy program, was developed at a time where the bulk of the capacity – gas-fired generation in particular – was fully dispatchable. Comparatively small levels of renewable generation were treated as incremental to the "core" of other dispatchable resources, and incorporated into deliverability methodologies taking into account their output characteristics, which were also relied upon by the CPUC in assessing qualifying capacity levels.

However, with the significant levels of both grid-connected and behind-the-meter generation being developed, this incremental approach is no longer viable either in determining the contribution of these resources to resource adequacy needs or transmission deliverability assessments, especially in considering additional procurement. Beginning with the 2018 resource adequacy compliance year, the CPUC replaced the exceedance-based qualifying capacity calculation for wind and solar with an ELCC-based approach to account for the growth of renewable energy resources. This reflected that the incremental reliability benefit of adding more solar hits a saturation point after enough capacity is installed. Additional solar resources provide a much lower incremental reliability benefit to the system than the initial solar resources, because their output profile ceases to align with the peak hour of demand on the transmission system which has shifted to later in the day due to the proliferation of behind-the-meter solar. The shift also indicated the need to revisit the application of the deliverability methodology used by the ISO to both award "full capacity deliverability status" for local and system capacity purposes, and to assess deliverability in transmission planning and reliability studies.

In response to this change, the ISO conducted an initiative in 2019 to revise the on-peak deliverability methodology assumptions. The primary objective of this proposal was to align the renewable resource output levels used in on-peak deliverability assessments with the later peak load periods now being experienced on the ISO system and also recognize the capacity benefits solar resources can still provide during other hours of the day. Accordingly, to assess on-peak deliverability, the ISO has developed methodology changes to study both "high system need" scenarios and "secondary system need" scenarios. The high system need scenario represents conditions when a capacity shortage is most likely to occur. In this scenario, the system reaches peak demand with low solar output. If the addition of a resource under this scenario causes a deliverability deficiency determined based on a deliverability test, then the constraint will be classified as either a local constraint requiring mandatory transmission or an area constraint with optional transmission upgrades. The secondary system need scenario represents conditions when the capacity shortage risk will increase if the renewable generation, when producing at a significant output level, is not deliverable. In this scenario, the system load is modeled to represent the peak gross consumption level (i.e., total electricity consumption including consumption served by behind-the-meter resources) and solar output is modeled at a significantly higher output than in the high system need scenario. If the addition of a resource under this scenario causes a deliverability deficiency determined based on a deliverability test and the limiting transmission constraint is not identified in the high system need scenario, then the constraint can be classified as an area constraint with optional transmission upgrades.

At the same time, generation developers noted that the existing deliverability study process, combined with the "full capacity deliverability status" conferred on resources meeting those requirements, was the one mechanism available and relied upon by developers to ensure that generation would not be exposed to excessive curtailment due to transmission limitations. Although transmission upgrades to deliver renewable energy reliably and economically are evaluated and approved through the ISO transmission planning process, concerns remain with the ability of the transmission planning process to identify on a timely basis the upgrades to facilitate generation development, especially local transmission upgrades that depend on the exact point of interconnection of the future generation. Therefore, the ISO initiative considered both modifications to the deliverability methodology to address requirements at peak system need, and to renewable energy delivery during hours outside of the summer peak load period to ensure some minimal level of protection to otherwise potentially unlimited curtailment.

The existing tariff also requires the ISO to perform informational off-peak deliverability studies. The ISO has developed revisions to the off-peak deliverability assessment to make it a binding study and to identify transmission upgrades needed to avoid excessive renewable curtailment.

The changes to the on-peak and off-peak deliverability assessments will require tariff amendment approvals and modifications to the business practice manuals.

Given the need to maintain a stable investment environment for new generators and the scope of changes developed for the deliverability assessment methodology, it is critical that these changes be introduced in a coordinated and measured way in both generation interconnection studies and transmission planning processes. Accordingly, the new methodology has not been incorporated into 2019-2020 transmission planning studies. However, the ISO has recognized the need to be cautious in approving new policy-driven transmission projects in this cycle that could be impacted by the changes developed for the deliverability methodology. Please refer to chapter 3.

Further, the ISO will need to complete at least a full annual study cycle—and more reasonably two full cycles—to assess the direct and indirect impacts of the changes to the study methodology. Highlighting this point, when the ISO Board of Governors approved the ISO's proposed deliverabilty methodology in December 2019, it asked ISO management to report back to the Board of Governors on the transition after the first annual study cycle is complete, assuming FERC approves the changes and the ISO implements the changes in the 2020 studies. [23] Accordingly, the ISO anticipates introducing the changes first in the generation interconnection reassessment studies conducted in early 2019, then the Cluster 12 phase II

[23] Although the ISO is seeking to have the changes in effect for both generator interconnection studies and transmission planning studies performed in 2020, the generation interconnection studies will provide useful input to inform renewable portfolio development for portfolios that would be used in transmission planning studies conducted in 2021. Accordingly, it can take more than one year for all of the implications of the transition to be resolved.

interconnection studies and Cluster 13 phase I interconnection studies, and then the 2020-2021 policy driven transmission planning studies. Although this first cycle will provide considerable understanding of the impact of the changes, the interaction with other aspects of transmission planning, state resource planning and generation development activities may need another full cycle to assess. For example, the generation development community has already responded to the potential deliverability methodology changes with considerable interest in adding storage at existing solar generation sites – or sites under development – to at least somewhat restore the resource adequacy capacity previously anticipated for those sites under previous CPUC resource adequacy rules, and continue to utilize the deliverability those sites may provide under the ISO's changes to its deliverability methodology.

1.1.5.4 Other 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 combined with 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 – but which are now being incorporated into the transmission planning processes as supplemental information. These latter studies form the basis of determinations of system - capacity and related flexibility - needs discussed earlier.

The genesis of the ISO's analysis of flexibility needs was the CPUC 2010-2011 Long-term Procurement Plan (LTPP) proceeding (in 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 efforts have led to a number of changes in market dispatch and annual resource adequacy program requirements, including considering uncertainty in the market optimization solution and developing flexible resource adequacy capacity requirements in the state's resource adequacy program. In addition to those promising enhancements, the ISO launched a stakeholder process to address a number of potential areas requiring further refinement. Of particular concern is ensuring the system maintains and incentivizes sufficient fast and flexible resources to address uncertainty and flexibility from an infrastructure perspective since "the flexible capacity showings to date indicate that the flexible capacity product, as currently designed, is not sending the correct signal to ensure sufficient flexible capacity will be maintained long-term."[24]

[24] Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Supplemental Issue Paper: Expanding the Scope of the Initiative, November 8, 2016, at p.3, available at http://www.caiso.com/Documents/SupplementalIssuePaper-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf.

This effort also led to the ISO's development of a methodology to assess the adequacy of the transmission system to access flexible capacity — the "flexible capacity" equivalent of deliverability assessed for local and system capacity. The ISO initially considered that this could be addressed through the generation interconnection process, with alignment in the annual transmission planning process, much like system resource adequacy capacity and deliverablity issues are currently addressed. Through more detailed consideration of the generation resource fleet and the grid, this issue has instead been incorporated into a separate study expected to be performed in each year's transmission planning studies. If in the future issues emerge that need to be addressed through the generation interconnection process, it will be revisited at that time. Please refer to chapter 6.

Past special study efforts and other initiatives have, in addition to the above, also led to the need to review and upgrade generation models used in frequency response studies discussed in more detail below. This 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. This has in turn led to the development of a rigorous multi-year program to ensure generation owners are providing valid and tested models, as discussed below, and the ISO appreciates the efforts made to date by market participants to address these issues. The frequency response studies themselves have now been elevated from the "special study" category to an annual study expected to be conducted each year for the foreseeable future. Please refer to chapter 6.

1.1.5.5 Non-Transmission Alternatives and Preferred Resources

The ISO continues to support preferred resources, including storage, as a means to meet local transmission system needs.

Since implementing the current transmission planning process in 2010, the ISO has 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 those energy storage solutions that are not transmission. 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. This is progressively becoming more complex, as reliance on preferred resources including energy storage is taking a larger role in the California Public Utilities Commission's (CPUC's) resource planning to successfully integrate higher volumes of renewable generation. As a result, the CAISO is having to consider a growing number of scenarios both in assessing potential reliability concerns and in assessing the effectiveness of potential mitigations.

To increase awareness of the role of preferred resources, section 8.3 summarizes how preferred resources will address specific reliability needs. In addition, discussion throughout chapter 2 show the reliance on preferred resources to meet identified needs on an area-by-area study basis.

The ISO's approach, as noted in previous transmission plans, has focused on specific area analysis, and testing the effectiveness of the resources provided by the market into the utility procurement processes for preferred resources as potential mitigations for identified reliability concerns.

This approach is set out in concept in the study plan for this planning cycle, developed in phase 1 of the planning process as described below. It has built on and refers to a methodology the ISO presented in a paper issued on September 4, 2013,[25] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[26] — 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 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. That methodology for assessing the necessary characteristics and effectiveness of preferred resources to meeting local needs was further advanced and refined through the development of the Moorpark Sub-area Local Capacity Alternative Study released on August 16, 2017.[27] In addition, the ISO has developed a methodology as discussed in section 6.6 of the 2017-2018 Transmission Plan for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources – which both builds and expands on the analysis framework of preferred resources. These efforts, with the additional detail discussed below, help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs. The ISO must also consider the cost effectiveness and other benefits these alternatives provide.

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:

In addition to providing opportunities for preferred resources including storage to be proposed in meeting needs that are being addressed within the year's transmission plan, each year's transmission plan also identifies areas where reinforcement may be necessary in the future, but immediate action is not required. The ISO expects developers interested in developing and proposing preferred resources as mitigations in the transmission planning process to take advantage of the additional opportunity to review those areas and highlight the potential benefits

[25] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014Transmission PlanningProcess.pdf.

[26] 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.

[27] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

of preferred resource proposals in their submissions into utilities' procurement processes. To assist interested parties, each of the planning area discussions in chapter 2 contains a section describing the preferred resources that are providing reliability benefits, and the ISO has summarized areas where preferred resources are being targeted as a solution or part of a solution to address reliability issues in section 8.3. Further, as noted earlier, the ISO has expanded the scope of the biennial 10 year local capacity technical requirements study to provide additional information on the characteristics defing the need in the areas and sub-areas, to further facilitate consideration of preferred resources. Please refer to chapter 6.

Energy storage:

Energy storage solutions can be a transmission resource or a non-transmission alternative. The ISO has considered storage in both contexts in the transmission planning process. Storage played a major role in the assessment of the viability of preferred resource alternatives in the LA Basin studies and Moorpark Sub-area Local Capacity Alternative Study, as well as the Oakland Clean Energy Initiative approved in the 2017-2018 Transmission Plan and modified in the 2018-2019 Transmission Plan.

Existing resource procurement mechanisms can support and have supported storage resources providing these services through the ISO's wholesale markets coupled with procurement directed by the CPUC. This approach ensures that system resources or resources within a transmission constrained area operate together to meet grid reliability needs, and enables the storage resource to participate broadly in providing value to the market. In the case of electric storage resources, procurement also may result in distribution-connected resources and in behind-the-meter resources that do not participate in the ISO's wholesale markets. In the system resource context, the storage resources would be functioning primarily as market resources, with contractual obligations to the off-taker to provide certain services supporting local reliability.

The ISO engaged in a number of parallel activities to facilitate energy storage development generally, including past efforts to refine the generator interconnection process to better address the needs of energy storage developers.

The ISO has also studied in past planning cycles several potential applications of energy storage proposed as transmission assets, including the Dinuba storage project approved in the 2017-2018 Transmission Plan. An important consideration in evaluating storage projects as an option to meeting transmission needs is whether or not the storage facility is operating as transmission to provide a transmission service and meet transmission needs. In other words, the CAISO assesses whether the resource is functioning as a transmission facility. In making this assessment, considering prior FERC direction and the ISO tariff, storage as a transmission asset must:

- Provide a transmission function (*e.g.*, voltage support, mitigate thermal overloads)[28];
- Meet an ISO-determined transmission need under the tariff (reliability, economic, public policy)[29]; and,
- "Be the more efficient or cost-effective solution to meet the identified need"[30] and "If a transmission solution is required to meet an economic need, the ISO must determine if the benefits of the transmission solution outweigh the costs. The benefits of the solution may include a calculation of any reduction in production costs, congestion costs, transmission losses, capacity, or other electric supply costs, *resulting from improved access to cost-efficient resources"*[31] (emphasis added).

Further, if the storage facility meets the above parameters and is selected as a regional transmission solution to meet a transmission need, it would be subject to competitive solicitation.

This direction provides that the determination of eligibility for transmission asset – and regulated rate recovery through the ISO tariff – is not only based on <u>if</u> a transmission need is being met, but <u>how</u> the storage project meets the need. As a result, it is necessary to consider this question individually for each storage project.

In evaluating the efficacy of the storage as a solution to meet identified needs, it is also important to consider if the resource can also earn market-based revenues for providing market services when not required for specific transmission services. Although the historical assumption had been that transmission assets could not also provide other market services or access other market-based revenue streams, FERC issued a policy statement "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery"[32] in 2017 clarifying the potential for electric storage resources to receive cost-based rate recovery for transmission services while also receiving market-based revenues for providing market services. In 2018, the CAISO launched its storage as a transmission asset initiative (SATA) to investigate the possibility of allowing storage to serve as a transmission asset while also providing opportunities to participate in the wholesale electricity market.

At the same time, the market and regulatory framework for storage that is meeting energy market and transmission system needs is also evolving. Utilization of electric storage resources is a significant issue to the ISO given the industry development underway and the growing role storage will play in supporting renewable integration. As the dependence on energy storage is expected to grow considerably in the future, the ISO is examining the means by which it can ensure these resources participating in the market are appropriately positioned to meet reliability needs without unduly limiting market participation opportunities. The ISO is exploring

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[28] *Western Grid Development, LLC,* 130 FERC ¶61,056 at PP 43-46, 51-52 *order on reh'g,* 133 FERC ¶61,029 at PP 11-18.

[29] *Nevada Hydro Company, Inc.,* 164 FERC ¶61,197 at PP 22-25 (2018).

[30] ISO Tariff Section 24.4.6.2., re selecting a transmission solution for an identified reliability need.

[31] ISO Tariff Section 24.4.6.7, re economic needs

[32] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017), at P 9, https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-2.pdf.

these issues in the ISO's on-going energy storage and distributed energy resources initiative and in its resource adequacy enhancements initiative.[33]

In vetting this policy, it became apparent that many of the same issues regarding dispatch and state-of-charge management that apply to market resources providing reliability services also apply to storage devices procured as transmission assets that are also participating in the market. The CAISO therefore placed the storage as a transmission asset initiative (regarding the potential to also earn market revenue) on hold while these operational issues are vetted in the CAISO's on-going energy storage and distributed energy resources initiative and in its resource adequacy enhancements initiative discussed above.

Despite the fact that a mechanism does not currently exist for storage as a transmission asset to access market revenues, the CAISO considered potential market revenues as benefits for energy storage projects as transmission, as appropriate. The ISO in this transmission planning cycle has continued its assumption from recent planning cycles that, unless the transmission services very specifically conflict with providing potential market services, market revenues could be accessed through an appropriately structured power purchase agreement or the eventual advancement of the SATA initiative.

Other 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 and local capacity needs.

Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC.[34] In 2019, the CAISO vetted the market processes it will use to dispatch slow demand response resources on a pre-contingency basis.[35]

This work has helped guide the approach the ISO is taking in the more comprehensive study of local capacity areas in this planning cycle examining both the load shapes and characteristics underpinning local capacity requirements, discussed earlier in this section.

[33] Details on the CAISO's energy storage and distributed energy resources intiative and the resource adequacy enhancements initiative can be found here: http://www.caiso.com/StakeholderProcesses/

[34] See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

[35] Local Resource Adequacy with Availability-Limited Resources and Slow Demand Response Draft Final Proposal found here: http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-LocalResourceAdequacy-AvailabilityLimitedResources-SlowDemandResponse.pdf

1.1.6 System Modeling, Performance, and Assessments

1.1.6.1 System modeling requirements and emerging mandatory standards

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 undertaken in the 2016-2017 planning cycle reviewing all generator models for use in dynamic stability studies and frequency response analysis.

The efforts undertaken in subsequent planning cycles reaffirmed the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. (Refer to section 6.3.3.1.) However, the effort also identified underlying challenges with obtaining validated models for a large – and growing – number of generators that are outside of the bounds of existing NERC mandatory standards and for which the ISO is dependent on tariff authority. The ISO has made significant progress in establishing and implementing a more comprehensive framework for the collection of this data, and will be continuing with its efforts, in coordination with the Participating Transmission Owners, to collect this important information and ensuring validated models are provided by generation owners.

1.1.6.2 Southern California Reliability and Gas-Electric Coordination

As in previous transmission plans, the ISO placed considerable emphasis in this 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.

Successfully mitigating reliability concerns remains dependent on material levels of preferred resources continuing to develop. Given the uncertainty regarding forecast resources materializing as planned, the ISO is continuing to monitor the progress of the forecast and planned procurement of conventional and preferred resources and ISO-approved transmission upgrades underway. The ISO will also continue to actively support the CPUC proceeding examining the needs met by the Aliso Canyon gas storage facilities. Chapter 2 touches on these issues.

1.4 Interregional Transmission Coordination per FERC Order No. 1000

Beginning in January 2018 a new biennial Interregional Transmission coordination cycle was initiated. This biennial coordination cycle spans two ISO annual transmission planning cycles, being the 2018-2019 transmission planning process and this 2019-2020 transmission planning process. Following guiding principles largely developed during the 2016-2017 Interregional Transmission Coordination cycle, the ISO along with the other Western Planning Regions[36] continued to participate and advance interregional transmission coordination within the broader landscape of the western interconnection. These guiding principles were established to ensure that an annual exchange and coordination of planning data and information was achieved in a manner consistent with expectations of FERC Order No. 1000. They are documented in the ISO's Transmission Planning Business Practice Manual as well as in comparable documents of the other Western Planning Regions. Since the 2018-2019 biennial interregional coordination cycle was initiated, the Western Planning Regions have held one Annual Interregional Coordination Meeting on February 22, 2018 to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[37]

The ISO hosted its submission period in the first quarter of 2018 in which proponents were able to request evaluation of an interregional transmission project (ITP). The submission period began on January 1 and closed March 31st with six interregional transmission projects being submitted to the ISO. Of the six project submitted, four projects were submitted into the 2016-2017 cycle and were resubmitted into the 2018-2019 cycle. Following the submission and successful screening of the ITP submittals, the ISO coordinated its ITP evaluation with the other relevant planning regions; NTTG and WestConnect.

The ISO considered all ITP proposals in its 2018-2019 TPP and did not identify an ISO need for the proposed ITPs. Consistent with the Order No. 1000 Common Interregional Tariff, the ISO was not required to consider the proposed ITPs beyond the ISO's 2018-2019 TPP planning cycle. Commensurate with this outcome, no further consideration of the submitted ITPs was required in the 2019-2020 TPP. Please refer to chapter 5.

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

[37] Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website athttp://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=433645F0-E680-4861-94F5-4CD23C3D46E1 .

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.

1.1.7 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 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.[38] More recently, the portfolio provided to the ISO via the CPUC's integrated resource planning proceeding for consideration in the 2018-2019 transmission planning cycle identified both deliverable generation (full capacity deliverability status) and energy-only generation by area.

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.

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 11.

[38] 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).") Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5686.

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.

The GIDAP studies for each queue cluster also provide information that supports future planning decisions. Each year, the ISO validates the capability of the planned system to meet the needs of renewable generation portfolios that have already been provided. The ISO augments this information with information about how much additional generation can be deliverable beyond the previously-supplied portfolio amounts with the results of the generator queue cluster studies. The results are provided each year to the CPUC for consideration in developing the next round of renewable generation portfolios.

1.1.8 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. As the amounts of distributed generation forecast in the recent renewable generation portfolios have declined from previous years, this creates less opportunity for this process to identify and allocate deliverablity status to new resources. Please refer to chapter 3.

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.

1.1.9 Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[39] 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.

1.1.10 Planning Coordinator Footprint

The ISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area in 2014, [40] in part in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities.

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 planning coordinator services agreement. 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

[39] ISO 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 ISO website.

[40] Technical Bulletin – "California ISO Planning Coordinator Area Definition" (created August 4, 2014, last revised July 28, 2016 to update URL for Appendix 2), http://www.caiso.com/Documents/TechnicalBulletin-CaliforniaISOPlanningCoordinatorAreaDefinition.pdf.

identified reliability issues under the planning coordinator services agreement – but only verifying that mitigations have been identified and that they address the identified reliability concerns. In essence, these services are provided to address mandatory standards via the planning coordinator services agreement, separate from and not part of the ISO's FERC-approved tariff governing transmission planning activities for facilities placed under ISO operational control. As such, the results are documented separately, and do not form part of this transmission plan.

The ISO has executed planning coordinator services agreements with Hetch Hetchy Water and Power, the Metropolitan Water District, and the City of Santa Clara. Since the execution of these agreements 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 and has met all requirements to fulfill its planning coordinator responsibilities for these entities.

In addition to the entities discussed above, 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. Considering the entirety of the ISO controlled grid, the ISO is not anticipating a need to offer these services to other parties, as the ISO is not aware of other systems inside the boundaries of the ISO's planning coordinator footprint requiring these services.

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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:

- 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 provided 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 are within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories and are listed below:

- PG&E Local Areas
    - Humboldt area;
    - North Coast and North Bay areas;
    - North Valley area;
    - Central Valley area;

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

2.1.3 Peak Demand

The ISO-controlled grid peak demand in 2019 was 44,301 MW and occurred on August 15 at 5:50 p.m. The following were the peak demand for the four load-serving participating transmission owners' service areas:

PG&E peak demand occurred on August 15, 2019 at 6:51 p.m. with 21,242 MW;

SCE peak demand occurred on September 4, 2019 at 3:20 p.m. with 23,177 MW;

SDG&E peak demand occurred on October 11, 2019 at 8:03 p.m. with 4,474 MW; and

VEA peak demand occurred on January 2, 2019 at 7:16 a.m. with 134 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 and the Central Coast in the PG&E service territory.

2.2 Reliability Standards Compliance Criteria

The 2019-2020 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 2020-2029 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2019-2020 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 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[41]; and
- NUC-001-3 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.[42]

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.[43] These standards:

- 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.

41 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.

42 https://www.wecc.biz/Standards/Pages/Default.aspx

43 http://www.caiso.com/Documents/ISOPlanningStandards-September62018.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[44] (2020-2024) and longer-term[45] (2025-2029) per the requirements of the reliability standards. Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2021, 2024 and 2029.

2.3.2 Transmission Assumptions

2.3.2.1 Transmission Projects

The study included 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 8.1-1 and Table 8.1-2 of chapter 8 (Transmission Project Updates) for the list of previously approved projects that are not yet in service. Projects put on hold were not modeled in the starting base case. Previously approved transmission projects that were not included in the base cases are identified below in the local area assessments.

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.

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 (SVCs) and other devices. Refer to area-specific study sections for a detailed list of generation plants and corresponding assumptions. Two of the key reactive power resources that were modeled in the studies include the following:

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

For a complete resources list, refer to the base cases available at the ISO Market Participant Portal secured website (https://portal.caiso.com/Pages/Default.aspx).[46]

44 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.

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

46 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.

2.3.2.3 Protection Systems

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

2.3.2.4 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 (note the PDCI Upgrade Project – to 3220 MW – was approved in 2017); and,
- 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 secure website.

2.3.3 Load Forecast Assumptions

2.3.3.1 Energy and Demand Forecast

The assessment used the California Energy Demand Updated Forecast, 2018-2030 adopted by California Energy Commission (CEC) on January 9, 2019[47].

During 2018, the CEC, CPUC and ISO reviewed the issue of how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end and consistent with past transmission plans, the 2018 IEPR final report, also adopted on January 9, 2019, recommended using the Mid Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Photovoltaic (AAPV) 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 AAEE and AAPV scenario for local studies has since been considered prudent.

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

[47] The CEC provided revised load forecast values for the Valley Electric Association area to the ISO on July 16, 2019 for use in the 2019-2020 TPP. The CEC staff reviewed documentation of new service requests provided by VEA and determined that an incremental adjustment to non-residential sales projections would be appropriate to account for additional planned electricity demand that would otherwise not be captured in a forecast using econometric methods.

In the 2019-2020 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 has continued to work with the CEC on the hourly load forecast issue during the development of 2018 IEPR.

2.3.3.2 Self-Generation

Baseline peak demand in the CEC demand forecast is reduced by projected impacts of self-generation serving on-site customer load. Most of the increase in self-generation over the forecast period comes from PV. The California Energy Demand Updated (CEDU) Forecast 2018-2030 also includes Additional Achievable Photovoltaic (AAPV). AAPV is incremental to the PV in the baseline forecast and, used in developing the managed forecast. ISO-wide combined self-generation PV and AAPV capacity is projected to reach 20,000 MW in the mid demand case by 2030. In 2019-2020 TPP base cases, both baseline PV and AAPV generation production were modeled explicitly.

PV Self-generation installed capacity for mid demand scenario by the PTO and forecast climate zones are shown in Table 2.3-1.

Table 2.3-1: Mid demand baseline PV self-generation installed capacity by PTO[48]

PTO	Forecast Climate Zone	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PGE	Central Coast	349	396	429	455	483	510	539	568	599	633
	Central Valley	1,182	1,331	1,447	1,542	1,612	1,675	1,738	1,803	1,871	1,945
	Greater Bay Area	1,347	1,558	1,758	1,920	2,075	2,206	2,323	2,433	2,539	2,639
	North Coast	352	394	412	429	463	497	532	566	601	635
	North Valley	258	289	314	334	351	367	382	398	413	428
	Southern Valley	1,556	1,720	1,846	1,959	2,066	2,178	2,296	2,423	2,564	2,722
	PG&E Total	**5,045**	**5,687**	**6,206**	**6,639**	**7,051**	**7,434**	**7,810**	**8,191**	**8,587**	**9,001**
SCE	Big Creek East	375	413	449	485	520	557	594	634	675	722
	Big Creek West	206	228	252	277	304	332	361	389	412	424
	Eastern	816	922	1,015	1,085	1,142	1,197	1,253	1,312	1,373	1,433
	LA Metro	1,288	1,486	1,688	1,876	2,061	2,225	2,370	2,501	2,625	2,744
	Northeast	574	640	707	768	831	897	965	1,037	1,110	1,188
	SCE Total	**3,258**	**3,688**	**4,111**	**4,490**	**4,858**	**5,207**	**5,544**	**5,873**	**6,195**	**6,511**
SDGE	SDGE	1,391	1,498	1,557	1,618	1,679	1,746	1,821	1,907	2,007	2,128
CAISO Total		**9,694**	**10,873**	**11,873**	**12,748**	**13,588**	**14,387**	**15,174**	**15,971**	**16,789**	**17,640**

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

Table 2.3-2 below shows AAPV installed capacity for Mid-Low and Mid-Mid Scenarios for each IOU planning areas.

Table 2.3-2 AAPV installed capacity (MW) for PG&E, SCE and SDG&E planning areas[49]

PTO	Forecast Climate Zone	2020		2021		2022		2023		2024		2025		2026		2027		2028		2029	
		Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low
PGE	Central Coast	5	5	10	9	16	14	22	18	29	23	35	27	40	31	46	34	52	38	57	42
	Central Valley	16	13	35	28	59	46	82	63	108	80	133	98	158	115	182	132	206	149	230	165
	Greater Bay Area	22	21	47	42	75	64	103	85	130	103	157	121	182	138	206	155	230	171	254	188
	North Coast	5	7	10	12	18	18	26	23	34	29	42	34	49	39	56	43	64	48	71	52
	North Valley	3	3	7	6	11	9	16	13	21	16	25	20	30	23	35	27	39	30	43	33
	Southern Valley	11	9	24	16	42	25	59	35	78	51	97	65	116	80	134	94	151	109	169	123
	PG&E Total	**62**	**58**	**133**	**113**	**222**	**176**	**308**	**238**	**399**	**302**	**489**	**365**	**575**	**426**	**659**	**486**	**742**	**545**	**824**	**603**
SCE	Big Creek East	5	4	10	9	16	14	22	19	28	24	34	29	40	33	46	38	51	43	57	48
	Big Creek West	3	3	6	6	10	9	14	13	17	16	20	19	23	22	26	25	29	28	32	31
	Eastern	13	11	26	23	42	37	57	50	72	64	87	77	102	90	116	103	130	116	144	129
	LA Metro	35	32	71	66	112	100	150	133	187	164	223	193	257	222	289	249	322	276	354	303
	Northeast	14	11	29	24	46	37	63	49	79	62	95	75	111	88	126	100	141	113	156	125
	SCE Total	**70**	**62**	**143**	**128**	**226**	**197**	**305**	**264**	**383**	**329**	**460**	**393**	**533**	**456**	**603**	**516**	**673**	**576**	**743**	**635**
SDGE	SDGE	16	13	33	22	51	38	69	53	87	69	104	85	120	100	136	114	151	128	166	142
	CAISO Total	**148**	**134**	**308**	**263**	**499**	**411**	**682**	**555**	**869**	**700**	**1,053**	**843**	**1,229**	**981**	**1,398**	**1,115**	**1,566**	**1,248**	**1,733**	**1,380**

49 https://efiling.energy.ca.gov/GetDocument.aspx?tn=222398

Outputs of the self-generation PV and AAPV were selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

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 CPUC issued a decision[50] on February 8, 2018 which adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals. Subsequently, the CPUC issued a decision[51] on April 25, 2019 which recommended that the CAISO utilize the Preferred System Plan (PSP) adopted in this decision as the base portfolio to be modeled in the TPP reliability assessment. The final base portfolio is posted to the CPUC's web site[52].

The CPUC staff has developed the "reliability base" portfolio using RESOLVE capacity expansion model. RESOLVE documentation specifies that renewable resources under development with CPUC-approved contracts with the three investor-owned utilities are assumed to be part of the baseline assumptions.

The portfolios are at a geographic scale that is too broad for transmission planning purposes, which requires more specific interconnection locations. The final allocation of the geographically-coarse resources to substations on the CAISO-controlled transmission grid was conducted by land-use experts at the CEC. The allocation is available on the CEC's website[53] .

The ISO relied on specific information received from the Imperial Irrigation District (IID) as part of the annual TPP base case coordination and made certain changes to the modeling locations recommended by the CEC. The CEC staff had recommended the following locations for modeling geothermal resources selected in all three portfolios:

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50 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

51 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

52 Website for final base portfolios: http://www.cpuc.ca.gov/General.aspx?id=6442460548

53 CEC Website for resource allocation within resource areas: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-MISC-03

MW Assignment	Substation
1052	Bannister
160	El Centro
32	Highline

Based on the input received from IID during the planning base case building process about the likely location for geothermal resource development based on IID's interconnection studies, the ISO modeled the Greater Imperial Zone geothermal resources as follows:

MW Assignment	Substation
622	Bannister 230 kV (IID)
622	Hudson Ranch 230 kV (connecting to IID's Midway 230 kV)

2.3.4.3 Thermal generation

For the latest updates on new generation projects, please refer to CEC website under the licensing section[54]. The ISO also relies on other data sources 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 were 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 recent 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 offline 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; and,
- Other Retirements – Unless otherwise noted, assumed retirement based resource age of 40 years or more.

[54] Licensing section: http://www.energy.ca.gov/sitingcases/all_projects.html

2.3.4.6 OTC Generation

Modeling of the once-through cooled generating units, shown in Table 2.3-3, 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.

The above assumptions were made, and analysis performed, prior to the current consideration of extensions being sought to certain OTC generating units' compliance dates to address overall supply sufficiency concerns[55]. These extensions are not yet in place, and the objective of the transmission planning process in any event is to enable the retirements – when system supply sufficiency concerns are addressed - unencumbered by local constraints.

[55] CPUC Decision 19-11-016, "DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023, November 7, 2019, Issues November 13, 2019, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

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

Generating Facility	Owner	Existing Unit/ Technology[56] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[57] (MW) and Technology[58] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Humboldt Bay	PG&E	1 (ST)	12/31/2010	9/30/2010	52	163 MW (10 ICs)	9/28/2010	Retired 135 MW and repowered with 10 ICs (163 MW)
		2 (ST)	12/31/2010		53			
Contra Costa	GenOn	6 (ST)	12/31/2017	April 30, 2013	337	Replaced by 760 MW Marsh Landing power plant (4 GTs)	May 1, 2013	New Marsh Landing GTs are located next to retired generating facility.
		7 (ST)	12/31/2017		337			
Pittsburg	GenOn	5 (ST)	12/31/2017	12/31/2016	312	Retired (no repowering plan)	N/A	
		6 (ST)	12/31/2017		317			
Potrero	GenOn	3 (ST)	10/1/2011	2/28/2011	206	Retired (no repowering plan)	N/A	
Moss Landing	Dynegy	1 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510	The State Water Resources Control Board (SWRCB) approved mitigation plan (Track 2 implementation plan) for Moss Landing Units 1 & 2.	N/A	The State Water Resources Control Board (SWRCB) approved OTC Track 2 mitigation plan for Moss Landing Units 1 & 2.
		2 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510			
		6 (ST)	12/31/2020 (see notes)	1/1/2017	754	Retired (no repowering plan)	N/A	
		7 (ST)	12/31/2020 (see notes)	1/1/2017	756	Retired (no repowering plan)	N/A	
Morro Bay	Dynegy	3 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	
		4 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	

[56] Most of the existing OTC units, with the exception of Moss Landing Units 1 and 2, are steam generating units.

[57] The ISO, through Long-Term Procurement Process and annual Transmission Planning Process, worked with the state energy agencies and transmission owners to implement an integrated and comprehensive mitigation plan for the southern California OTC and SONGS generation retirement located in the LA Basin and San Diego areas. The comprehensive mitigation plan includes preferred resources, transmission upgrades and conventional generation.

[58] IC (Internal Combustion), GT (gas turbine), CCGT (combined cycle gas turbine)

Generating Facility	Owner	Existing Unit/ Technology[56] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[57] (MW) and Technology[58] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Diablo Canyon Nuclear Power Plant	PG&E	1 (ST)	12/31/2024	2025	1122	PG&E plans to replace with renewable energy, energy efficiency and energy storage.	N/A	On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2024 and 2025, respectively.
		2 (ST)	12/31/2024	2025	1118			
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	Retired (no repowering)		Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215	SCE plans to replace with renewable energy and storage		
Ormond Beach	GenOn	1 (ST)	12/31/2020		741	To be retired (no repowering)	N/A	
		2 (ST)	12/31/2020		775			
El Segundo	NRG	3 (ST)	12/31/2015	7/27/2013	335	560 MW El Segundo Power Redevelopment (CCGTs)	August 1, 2013	Unit 3 was retired on 7/27/2013.
		4 (ST)	12/31/2015	12/31/2015	335	Retired (no repowering)	N/A	Unit 4 was retired on December 31, 2015.
Alamitos	AES	1 (ST)	12/31/2020	12/31/2019	175	640 MW CCGT on the same property	4/1/2020	
		2 (ST)	12/31/2020	12/31/2019	175			
		3 (ST)	12/31/2020	12/31/2020	332			
		4 (ST)	12/31/2020	12/31/2020	336			
		5 (ST)	12/31/2020	12/31/2020	498			
		6 (ST)	12/31/2020	12/31/2019	495			
Huntington Beach	AES	1 (ST)	12/31/2020	10/31/2019	226	644 MW CCGT on the same property	3/1/2020	
		2 (ST)	12/31/2020	12/31/2020	226			
		3 (ST)	12/31/2020	11/1/2012	227			Units 3 and 4 were retired in 2012 and converted to synchronous condensers in June 2013 to operate on an interim basis. On December 31, 2017, these two synchronous
		4 (ST)	12/31/2020	11/1/2012	227			

Generating Facility	Owner	Existing Unit/ Technology[56] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[57] (MW) and Technology[58] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
								condensers were retired.
Redondo Beach	AES	5 (ST)	12/31/2020		179	To be retired	N/A	
		6 (ST)	12/31/2020		175			
		7 (ST)	12/31/2020	10/31/2019	493			
		8 (ST)	12/31/2020		496			
San Onofre Nuclear Generating Station	SCE/ SDG&E	2 (ST)	12/31/2022	June 7, 2013	1122	Retired (no repowering)	N/A	
		3 (ST)	12/31/2022		1124			
Encina	NRG	1 (ST)	12/31/2017	3/1/2017	106	500 MW (5 GTs or peakers) Carlsbad Energy Center, located on the same property as the Encina Power Plant.	12/11/2018	The State Water Resources Control Board approved extension of compliance date for Units 2 through 5 to December 31, 2018 due to delay of in-service date for Carlsbad Energy Center. Encina Units 2 – 5 were retired on December 11, 2018.
		2 (ST)	12/31/2017	12/31/2018 [59]	103			
		3 (ST)	12/31/2017	12/31/2018	109			
		4 (ST)	12/31/2017	12/31/2018	299			
		5 (ST)	12/31/2017	12/31/2018	329			
South Bay (707 MW)	Dynegy	1-4 (ST)	12/31/2011	12/31/2010	692	Retired (no repowering)	N/A	Retired 707 MW (CT non-OTC) – (2010-2011)

[59] The State Water Resources Control Board approved extending the compliance date for Encina Units 2 to 5 for one year to December 31, 2018 due to delay of Carlsbad Energy Center in-service date.

2.3.4.7 2012 LTPP Authorization Procurement

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

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

LCR Area	LTPP Track-1		LTPP Track-4[60]	
	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

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

	LTPP EE (MW)	Behind the Meter Solar PV (NQC MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE's procurement for the Western LA Basin[61]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark Sub-area[62]	6.00	5.66	0	0	0	11.66
SDG&E's procurement[63]	19 (approved)	0	83.5[64] (approved)	4.5 (approved)	800[65]	907

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

[61] 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.

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

[63] For additional details on approved and pending projects, see San Diego Gas & Electric applications A.14-07-009, available online at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=98406519, A.16-03-014 available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1603014, and A.17-04-017 available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1704017.

[64] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K337/215337477.PDF

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

2.3.5 Preferred Resources and Energy Storage

Commensurate with 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 Pacific Gas & Electric (PG&E). PG&E provided a bus-level model of PG&E's demand response (DR) programs for the inclusion in the 2019-2020 Transmission Plan Unified Planning Assumptions and Study Plan.

Methodology

The ISO issued a paper[66] 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 Moorpark 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 2018-2019 planning cycle, reliability assessments in the current planning cycle considered a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies also incorporated the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the CPUC Default RPS Portfolio and a mix of preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization and subsequent authorizations. 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 were initially performed using preferred resources other than energy-limited preferred resources such as DR and energy storage to identify reliability concerns in the area. If reliability concerns were identified in the initial assessment, additional rounds of assessments were performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If these preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis was then be performed, if considered necessary given the mix of

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

resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage. An example of such a study is the special study the ISO performed for the CEC in connection with the Puente Power Project proceeding to evaluate alternative local capacity solutions for the Moorpark area[67]. The ISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

Demand Response

Section 6.6 of the ISO 2017-2018 Transmission Plan provided a status update on the progress to identify the necessary characteristics for slow response local capacity resources, such that the resources can be relied upon to meet reliability needs. For long term transmission expansion studies, the methodology described above and in section 3.8.2 of the 2019-2020 study plan was utilized for considering fast-response DR and slow-response PDR resources[68].

The DR Load Impact Reports filed with the CPUC on April 3, 20l7, and other supply-side DR procurement incremental to what is assumed in the Load Impact Reports, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that supply-side DR has on the system. A description of the total supply-side DR capacity assumptions[69] is shown in Table 2.3-6.

[67] https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf

[68] For local capacity requirement studies, slow response DR will be utilized once the necessary characteristics have been accepted in the CPUC's RA proceedings, as indicated in the CAISO's comments in the RA proceeding.

[69] http://www.cpuc.ca.gov/General.aspx?id=6442451972

Table 2.3-6: Existing DR Capacity Range in Local Area Reliability Studies

Supply-side DR (MW):		PG&E	SCE	SDG&E	All IOUs	Assumed Market	Assumed 30 minute responsive
Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2027 ex-ante DR impacts at ISO peak							
BIP		300	610[70]	6.74	917	RDRR	Yes
AP-I			50[71]	0.0	50	RDRR	Yes
AC Cycling Res[72]		61	56	7.18	124	PDR	Yes
AC Cycling Non-Res		0	20[73]	1.79	22	PDR	Yes
CBP		103[74]	143[75]	8.44	254	PDR	No
Other procurement program DR							
SCE LCR RFO,[76] post 2018			5.0		5	RDRR	Yes
DRAM[77]	2017	56.4	56.2	12	125	PDR[78]	No
	2018	79.5	88.5	13.9	182		
	2019	90.1	99.2	15.7	205		

DR capacity was 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 were modeled offline in the initial reliability study cases and were used as potential mitigation in those planning areas where reliability concerns are identified.

The factors shown in Table 2.3-7 were applied to the DR projections to account for avoided distribution losses.

Table 2.3-7: Factors to Account for Avoided Distribution Losses

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

70 D.16-06-029 authorizes SCE to use existing BIP funds to gain 5 MW of incremental load impact for the program.

71 D.16-06-029 authorizes SCE to use existing AP-I funds to gain 4 MW of incremental load impact for the program.

72 AC Cycling programs include Smart AC (PG&E), SDP (SCE), and Summer Saver (SDG&E)

74 D.16-06-029 approved PG&E's request to terminate its AMP program. It is assumed that 82 MW from PG&E's AMP program will migrate to PG&E's CBP program.

75 D.16-06-029 approved SCE's request for an extension of its AMP program through 2017. However, it is assumed that 93 MW from SCE's AMP program will migrate to its CBP program by 2026.

76 SCE LCR RFO refers to procurement authorized in D.14-03-004 with contract approved in D.15-11-041

77 Demand Response Auction Mechanism (DRAM) is a 4-year pilot program with contract lengths set at a maximum of one year.

78 Although the 2017 DRAM solicitation could include a mix of Reliability Demand Response Resource (RDRR) and Proxy Demand Resource (PDR), for modeling we will assume it is all PDR absent more definitive information.

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, with 700 MW to be transmission-connected, 425 MW to be distribution-connected, and 200 MW to be customer-side. D.13-10-040 also allocated procurement responsibilities for these amounts to each of the three major IOUs. Energy storage to be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision discussed above was subsumed within the 2020 procurement target as well as other authorizations.

More recent CPUC approvals have also led to additional or more targeted grid-connected energy storage development.

CPUC Resolution E-4791 was adopted on May 26, 2016 and was issued to address electrical reliability risks due to the (then) moratorium on injections into the Aliso Canyon Natural Gas Storage Facility. This led to the expedited development of storage in by both SDG&E and SCE.

The CPUC is currently reviewing applications by SCE for a total of 195 MW and 780 MWh of energy storage projects that are needed to meet local capacity requirements in the Santa Clara area. These resources are part of a multi-faceted solution approved by the CAISO in the 2017-2018 Transmission Plan for the Moorpark and Santa Clara sub-areas that also included the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double circuit towers

In the 2017-2018 Transmission Plan, the ISO also approved the Oakland Clean Energy Initiative, which included storage and preferred resources as a component of the overall plan. The portfolio procurement need for the previously approved project, has been updated due to the increase in the area's load forecast and based on the latest Northern Oakland area load profile. The portfolio need has increased to about 36 MW and 173 MWh for 2024 from storage to sufficiently meet the current forecasted reliability need as set out in section 2.5.5.3.

The CPUC issued Resolution E-4949 on November 8, 2018 approving battery storage projects adopted to eliminate or reduce the need for (then) California ISO-issued backstop contracts for three natural gas-fired generation plants in the Greater Bay area. The CPUC had adopted Resolution E-4909 in January 2018, authorizing PG&E to hold competitive solicitations for energy storage and/or preferred resources, to reduce or eliminate the need for reliability must run (RMR) contracts in three subareas and mitigate the exercise of market power. Table 2.3-8 includes the battery energy storage system projects that were approved by the CPUC in response to the resolution.

Table 2.3-8: CPUC-Approved PG&E Contracts for Storage to Replace Natural Gas-Fired Generation in Northern California[79]

Project	Size (MW)	Term (Years)	On-Line Date
Vistra Moss Landing	300	20	12/1/2020
Hummingbird	75	15	12/1/2020
mNOC AERS	10	10	10/1/2019
Tesla Moss Landing	182.5	20	12/31/2020

The procurement activities to date have been summarized by the CEC in Table 2.3-9 and the study assumption volumes are set out in each area's study sub-section later in this chapter.

Table 2.3-9: IOU Existing and Proposed Energy Storage Procurement[80]

Pacific Gas and Electric					
	Target	On-Line Storage	Approved, Some are in Progress	Pending Approval	TOTAL PROCURED
Transmission	310	0	567.5	125	692.5
Distribution	185	6.5	10	20	36.5
Customer	85	26.1	0	20	46.1
Southern California Edison					
	Target	On-Line Storage	Approved, Some are in Progress	Pending Approval	TOTAL PROCURED
Transmission	310	20	100	0	120
Distribution	185	56	65.5	10	131.5
Customer	85	110	195	0	305
San Diego Gas & Electric					
	Target	On-Line Storage	Approved, Some are in Progress	Pending Approval	TOTAL PROCURED
Transmission	80	40	39	0	79
Distribution	55	43.6	13.5	0	57.1
Customer	30	30	0	0	30
TOTAL – All IOUs	1,325	332.2	990.5	175	1,497.7

These storage capacity amounts were modeled in the initial reliability base cases using the locational information as well as the in-service dates provided by CPUC.

The above information does not include storage procured as transmission assets that are not participating in the electricity market.

79 Final 2018 CEC IEPR Update Volume II https://www.energy.ca.gov/2018_energypolicy/documents

80 Final 2018 CEC IEPR Update Volume II https://www.energy.ca.gov/2018_energypolicy/documents

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. The capability and power flows modeled in each scenario on these paths in the northern area assessment[81] are listed in Table 2.3-10.

Table 2.3-10: Major paths and power transfer ranges in the Northern California assessment[82]

Path	Transfer Capability/SOL (MW)	Scenario in which Path was stressed
Path 26 (N-S)	4000[83]	Summer Peak
PDCI (N-S)	3220[84]	
Path 66 (N-S)	4800[85]	
Path 15 (N-S)	-5400[86]	Spring Off Peak
Path 26 (N-S)	-3000	
Path 66 (N-S)	-3675	Winter Peak

For the spring 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 2.3-11 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.

[81] These path flows were modeled in all base cases.

[82] 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)

[83] May not be achievable under certain system loading conditions.

[84] PDCI Upgrade Project – to 3220 MW – was approved in 2017

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

[86] May not be achievable under certain system loading conditions

Table 2.3-11: Major Path flow ranges in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path was stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3220	3220	
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 10,100	Summer Peak
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	400	0 to 250	Summer Peak
Path 45 (S-N)	800	0 to 300	Off 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 the website: 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 were 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. With hourly demand forecast being available from CEC, all base scenarios representing peak load conditions, for both summer and winter, represented hour of the highest net load. The net peak hour reflects changes in peak hours brought on by demand modifiers. Furthermore, for the coincident system peak load scenarios, the hour of the highest net load were consistent with the hour identified in the CEC demand forecast report. For the non-coincident local peaks scenarios, the net peak hour may represent hour of the highest net load for the local area. Winter peak, spring off-peak or winter off-peak were also 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 2.3-12 lists the studies that were conducted in this planning cycle.

Path flows:

For local area studies, transfers on import and monitored internal paths were modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths were 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 2.3-12 summarizes these study areas and the corresponding base scenarios for the reliability assessment.

Table 2.3-12: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2021	2024	2029
Northern California (PG&E) Bulk System	Summer Peak Spring Off-peak	Summer Peak Spring Off-peak	Summer Peak Spring Off-peak Winter off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-peak	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Off-peak	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer/Winter Peak Spring Off-peak	Summer/Winter Peak Spring Off-Peak	Summer Peak

2.3.8.2 Sensitivity study cases

In addition to the base scenarios that the ISO assessed in the reliability analysis for the 2019-2020 transmission planning process, the ISO assessed the sensitivity scenarios identified in Table 2.3-13. 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 2.3-13: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2021	2024	2029
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Off peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	-
Summer Peak with high SVP forecasted load			PG&E Greater Bay Area
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off-peak with heavy renewable output	-	VEA Area	-
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)[87]
- 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)

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)[88]
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)
- Loss of a single pole of DC lines (P3.5)

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

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

Multiple contingency (Category P4)

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

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

Multiple contingency (Category P5)

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

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

Multiple contingency (Category P6)

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

Multiple contingency (Category P7)

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

- Any two adjacent circuits on common structure[89] (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.

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

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 program 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. However, other tools such as DSA tools software may be used in other studies such as voltage stability, small signal stability analyses and transient stability studies. The studies in the local areas focus on the impact from the grid under system normal conditions and following the Categories 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 were used in the study:

Steady State Contingency Analysis

The ISO performed power flow contingency analyses based on the ISO Planning Standards[90] 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)[91]. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

Line and transformer bank ratings in the power flow cases 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.

The contingency analysis simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses included the impact of subsequent tripping of transmission elements where relay loadability limits are exceeded and generators where simulations show generator

[90] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

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

bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations unless corrective action plan is developed to address the loading and voltages concerns.

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 8% voltage deviation for P1 events.

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 guide for voltage support and reactive power, approved by WECC Technical Study Subcommittee (TSS) on March 30, 2006, was used for the analyses in the ISO controlled grid. According to the guide, 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 WECC criteria and ISO Planning Standards.

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

A simplified map of the PG&E bulk transmission system is shown in Figure 2.4-1.

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. However, depending on the generation dispatch and the load value in northern and southern California, Path 26 may have north-to-south flow direction during off-peak periods also. 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 peak and off-peak sensitivity scenarios with high renewable generation output and low gas generation output. Post transient contingency analysis was also performed for all flow patterns and scenarios (seven base cases and three sensitivity cases) described in section 2.4.2 below. Transient stability studies were performed for the selected six cases: four base cases – 2024 and 2029 Summer Peak and 2024 and 2029 Spring off-Peak and two sensitivity cases: 2024 Summer Peak with high CEC forecast and 2024 Spring off-Peak with high renewable and low gas generation output.

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 a 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 and spring off-peak cases for the years 2021, 2024 and 2029; and winter off-peak peak case for 2029. In addition, 3 sensitivity cases were studied: the 2021 Summer Peak case with high renewable and low gas generation output, 2024 Spring off-Peak case with high renewable and low gas generation output and 2024 Summer Peak with high CEC forecasted load. 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 some summer peak 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 and Northern California Hydro generation level for the northern area bulk study

BASE CASE	Scenario Type	Description	COI MW	Path 15 MW	Path 26 MW	PDCI MW	N.Cal Hydro, %
PGE-Bulk-2021-SP	Base Line	2021 Summer peak load conditions. Peak load time -hour ending 18:00	4790 N-S	2350 N-S	3700 N-S	3200 N-S	80%
PGE-Bulk-2021-SpOp	Base Line	2021 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	3380 S-N	1670 S-N	1760 N-S	40 S-N	70%
PGE-Bulk-2024-SP	Base Line	2024 Summer peak load conditions. Peak load time - hour ending 19:00	4800 N-S	100 N-S	1200 N-S	3220 N-S	80%
PGE-Bulk-2024-SpOP	Base Line	2024 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	3675 S-N	2680 S-N	730 N-S	170 S-N	65%
PGE-Bulk-2029-SP	Base Line	2029 Summer peak load conditions. Peak load time - hour ending 19:00	4800 N-S	580 S-N	1380 S-N	3210 N-S	80%
PGE-Bulk-2029-SpOP	Base Line	2029 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	3650 S-N	840 S-N	370 N-S	1000 S-N	65%
PGE-Bulk-2029-WOP	Base Line	2029 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	220 S-N	540 S-N	1310 S-N	930 S-N	75%
PGE-Bulk-2021-SP-HiRenew	Sensitivity	2021 Summer peak load conditions with high renewables and minimum gas	3640 N-S	220 S-N	2320 N-S	3200 N-S	80%
PGE-Bulk-2024-SP-Hi CEC	Sensitivity	2024 Summer peak load conditions with high CEC forecasted load	4800 N-S	930 S-N	320 N-S	3220 N-S	80%
PGE-Bulk-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with high renewables and minimum gas	2970 S-N	210 N-S	3350 N-S	160 S-N	54%

All power flow cases included certain amount of renewable resources, which was dispatched at different levels depending on the case studied. The assumptions on the generation installed capacity and the output are summarized in Table 2.4-2.

Table 2.4-2. Generation Assumptions – PG&E Bulk System

BASE CASE	Scenario Type	Description	Battery Storage		Solar		Wind		Hydro		Thermal		Nuclear	
			Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch
			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
PGE-Bulk-2021-SP	Base Line	2021 Summer peak load conditions. Peak load time -hour ending 18:00	894	0	4,716	610	1,692	1,447	10,421	8,113	20,433	15,897	2,400	2,380
PGE-Bulk-2021-SpOp	Base Line	2021 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	894	0	4,716	4,298	1,692	954	10,421	5,415	20,433	4,117	2,400	2,380
PGE-Bulk-2024-SP	Base Line	2024 Summer peak load conditions. Peak load time - hour ending 19:00	914	0	4,716	289	1,692	1,165	10,421	7,703	20,433	15,832	2,400	2,380
PGE-Bulk-2024-SpOP	Base Line	2024 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	914	0	4,716	4,092	1,692	162	10,421	5,186	20,433	4,207	2,400	2,380
PGE-Bulk-2029-SP	Base Line	2029 Summer peak load conditions. Peak load time - hour ending 19:00	914	0	4,742	201	2,641	1,726	10,421	7,882	20,830	15,506	0	0
PGE-Bulk-2029-SpOP	Base Line	2029 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	914	0	4,742	4,271	2,641	1,515	10,421	5,145	20,830	3,513	0	0
PGE-Bulk-2029-WOP	Base Line	2029 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	914	-874	4,742	201	2,641	104	10,421	4,677	20,830	14,238	0	0
PGE-Bulk-2021-SP-HiRenew	Sensitivity	2021 Summer peak load conditions with high renewables and minimum gas	894	0	4,716	4,254	1,692	1,363	10,421	8,107	20,433	7,253	2,400	2,380
PGE-Bulk-2024-SP-Hi CEC	Sensitivity	2024 Summer peak load conditions with high CEC forecasted load	914	0	4,716	282	1,692	1,165	10,421	7,711	20,433	16,090	2,400	2,380
PGE-Bulk-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with high renewables and minimum gas	914	0	4,716	4,254	1,692	1,117	10,421	4,747	20,433	4,114	2,400	2,380

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. Table 2.4-3 shows the assumed load levels for selected areas under summer peak and non-peak conditions. The table shows gross PG&E load in all the cases studied and the load modifiers: Additional Achievable Energy Efficiency, output of the Behind the Meter solar PV generation, and it also shows the load for irrigational pumps and hydro pump storage plants if they are operating in the pumping mode. In the base cases, pumping load is modeled as negative generation. Net load is the gross load with the Additional Achievable Energy Efficiency and the output of the Behind the Meter solar PV generation subtracted and the pumping load added.

Table 2.4-3: Load and Load Modifier Assumptions – PG&E Bulk System

BASE CASE	Scenario Type	Description	Gross PG&E Load	AAEE	Behind the Meter PV		Net Load	Demand Response		Pumps (Irrigation and pump-storage)
					Installed	Output		Total	D2	
			MW	MW	MW	MW	MW	MW	MW	MW
PGE-Bulk-2021-SP	Base Line	2021 Summer peak load conditions. Peak load time -hour ending 18:00	29,354	561	5,782	983	**27,810**	414	211	603
PGE-Bulk-2021-SpOp	Base Line	2021 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	15,681	332	5,782	4,629	**10,720**	414	211	1,502
PGE-Bulk-2024-SP	Base Line	2024 Summer peak load conditions. Peak load time - hour ending 19:00	30,564	1,022	7,251	226	**29,316**	415	211	615
PGE-Bulk-2024-SpOP	Base Line	2024 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	16,695	594	7,251	5,874	**10,227**	415	211	1,515
PGE-Bulk-2029-SP	Base Line	2029 Summer peak load conditions. Peak load time - hour ending 19:00	32,053	1,975	9,371	279	**29,799**	417	211	631
PGE-Bulk-2029-SpOP	Base Line	2029 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	17,579	1,027	9,371	7,498	**9,054**	417	211	1,531
PGE-Bulk-2029-WOP	Base Line	2029 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	19,269	1,030	9,371	0	**18,239**	417	211	1,531
PGE-Bulk-2021-SP-HiRenew	Sensitivity	2021 Summer peak load conditions with high renewables and minimum gas	29,354	561	5,782	5,725	**23,068**	414	211	602
PGE-Bulk-2024-SP-Hi CEC	Sensitivity	2024 Summer peak load conditions with high CEC forecasted load	30,621	0	7,251	226	**30,395**	415	211	615
PGE-Bulk-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with high renewables and minimum gas	16,695	594	7,251	7,180	**8,921**	415	211	1,515

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. Comprehensive details of these protection systems are provided in various ISO operating procedures, engineering and design documents.

2.4.3 Assessment and Recommendations

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

The starting cases used Security Constrained Generation Dispatch. Thus, no Category P0 overloads were observed on the PG&E Bulk system on the facilities 230 kV and above. Several overloads that were observed under normal conditions on the 115 kV transmission lines could be mitigated by congestion management – reducing generation connected to these transmission lines. The 60 kV and 70 kV facilities are not considered to be Bulk Electric System (BES), therefore, even if some of them were overloaded under normal system conditions and with contingencies, their overloads are not discussed here further. These overloads are considered in the local area studies.

Heavy loading above 95% under normal system conditions was observed on three 230 KV lines: 1) Cayetano-Lone Tree 230 kV line under peak load conditions with high generation in the Contra Costa area, 2) a section of the Los Banos-Panoche #1 230 kV line in 2021 prior to its upgrade, with high output from the renewable project connected to this line and 3) Moss Landing – Las Aguilas 230 kV line under off-peak conditions with high output of the Las Aguilas generation and low output of generation at Moss Landing.

Also, heavy loading under normal system conditions was observed on the 500/230 kV Table Mountain transformer under off-peak conditions with high hydro generation connected to this transformer.

The same transmission facilities were also overloaded with single and double contingencies.

Thermal overloads identified in the PG&E Bulk System studies are discussed below.

- Two Category P1 overloads were identified under summer peak conditions in the base cases on the 500 kV transmission lines. These overloads were observed on the two circuits in the same corridor: Round Mountain-Table Mountain # 1 and # 2 500 kV lines with an outage of the parallel circuit.
- Three Category P1 overloads were identified on the 500/230 kV transformers: Olinda, Round Mountain and Table Mountain with single contingencies of 500/230 kV transformers or 500 kV lines in the Northern part of PG&E. These overloads may occur under off-peak load conditions with high output of hydro generation in Northern California connected to the 230 kV sides of these transformers.
- Two 230 kV transmission lines were identified as overloaded under Category P1 contingencies: Delevan-Cortina 230 kV line and Moss Landing-Las Aguilas 230 kV line. The first line may overload under peak load conditions in 2029 with an outage of the Olinda-Tracy 500 kV line, and the second one – under spring off-peak load conditions in 2024 with an outage of the Moss Landing-Los Banos 500 kV transmission line.
- Under a Category P2 contingency, Round Mountain-Table Mountain # 1 500 kV line may also overload. This Category P2 contingency includes an outage of the parallel 500 kV Round Mountain-Table Mountain 500 kV circuit. Other Category P2 overloads include Olinda and Table Mountain 500/230 kV transformers under spring off-peak conditions with the contingencies that involve an outage of a 500/230 kV transformer or 500 kV lines in the area. Category P2 contingencies of the 230 kV lines include overloads on the Cayetano-Lone tree 230 kV line and Delevan-Cortina 230 kV lines under summer peak load conditions.
- Under Category P3 contingencies with an outage of one of the Diablo Canyon generation units and another transmission facility and in addition to the facilities that were overloaded under Categories P0 and P1 contingencies, the Delta-Cascade 115 kV line may also slightly overload with an outage of the Diablo Canyon unit and the Captain Jack-Olinda 500 kV line under summer peak load conditions in 2024. In the sensitivity cases, the Gates 500/230 kV transformer may also overload with an outage of the Diablo Canyon generation unit and another facility. The Gates 500/230 kV transformer overload was observed only in the 2024 spring off-peak case with high renewable and minimum gas generation output. It was assumed that there were no system adjustments between the contingencies.

- Fourteen P6 overloaded facilities were identified in the studies in the base cases. Out of these, ten overloads were identified under summer peak conditions including three 500/230 transformers at the same substation (Metcalf) and two pairs of the 500 kV transmission lines in the same corridor: Round Mountain-Table Mountain and Midway-Vincent. Two 500/230 kV transformers, Olinda and Table Mountain, and two 230 kV transmission lines, Moss Landing- Las Aguilas and Los Banos-Padre Flat, were identified as overloaded under off-peak spring conditions. These 230 kV lines were also overloaded with Category P6 contingencies in the peak sensitivity case with high renewable generation. The Newark 230/115 kV transformer was identified as overloaded with Category P6 contingencies under peak load conditions both in the base and in the sensitivity cases. Four additional transmission lines were identified as overloaded only in the sensitivity cases, all under peak load conditions. In the P6 studies, no generation re-dispatch was assumed after the first contingency.
- Ten overloaded facilities were identified with 500 kV double contingencies in the same corridors; six under peak conditions, and four under off-peak conditions in the base and sensitivity cases.

Details of the overloaded facilities are provided in Appendix B.

The ISO-proposed solutions to mitigate the identified reliability concerns are the following:

- Manage COI flow according to the seasonal nomograms
- Implement SPS to bypass series capacitors on the Round Mountain-Table Mountain 500 kV lines # 1 and # 2 if any of these lines overloads.

For overloads that are managed with congestion management or operating within the defined path nomograms, upgrades could be considered if congestion is observed in the production simulation and the upgrades are determined to be economically-driven. The following facilities were identified as being overloaded with the reliability mitigation plans being congestion management and operating path flows within the nomograms

- Cottonwood- Round Mountain 230 kV # 3 transmission line
- Moss Landing-Las Aguilas 230 kV transmission line
- Table Mountain 500/230 kV transformer

Other proposed mitigation solutions for thermal overloads

- Upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line
- Implement congestion management after first contingency for Category P6 overloads.
- If the Moss Landing and/or Metcalf power plants retire, the mitigation plan for Category P6 contingencies in the Metcalf-Tesla-Moss Landing-Los Banos area that result in losing the 500 kV source will be needed.

Dynamic stability studies used the latest WECC composite load model to reflect more accurate load composition and load parameters. The composite load model included distributed solar PV generation using the latest models that are more detailed than the distributed generation models used previously. The load was modeled according to the WECC composite load model Phase II with the stalling of single-phase air-conditioners enabled. Parameters of the composite load model were selected according to the WECC recommendations and research. In addition to loads, behind-the-meter distributed generation (solar PV) was explicitly modeled as well.

The following conclusions can be made from the dynamic stability studies:

- Due to high voltages in the power flow cases, some renewable units may be tripped in local areas that will require further assessment in the interconnection process..
- Several renewable generation projects were tripped by low or high voltage, or low or high frequency, with three-phase faults close to the units, which is most likely a modeling issue.
- Composite load model tripped some fraction of load with 3-phase faults because of low voltages.
- Some under-voltage load tripping may occur due to stalling of single-phase air-conditioning load with three-phase faults.
- No criteria violations were identified. Some slow voltage recovery was observed on the low voltage buses at the end of the feeders, which is not a criteria violation.
- More work is required on the load and distributed generation modeling, including modeling and studies with momentary cessation of inverters. The ISO is working with the PTOs and generation owners on the improving the models and on the model parameters to achieve more accurate study results.

High voltages were observed on 500 kV system in Central California after the Diablo Canyon Nuclear Power Plant retires. Low voltages were observed on the WAPA's Maxwell 500 kV Substation for COI 500 kV double line outages under peak load conditions. To mitigate the voltage issues, dynamic reactive support on the Round Mountain and Gates 500 kV Substations was approved in the 2018-2019 ISO Transmission Plan. The Gates 500 kV Dynamic Reactive Support project has been awarded to LS Power and the Round Mountain 500 kV Dynamic Reactive Support project is still undergoing the competitive solicitation process to select the project sponsor for this project.

No voltage deviation or reactive margin concerns were identified in the studies. It was assumed that all appropriate RAS are in service for all double line outages that were studied.

2.4.4 Request Window Proposals

Projects submitted to the ISO through the Request Window for the PG&E Bulk System are shown in Table 2.4-1

Table 2.4-1 Request Window Submissions for the PG&E Bulk System

Project Name	Proponent	Size/capacity	Cost Estimate	Operational Date
Table Mountain 230 kV Energy Storage Project	Horizon West	60 MW/75 MVA	$71.2M	12/01/2024
Smart Wires COI Flow Control Project (Smart Valve Devices)	Smart Wires	5.17 Ohm, 5.17 Ohm, 2.73 Ohm and 18.98 Ohm	$19.1M	06/01/2021

Table Mountain 230 kV Energy Storage Project

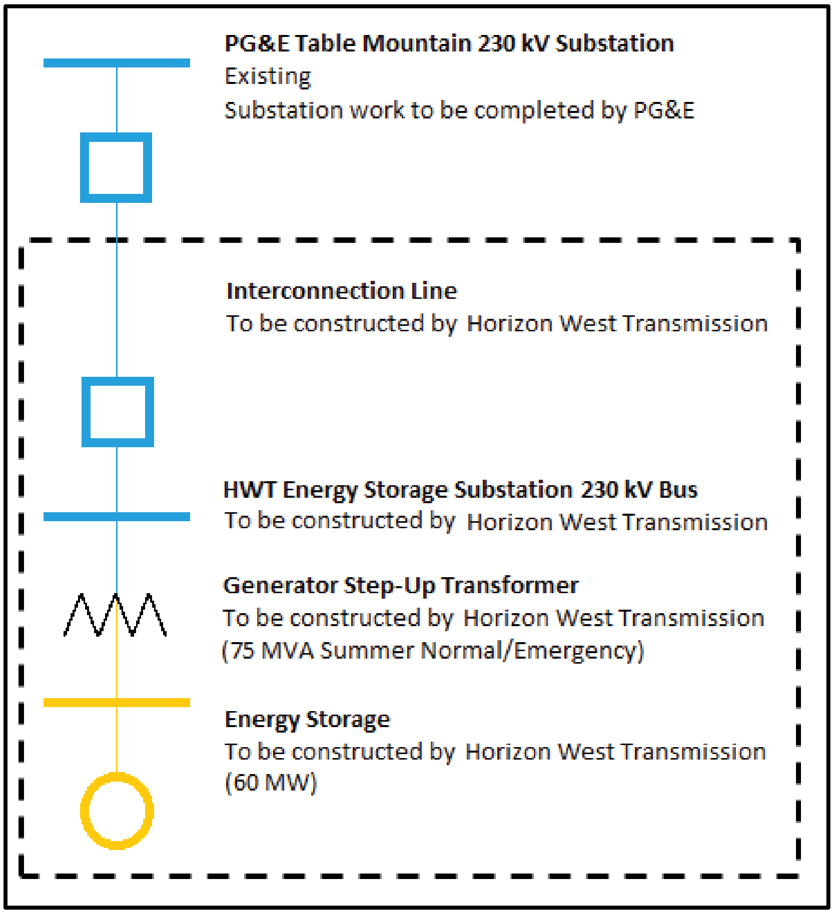
The following project was submitted in the 2019 Request Window as a transmission solution to resolve the issue of overload of the Table Mountain 500/230 kV transformer under off-peak load conditions. The project was proposed by a non-PTO, Horizon West Transmission, LLC as a Reliability Transmission Project. The project is proposed to be located at the Table Mountain 230 kV Substation.

The proposed project consists of:

- A 60 MW/75 MVA Energy Storage Facility as a Transmission Asset to be used primarily for active power flow/congestion management at the Table Mountain 230 kV bus to eliminate overloads on the 500/230 kV transformer at Table Mountain due to single and multiple contingencies under off-peak load conditions. The proposed energy storage, in addition to mitigating reliability issues at Table Mountain was claimed to enhance flow management, voltage control and provide operational flexibility to the system and to help mitigate loading and voltage issues at neighboring facilities.

A single-line diagram illustrating the main components of the proposed solution is provided in Figure 2.4-2.

Figure 2.4-2. Table Mountain 230 kV Substation Energy Storage Project



The estimated cost of the proposed Table Mountain 230 kV Energy Storage Project is approximately $71.2 Million. The estimated in-service date is December 1, 2024.

The project proposed specifications are:

- Point of Interconnection: Table Mountain 230 kV
- BESS Capacity: 60 MW / 75 MVA (240 MWh) - 4 hours
- Main Transformer: 230/34.5 kV 46/60/75 MVA Capacity
- Collector System Voltage: 34.5 kV

The proposed scope of work includes:

- Horizon West Transmission: Build a new 230 kV bus outside PG&E Table Mountain 230 kV substation.
- Horizon West Transmission: Build a new 230 kV connecting line into PG&E Table Mountain 230 kV Bus. Approximate distance will be 1 mile.

- Horizon West Transmission: Build proposed energy storage facility and connect it to the new 230 kV bus outside the PG&E Table Mountain 230 kV substation.
- Incumbent: 230 kV substation work including bus work and line termination.

The ISO reviewed this proposal. Although the ISO agrees that the proposed project can mitigate the identified overloads on the Table Mountain 500/230 kV transformer, there is not a reliability need for such project, since the overload can be mitigated by operating within the COI nomogram or by congestion management reducing generation connected to the 230 kV Table Mountain bus. Another alternative may be the installation of a second Table Mountain 500/230 kV transformer if it appears to be economic. The Table Mountain 230 kV Energy Storage Project could be submitted as a potential economic study request in the next transmission planning cycle.

Smart Wires COI Flow Control Project (Smart Valve Devices)

The following project was submitted in the 2019 Request Window as a transmission solution to resolve thermal overloads on the Round Mountain – Table Mountain #1 and #2 500 kV lines, Cottonwood E - Round Mountain 230 kV line #3 and the Delevan – Cortina 230 kV line. These thermal overloads can occur under various scenarios with contingencies when North-to-South flows on the California-Oregon Intertie (COI) are high combined with high hydro generation in Northern California.

The project was proposed by a non-PTO, Smart Wires Inc. as a reliability transmission Project.

The proposed project consists of:

- Installation of Smart Wires modular power flow control technology on:
  a. Round Mountain – Table Mountain 500 kV Lines #1 and #2,
  b. Cottonwood E – Round Mountain 230 kV line #3, and
  c. Delevan – Cortina 230 kV
- An alternative is to deploy a hybrid solution to include:
  a. Smart Wires power flow control devices on Round Mountain – Table Mountain 500 kV Lines #1 and #2 and
  b. Reduced COI flow for the remaining constrains on the Cottonwood E – Table Mountain 230 kV line #3 and Delevan – Cortina 230 kV line.

The estimated cost of the proposed is approximately $19.1 Million in 2019 dollars; the cost of the alternative when the Smart Wires devices are installed only on the Round Mountain-Table Mountain 500 kV lines is $14.5 Million. The estimated in-service date is June 1, 2021.

The ISO reviewed this proposal. Although the ISO agrees that the proposed project can mitigate the identified overloads, there is not a reliability need for such project, since the overload can be mitigated by bypassing series capacitors on the Round Mountain-Table Mountain 500 kV lines with contingencies, operating within the COI nomogram or by congestion management reducing generation in the area of overloads. This project could be submitted as a potential economic study request in the next transmission planning cycle.

2.4.5 California-Oregon Intertie (COI) Nomogram

For several thermal overloads identified in the reliability studies, one of the proposed mitigation measures was reducing California-Oregon Intertie (COI) flow and operating the system in accordance with the seasonal COI nomogram. Such nomograms are developed each year by the ISO. Also, in the current 2019-2020 TPP, COI nomograms were developed for the long-term planning horizon to estimate what limitations in the COI flow may be in the future and if any additional transmission projects or other measures will be required to maintain current COI ratings. COI nomograms were developed both for the North-to-South and South-to-North flow on COI.

COI consists of three 500 kV transmission lines: Malin-Round Mountain # 1 and # 2 and Captain Jack – Olinda. Transfer limits on this path are: 4800 MW in the north-to-south direction and 3675 MW in the south-to-north direction. In the ISO studies, only the impact on the ISO system was studied. The limits on COI transfers are mostly affected by the dispatch of hydro generation in Northern California. Thus, the nomograms were created to show the COI flow limit versus Northern California hydro generation. Also, generation from the Hatchet Ridge wind power plant that is connected to the Round Mountain 230 kV bus, and generation output from Colusa power plant impact limits on the COI flow.

The 2029 Summer Peak case was selected for the nomogram in the north-to-south direction and the 2029 Spring Off-Peak case was selected for the nomogram in the South-to-North direction.

Details of the analysis and the nomograms are provided in Appendix B. The following provides a summary of the analysis and findings.

<u>North to South Flows on COI</u>

The most limiting single contingency (Category P1) is an outage of the Round Mountain - Table Mountain 500 kV line # 1 that may overload parallel Round Mountain - Table Mountain 500 line # 2 if the north-to-south flow on COI is high. The nomogram was developed with various assumptions of the Northern California hydro generation output and under several assumptions on the output of the Hatchet Ridge and Colusa generation. Dispatch of the Northern California hydro generation was assumed according to the ISO procedures.

For P1 contingencies, there are no limitations if Colusa and Hatchet Ridge generation is off, but with these projects generating at full output, then limitations on COI start when Northern California hydro generation is dispatched above 60%, and with these projects generating at half of their capacity, limitations on COI start when Northern California hydro generation is dispatched above 70%. Bypassing series capacitors on the overloaded Round Mountain-Table Mountain 500 kV circuit will mitigate the overload and will eliminate limitations on the COI flow for Category P1 contingencies.

The most limiting assumed double contingency (Category P7) is the 500 kV Double Line Outage South of Table Mountain (Table Mountain-Vaca Dixon and Table Mountain –Tesla 500 kV lines). With this contingency and high north-to-south flow on COI, RAS is applied that trips Northwest generation, disconnects reactors and bypasses series capacitors on several 500 kV lines. This RAS was modeled in the studies. The limiting facilities for the COI nomogram for

Category P7 contingency are Round Mountain-Cottonwood 230 kV # 3 or Delevan-Cortina 230 kV lines. Delevan-Cortina becomes the limiting element when Colusa generation is high (640 MW and above).

Summary of North-to-South COI flow assessment

- Limiting single contingency: Round Mountain-Table Mountain 500 kV line #1
- Limiting facility: Round Mountain -Table Mountain 500 kV line #2
- There will be no single contingency limitation if series capacitors on the overloaded line are by-passed
- Limiting double contingency: 500 kV lines south of Table Mountain (Table Mountain-Tesla and Table Mountain-Vaca Dixon)
- Limiting facilities: Round Mountain-Cottonwood 230 kV line # 3 if Colusa generation is low, and Delevan-Cortina 230 kV line if Colusa generation is high

Recommendations:

- Add Colusa generation tripping to COI RAS
- Bypass series capacitors on Round Mountain –Table Mountain 500 kV lines with an outage of the parallel line if there is an overload
- Continue to assess Northern California hydro dispatch patterns to improve modeling

South to North flows on COI

Under the most critical conditions, when both Colusa and Hatchet Ridge generation is high, limitations on the COI flow start when Northern California hydro generation is higher than 60% of capacity. With low output of Colusa generation, the COI transfer limit will be higher because Colusa generation helps to reduce flow on the Round Mountain-Cottonwood 230 kV line, which is the limiting facility. However, when Colusa output is high, the Delevan-Cortina 230 kV line becomes the limiting facility for the transfers on COI.

The most limiting facility in the south-to-north COI nomogram was observed to be the Table Mountain 500/230 kV transformer. This transformer may overload even under normal system conditions when the load in the area is low and the generation from the Hyatt and Thermalito generation that directly connect to the 230 kV Table Mountain bus is high. Hyatt and Thermalito are part of the Northern California hydro generation that counts towards the nomograms.

For Category P1 contingencies, the most limiting outage under off-peak load conditions was an outage of the Round Mountain 500/230 kV transformer, and the most limiting facility also was the Table Mountain 500/230 kV transformer. For both normal conditions and Category P1 contingency, Hatchet Ridge generation output doesn’t have a material impact on the nomogram, Colusa generation has only a marginal impact, and the main impact on the loading of the Table Mountain 500/230 kV transformer is the Hyatt and Thermalito generation output. The overload on the Table Mountain 500/230 kV transformer depends more on the output of the Hyatt and Thermalito generation than on the COI flow.

The most limiting assumed Category P7 contingency appeared to be a 500 kV double-line outage south of Table Mountain: Table Mountain- Tesla and Table Mountain- Vaca Dixon 500 kV lines. In this case, the limiting facility also was the Table Mountain 500/230 kV transformer.

The limiting facility was the Table Mountain 500/230 kV transformer. With Northern California hydro generation dispatched at 46 percent and lower, the nomogram is limited by the 500 kV double-line outage south of Table Mountain. With Northern California hydro dispatched above 46 percent, the nomogram is limited by the Round Mountain 500/230 kV transformer outage. The limitation depends mostly on the generation output connected to the Table Mountain 230 kV substation than on the total Northern California hydro generation. Generation from Hatchet Ridge doesn't have any impact, since the flow is south-to-north and this project is located north of Table Mountain. Generation from Colusa power plant slightly improves the nomogram limits.

The studies of the COI versus Northern California hydro generation for the south-to-north flow were also performed with an assumption that a second 500/230 kV transformer is installed at the Table Mountain Substation. The goal of these studies was to identify the next limitation of the nomogram. The studies showed that there were no limitations up to COI path rating of 3675 MW under normal conditions. For P1 contingencies, the limiting outage appeared to be the Round Mountain 500/230 kV transformer, and the limiting facility – the Olinda 500/230 kV transformer. As in the case with the Table Mountain 500/230 kV transformer overload, the study results showed that the most impact on the loading is from the generation connected to the 230 kV side of the transformer than on the total Northern California hydro generation or the COI flow. Loading of the Olinda 500/230 kV transformer significantly depends on Shasta and Keswick generation.

Summary of South-to-North COI flow assessment

- Limitations under normal conditions are due to high Hyatt and Thermalito generation
- Limiting facility: Table Mountain 500/230 kV transformer
- Limiting single contingency: Round Mountain 500/230 kV transformer
- Limiting facility: Table Mountain 500/230 kV transformer
- Limiting double contingency – 500 kV lines south of Table Mountain
- Limiting facility: Table Mountain 500/230 kV transformer

Recommendations:

- Continue to assess Northern California hydro dispatch patterns to improve modeling
- Continue to assess potential upgrade of the Table Mountain 500/230 kV transformer in future cycles and economic assessments

Conclusions from the study with the second Table Mountain 500/230 kV transformer:

- No limitations were identified under normal system conditions
- Limiting single contingency: Round Mountain 500/230 kV transformer
- Limiting facility: Olinda 500/230 kV transformer

- Loading significantly depends on Shasta and Keswick generation output
- Double line credible contingencies appeared not to be binding

2.4.6 Recommendations

The bulk system assessment identified a number of P1 to P7 contingencies that result in transmission constraints. The recommended solutions to mitigate the identified reliability concerns are the following:

- Manage COI flow according to the seasonal nomograms
- Implement SPS to bypass series capacitors on the Round Mountain-Table Mountain 500 kV lines # 1 and # 2 if any of these lines overloads.

For overloads that are managed with congestion management or operating within the defined path nomograms, upgrades could be considered if congestion is observed in the production simulation and the upgrades are determined to be economically-driven. The following lines were identified as being overloaded with the reliability mitigation plans being congestion management and operating path flows within the nomograms.

- Cottonwood- Round Mountain 230 kV # 3 transmission line
- Moss Landing-Las Aguilas 230kV transmission line
- Table Mountain 500/230 kV transformer

Other proposed mitigation solutions for thermal overloads are the following:

- Upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line
- Implement congestion management after first contingency for Category P6 overloads.
- If the Moss Landing and/or Metcalf power plants retire, the mitigation plan for Category P6 contingencies in the Metcalf-Tesla-Moss Landing-Los Banos area that result in losing the 500 kV source will be needed.

In addition to the identified thermal overloads, high voltages were observed on 500 kV system in Central California after Diablo Canyon Nuclear Power Plant retires. Low voltages were observed on the WAPA’s Maxwell 500 kV Substation for COI 500 kV double line outages under peak load conditions. To mitigate the voltage issues, dynamic reactive support on the Round Mountain and Gates 500 kV Substations was approved in the 2018-2019 ISO Transmission Plan. These two projects were eligible for competitive solicitation. The Gates 500 kV Dynamic Reactive Support project has been awarded to LS Power and the Round Mountain 500 kV Dynamic Reactive Support project is still undergoing the competitive solicitation process to select the project sponsor for this project.

2.5 PG&E Local Areas

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. 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.

2.5.1.2 Area-Specific Assumptions and System Conditions

The Humboldt 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 related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Humboldt Area study are provided in Table 2.5-1 and Table 2.5-2.

Table 2.5-1: Humboldt load and load modifier assumption

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
HMB-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	131	3	25	0	128	3	3
HMB-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	136	5	34	0	132	3	3
HMB-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	144	9	46	0	135	3	3
HMB-2029-SP-QF	Baseline	2029 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	144	9	46	0	135	3	3
HMB-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	98	2	25	20	76	3	3
HMB-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	105	3	34	27	75	3	3
HMB-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours between 20:00 and 21:00.	167	3	25	0	164	3	3
HMB-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours between 20:00 and 21:00.	175	5	34	0	171	3	3
HMB-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours between 20:00 and 21:00.	184	6	46	0	178	3	3
HMB-2024HS-SP-P7	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	136	0	34	0	136	3	3
HMB-2021-HR-P7	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	120	3	25	24	92	3	3
HMB-2024-HR-P7	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	105	3	34	33	68	3	3

Table 2.5-2: Humboldt generation assumption

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
HMB-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	0	0	0	0	0	5	0	259	172
HMB-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	0	0	0	0	0	5	0	259	187
HMB-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	0	0	0	0	0	5	0	259	187
HMB-2029-SP-QF	Baseline	2029 summer peak load conditions. Peak load time - hours between 20:00 and 21:00.	0	0	0	0	0	5	0	259	187
HMB-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	0	0	0	0	0	5	0	259	15
HMB-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	0	0	0	0	0	5	0	259	15
HMB-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours between 20:00 and 21:00.	0	0	0	0	0	5	0	259	187
HMB-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours between 20:00 and 21:00.	0	0	0	0	0	5	0	259	187
HMB-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours between 20:00 and 21:00.	0	0	0	0	0	5	0	259	229
HMB-2024HS-SP-P7	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	0	0	5	0	259	187
HMB-2021-HR-P7	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	5	0	259	187
HMB-2024-HR-P7	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	5	0	259	15

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of the approved projects identified in Table 2.5-3 that were not modeled in the study scenario base cases.

Table 2.5-3: Humboldt Approved Project not Modeled in Base Case

Project Name	TPP Approved In	Current ISD
None		

2.5.1.3 Assessment Summary

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 2019-2020 reliability assessment of the PG&E Humboldt Area has identified no reliability concerns consisting of thermal overloads under contingencies. The areas where additional mitigation requirements were identified are discussed below.

Within the Humboldt Area there were a few P1 and P3 contingencies that resulted in overloads in the sensitivity scenarios only. The overloaded facilities and contingencies were related to Non-BES facilities and only in the sensitivity scenarios, per the ISO Planning Standards, no mitigation has been recommended for approval.

Summary of review of previously approved projects

There is no previously approved projects in the Humboldt area not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The final recommendation for this one project not modeled in the study cases is shown in Table 2.5-4.

Table 2.5-4: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
None	None

Details of the review of previously approved projects not modeled in study cases are presented in Appendix B.

2.5.1.4 Request Window Submissions

There are no Request Window Submissions for the Humboldt Area.

2.5.1.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1.2, about 5 MW of AAEE and more than 34 MW of installed behind-the-meter PV reduced the Humboldt Area load in winter 2024. This year's reliability assessment for Humboldt Area included "2024 Sumer peak with high CEC forecast" and "2021 Summer peak with high renewables" sensitivity cases for which modeled no AAEE. Comparison between the reliability issues identified in the 2024 winter peak baseline case and the sensitivity cases shows that the facility overloads shown in Table 2.5-5 are potentially avoided due to reduction in net load.

Table 2.5-5: Reliability Issues in Sensitivity Studies

Facility	Category
Bridgeville – Fruitland Jct 60kv Line	P1, P3

Furthermore, 3 MW of demand response are modeled in Humboldt. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, but didn't completely alleviate the overloads.

2.5.1.6 Recommendation

Based on the studies performed for the 2019-2020 Transmission Plan, there were no reliability concerns identified for the PG&E Humboldt area. There are no new projects recommended for approval.

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. 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. 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 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 related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Coast and North Bay Area study are shown in Table 2.5-5 and Table 2.5-6.

Table 2.5-5: North Coast and North Bay load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
NCNB-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	1,483	25	416	0	1,458	18	7
NCNB-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	1,519	47	498	0	1,472	18	7
NCNB-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	1,594	87	615	0	1,507	18	7
NCNB-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	864	19	416	333	512	18	7
NCNB-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	917	36	498	403	478	18	7
NCNB-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours between 18:00 and 19:00.	1,480	25	416	0	1,455	18	7
NCNB-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours between 18:00 and 19:00.	1,518	47	498	0	1,471	18	7
NCNB-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours between 18:00 and 19:00.	1,595	64	615	0	1,531	18	7
NCNB-2024HS-SP	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	1,519	0	498	0	1,519	18	7
NCNB-2021-HR	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	1,502	32	416	412	1,058	18	7
NCNB-2024-HR	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	917	36	498	493	389	18	7
NCNB-2029-QF	Sensitivity	2027 summer peak load conditions with QF retirement sensitivity	1,594	87	615	0	1,507	18	7

Table 2.5-6: North Coast and North Bay generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
NCNB-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	0	0	25	12	1,534	809
NCNB-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	0	0	25	12	1,534	759
NCNB-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	0	0	25	12	1,534	759
NCNB-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	0	0	0	0	0	25	6	1,534	702
NCNB-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	0	0	0	0	0	25	4	1,534	702
NCNB-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	0	0	25	12	1,534	728
NCNB-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	0	0	25	12	1,534	756
NCNB-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	0	0	25	17	1,534	806
NCNB-2024HS-SP	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	0	0	25	12	1,534	753
NCNB-2021-HR	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	25	12	1,534	778
NCNB-2024-HR	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	25	4	1,534	702
NCNB-2029-QF	Sensitivity	2027 summer peak load conditions with QF retirement sensitivity	0	0	0	0	0	25	12	1,534	759

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.2.3 Assessment Summary

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 2019-2020 reliability assessment of the PG&E North Coast North Bay Area has identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies, most of which are addressed by previously approved projects. In the interim, the ISO will continue to rely on operational action plans to mitigate the constraints. The areas where additional mitigation requirements were identified are discussed below.

The following new overloads were observed in the North Coast and North Bay area.

Limiting elements on Tulucay-Napa #2 60 kV line

Category P0 causes an overload on Tulucay-Napa #2 60 kV line starting in 2024. The overloads worsen in high CEC forecast sensitivity.

2.5.2.4 Request Window Submissions

There was one project submission in the North Coast North Bay area in the 2019 request window.

Tulucay-Napa #2 60 kV Line Capacity Increase

PG&E submitted the Tulucay-Napa #2 60 kV Line Capacity Increase project to address the limiations identified above. The scope of the project submitted by PG&E is to:

- Replace limiting switches and jumpers at Basalt and Tulucay 60 kV substations to match the conductor rating of 1126 Amps.
- Upgrade any other associated terminal equipment to achieve the maximum conductor rating.

The estimated cost to remove and upgrade the limiting switches, jumpers and other associated terminal equipment is $5 to 10 million with an estimated in-service date of May 2023. The ISO recommends the Tulucay-Napa #2 60 kV Line Capacity Increase project for approval.

2.5.2.5 Consideration of Preferred Resources and Energy Storage

As presented in section 2.5.2, about 47 MW of AAEE and around 498 MW of installed capacity behind-the-meter PV reduced the North Coast North Bay Area load in 2024. This year's reliability assessment for North Coast North Bay Area included a "high CEC forecast" sensitivity case for year 2024 which modeled 36 MW of AAEE and about 498 MW installed capacity behind-the-meter PV output. A comparison between the reliability issues identified in the 2024 summer peak baseline case and the "high CEC forecast" sensitivity case shows that facility overloads shown in Table 2.5-7 are potentially avoided due to the reduction in net load:

Table 2.5-7: Reliability Issues in Sensitivity Studies

Facility	Category
Mendocina - Upper Lake 60kV Line	P2-2

Furthermore, about 18 MW of demand response and no battery energy storage are modeled in North Coast North Bay Area. These resources are modeled offline in the base case and are used as potential mitigations as needed. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.2.6 Recommendation

Based on the studies performed for the 2019-2020 Transmission Plan, several reliability concerns were identified for the PG&E North Coast North Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P1 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Coast North Bay area.

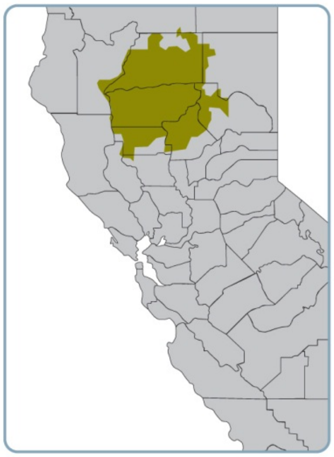
To address reliability constraints in the North Coast and North Bay Area, the ISO recommends approval of the following project.

- Tulucay-Napa #2 60 kV Line Capacity Increase

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 AC Intertie between California and the Pacific Northwest. The 230 kV facilities, which complement the Pacific AC 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 AC 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. Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions.

2.5.3.2 Area-Specific Assumptions and System Conditions

The North Valley Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured market participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Valley Area study are shown in Table 2.5-8 and Table 2.5-9.

Table 2.5-8: North Valley load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
NVLY-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 19:00.	897	10	299	0	888	17	7
NVLY-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 19:00.	938	18	370	0	920	17	7
NVLY-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 19:00.	981	33	463	0	948	17	7
NVLY-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	349	7	299	349	102	17	7
NVLY-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	382	14	370	300	68	17	7
NVLY-2024-SP-HiCEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	938	0	370	0	938	17	7
NVLY-2024-SOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	382	14	370	367	2	17	7
NVLY-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	882	13	299	296	573	17	7
NVLY-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	981	33	463	0	948	17	7

Table 2.5-9: North Valley generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
NVLY-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	103	68	1,798	1,288	1,072	759
NVLY-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	103	0	1,774	1,436	1,072	570
NVLY-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	103	68	1,798	1,153	1,072	408
NVLY-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	0	0	0	103	59	1,774	1,290	1,072	234
NVLY-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	0	0	0	103	3	1,774	1,291	1,072	323
NVLY-2024-SP-HiCEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	103	0	1,774	1,443	1,072	565
NVLY-2024-SOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	0	0	0	103	69	1,774	1,005	1,072	325
NVLY-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	0	0	0	103	86	1,798	1,568	1,072	416
NVLY-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	0	0	0	103	68	1,798	1,152	1,072	408

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.3.3 Assessment Summary

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 2019-2020 reliability assessment of the PG&E North Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P1 to P7 contingencies most of which are addressed by previously approved projects. The remaining issues are only under sensitivity scenario and in the long term so ISO continues to monitor those issues in future planning cycles. Details of the reliability assessment are presented in Appendix B.

2.5.3.4 Request Window Submissions

There were no project submissions in the North Valley area in the 2019 Request Window.

2.5.3.5 Consideration of Preferred Resources and Energy Storage

As presented in Section2.5.2, about 18 MW of AAEE and around 370 MW of installed behind-the-meter PV reduced the North Valley Area load in 2024 by about 2%. This year's reliability assessment for North Valley Area included "high CEC forecast" sensitivity case for year 2024 which modeled no AAEE. A comparison of the reliability issues identified in the 2024 summer peak baseline case and the "high CEC forecast" sensitivity case shows that facility overloads shown in Table 2.5-10 are potentially avoided due to reductions in net load:

Table 2.5-10: Reliability Issues in Sensitivity Studies

Facility	Category
Keswick - Cascade 60 kV	P6
Table Mountain - Butte #1 115 kV	P2
Paradise - Table Mountain 115 kV	P2

Furthermore, more than 17 MW of demand response is modeled in the North Valley Area. These resources are modeled offline in the base case and are used as potential mitigations as needed. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

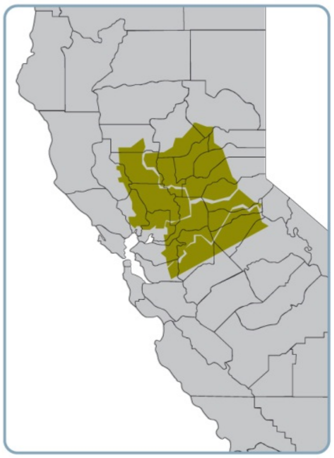
2.5.3.6 Recommendation

Based on the studies performed in the 2019-2020 transmission planning cycle, several reliability concerns were identified for the PG&E North Valley Area. These concerns consisted of thermal overloads and voltage concerns under Category P1 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Valley area. The remaining issues are only under sensitivity scenario or in the long term. The ISO continues to monitor those issues in future planning cycles.

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 the 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 currently 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 two 115/60 kV transformer banks at Salado.

Historically, the Central Valley area experiences its highest demand during the summer season. Accordingly, system assessments in these areas included technical studies using load assumptions for the summer peak conditions.

2.5.4.2 Area-Specific Assumptions and System Conditions

The Central Valley Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured market participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Valley Area study are shown in Table 2.5-11 and Table 2.5-12.

Table 2.5-11: Central Valley load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
CVLY-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 19:00.	4,174	56	1,340	0	4,117	91	40
CVLY-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 19:00.	4,364	106	1,697	0	4,258	92	40
CVLY-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 19:00.	4,625	192	2,164	0	4,434	92	40
CVLY-2021-SpOP	Baseline	2021 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,728	43	1,340	1072	613	91	40
CVLY-2024-SpOP	Baseline	2024 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,852	79	1,697	1374	399	92	40
CVLY-2024-SP-Hi-CEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	4,364	0	1,697	0	4,364	92	40
CVLY-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	1,852	79	1,697	1680	93	92	40
CVLY-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	4,285	72	1,338	1325	2,888	91	40
CVLY-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	4,625	192	2,164	0	4,433	92	40

Table 2.5-12: Central Valley generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
CVLY-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 19:00.	0	38	1	1185	774	1427	1368	1,281	971
CVLY-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 19:00.	0	38	1	1079	704	1401	1355	1,275	981
CVLY-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 19:00.	0	38	1	1079	704	1427	1181	1,275	903
CVLY-2021-SpOP	Baseline	2021 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	0	38	35	1185	668	1401	1048	1,281	440
CVLY-2024-SpOP	Baseline	2024 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	0	38	34	1079	27	1401	945	1,275	504
CVLY-2024-SP-Hi-CEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	0	38	1	1079	704	1401	1377	1,275	1,005
CVLY-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	0	38	35	1079	715	1404	851	1,275	450
CVLY-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	0	38	35	1185	959	1427	1139	1,281	346
CVLY-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	0	38	1	1079	650	1427	1217	1,275	882

The transmission modeling assumptions were consistent with the general assumptions described in section 2.3.

2.5.4.3 Assessment Summary

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 2019-2020 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 most of which are addressed by previously approved projects. The areas where additional mitigation requirement were identified are discussed below.

In the Near-term planning horizon a number of overloads were observed that will be addressed when the previously approved projects are complete and in-service. In the interim, the ISO will continue to rely on operational action plans to mitigate the constraints.

The following new overloads and voltage issues were observed in the Central Valley area.

Vaca – Plainfield 60 kV Line Overload

The total load at Plainfield and Winters substations is forecast to reach around 33 MW by year 2024 and 35 MW by year 2029 which causes P0 overload if the entire load is radially supplied from Vaca Dixon substation. In 2018-2019 TPP the ISO recommended PG&E reconfigure the Plainfield substation and connect load bank #1 to the E. Nicolaus substation. The ISO recommends PG&E continue that practice. The ISO will continue to monitor the load forecast in this area in future planning cycles.

Hammer – Country Club 60 kV Line Overload

The Mosher substation is currently served radially by Hammer – Country Club 60 kV line. The rating of the line is 62.4 MVA while the load at Mosher substation is expected to reach 64.2 MW in 2024 and 65.4 MW in 2029 which will result in P0 overload on the line. The ISO is working with PG&E to identify the limitation on the line and the potential mitigation measure to address the issue in the next planning cycle.

Placerville and Eldorado Area

P2-1 contingencies resulted in overloads on the Gold Hill – Eldorado 115 kV lines in 2029. The ISO will continue to monitor the forecast load in the Placerville and Eldorado area to address the forecast P2-1 overloads in 2029.

Bellota 230 kV Bus

P2-4 contingency at Bellota 230 kV substation resulted in overloads and voltage issues in the underlying 115 kV network in the area. The ISO recommends an SPS to address this issue. The recommended SPS trips the 115 kV lines connected to the Bellota 115 kV bus following the P2-4 contingency. Considering that the monitoring and tripping actions of such SPS will be within Bellota substation, the ISO expects the SPS to be a cost effective solution to address the issue.

Tesla 115 kV Bus

P2-4 contingency at Tesla 115 kV substation resulted in overloads and voltage issues in the underlying 115 kV network in the area. The ISO is considering either an SPS or the upgrade of the Tesla 115 kV substation to address this issue. Alternatives for the SPS and the substation upgrade will be evaluated in the next planning cycle and the preferred solution will be recommended.

2.5.4.4 Request Window Submissions

There were two projects submitted into the 2019 Request Window.

Bellota 230 kV Bus Upgrade Project

PG&E proposed the Bellota 230 kV Bus Upgrade Project to address P2-4 issues at Bellota substation by further sectionalizing the 230 kV bus at Bellota. Currently both 230/115 kV transformers at Bellota substaiton are connected to the same section of the 230 kV bus which results in both transforerms tripping following the P2-4 contingency. The proposed project uses sectionalizing breakers to form a new section on the 230 kV bus and moves one of the transformers to the new section. As a result one 230/115 kV transformer will continue to supply the 115 kV system post contingency which addresses the issues. The project is expected to cost $20 million to $40 million with an estimated in-service date of January 2026.

The ISO's recommendation to address the P2-4 issue at Bellota 230 kV bus is an SPS that trips the 115 kV lines at Bellota substation post P2-4 contingency.

Weber – Manteca 230 kV Project

Horizon West Transmission, LLC (Horizon West) proposed the Weber – Manteca 230 kV project to address the P2-4 issues at Bellota and Tesla substations and to mitigate Weber load loss following the P6 contingency. The project scope includes a new 230/115 kV substation at Weber, looping in115 kV lines in the Weber area into the Weber substation, a new 230/115 kV substation at Manteca, and 10 miles of new 230 kV transmission line from Weber to the new Manteca substation. This project is estimated to cost $35 million (excluding any incumbent costs) with an estimated in-service date of December 2024.

The ISO is currently working with PG&E to evaluate SPS and substation upgrade options to address P2-4 issues at Tesla substation. In the short term, the ISO's analysis indicated that P2-4 contingency at Tesla 115 kV substation will result in loss of load in the Tesla – Bellota area only and will not propagate to the rest of the system.

2.5.4.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1, about 106 MW of AAEE and more than 1697 MW of installed behind-the-meter PV reduced the Central Valley Area load in 2024 by about 2.4%. This year's reliability assessment for the Central Valley Area included the "high CEC forecast" sensitivity case for year 2024 which modeled no AAEE. Comparisons between the reliability issues identified in the 2024 summer peak baseline case and the "high CEC forecast" sensitivity case show that the facility overloads shown in Table 2.5-13 are potentially avoided due to reduction in net load:

Table 2.5-13: Reliability Issues in Sensitivity Studies

Facility	Category
Stanislaus-Melones-Riverbank 115 kV Line	P1, P2
Lockeford – Bellota 230 kV Line	P6
Brighton – Davis 115 kV Line	P2, P7
West Sacramento – Davis 115 kV Line	P6
Brighton 230/115 kV Bank No. 9	P6
Lincoln – Ultra JT 115 kV Line	P6
Tesla – Schulte No.1 115 kV Line	P6
Salado – Newman 60 kV Line	P1, P3

Furthermore, more than 90 MW of demand response are modeled in the Central Valley Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.4.6 Recommendation

Based on the studies performed for the 2019-2020 Transmission Plan, several reliability concerns were identified for the PG&E Central Valley Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Central Valley area. The ISO is recommending an SPS to address the P2-4 issue at Bellota 230 kV substation and is working with PG&E to address P2-4 issue at Tesla 115 kV substation through either an SPS or substation upgrade.. The remaining issues are only observed under the sensitivity scenario or in the long term. The ISO will continue to monitor those issues and will mitigate them if the issues are identified in future assessments.

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. Lastly, 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.

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 related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Greater Bay Area study are provided in Table 2.5-14 and Table 2.5-15.

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3.

Table 2.5-14 Greater Bay Area load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
GBA-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 18:00.	9,003	148	1,571	158	8,697	134	76
GBA-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours ending 19:00.	7,850	148	1,571	0	7,702	134	76
GBA-2021-SpOP	Baseline	2021 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	6,007	112	1,571	1256	4,639	134	76
GBA-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	6,007	112	1,571	1256	4,639	134	76
GBA-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 18:00.	9,284	276	2,055	206	8,802	134	76
GBA-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours ending 19:00.	8,401	273	2,055	0	8,128	134	76
GBA-2024-SpOP	Baseline	2024 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	6,370	207	2,055	1665	4,498	134	76
GBA-2024-SP-Hi-CEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	9,284	0	2,055	206	9,078	134	76
GBA-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	6,370	207	2,055	1665	4,498	134	76
GBA-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 18:00.	9,634	502	2,788	0	9,132	134	76
GBA-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours ending 19:00.	8,404	372	2,788	0	8,032	134	76
GBA-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	9,634	502	2,788	0	9,132	134	76
GBA-2029-SVP	Sensitivity	2029 summer peak load conditions with high SVP load sensitivity	9,634	502	2,788	0	9,132	134	76

Table 2.5-15 Greater Bay Area generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
GBA-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 18:00.	80	20	2	221	98	0	0	7,838	5,149
GBA-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours ending 19:00.	80	20	0	221	35	0	0	7,838	4,925
GBA-2021-SpOP	Baseline	2021 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	80	20	20	221	119	0	0	7,838	1,373
GBA-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	80	20	20	221	173	0	0	7,838	1,666
GBA-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 18:00.	109	20	2	221	76	0	0	7,838	5,497
GBA-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours ending 19:00.	109	20	0	221	16	0	0	7,838	5,460
GBA-2024-SpOP	Baseline	2024 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	109	20	19	221	4	0	0	7,838	1,345
GBA-2024-SP-Hi-CEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	109	20	2	221	76	0	0	7,838	5,497
GBA-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	109	20	19	221	109	0	0	7,838	845
GBA-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 18:00.	109	20	0	221	39	0	0	7,838	4,837
GBA-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours ending 19:00.	109	20	0	281	76	0	0	7,838	5,820
GBA-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	109	20	0	221	39	0	0	7,838	4,837
GBA-2029-SVP	Sensitivity	2029 summer peak load conditions with high SVP load sensitivity	109	20	0	221	39	0	0	7,838	4,837

2.5.5.3 Assessment Summary

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 2019-2020 reliability assessment of the PG&E Greater Bay Area identified several reliability concerns consisting of thermal overloads under Category P1 to P7 contingencies, most of which are addressed by previously approved projects. The areas where additional mitigation requirements were identified are discussed below.

East Shore 230 kV Bus Terminals Reconfiguration

Category P2 overload was identified on the East Shore 230/115 kV transformer #1. The P2 overload is due to the simultaneous loss of the San Mateo-East Shore 230 kV line and the parallel 230/115 kV transformer #2. The ISO is recommending approval of the “East Shore 230 kV Bus Terminals Reconfiguration" project which includes rerouting of the Russell City-East Shore and San Mateo-East Shore 230 kV lines at the East Shore 230 kV station. Estimated cost of this project is $2M to $4M and in-service date is 2024. In the interim the area will rely on the operating action plan.

Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition

Category P2 overloads were identified on the Newark 230/115 kV Transformer #11. The overload is due to loss of the parallel transformer #7 and other 230 kV lines associated with the P2 contingency. The ISO is recommending approval of the “Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition" project. Estimated cost of this project is between $3M to $6M and in-service date is 2024. In the interim the area will rely on the operating action plan.

Moraga 230 kV Bus Upgrade

Category P2 contingency overloads were identified on the Oakland D-L 115 kV cable, Sobrante-Claremont 115 kV line and 230 kV lines in Contra Costa-Newark corridor. The ISO is recommending approval of the “Moraga 230 kV Bus Upgrade" project which includes adding sectionalizing breakers and a bus-tie breaker at Moraga 230 kV bus. Estimated cost of this project is $17M and in-service date is 2024.

Oakland Clean Energy Initiative Project

Moraga-Claremont and Moraga-Station X 115 kV lines and Northern Oakland area 115 kV cables overloaded for various categories P2 and P6 contingencies. In the near-term, dispatching Oakland area local generation mitigates these overloads. The *Oakland Clean Energy Initiative Project,* approved in the 2017-2018 TPP with current targeted amount of portfolio procurement (29 MW and 116 MWh of energy storage and 1 MW of energy efficiency) will mitigate most of these overloads in the long-term. Due to the increase in the area’s load forecast and based on the latest Northern Oakland area load profile, the portfolio need has increased to about 36 MW and 173 MWh for 2024 from storage to sufficiently meet the current forecasted reliability need. This includes 7 MW and 28 MWh storage at Oakland L and 29 MW and 145 MWh storage at Oakland C. The approved project is expected to be in-service in 2022.

2.5.5.4 Request Window Submissions

The ISO received 11 submissions in the 2019 Request Window in the Greater Bay Area.

Request Window Submission - East Shore 230 kV Bus Terminals Reconfiguration

Pacific Gas & Electric (PG&E) proposed a project, East Shore 230 kV Bus Terminals Reconfiguration, targeting thermal overloads on the East Shore 230/115 kV transformer #1. The project include reconfiguring Russell City-East Shore and San Mateo-East Shore 230 kV lines at East Shore 230 kV station. The ISO review found that the East Shore 230 kV Bus Terminals Reconfiguration project addresses reliability issues. Hence, the ISO determined that the *East Shore 230 kV Bus Terminals Reconfiguration* is needed. The project is discussed in Section 2.5.5.3.

Request Window Submission 230/115 kV Transformer Bank #7 Circuit Breaker Addition

Pacific Gas & Electric (PG&E) proposed a project, Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition, targeting thermal overloads on the Newark 230/115 kV transformer #11. The project include adding high-side breaker to Newark 230/115 kV transformer #7. The ISO review found that the project addresses reliability issue. Hence, the ISO determined that the *Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition* is needed. The project is discussed in Section 2.5.5.3.

Request Window Submission – Northern Oakland Area Reinforcement

Pacific Gas & Electric (PG&E) proposed a project, Northern Oakland Area Reinforcement, targeting long-term reliability need in the Northern Oakland area and compliance with the CPUC General Order 95 ground to conductor clearance requirements. PG&E proposed a combination of substation upgrade, reconductor and rebuild of existing 115 kV lines and new 115 kV line addition in Oakland area. The project include the following:

1. Rebuild Moraga- Oakland X 115 kV four-line path with three lines with conductor rated for 1100 Amps or higher summer emergency rating;
2. Reconductor Moraga-Claremont #1& #2 115kV lines with conductor rated for 1100 Amps or higher summer emergency rating;
3. Build a new 115 kV line from Oakland X to Oakland L substation with conductor rated for 1100 Amps or higher summer emergency rating;
4. Upgrade Moraga 230 kV Bus (Add sectionalizing breakers and a bus tie breaker to Moraga 230 kV bus)

Out of the four scopes mentioned above, the ISO has separately recommended approval of the Moraga 230 kV bus upgrade as this project also provides benefit and mitigates overloads identified in the Diablo division. The Moraga 230 kV bus upgrade project is discussed in detail in Section 2.5.5.3.

Building of a new 115 kV line from Oakland X to Oakland L substation could address long-term need of serving growing load at Oakland D & L substations beyond what has been identified in this year’s assessment. As such, the ISO will continue to monitor need for this part of the scope in future cycle.

Rebuilding of Moraga- Oakland X 115 kV four-line path with three lines and reconductoring of the Moraga-Claremont #1& #2 115 kV lines are primarily driven by CPUC GO-95 compliance and the work will be performed under PG&E's maintenance budget. The ISO reviewed and concurs the proposed scope of work.

Request Window Submission - Contra Costa - Pittsburg 230 kV Transmission System

Horizon West proposed a project, Contra Costa - Pittsburg 230 kV Transmission System, targeting thermal overloads in Contra Costa-Newark 230 kV corridor. Horizon West proposed a new 230 kV overhead transmission line or a submarine cable from Contra Costa to Pittsburg substation with a 16-ohm series reactor and associated by-pass circuit breaker.

The project as proposed has higher cost compared to other alternatives considered and also doesn't address all reliability issues identified in the Contra Costa-Newark 230 kV corridor. Hence, the ISO determined that the Contra Costa - Pittsburg 230 kV Transmission System is not the appropriate solution for reliability issues identified in Contra Costa-Newark 230 kV corridor.

Request Window Submission - Birds Landing-Pittsburg 230 kV Transmission System

Horizon West proposed a project, Birds Landing-Pittsburg 230 kV Transmission System, targeting thermal overloads in Contra Costa-Newark 230 kV corridor. Horizon West proposed a new 230 kV overhead transmission line from Birds Landing to Pittsburg substation with a 12-ohm series reactor and associated by-pass circuit breaker.

The project as proposed has higher cost compared to other alternatives considered and also doesn't address all reliability issues identified in the Contra Costa-Newark 230 kV corridor. Hence, the ISO determined that the Birds Landing-Pittsburg 230 kV Transmission System is not appropriate solution for reliability issues identified in Contra Costa-Newark 230 kV corridor.

Request Window Submission - HWT-Embarcadero 230 kV Transmission Project

Horizon West proposed a project, the HWT-Embarcadero 230 kV Transmission Project, to construct a new 230 kV substation near Sobrante looping-in the Sobrante-Crockett and Sobrante-Lakeville 230 kV lines and connecting to the existing Embarcadero 230 kV substation via a new 230 kV submarine cable.

The HWT-Embarcadero 230 kV Transmission Project is not considered a reliability alternative as the submission does not meet a reliability need identified by the ISO.

Request Window Submission - Sobrante-Embarcadero 230 kV Transmission Project

Horizon West proposed a project, the Sobrante-Embarcadero 230 kV Transmission Project, to build a new combination of 230 kV overhead line and underground/submarine cable connecting existing Sobrante and Embarcadero 230 kV substations and install a 63-MVAR line –shunt reactor after each cable terminus.

The Sobrante-Embarcadero 230 kV Transmission Project is not considered as a reliability alternative as the submission does not meet a reliability need identified by the ISO.

Request Window Submission - New Sobrante-Oakland "C" 230 kV Transmission Project

Horizon West proposed a project, New Sobrante-Oakland “C” 230 kV Transmission Project, targeting long-term reliability need in the Northern Oakland area. Horizon West proposed a new 230 kV transmission line from Sobrante to a new station close to existing Claremont substation and a 230/115 kV auto transformer at the new station and connecting to the existing Oakland C substation.

The project as proposed doesn’t address all long-term reliability needs in the Oakland area. Hence, the ISO determined that the New Sobrante-Oakland “C” 230 kV Transmission Project is not an appropriate solution to address long-term reliability needs in the Oakland area.

Request Window Submission - Christie - Sobrante 115 kV Project

Smart Wires proposed a project, Christie - Sobrante 115 kV Project, which proposes to install Smart Wires power flow control technology on the Christie – Sobrante 115 kV.

The Christie - Sobrante 115 kV Project is not considered as reliability solution as the submission is functionally duplicative of transmission solutions that have previously been approved by the ISO.

Request Window Submission - Bi-Directional flow control Upgrade

Trans Bay Cable proposed a project, Bi-Directional flow control Upgrade, which proposes to enhance the existing HVDC system to operate in a bidirectional mode to allow power flow in either direction.

The Bi-Directional flow control Upgrade is not considered as reliability alternative as the submission does not meet a reliability need identified by the ISO.

Request Window Submission - Delta Reliability Energy Storage (DRES)

Tenaska proposed a project, Delta Reliability Energy Storage (DRES), which proposes to install a 72 MW x 4 hour discharge (288 MWh) energy storage interconnecting to the existing Delta Switchyard 230 kV.

The Delta Reliability Energy Storage (DRES) is not considered a reliability alternative as the submission does not meet a reliability need identified by the ISO. However, the project is considered as an alternative for potential Local Capacity Requirement (LCR) reductions in the Contra Costa subarea for which a detailed discussion is included in Chapter 4.

2.5.5.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.5.2, about 276 MW of AAEE and more than 2000 MW of installed behind-the-meter PV reduced the Greater Bay Area load in 2024 by about 5%. This year’s reliability assessment for Greater Bay Area included the “high CEC forecast” sensitivity case for year 2024 which modeled no AAEE. Comparisons between the reliability issues identified in the 2024 summer peak baseline case and the “high CEC forecast” sensitivity case show that the facility overloads shown in Table 2.5-16 are potentially avoided due to reduction in net load.

Table 2.5-16: Reliability Issues Avoided due to AAEE

Facility	Category
Cayetano-Lone Tree (Lone Tree-USWP) 230kV Line	P2
Monta Vista-Wolfe 115 kV Line	P1 & P2
Newark 230/115kV Transformer #11	P2
Las Positas-Newark 230kV Line	P2
Los Esteros-Nortech 115 kV Line	P2

Furthermore, about 134 MW of demand response and 109 MW of battery energy storage are modeled in the Greater Bay Area in the year 2024. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources mitigated overloads in Oakland and San Jose areas and helped reduce thermal overloads on Metcalf transformer banks. as well.

Preferred resources as potential mitigation are also identified for areas of additional mitigation requirements as discussed in section 2.5.5.3. The areas for which preferred resources are identified as a recommended solution or as a potential mitigation solution for areas currently relying on interim operational action along with high-level size of resource needed to mitigate reliability issues are shown in Table 2.5-17.

Table 2.5-17: Areas preferred resources are identified as potential solutions

Area	Overloaded Facility	Category	Need		Location
			Peak (MW)	Duration (Hr)	
San Jose 115 kV	Metcalf 230/115 kV banks	P2	240	6	Swift

2.5.5.6 Recommendation

Based on the studies performed in the 2019-2020 transmission planning cycle Transmission Plan, several reliability concerns were identified for the PG&E Greater Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Bay area.

Stakeholders submitted 11 projects through the Request Window in the Greater Bay Area in this cycle. Out of 11 projects submitted, the ISO found three projects needed for reliability and those three are recommended for approval. Other projects are either not considered as reliability alternative as the submission does not meet a reliability need identified by the ISO or instead may considered in the economic study process if found applicable. One other project was not considered as a reliability solution as the submission is functionally duplicative of transmission solutions that have previously been approved by the ISO.

The portfolio procurement need for the previously approved project, “Oakland Clean Energy Initiative (OCEI)”, has been updated due to the increase in the area’s load forecast and based on the latest Northern Oakland area load profile. The portfolio need has increased to about 36 MW and 173 MWh for 2024 from storage to sufficiently meet the current forecasted reliability need. This includes 7 MW and 28 MWh storage at Oakland L and 29 MW and 145 MWh storage at Oakland C.

One previously approved project, Newark-Lawrence 115 kV line limiting Facility Upgrade, is recommended to be canceled in this cycle due to the finding that the line section has higher ratings than what was modeled in the base cases used at the time.

One additional previously approved project, Moraga-Sobrante 115 kV line reconductor, has been recommended to put on hold due to significant change in load distribution within the East Bay division and its interaction with the Moraga 230 kV bus upgrade project.

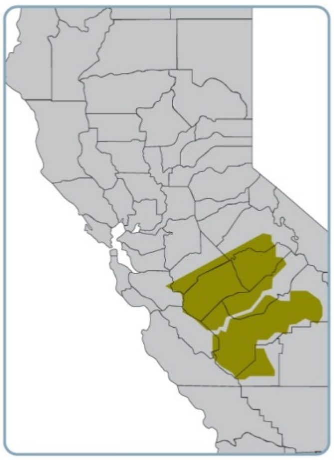
To address reliability constraints in the Greater Bay Area, the ISO recommends approval of the following three projects.

- East Shore 230 kV Bus Terminal Reconfiguration
- Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition
- Moraga 230 kV Bus Upgrade

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. 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 8.

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 market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are shown in Table 2.5-18 and Table 2.5-19.

Table 2.5-18 Greater Fresno Area load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
GFA-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 19:00.	3,150	42	1,226	0	3,108	56	14
GFA-2021-SpOP	Baseline	2021 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,104	31	1,226	981	92	56	14
GFA-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	3,289	52	1,224	1212	2,025	56	14
GFA-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 19:00.	3,386	78	1,557	0	3,308	56	14
GFA-2024-SpOP	Baseline	2024 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,232	57	1,552	1257	(82)	56	14
GFA-2024-SP-Hi-CEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	3,386	0	1,557	0	3,386	56	14
GFA-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	1,232	57	1,552	1537	(362)	56	14
GFA-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 19:00.	3,633	142	2,022	0	3,491	56	14
GFA-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	3,633	142	2,022	0	3,491	56	14

Table 2.5-19: Greater Fresno Area generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
GFA-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 19:00.	316	2610	0	13	9	1892	1800	1,480	1,195
GFA-2021-SpOP	Baseline	2021 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	316	2610	2509	13	7	1892	-365	1,480	121
GFA-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	316	2610	2582	13	11	1892	1484	1,480	301
GFA-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 19:00.	316	2610	0	13	9	1892	1800	1,480	1,192
GFA-2024-SpOP	Baseline	2024 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	316	2610	2452	13	0	1892	-415	1,480	96
GFA-2024-SP-Hi-CEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	316	2610	0	13	9	1892	1800	1,480	1,192
GFA-2024-SpOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	316	2610	2584	13	9	1892	-541	1,480	266
GFA-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 19:00.	316	2610	0	13	9	1892	1799	1,480	1,189
GFA-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	316	2610	0	13	0	1892	1799	1,480	1,175

2.5.6.3 Assessment Summary

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 2019-2020 reliability assessment of the PG&E Greater Fresno Area has identified several reliability concerns consisting of thermal overloads under Category P1 to P7 contingencies most of which are addressed by previously approved projects. The areas where additional mitigation requirements were found to be needed are discussed below.

Borden 70 kV Area overloads

There were P1 and several P3, P6 overloads on the Borden 230/70kV TB #1 in the baseline summer peak years. Although the contingency causing the overloads are non-BES and limiting elements are also no BES the overloads being P1 and P3 we propose to mitigate the limiting equipment at Borden 70kV sub in order for the TB to be able to be operated at its full capacity.

Wilson-Atwater 115 kV Area overloads

There were several P6 overloads in this area for all Baseline scenarios. The mitigation is for the P6 is to do Operational Switching post first contingency while the long-term mitigation would be to expand the Atwater SPS.

Wilson-Oro Loma 115 kV overloads

There were several P2, including P2-1 overloads in this area for all Baseline summer peak scenarios and sensitivity scenarios on the Wilson-El Nido 115kV Line section. Since one of the contingencies is a P2-1 the mitigation proposal is to reconductor the overloaded section.

McCall 115 kV Area overloads

There was a P6 contingency SANGER-REEDLEY 115kV & MCCALL-REEDLEY 115kV, causing overload on the Reedley-Wahtoke 115k Section of the McCall-Reedley 115kV line, Sanger-Reedley 115kV line and Reedley-Piedra 115kV line. This contingency also caused low voltage at Reedley and Wahtoke 115kV. The mitigation would to drop the load at Wahtoke

There were P2 and P6 overloads in this area for 2029 Baseline scenario as well as two sensitivity scenarios. We will continue to monitor future load forecast in the area.

P5 overloads

There were P5 Contingency -GREGG 230 KV BAAH BUS #2 (FAILURE OF NON-REDUNDENT RELAY) and MCCALL 115kV BAAH BUS #1 (FAILURE OF NON-REDUNDENT RELAY) overloads on several 115 kV and 230 kV lines in the Baseline and sensitivity cases. The mitigation is a recommendation to add redundant relay protection.

2029 Overload issues

There were several P2 and P5 overloaded elements that only appeared in the 2029 Summer peak baseline scenario. These include Warnerville Wilson 230kV Line, Herndon-Manchester 115kV line, and GWF-Contandina-Jackson 115kV line, California Ave-Sanger 115kV Line and McCall 230/115kV TB #3. We will continue to monitor future load forecast for these issues.

Spring off-peak only overloads

There were some P2, P6, P7 overloads that only appeared in the Spring off-Peak cases such as Los Banos-Padre Flat 230kV line, Le Grand Chowchilla 115kV line, Chowchilla-Kerckhoff 115kV line, and Herndon-Woodward 115kV line. Mitigation is generation redispatch.

Reedley 115 kV & Coalinga 70kV Area Voltage concerns

In the 2029 Summer Peak baseline scenario for Category P3 and P6 some low voltages were identified. Coalinga 70kV area has low voltage issues in the 2029 Baseline case for P1 type contingencies. The ISO will continue to monitor future load forecast for this issue.

Reedley 70kV Area

Dinuba Energy Generator announced retirement and due to it new P1, P2, P3, P6 issues were identified in the Reedley 70kV Area in the future years 2024 and 2029 and the Previously Approved Dinuba 7MW BEES project is no longer sufficient to mitigate these constraints. The BESS project is recommended to be resized to 12MW to mitigate the constraints.

2.5.6.4 Request Window Submissions

Wilson-Oro Loma 115kV Line Reconductoring

PG&E submitted Wilson-Oro Loma 115kV Line Reconductoring project into the 2019 Request Window. The project consists of reconductor ~9 circuit miles between Wilson and El Nido Substations (Wilson-002/004 section and 008/002- El Nido section) on the Wilson-Oro Loma 115kV Line with larger conductor to achieve at least 650 Amps of summer emergency rating (preferably 715.5-37 AAC conductor). Also removes any limiting components to achieve the full conductor capacity

The project protects against NERC Category P2 (including P2-1, P2-2, and P2-4) contingencies that involve loss of the circuit from Panoche to Panoche Junction. The most severe of these contingencies may lead to loading of Wilson-El Nido 115 kV section up to 124% of its summer emergency rating. Approximately, 20 MW of 120 MW total local load may need to be dropped in order to mitigate the overload in the absence of system upgrades.

This project would establish the Wilson-Oro Loma 115 kV line as a strong power source to the Oro Loma 70kV system and will provide enough transmission capacity to meet future local demand. This project will increase operating flexibility, load serving capability, customer reliability and reduce losses. This project is expected to cost between $11.3 to $22.7 million.

The ISO recommends this project for Approval being it a solution to the identified P2-1 violation.

Borden 230/70 kV Transformer Bank #1 Capacity Increase

PG&E submitted Borden 230/70 kV Transformer Bank #1 Capacity Increase which is set to Upgrade Bank Breaker CB 52 and associated switches to match the Transformer Bank # 1’s full capacity (200 N/220 E MVA) and upgrade Borden 70 kV Bus Section “D” to match the Transformer Bank # 1’s full capacity.

The project protects against NERC Category P1 (in the 2024 case), P3 and P6 contingencies that involve loss of Borden 230/70 Transformer Bank 4 and Friant Dam Power Plant. The most severe of such contingencies may lead to loading of Borden 230/70 Transformer Bank #1 up to 115.6% of its summer emergency rating. Approximately, 15 MW local load may need to be dropped in order to mitigate the overload in the absence of system upgrades.

This project would achieve the full capacity of existing Borden 230/70 kV Transformer Bank #1 and establish the Borden substation as a stronger power source to the local 70 kV system and will provide enough transmission capacity to meet future local demand. This project will increase operating flexibility, load serving capability, customer reliability and reduce losses. This project is expected to cost between $11.5 to $23 million.

The ISO recommends this project for Approval as being a good solution to the identified P1, P3 and P6 violations.

2.5.6.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.6.2, about 78 MW of AAEE reduced the Greater Fresno Area load in 2024 by about 2.3%. This year's reliability assessment for the Greater Fresno Area included the "high CEC forecast" sensitivity case for the year 2024 which modeled no AAEE. Comparisons between the reliability issues identified in the 2024 summer peak baseline case and the "high CEC forecast" sensitivity case are shown in Table 2.5-20 and indicate these facility overloads are potentially avoided due to reductions in net load.

Table 2.5-20: Reliability Issues in Sensitivity Studies

Facility	Category
Herndon-Manchester 115kV line	P2
Chowchilla-Kerckhoff #2 115kV line	P5
GWFHEP to Contadina 115 kV line	P5

Furthermore, about 56 MW of demand response is modeled in Greater Fresno Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.6.6 Recommendation

Based on the studies performed in the 2019-2020 transmission planning cycle, several reliability concerns were identified for the PG&E Greater Fresno Area. These concerns consisted of thermal overloads and voltage concerns under Categories P1 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Fresno Area.

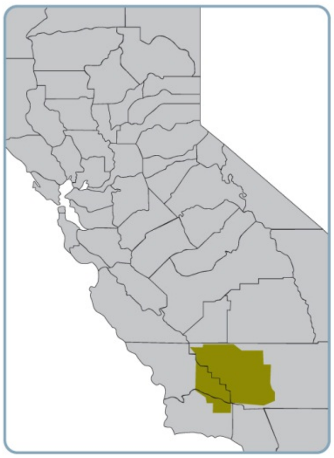
To address new reliability constraints in the Greater Fresno Area, the ISO recommends approval the following two projects.

- Wilson-Oro Loma 115kV Line Reconductoring
- Borden 230/70 kV Transformer Bank #1 Capacity Increase

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.

2.5.7.2 Area-Specific Assumptions and System Conditions

The Kern Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are shown in Table 2.5-21 and Table 2.5-22.

Table 2.5-21 Kern Area load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
KERN-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 20:00.	1,987	23	512	0	1,965	65	49
KERN-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 20:00.	2,099	44	592	0	2,055	65	49
KERN-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 20:00.	2,238	82	732	0	2,157	66	49
KERN-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	1,016	17	512	410	589	65	49
KERN-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	1,079	32	592	479	568	65	49
KERN-2024-SP-HiCEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	2,099	0	592	0	2,099	65	49
KERN-2024-SOP-HiRene	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	1,079	32	592	586	461	65	49
KERN-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	1,981	29	512	507	1,445	65	49
KERN-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	2,238	82	732	0	2,157	66	49

Table 2.5-22 Kern Area generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
KERN-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 20:00.	2	440	0	0	0	29	16	3,393	1,711
KERN-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 20:00.	0	418	0	0	0	29	16	3,383	1,712
KERN-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 20:00.	0	418	0	0	0	29	16	3,383	1,347
KERN-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	2	440	440	0	0	29	22	3,393	473
KERN-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	0	418	410	0	0	29	16	3,383	473
KERN-2024-SP-HiCEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	0	418	0	0	0	29	16	3,383	1,712
KERN-2024-SOP-HiRene	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	0	418	414	0	0	29	16	3,383	473
KERN-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	2	440	434	0	0	29	16	3,393	718
KERN-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	0	418	0	0	0	29	11	3,383	1,346

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.7.3 Assessment Summary

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 2019-2020 reliability assessment of the PG&E Kern Area identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously approved projects and/or continued reliance on existing summer setups for the area.

Wheeler Ridge Junction Station Project

There were multiple P1, P2, P3 & P6 overloads in both Kern 115 areas and the 230 kV Midway-Wheeler ridge 230 kV lines. These overloads would be mitigated by the Wheeler Ridge Junction project when it comes into service. Based upon the current area needs and increases in the cost estimate for the project the ISO is recommending that this project be put back on hold. The ISO will further assess the need and potential other alternatives in the next planning cycle.

2.5.7.4 Request Window Submissions

There were no request window submissions for Kern Area.

2.5.7.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.7.2, about 44 and 82 MW of AAEE reduced the Kern Area net load by 2 and 4 % in 2024 and 2029 respectively .Similar to last year, this year's reliability assessment for Kern Area included the "high CEC forecast" sensitivity case for year 2024 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2024 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads shown in Table 2.5-23 are diminished due to reduction in net load.

Table 2.5-23: Reliability Issues in Sensitivity Studies

Facility	Category
Midway-Tupman 115 kV	P2
Taft 115/70 kV Bank	P3
Weedpatch-Magunden 70 kV	P3

Furthermore, about 65 MW of demand response and 2 MW of battery energy storage are modeled in Kern Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn't completely alleviate the overloads.

2.5.7.6 Recommendation

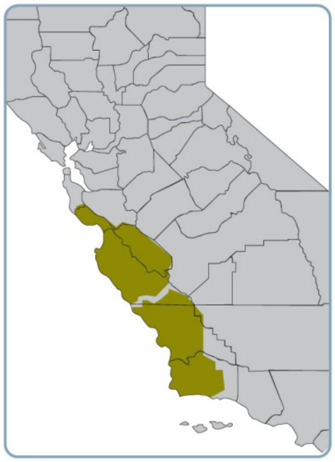
Based on the studies performed for the 2019-2020 Transmission Plan, several reliability concerns were identified for the PG&E Kern Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. All of the reliability concerns are addressed by previously approved projects, PG&E maintenance projects, generation redispatch or continued reliance on existing summer setups for the area.

Further assessment is required on potential alternatives and review of cost estimates to address the reliability needs in the Wheeler Ridge area. The ISO recommends that the previously approved Wheeler Ridge Junction project be put back on hold for further assessment in future planning cycles.

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 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.

2.5.8.2 Area-Specific Assumptions and System Conditions

The Central Coast and Los Padres areas 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 related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Coast and Los Padres areas study are shown in Table 2.5-24 and Table 2.5-25.

Table 2.5-24: Central Cost and Los Padres Area load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
CCLP-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 21:00.	1,231	30	397	0	1,201	30	16
CCLP-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 21:00.	1,282	56	454	0	1,226	30	16
CCLP-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 21:00.	1,360	103	550	0	1,257	30	16
CCLP-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	766	22	397	318	426	30	16
CCLP-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	830	42	454	368	420	30	16
CCLP-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours ending 19:00.	1,133	30	397	0	1,104	30	16
CCLP-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours ending 19:00.	1,270	55	453	0	1,214	30	16
CCLP-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours ending 19:00.	1,262	76	550	0	1,185	30	16
CCLP-2024-SP-HiCEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	1,282	0	454	0	1,282	30	16
CCLP-2024-SOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	830	42	454	450	338	30	16
CCLP-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	1,215	38	397	393	784	30	16
CCLP-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	1,360	103	550	0	1,257	30	16

Table 2.5-25: Central Cost and Los Padres Area generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
CCLP-2021-SP	Baseline	2021 summer peak load conditions. Peak load time - hours ending 21:00.	483	841	0	0	0	0	0	3,774	1,073
CCLP-2024-SP	Baseline	2024 summer peak load conditions. Peak load time - hours ending 21:00.	483	816	0	0	0	0	0	3,773	1,134
CCLP-2029-SP	Baseline	2029 summer peak load conditions. Peak load time - hours ending 21:00.	483	816	0	0	0	0	0	3,773	1,025
CCLP-2021-SOP	Baseline	2021 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	483	841	841	0	0	0	0	3,774	269
CCLP-2024-SOP	Baseline	2024 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	483	816	800	0	0	0	0	3,773	353
CCLP-2021-WP	Baseline	2021 winter peak load conditions. Peak load time - hours ending 19:00.	483	841	0	0	0	0	0	3,774	1,073
CCLP-2024-WP	Baseline	2024 winter peak load conditions. Peak load time - hours ending 19:00.	483	816	0	0	0	0	0	3,773	1,134
CCLP-2029-WP	Baseline	2029 winter peak load conditions. Peak load time - hours ending 19:00.	483	816	0	0	0	0	0	3,773	1,041
CCLP-2024-SP-HiCEC	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	483	816	0	0	0	0	0	3,773	1,134
CCLP-2024-SOP-HiRenew	Sensitivity	2024 spring off-peak load conditions with hi renewable dispatch sensitivity	483	816	808	0	0	0	0	3,773	1,127
CCLP-2021-SP-HiRenew	Sensitivity	2021 summer peak load conditions with hi-renewable dispatch sensitivity	483	841	832	0	0	0	0	3,774	138
CCLP-2029-SP-QF	Sensitivity	2029 summer peak load conditions with QF retirement sensitivity	483	816	0	0	0	0	0	3,773	1,020

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with the exception of approved projects shown in Table 2.5-26 which were not modeled in the base cases.

Table 2.5-26: Central Coast / Los Padres approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
None		

2.5.8.3 Assessment Summary

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 2019-2020 reliability assessment of the PG&E Central Coast and Los Padres areas have identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously approved projects.

The areas where additional mitigation requirements were identified are discussed below.

Salinas-Firestone #1 and #2 60 kV Lines

Category P1 and P3 contingency overloads were identified on the Salinas - Firestone 60 kV lines. The ISO is recommending reconductoring of these two lines. The estimated cost is $19M-$38M and have an expected in-service date of May 2024.

Project Preferred Scope:

4. Reconductor Sanborn Junction to Spence to achieve at least 600 Amp summer emergency rating (about 8 miles) and remove any limiting components in the line and substation to achieve the full rating.
5. Reconductor Buena Vista Junction to Firestone to achieve at least 600 Amp summer emergency rating (about 3 miles) and remove any limiting components in the line and substation to achieve the full rating.
6. Reconductor Spence to SPNCE J2 to achieve at least 600 Amp summer emergency rating (about 0.16 miles) and remove any limiting components in the line and substation to achieve the full rating.
7. Reconductor SPNCE J2 Firestone to achieve at least 600 Amp summer emergency rating (about 1.46 miles) and remove any limiting components in the line and substation to achieve the full rating.

Summary of review of previously approved projects

There is one previously approved active project in the Central Coast/Los Padres area not modeled in the study cases due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The final recommendation for the project not modeled in the study cases is shown in Table 2.5-27.

Table 2.5-27: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
North of Mesa Upgrades (previously Midway – Andrew)	Approval

Details of the review of previously approved projects not modeled in study cases are presented in Appendix B.

North of Mesa Upgrades (Previously Midway-Andrew) Project

The previously approved Midway-Andrew 230 kV project approved in the 2012-2013 TPP. The Midway-Andrew 230 kV project was not modelled in the base case due to the fact that it was split into two separate projects in the 2018-2019 TPP cycle, the North of Mesa Upgrades and the South of Mesa Upgrades. The South of Mesa Upgrades was approved in the 2018-2019 TPP cycle, it was recommended that the North of Mesa upgrades remain on hold so further study assessments could be performed. In this cycle the reliability assessment identified severe P2 and P6 thermal overloads in the 115 kV system supplied from the Mesa substation, thus mitigation is still required. In addition, the load forecast and profile in the area does not provide periods for maintenance to facilities where the next contingency would not result in load loss in the area.

North of Mesa Upgrade Alternatives

- Alternative 1: Build Andrew 230/115 kV substation, energize Diablo – Midway 500 kV line at 230 kV and connect to Andrew substation, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.

- Alternative 2: Increase the Winter emergency rating of San Luis Obispo (SLO) – Santa Maria 115 kV line to 170 MVA, increase the Winter emergency rating of SLO – Mesa 115 kV line to 130 MVA, and install 50 Mvar capacitor bank at Mesa or SLO, and install SPS to shed load if P6 occurs under peak load.

The estimated cost of the North of Mesa Upgrades is $114 to $144 million with an expected in-service date of 2026, after Diablo generation has retired and one of the 500 kV lines can be converted to 230 kV. The ISO is recommending for the project to remain on hold for further assessment in future planning cycles.

2.5.8.4 Request Window Submissions

Lopez-Divide 230 kV Transmission System Project

Horizon West Transmission, LLC proposed the Lopez-Divide 230 kV Transmission System project

The Lopez - Divide 230 kV Transmission System Project, connects PG&E's Diablo Canyon-Midway 500 kV Line to the Divide 115 kV substation. The project scope is to:

- Converting a single Diablo Canyon-Midway 500 kV line to 230 kV operation
- A new Lopez 230kV 3 breaker ring bus looped into the repurposed Diablo Canyon-Midway 230 kV Line
- A new 25-mile 230 kV line from the new Lopez substation to the area of the Divide 115
    - Conductor type 954 ACSR Rail, Normal Rating 440 MVA, Emergency Rating 480 MVA
- A new Divide 230 kV bus near the existing PG&E Divide 115 kV substation
- A new Divide 230/115 kV transformer rated at 400 MVA Normal, 463 MVA Emergency.
- A new 10-mile Divide-Sisquoc 115 kV Line
    - Conductor type 795 ACSR TURN, Normal Rating 825 Amps, Emergency Rating 975 Amps

The project is intended to address the post contingency thermal and voltage collapse issues for reliability issues identified in the 2019-2020 TPP. The submission does not address feasibility issues, such as zoning and other local permissions required to construct the new lines.

This project would address similar reliability issues as the North of Mesa Upgrades, which is recommended to remain on hold, and the previously approved South of Mesa Upgrades project. The Lopez-Divide project would also likely cost more than the North of Mesa upgrades once incumbent costs are added to the estimated $85M project cost.

2.5.8.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.8.2, about 56 and 103 MW of AAEE reduced the Central Coast and Los Padres Area net load by 3 and 6% in 2024 and 2029 respectively. This year's reliability assessment for Central Coast and Los Padres Area included the "high CEC forecast" sensitivity case for year 2024 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2024 summer peak baseline case and the “high CEC forecast” sensitivity case are shown in Table 2.5-28 and indicate that the facility overloads are potentially avoided due to reduction in net load.

Table 2.5-28: Reliability Issues in Sensitivity Studies

Facility	Category
30760 COBURN 230 36075 COBURN 60.0 1	P1, P2
36260 SISQUOC 115 36286 PALMR 115 1	P6, P7
36264 S.YNZ JT 115 36288 ZACA 115 1	P2, P6, P7
36286 PALMR 115 36287 AECCEORTP 115 1	P6, P7
36287 AECCEORTP 115 36288 ZACA 115 1	P2, P7

Furthermore, about 30 MW of demand response and 0 MW of battery energy storage are modeled in Central Coast and Los Padres Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn’t completely alleviate the overloads.

2.5.8.6 Recommendation

Based on the studies performed for the 2019-2020 Transmission Plan, several reliability concerns were identified for the PG&E Central Coast and Los Padres Area. These concerns consisted of thermal overloads and voltage concerns under Categories P1, P2, P3, P6 and P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Central Coast and Los Padres Area.

To address reliability constraints in the Central Coast and Los Padres Area, the ISO recommends approval the following project(s).

- Salinas – Firestone #1 & #2 60kV line Reconductor

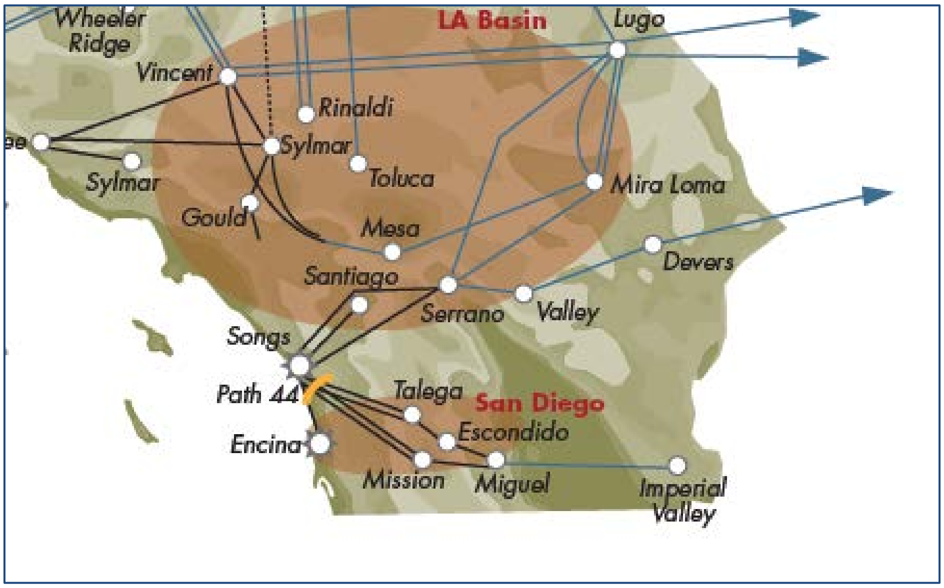
The North of Mesa project is recommended to remain on hold for further review in future planning cycles.

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). An illustration of the southern California's bulk transmission system is shown in Figure 2.6-1.

Figure 2.6-1: 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[92] and certain other cities[93]. Most of the SCE load is located within the Los Angeles Basin. The CEC's gross load growth forecast for the SCE Transmission Access Charge (TAC) area is about 165 MW[94] on the average per year; however, after considering the projection for mid additional achievable energy efficiency (AAEE) and additional achievable PV (AAPV) , the demand forecast is declining at an average rate of 82 MW per year[95]. The CEC's 1-in-5 load forecast for the SCE TAC Area includes the SCE service area, and the Anaheim Public Utilities, City of Vernon Light & Power Department, Pasadena Water and Power Department, Riverside Public Utilities, California Department of Water Resources and Metropolitan Water District of southern California pump loads. The 2029

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

[93] 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.

[94] Based on the CEC-adopted California Energy Demand Forecast 2018-2030 (Form 1.5c) – Mid Demand Baseline Case, No AAEE or AAPV Savings, January 2019 version

[95] Based on the CEC-adopted California Energy Demand Forecast 2018-2030 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE and AAPV Savings, January 2019 version

summer peak 1-in-5 forecast sales load, including system losses, is 23,260 MW[96]. 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[97] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2029 summer peak 1-in-5 forecast load for the SDG&E area including Mid-AAEE, AAPV and system losses is 4,783 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 5,931 MW of OTC-related electric generation has been retired since 2010. The remaining 4,829 MW of OTC-related gas-fired generation is scheduled to retire in the near term, to comply with the State Water Resources Control Board's Policy on OTC Plants. Some are scheduled to be replaced, such as Alamitos and Huntington Beach, 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 2019-2020 transmission plan, the ISO has also taken into account the potential retirement of 1,328 MW of aging non-OTC and mothballed generation in the area[98].

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 Moorpark area, and SDG&E to procure between 800 and 1100 MW in the San Diego area.[99] 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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[96] Based on the CEC-adopted California Energy Demand Forecast 2018-2030 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE and AAPV Savings, January 2019 version

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

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

[99] 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[100]. 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.

2.6.2 Area-Specific Assumptions and System Conditions

The southern California bulk transmission system steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers and generation dispatch assumptions for the various scenarios used for the southern California bulk transmission system assessment are provided in Table 2.6-1.

[100] The Carlsbad Energy Center was energized at the end of 2018.

Table 2.6-1: Southern California bulk transmission load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2021-Summer Peak	Baseline	2021 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	26,343	641	3,755	1,652	24,050	465	23	423	7,508	4,204	4,251	2,625	1,571	1,145	22,646	8,200
B2	2024-Summer Peak	Baseline	2024 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	27,722	1,336	5,123	2,254	24,132	465	23	473	7,508	3,904	4,233	1,524	1,591	1,300	23,160	8,488
B3	2029-Summer Peak	Baseline	2029 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	25,112	2,023	7,083	0	23,089	465	23	473	12,723	0	4,428	2,391	1,567	1,305	23,185	8,889
B4	2021-Spring Light Load	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	12,817	641	4,556	3,645	8,531	465	23	473	7,508	7,421	4,233	2,201	1,599	180	23,592	638
B5	2024-Spring Off-Peak	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	18,652	1,336	5,123	0	17,316	465	23	473	7,508	0	4,233	1,947	1,567	1,306	23,213	9,291
S1	2024-SP High CEC Load	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	29,291	1,336	5,123	2,254	25,701	465	23	473	7,508	3,904	4,233	1,524	1,591	1,300	23,160	9,745
S2	2024-SOP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	18,652	1,336	7,766	3,417	13,899	465	23	473	7,508	7,435	4,233	2,836	1,567	920	23,093	3,983
S3	2021-SP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	26,343	641	7,766	3,417	22,285	465	23	423	7,508	7,435	4,251	2,836	1,571	852	22,646	5,331

Transmission Assumptions

All previously approved transmission projects were modeled in the southern California bulk transmission system assessment in accordance with the general assumptions described in section 2.3.

2.6.2.1 Path Flow Assumptions

The transfers modeled on major paths in the southern California assessment are shown in Table 2.6-2.

Table 2.6-2: Path Flow Assumptions

Path	SOL/Transfer Capability (MW)	2021 SP (MW)	2024 SP (MW)	2029 SP (MW)	2021 LL (MW)	2024 OP (MW)	2024 SP w/High CEC Load (MW)	2024 OP Heavy Ren. (MW)	2024 SP Heavy Ren. (MW)
Path 26 (N-S)	4,000	3,950	3,756	-1,069	180	1,660	3,702	-310	2,391
PDCI (N-S)	3,220	2,500	3,220	3,210	400	1,474	3,220	1,474	2,500
SCIT	17,870	14,129	13,724	13,917	1,963	8,942	14,512	6,907	12,315
Path 46 (WOR)(E-W)	11,200	5,873	6,586	10,645	-133	6,225	6,788	3,340	5,067
Path 49 (EOR)(E-W)	10,100	2,965	3,477	5,245	-2,037	3,670	4,287	636	2,702

2.6.3 Assessment Summary

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

Midway-Whirlwind 500 kV thermal overload

The Midway-Whirlwind 500 kV line was overloaded under a Category P7 condition in the 2021 and 2024 summer peak cases. The loading concern can be addressed in the operations horizon without relying on non-consequential load loss by such operational measures as re-dispatching resources, and RAS. The 30-minute line rating is sufficient to handle the overload, along with the Midway – Vincent RAS.

The southern California bulk system assessment did not identify reliability concerns that require corrective action plans to meet TPL 001-4 requirements.

2.6.4 Request Window Project Submissions

The applicable local area sections below detail the request window submittals the ISO received in the current planning cycle and the results of the ISO evaluation.

2.6.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the southern California bulk transmission system assessment as follows.

- As indicated earlier, projected amounts of up to 2,023 MW of additional energy efficiency (AAEE), and up to 7,083 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 20 percent.
- The existing and planned fast-response demand response amounting 465 MW and energy storage amounting 473 MW were used to mitigate any Category P6 or P7 related thermal overloads.
- Since no reliability issues that require mitigation were identified, incremental preferred resources and storage were not considered in the southern California bulk transmission system assessment.

2.6.6 Recommendation

The southern California bulk system assessment did not identify reliability concerns that require new corrective action plans to meet TPL 001-4 requirements. Loading concerns associated with the Midway-Whirlwind 500 kV line will be addressed in the short term using existing operating procedures.

2.7 SCE Local Areas Assessment

2.7.1 SCE Tehachapi and Big Creek Area

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.

The Tehachapi and Big Creek Corridor area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 2,905 MW in 2029 including the impact of 784 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 73 MW of additional achievable energy efficiency (AAEE).

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

- San Joaquin Cross Valley Loop Transmission Project (completed);
- Tehachapi Renewable Transmission Project (completed);
- East Kern Wind Resource Area 66 kV Reconfiguration Project (completed); and
- Big Creek Corridor Rating Increase Project (in-service date: 2019).

2.7.1.2 Area-Specific Assumptions and System Conditions

The SCE Tehachapi and Big Creek Corridor Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the Tehachapi and Big Creek Corridor area study are provided below.

The SCE Tehachapi and Big Creek Corridor area study included five base and three sensitivity scenarios as shown in Table 2.7-1.

Table 2.7-1 Tehachapi and Big Creek Areas load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2021-Summer Peak	Baseline	2021 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	3,160	20	418	184	2,956	115.3	19.9	0	3,780	3,780	3,541	325	1,183	1,166	1,706	1,396
B2	2024-Summer Peak	Baseline	2024 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	3,231	46	548	241	2,944	115.3	19.9	0	3,780	3,746	3,523	189	1,179	1,166	1,706	1,444
B3	2029-Summer Peak	Baseline	2029 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	2,978	73	784	0	2,905	115.3	19.9	0	4,793	3,712	3,676	365	1,179	1,166	1,706	834
B4	2021-Spring Light Load	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	980	20	491	393	567	115.3	19.9	0	3,780	1,890	3,523	3,281	1,183	1,177	1,672	975
B5	2024-Spring Off-Peak	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	1,543	46	548	0	1,497	115.3	19.9	0	3,780	1,890	3,523	3,240	1,179	1,176	1,706	1,444
S1	2024-SP High CEC Load	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	2,772	46	548	241	2,485	102.7	1.3	0	3,780	1,965	3,523	1,268	1,179	1,076	1,706	1,366
S2	2024-SOP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	2,389	46	868	382	1,961	102.7	1.3	0	3,780	3,743	3,523	2,360	1,179	696	1,706	225
S3	2021-SP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	2,543	20	868	382	2,141	102.7	1.3	0	3,780	3,743	3,541	2,360	1,183	692	1,706	756

Demand-Side Assumptions

The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table above provides the demand-side assumptions used in the Tehachapi and Big Creek Corridor area assessment including the impact of BTM PV and AAEE. The load values include distribution system losses.

Supply-Side Assumptions

The table above provides a summary of the supply-side assumptions modeled in the Tehachapi and Big Creek Corridor Area assessment including conventional and renewable generation, demand response and energy storage. A detailed list of existing generation in the area is included in Appendix A.

Transmission Assumptions

All previously approved transmission projects were modeled in the Tehachapi and Big Creek Corridor Area assessment in accordance with the general assumptions described in section 2.3.

2.7.1.3 Assessment Summary

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

The SCE Tehachapi and Big Creek Corridor area steady state assessment identified several Category P1 and P6 related thermal overloads under contingency conditions. The identified issues can be mitigated in the operations horizon without relying on non-consequential load loss, by such operational measures as reconfiguring the system or re-dispatching resources after the initial or second contingency as discussed in Appendix B. As a result, system additions and upgrades were not identified as needed for the Tehachapi and Big Creek Corridor area.

The stability analysis performed in the Tehachapi and Big Creek Corridor area base case assessment identified no transient issues.

2.7.1.4 Request Window Project Submissions

The ISO did not receive request window submissions for the SCE Tehachapi and Big Creek Corridor Area in this planning cycle.

2.7.1.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the SCE Tehachapi and Big Creek Corridor Area assessment as follows.

- As indicated earlier, projected amounts of up to 73 MW additional energy efficiency (AAEE), and up to 784 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 15 percent.
- The Tehachapi and Big Creek Corridor Area assessment did not identify a need for additional preferred and storage resources in the area.

2.7.1.6 Recommendation

The SCE Tehachapi and Big Creek Corridor area assessment identified several category P6 related thermal overloads. Operating solutions including dispatching existing and planned preferred resources and energy storage under contingency conditions are recommended to address these issues.

2.7.2 SCE North of Lugo Area

2.7.2.1 Area Description

The North of Lugo (NOL) 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 is comprised of 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 Nos. 1&2 230 kV lines. Two 500/230 kV transformer banks at the Lugo substation provide access to SCE's main system. The NOL area can be divided into the following sub-areas: north of Control; Kramer/North of Kramer/Cool Water; and Victor specifically.

2.7.2.2 Assumptions and System Conditions

The North of Lugo area steady state and transient stability assessment was performed consistently with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the North of Lugo area study are provided Table 2.7-2.

Table 2.7-2 North of Lugo Area load and generation assumptions

S. No.	Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2021-Summer Peak	Baseline	2021 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,187	10	641	282	895	60.0	1.3	0	878	791	0	0	74	54	1,738	1,238
B2	2024-Summer Peak	Baseline	2024 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,284	24	839	369	891	60.0	1.3	0	878	791	0	0	74	54	1,738	1,238
B3	2029-Summer Peak	Baseline	2029 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	918	40	1,204	0	878	60.0	1.3	0	1202	1,115	0	0	74	54	1,738	1,238
B4	2021-Spring Light Load	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	923	10	769	615	298	60.0	1.3	0	878	791	0	0	74	54	1,738	1,238
B5	2024-Spring Off-Peak	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	639	24	839	0	615	60.0	1.3	0	878	791	0	0	74	54	1,738	1,238
S1	2024-SP High CEC Load	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	1,343	24	839	369	950	60.0	1.3	0	878	456	0	0	74	28	1,738	525
S2	2024-SOP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	639	24	1,327	584	31	60.0	1.3	0	878	869	0	0	74	28	1,738	265
S3	2021-SP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	1,187	10	1,327	584	593	60.0	1.3	0	878	869	0	0	74	8	1,738	394

All previously approved transmission projects were modeled in the North of Lugo area assessment in accordance with the general assumptions described in section 2.3. The following previously approved transmission upgrades were modeled in the 2021, 2024 and 2029 study cases:

- Victor Loop-in Project: Loop in the existing Kramer-Lugo Nos. 1&2 230 kV lines into Victor Substation.
- Kramer Reactor Project: Install two 23 Mvar reactors to the 12 kV tertiary winding of the existing 230/115 kV Nos. 1&2 transformers and one 45var shunt reactor at the Kramer 230 kV bus.

2.7.2.3 Assessment Summary

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

The 2019-2020 reliability assessment of the North of Lugo area has identified several thermal overloads and low voltages issues under Category P2, P5, and P6 contingencies. All of those issues can be mitigated in the operation horizon by relying upon the existing operating procedure or utilizing congestion management. Appendix B has a detailed discussion.

The transient stability assessment identified a voltage recovery and voltage dip violation following a Category P6 and P7 contingency. The ISO recommends relying on existing RAS, and redispatching generation after the first contingency.

2.7.2.4 Request Window Project Submissions

The ISO did not receive request window submissions for the North of Lugo Area in this planning cycle.

2.7.2.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the North of Lugo area assessment as follows.

- Projected amounts of up to 40 MW additional achievable energy efficiency (AAEE), and up to 1,204 MW of distributed generation were used to avoid potential reliability issues by reducing area load.
- The existing and planned fast-response demand response amounting to 60 MW was identified and available in the base and sensitivity cases, but did not need to be activated to address any local transmission concerns in this analysis.
- The NOL Area assessment did not identify a need for additional preferred and storage resources in the area.

2.7.2.6 Recommendation

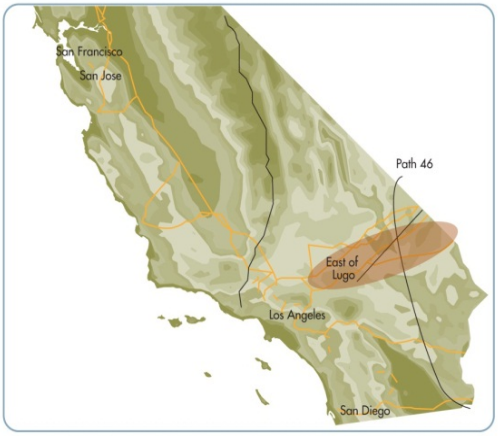
The North of Lugo area assessment identified several category P6 related thermal overloads and low voltage issues. Operating solutions, including relying upon existing operating procedures, existing RAS, and congestion management are recommended to address the issues.

The assessment also identified one transient voltage recovery and voltage dip violation for a category P6 contingency with existing HDPP and Mohave Desert RAS schemes. The ISO recommends relying on generation redispatch after the first contingency, and RAS.

2.7.3 SCE East of Lugo Area

2.7.3.1 Area Description

The East of Lugo (EOL) area consists of the transmission system between the Lugo and Eldorado substations. The EOL 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 Harry Allen-Eldorado 500 kV line was approved by the ISO Board of Governors in 2014, is expected to be operational in 2020, and will be part of the EOL system.



The existing EOL 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 Area-Specific Assumptions and System Conditions

The East of Lugo area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the East of Lugo area study are provided in Table 2.7-3.

Table 2.7-3 East of Lugo Area load and generation assumptions

S. No.	Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV Installed (MW)	BTM-PV Output (MW)	Net Load (MW)	Demand Response Fast (MW)	Demand Response Slow (MW)	Battery Storage (MW)	Solar Installed (MW)	Solar Dispatch (MW)	Wind Installed (MW)	Wind Dispatch (MW)	Hydro Installed (MW)	Hydro Dispatch (MW)	Thermal Installed (MW)	Thermal Dispatch (MW)
B1	2021-Summer Peak	Baseline	2021 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	3.44	0	0	0	3.44	0	0	0	1254	702	0	0	0	0	525	419
B2	2024-Summer Peak	Baseline	2024 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	3.59	0	0	0	3.59	0	0	0	1254	652	0	0	0	0	525	419
B3	2029-Summer Peak	Baseline	2029 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	3.20	0	0	0	3.20	0	0	0	1254	0	0	0	0	0	525	418
B4	2021-Spring Light Load	Baseline	2021 spring off-peak load conditions. Off-peak load time – weekend morning.	1.47	0	0	0	1.47	0	0	0	1254	1241	0	0	0	0	525	0
B5	2024-Spring Off-Peak	Baseline	2024 spring off-peak load conditions. Off-peak load time – weekend morning.	2.29	0	0	0	2.29	0	0	0	1254	0	0	0	0	0	525	419
S1	2024-SP High CEC Load	Sensitivity	2024 summer peak load conditions with hi-CEC load forecast sensitivity	3.80	0	0	0	3.80	0	0	0	1254	652	0	0	0	0	525	419
S2	2024-SOP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2024 summer peak load conditions with hi renewable dispatch sensitivity	2.29	0	0	0	2.29	0	0	0	1254	1241	0	0	0	0	525	0
S3	2021-SP Heavy Renewable Output & Min. Gas Gen.	Sensitivity	2021 summer peak load conditions with hi renewable dispatch sensitivity	3.44	0	0	0	3.44	0	0	0	1254	1241	0	0	0	0	525	0

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3. The transmission upgrade modeled in the 2021 study cases are:

- Harry Allen-Eldorado 500 kV transmission line

The transmission upgrades modeled in the 2024 and 2029 study cases are:

- Eldorado-Lugo 500 kV series capacitor and terminal equipment upgrade
- Lugo-Mohave 500 kV series capacitor and terminal equipment upgrade
- New Calcite 230 kV Substation and loop into Lugo-Pisgah #1 230 kV line
- Lugo-Victorville 500 kV terminal equipment upgrade and remove ground clearance limitations

2.7.3.3 Assessment Summary

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

The SCE East of Lugo area steady state assessment identified one Category P6 system divergence issue in all cases. The system divergence issue could be mitigated by an existing protection scheme. The stability analysis performed in the EOL Area assessment did not identify transient issues that require mitigation.

As a result, system additions and upgrades are not identified for the East of Lugo area.

2.7.3.4 Request Window Project Submissions

The ISO did not receive request window submissions for the SCE East of Lugo area in this planning cycle.

2.7.3.5 Consideration of Preferred Resources and Energy Storage

The SCE East of Lugo area is comprised of high voltage transmission lines and generation facilities with limited customer load, so the assessment did not identify a need for preferred resources and energy storage in the area.

2.7.3.6 Recommendation

The SCE East of Lugo area assessment identified one potential system divergence issue for a Category P6 outage which would be mitigated by an existing protection scheme.

2.7.4 SCE Eastern Area

2.7.4.1 Area Description

The ISO controlled grid in the SCE Eastern Area serves the portion of Riverside County around 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 Vista Substation to Devers Substation and continues on to Palo Verde Substation in Arizona. The area has ties to Salt River Project (SRP), the Imperial Irrigation District (IID), Metropolitan Water District (MWD), and the Western Area Lower Colorado control area (WALC).

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

- West of Devers Upgrade Project (2021) and
- Delaney-Colorado River 500 kV line Project (2021).

2.7.4.2 Area-Specific Assumptions and System Conditions

The SCE Eastern Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The load values include distribution system losses. The spring light load and spring off-peak cases assume approximately 34 percent and 68 percent of the net peak load respectively. Specific assumptions related to study scenarios, load, resources and transmission that were applied to the Eastern area study are shown in Table 2.7-4.

Table 2.7-4 Eastern Area load and generation assumptions

Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response		Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Output (MW)		Fast	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
2021 Summer Peak	Baseline	2021 summer peak load conditions on 9/7/2021 at hour 16	4,938	101	827	364	4,473	52	17	0	1527	855	710	441	0	0	3,771	3,141
2024 Summer Peak	Baseline	2024 summer peak load conditions on 9/3/2024 at hour 16	5,196	228	1,087	478	4,489	52	17	0	1527	794	710	256	0	0	3,771	2,665
2029 Summer Peak	Baseline	2029 summer peak load conditions on 9/4/2029 at hour 19	4,800	347	1,439	0	4,453	52	17	0	1527	0	710	384	0	0	3,771	3,373
2021 Light Load	Baseline	2021 spring off peak load conditions on 4/4/2021 at hour 12	2,397	101	827	776	1,520	52	17	0	1527	1512	710	369	0	0	3,771	91
2024 Off Peak	Baseline	2024 spring off peak load conditions on 5/3/2024 at hour 20	3,296	228	1,087	0	3,068	52	17	0	1527	0	710	327	0	0	3,771	3,373
2024 Peak High CEC Load	Sensitivity	2024 summer peak load conditions with high CEC Load	5,489	228	1,087	478	4,782	63	6	0	1527	794	710	256	0	0	3,771	3,343
2024 Off Peak HR	Sensitivity	2024 spring off peak load conditions with high renewable dispatch	3,296	228	1,087	753	2,315	63	6	0	1527	1512	710	476	0	0	3,771	834
2021 Peak HR	Sensitivity	2021 summer peak load conditions with high renewable dispatch	4,938	101	827	753	4,084	63	6	0	1527	1512	710	476	0	0	3,771	1,687

Transmission Assumptions

All previously approved transmission projects were modeled in the Eastern Area assessment in accordance with the general assumptions described in section 2.3.

2.7.4.3 Assessment Summary

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

The SCE Eastern area steady state assessment identified several Category P1 and P6 contingency-related thermal overloads. The issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as curtailing generation before the contingency or reconfiguring the system after the initial or second contingency as discussed in Appendix B. The stability analysis performed in the Eastern Area assessment did not identify transient issues that require mitigation.

As a result, system additions and upgrades are not identified for the Eastern area.

2.7.4.4 Request Window Project Submissions

The ISO received a number of request window submissions for the SCE Eastern Area in this planning cycle. Below is a description of each proposal followed by ISO comments and findings.

Red Bluff-Mira Loma 500 kV Transmission Project

The project was submitted by NextEra Energy Transmission West LLC and involves construction of a new 139-mile 500 kV transmission line between Red Bluff 500 kV substation and Mira Loma 500 kV substation. The project has an estimated cost of $850 million and expected in-service date of December 1, 2024.

The need for this project was assessed as part of the 2016-17, 2017-18, and 2018-19 ISO transmission planning cycle and was not found to be needed. The project has also not been found to be needed for reliability reasons in this planning cycle. There was no overloading found in the Colorado River corridor under N-1 or N-2 contingencies after tripping generators by the Colorado River Corridor and Devers RAS. The project was also submitted as an economic study request as set out in chapter 4.

2.7.4.5 Consideration of Preferred Resources and Energy Storage

No additional grid-connected preferred resources or storage was modeled in the SCE Eastern Area, and the assessment did not identify a need for additional preferred and storage resources in the area.

2.7.4.6 Recommendation

The SCE Eastern area assessment identified several category P1 and P6 related thermal overloads. Operating solutions including curtailing generation before the contingency or reconfiguring the system after the initial or second contingency are recommended to address the issues.

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 Los Angeles, Orange, Ventura counties and surrounding areas. The points of interconnections with the external system include Vincent, Mira Loma, Rancho Vista and Valley 500 kV Substations and Sylmar, San Onofre and Pardee 230 kV Substations. The bulk of SCE load as well as most southern California coastal generation is located in the SCE Metro area.

The Metro area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 17,866 MW in 2029 including the impact of 4,229 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 1,252 MW of additional achievable energy efficiency (AAEE).

The area will have approximately 4,600 MW of grid-connected generation in 2021 after the assumed retirement of 5,160 MW of generation at the end of 2020 to comply with the state's policy regarding once-through-cooled (OTC) generation. The California Public Utilities Commission (CPUC) has approved a total of 1,824 MW of conventional generation and preferred resources for the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the OTC generating plants. The CPUC is also reviewing applications by SCE for a total of 195 MW/780 MWh of energy storage projects that are needed to meet local capacity requirements in the Santa Clara area.

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

- Mesa 500 kV Substation (March 2022);
- Laguna Bell Corridor Upgrade (December 2020);
- Method of Service for Alberhill 500/115 kV Substation (September 2022);
- Method of Service for Wildlife 230/66 kV Substation (September 2024); and
- Moorpark-Pardee No. 4 230 kV Circuit Project (December 2020).

2.7.5.2 Area-Specific Assumptions and System Conditions

The SCE Metro Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for the various scenarios used for the SCE Metro Area assessment are provided in Table 2.7-5.

Table 2.7-5: Metro Area load and generation assumptions

Scenario No.	Base Case	Gross Load (MW)	AAEE (MW)	BTM-PV Installed (MW)	BTM-PV Output (MW)	Net Load (MW)	Demand Response (installed) Fast (MW)	Demand Response (installed) Slow (MW)	Battery Storage (Installed) (MW)	Solar (Grid Connected) Installed (MW)	Solar (Grid Connected) Dispatch (MW)	Wind Installed (MW)	Wind Dispatch (MW)	Hydro Installed (MW)	Hydro Dispatch (MW)	Thermal NQC (MW)	Thermal Dispatch (MW)
B1	2021 Summer Peak	19,220	334	2,249	974	17,911	266	376	423	225	126	0	0	0	0	4,616	3,781
B2	2024 Summer Peak	20,295	777	3,160	1,375	18,144	271	376	473	225	117	0	0	0	0	4,616	4,095
B3-1	2029 Summer Peak	19,117	1,252	4,299	0	17,866	271	376	473	225	0	0	0	0	0	4,231	3,891
B3-2	2029 CAISO Summer Pea	19,044	1,515	4,299	0	17,529	271	376	473	225	0	0	0	0	0	4,231	3,978
B4	2021 Spring Light Load	8,212	110	2,249	2,191	5,911	266	376	423	225	223	0	0	0	0	4,616	336
B5	2024 Spring Off-Peak	13,055	536	3,160	0	12,519	271	376	473	225	0	0	0	0	0	4,616	4,047
S1	2024 SP High CEC Load	21,484	777	3,160	1,375	19,332	271	376	473	225	117	0	0	0	0	4,616	4,371
S2	2024 SOP Heavy Renewable Output & Min. Gas Gen.	13,055	536	3,160	2,014	10,504	271	376	473	225	223	0	0	0	0	4,616	3,080
S3	2021 SP Heavy Renewable Output & Min. Gas Gen.	19,220	334	2,249	2,014	16,871	266	376	423	225	223	0	0	0	0	4,616	3,119

Transmission Assumptions

All previously approved transmission projects were modeled in the Metro Area assessment in accordance with the general assumptions described in section 2.3.

2.7.5.3 Assessment Summary

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

The SCE Metro area steady state assessment identified several thermal overloads under various category P1-P7 contingency conditions. Most of the issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as reconfiguring the system or re-dispatching resources before or after the contingency as discussed in Appendix B. The following thermal overload issue was found to require mitigation.

Thermal overload on Sylmar–Pardee No. 1 and No. 2 lines

The Sylmar-Pardee No. 1 and No. 2 lines were severely overloaded under P1, P3 and P6 contingency conditions in the 2029 summer peak cases. The lines were overloaded under Category P1 conditions in the 2029 CAISO Summer Peak case that represents the ISO-wide peak system condition, which is forecast to occur in September during the hour-ending 20, under which the system was stressed due to unavailability of solar generation throughout the ISO system combined with the retirement of a substantial amount of nuclear and gas-fired generation. The category P1 overload was also observed in a 2025 CAISO summer peak sensitivity case representing similar system conditions that was developed for the purpose of determining the timing of the need. Existing and planned preferred resources were not found to be sufficient to mitigate the overload.

2.7.5.4 Request Window Project Submissions

The ISO has received the following request window submittals for the SCE Metro Area in this planning cycle.

Pardee-Sylmar No. 1 and No. 2 230 kV Line Rating Increase Project

The project involves replacing circuit breakers and other terminal equipment at Pardee and Sylmar Substations to increase the rating of the lines to match the rating of the line conductors (2B-1590 ACSR). SCE will replace four (4) 3000A circuit breakers and other terminal equipment at Pardee Substation. LADWP will replace six (6) 3000A circuit breakers and other terminal equipment at Sylmar Substation. The project will increase the normal and emergency ratings of the lines by 8% and 45%, respectively. The total cost of the project is estimated at $15.36 million. SCE's estimate for its portion of the work is $2.76 million based on the unit cost guide. LADWP's estimate for its portion of the work is $12.6 million based on a similar project. The proposed in-service date is May 1, 2025 based on the timing of the identified reliability need.

Pacific Transmission Expansion (PTE) Project

The proposed PTE Project is a 237 mile HVDC transmission line that connects northern and southern California via submarine cables to be located in the Pacific Ocean off the coast of California. The project, as proposed, will have one northern point of interconnection in the PG&E area and three points of interconnection in the SCE area for its southern terminals. The proposed project includes four Voltage Source Converter (VSC) stations as follows:

- one 2,000 MW, 500 kV DC/500 kV AC converter station located at the northern terminus of the project at Diablo Canyon 500 kV switchyard,
- one 500 MW, 500 kV DC/220 kV AC converter station connected to SCE Goleta substation via a 3 mile underground AC cable,
- one 1,000 MW, 500 kV DC/220 kV AC converter station connected at Redondo Beach, and
- one 500 MW, 500 kV DC/220 kV AC converter station connected at Huntington Beach.

The project will have a total transfer capacity of 2,000 MW from the PG&E area into the SCE area or vice versa. The PTE has an estimated cost of $1.85 billion and a proposed in service date of December 2026.

ISO Assessment of Request Window Proposals

Pardee-Sylmar No. 1 and No. 2 230 kV Line Rating Increase Project

Table 2.7-6 provides the loading on the Pardee–Sylmar 230 kV lines before and after the line rating increase. The project mitigates the category P1 and P3 overloads and considerably reduces the category P6 overloads. The remaining Category P6 overloads can then be mitigated by dispatching demand response and existing and planned energy storage resources.

Table 2.7-6: Pre and post-project Pardee–Sylmar 230 kV line loadings

Worst Contingencies	Category	Pre-Project Loading (%)			Post-Project Loading (%)		
		CAISO 2025 Summer Peak	2029 Summer Peak	CAISO 2029 Summer Peak	CAISO 2025 Summer Peak	2029 Summer Peak	CAISO 2029 Summer Peak
One Pardee - Sylmar 230 kV	P1	**118**	97	**129**	81	67	89
Pastoria Block 1 and one Pardee - Sylmar 230 kV line	P3	**133**	**109**	**142**	92	78	99
Victorville - Lugo 500 kV & One Pardee - Sylmar 230 kV line	P6	**158**	**123**	**170**	**109** (89)[1]	86	**117** (100)[1]

Note: (1) Values in parenthesis indicate loading after dispatching existing and planned preferred resources and energy storage

Since the Pardee-Sylmar 230 kV lines are the limiting elements that establish local capacity requirement for Big Creek–Ventura area, the project was also evaluated as part of the Big Creek–Ventura area LCR reduction study. The results of the study show that the project reduces LCR by 837 MW[101]. The economic evaluation for the project that is presented in chapter 4 indicates a net present value (NPV) for the project of $185 million–$252 million and a benefit-cost ratio of 10.3–13.6. The economic analysis also included evaluation of advancing the project by two years based on the achievable in-service date of May 2023. The results show an NPV of $23.4–$31.9 million in favor of advancing the project.

Pacific Transmission Expansion (PTE) Project

The project's effectiveness in addressing the Pardee-Sylmar 230 kV overload was evaluated. The project will not alleviate the loading concerns identified in the 2025 summer peak case because it will not be in service until 2026. Table 2.7-7 provides the loading results before and after the PTE Project based on the CAISO 2029 Summer Peak case. The analysis is performed based on two scenarios regarding transfers on the PTE. In one scenario the PTE was modeled with a 2000 MW transfer from north to south and in the other with a 500 MW transfer from the north to the terminal connecting to the Goleta Substation. In both scenarios, the reduction on the post-contingency loading on the Pardee–Sylmar lines is less than that achieved with Pardee-Sylmar 230 kV Line Rating Increase Project.

Table 2.7-7: Pre and post-project Pardee–Sylmar 230 kV line loadings

Worst Contingencies	Category			Post-Project Loading (%)		
		CAISO 2025 Summer Peak	CAISO 2029 Summer Peak	CAISO 2025 Summer Peak (PTE not in service)	CAISO 2029 Summer Peak (PTE-2000 MW N→S)	CAISO 2029 Summer Peak (PTE-500 MW N→S)
One Pardee - Sylmar 230 kV	P1	**118**	**129**	**118**	**115%**	**109**
Pastoria Block 1 and one Pardee - Sylmar 230 kV line	P3	**133**	**142**	**133**	**129%**	**120%**
Victorville - Lugo 500 kV & One Pardee - Sylmar 230 kV line	P6	**158**	**170**	**158**	**156%**	**147%**

[101] The LCR reduction study was performed as an extension to the 2018-2019 Transmission Plan. The 2028 summer peak LCR study case from last year, which reflects different load forecast, generation and transmission assumptions compared to the study cases used in the current reliability assessment, was employed to determine the reduction in LCR. While the Sylmar-Pardee project is expected to have similar LCR reduction benefits, the Big-Creek Ventura area LCR is subject to change in the future depending on the prevailing load forecast, generation and transmission assumptions.

2.7.5.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and energy storage were considered in the SCE Metro Area assessment as follows.

- As indicated earlier, projected amounts of up to 1,515 MW of additional energy efficiency (AAEE), and up to 4,299 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 11 percent.
- Up to 271 MW of the existing and planned fast-response demand response and up to 473 MW of existing energy storage were used in the base or sensitivity cases to mitigate thermal overloads and low voltage concerns.
- 195 MW of energy storage is being procured in the Santa Clara area to address local capacity need. The resources were also utilized to address the P6 related overload on Pardee–Sylmar line.

2.7.5.6 Recommendation

The SCE Metro area assessment identified several thermal overloads under contingency conditions. Operating solutions, such as reconfiguring the system or re-dispatching resources before or after the contingency conditions as described in more detail in Appendix B, are recommended to address most of the issues identified.

The Pardee-Sylmar No. 1 and No. 2 230 kV Line Rating Increase Project that was proposed by SCE is recommended for approval to address overload on the lines under category P1, P3 and P6 conditions. The project also reduces the Big Creek–Ventura area LCR by 837 MW which, along with production cost savings, results in a benefit-cost ratio (BCR) of 10.3–13.6. The recommended in service date for the project is May 2023.

The effectiveness of the proposed Pacific Transmission Expansion (PTE) Project in addressing the overload on the Pardee–Sylmar lines was also evaluated. The results indicate that the project is less effective in addressing the loading concern than the Pardee-Sylmar 230 kV Rating Increase Project. The economic evaluation of the PTE is presented in chapter 4.

2.8 Valley Electric Association Area

2.8.1 Area Description

The Valley Electric Association (VEA) transmission system is comprised of 230 kV and 138 kV facilities under ISO control. GridLiance West, LLC (GLW) is the Transmission Owner for the 230 kV facilities in the VEA area. All the distribution load in the VEA area is supplied from the 138 kV system which is mainly supplied through 230/138 kV transformers at Innovation, Pahrump and WAPA's Amargosa substations. The Pahrump and Innovation 230 kV substations are connected to the SCE's Eldorado, NV Energy's Northwest and WAPA's Mead 230 kV substations through three 230 kV lines.

The VEA system is electrically connected to neighboring balancing area systems 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 – Sloan Canyon 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 steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the VEA area study are provided in Table 2.8-1.

Table 2.8-1: VEA Area load and generation assumptions

Scenario No.	Study Case	Gross Load (MW)	AAEE (MW)	BTM-PV		PLOAD	Net Load (MW)	Demand Response		Installed Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Output (MW)			Fast (MW)	Slow (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2021 Summer Peak	176	0	0	0	176	176	0	0	0	118.4	61.4	0	0	0	0	0	0
B2	2024 Summer Peak	185	0	0	0	185	185	0	0	0	118	66	0	0	0	0	0	0
B3	2029 Summer Peak	199	0	0	0	199	199	0	0	0	820	702	0	0	0	0	0	0
B4	2021 Spring light load	59	0	0	0	59	59	0	0	0	118	117	0	0	0	0	0	0
B5	2024 Spring Off-Peak	128	0	0	0	128	128	0	0	0	118	0	0	0	0	0	0	0
S1	2021 Summer Peak with high forecasted load	181	0	0	0	181	181	0	0	0	118	61	0	0	0	0	0	0
S2	2024 Summer Peak with high forecasted load	207	0	0	0	207	207	0	0	0	118	66	0	0	0	0	0	0
S3	2024 Off-Peak with heavy renewable output	128	0	0	0	128	128	0	0	0	820	811	0	0	0	0	0	0

All previously approved transmission projects were modeled in the Valley Electric Association area assessment in accordance with the general assumptions described in section 2.3. The transmission upgrades modeled in the 2021, 2024, and 2029 study cases are:

- New Sloan Canyon (previously named Bob) 230 kV switching station that loops into the existing Pahrump-Mead 230kV Line
- New Eldorado-Sloan Canyon 230kV transmission line

The transmission upgrade only modeled in the 2023 and 2028 study cases is:

- Sloan Canyon-Mead 230kV line reconductoring

The transmission upgrade on hold and not being modeld in this TPP cycle is:

- New Charleston-Gamebird 138 kV transmission line

2.8.3 Assessment Summary

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

Amargosa 230/138 kV Transformer Overload and 138 kV Low Voltage Issues Mitigation

The VEA area steady state assessment identified thermal overloads on the Amargosa 230/138 kV transformer and low voltage issues at 138 kV buses following multiple Category P1, P4, P6 and P7 contingencies under various base and sensitivity scenarios. Several alternatives were submitted through the Request Window Submission process to address the issue. Load growth in the VEA area was found to be the primary driver behind this reliability issue. It was discovered that upgrading VEA's existing 138 kV Gamebird substation by adding a new 230/138 kV transformer and looping GLW's Pahrump – Sloan Canyon 230 kV line into the upgraded Gamebird substation would mitigate the Amargosa transformer overloads and low voltage issues.

Pahrump Transformer Overloads

The assessment identified thermal overloads on each of the Pahrump 230/138kV transformer banks following a Category P1 contingency of the other Pahrump transformer under 2029 Summer peak scenario and a Category P6 contingency of the other Pahrump bank and Vista – Johnnie – Valley Tap 138 kV line under the 2029 base and 2024 high renewables sensitivity scenarios. The Gamebird 230/138 kV transformer upgrade discussed above would address these overloads.

Jackass Flats – Mercury Switch Overloads

The assessment identified thermal overloads on Jackass Flats – Mercury Switch 138 kV line following several P1, P4 and P7 contingencies under 2029 Summer peak scenario and 2021 spring off-peak scenario. Congestion management, RAS identified through GIDAP studies to trip generation and a line upgrades being explored through GIDAP studies will mitigate this reliability issue.

In addition to the Amargosa transformer overloads, Pahrump transformer overloads and Jackass Flats – Mercury Switch 138 kV line overloads the assessment identified several Category P1, P4 and P6 related thermal overloads under the 2024 high renewable sensitivity scenario which could be mitigated by previously identified generation-tripping RASs or congestion management.

The stability analysis performed in the VEA area assessment did not identify any transient issues that require mitigation.

2.8.4 Request Window Project Submissions

The ISO received four request window submissions for the Valley Electric Association area in this planning cycle. Below is a description of each submission followed by ISO comments and findings.

Gamebird 230/138 kV Transformer Project

The project was submitted by GridLiance West, LLC (GLW). The scope of the project includes upgrading VEA's existing 138 kV Gamebird substation by adding a new 230/138 kV transformer and looping GLW's Pahrump – Sloan Canyon 230 kV line into the upgraded Gamebird substation. GLW provided a cost estimate of $4.9 million and the expected in-service date of May 01, 2021.

The proposed project would mitigate the Amargosa bank overloads, 138 kV low voltage issues and Pahrump 230/138 kV bank overloads described in Appendix B.

The following mitigation alternatives were considered as part of the request window evaluation:

- A new Charleston – Vista 138 kV line

  The ISO estimated the cost of this project to be approximately $23 million. This upgrade alternative would not mitigate the Pahrump 230/138 kV transformer overloads observed under P1 contingency conditions as described in Appendix B.

- Amargosa 230/138 kV transformer upgrade

  The ISO estimated the cost of this project to be approximately $5 million. This upgrade poses a challenge because it is not an ISO-controlled facility. This upgrade alternative would not mitigate the Pahrump 230/138 kV transformer overloads observed under P1 contingency conditions as described in Appendix B.

- Carpenter Canyon – Charleston 230 kV project

  This alternative was submitted through the request window with an estimated cost of approximately $35 million. This upgrade alternative would not mitigate the Amargosa 230/138 kV bank overloads and 138 kV low voltage issues observed in 2021 due to its dependence on the Carpenter Canyon 230 kV substation proposed in GIDAP. This alternative would not mitigate the Pahrump 230/138 kV transformer overloads observed under P1 contingency conditions as described in Appendix B.

- Energy storage at Sandy 138 kV substation

  The ISO estimated that a minimum of 10 MW energy storage would be required to address the thermal overload issues. With an assumption of 0.95 power factor the 10 MW energy storage device would not mitigate the 138 kV low voltage issues described in Appendix B. Thermal relief provided by the 10 MW energy storage would be unlikely to be adequate beyond 2030 requiring a new mitigation in future planning cycles. This is a significant concern because VEA is the area with the highest load growth in CAISO. The ISO estimated the cost of this upgrade alternative to be approximately $10 million.

Evaluation of the aforementioned alternatives demonstrates that the Gamebird 230/138 kV Transformer project is the most cost effective solution amongst all the alternative mitigations submitted through the Request Window and considered by the ISO. Therefore, the ISO has determined that the Gamebird 230/138 kV Transformer project is needed.

Gamebird 230/138 kV Substation Project

This project was submitted by Horizon West Transmission, LLC (Horizon West). The scope of the project includes building a new Gamebird 230 kV substation in the vicinity of the existing 138 kV Gamebird substation, adding a new 230/138 kV transformer, a connection to the existing 138 kV Gamebird substation, and looping GLW's existing Pahrump – Sloan Canyon 230 kV line into the new Gamebird 230 kV substation. Horizon West provided a cost estimate of $28 million and the expected in-service date of December 2024.

The proposed project would not be able to mitigate thermal overloads observed on the Amargosa transformer bank in the 2021 scenario. Furthermore, the Gamebird 230/138 kV Transformer Project submitted by GLW is an upgrade to the existing Gamebird substation owned by VEA, an incumbent transmission owner. VEA is the incumbent Participating Transmission Owner, so the project would be assigned to VEA. The potential for VEA to agree to GLW to own and construct the project based on a preexisting agreement between those two parties does not alter the Tariff requirement for the CAISO to assign the project to VEA. The upgraded substation would remain an integrated facility operating as a single substation. The looping in and out of the existing 230 kV transmission line is a modification to GLW-owned facilities and would be assigned directly to GLW. The ISO's understanding is that the land for the expansion is already part of the existing site, notwithstanding the need to expand the existing fence line.

The Gamebird 230 kV Substation Project proposed by Horizon West is a new substation, located in the vicinity of the existing substation. The ISO has not identified the need for and benefits of a separate facility that surpasses the efficiency of an integrated upgraded substation operating as an integrated facility. Therefore, project was not found to be needed.

Pahrump – Sloan Canyon 230 kV Line Rebuild Project

The project was submitted by GridLiance West, LLC (GLW). The scope of the project includes rebuilding the Pahrump – Sloan Canyon 230 kV line and replacing terminal equipment at Pahrump as necessary. GLW provided a cost estimate of $96.4 million and the expected in-service date of January 01, 2023.

While the proposed project adds transmission capacity to the GLW system it would not effectively address all the NERC reliability issues described in Appendix B. The project would mitigate several thermal overloads caused by the future renewable generation modeled in the 2024 sensitivity studies and in the 2029 scenario; all of these thermal overloads can be mitigated by relying on previously identified RASs to trip appropriate generation. Therefore, the project was not found to be needed.

Carpenter Canyon (Gamebird) – Charleston 230 kV Transmission System Project

The project was submitted by Horizon West Transmission, LLC (Horizon West). The scope of the project includes connecting a proposed Carpenter Canyon (Gamebird) 230 kV substation with Charleston 138 kV substation via a 230 kV line and subsequent 230/138 kV transformation. Horizon West provided a cost estimate of $35 million and the expected in-service date of December, 2024.

The proposed project would not be able to mitigate thermal overloads observed on Amargosa transformer bank in the 2021 scenario because it relies on the proposed Carpenter Canyon (Gamebird) 230 kV substation which is proposed through GIDAP. The proposed project can mitigate Amargosa transformer bank overloads in the 2029 scenario but will not be able to mitigate Pahrump transformer bank overloads. The Gamebird 230/138 kV Transformer Project was found to be a more effective mitigation for the NERC reliability issues observed in this study area. Therefore, the Carpenter Canyon (Gamebird) – Charleston 230 kV Transmission System Project was not found to be needed.

Hafen Ranch and Blagg 138-24.9 kV Substations Project

The project was submitted by VEA. The scope of the project includes a new Hafen Ranch substation which will be looped into the existing Thousandaire – Gamebird 138 kV line and a new Blagg substation which will be looped into the existing Thousandaire – Charleston 138 kV line. VEA provided a cost estimate of $10.5 million for the Hafen Ranch substation and $10 million for the Blagg substation. The expected in-service date is December 01, 2024.

New residential and commercial construction is forecasted to increase local power demand, especially in VEA's Pahrump and Thousandaire areas. This new demand cannot be served from existing distribution substation capacity without causing overloads and under-voltages on distribution facilities. VEA's Distribution Long Term Plan identified these two new distribution substations as required to meet distribution reliability standards. The ISO concurs with the Hafen Ranch and Blagg 138-24.9 kV Substation interconnections.

2.8.5 Consideration of Preferred Resources and Energy Storage

The VEA area assessment did not identify a need for additional preferred and storage resources in the area.

2.8.6 Recommendation

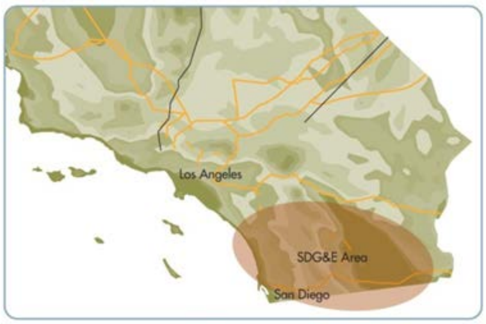
The VEA area assessment identified several thermal overloads and low voltage issues under both base and sensitivity scenarios for Category P1, P4, P6 and P7 contingencies as described in Appendix B. In addition to relying on existing and proposed RASs and operating procedures, the ISO recommends approval of the following reliability project in order to address reliability concerns observed in the VEA area:

- Gamebird 230/138 kV Transformer Upgrade Project

2.9 SDG&E Area

2.9.1 San Diego Local Area Description

SDG&E is a regulated public utility that provides energy service to 3.6 million consumers through 1.4 million electric meters and more than 873,000 natural gas meters in San Diego and southern Orange counties. The utility's service area spans 4,100 square miles from Orange County to the US-Mexico border, covering 25 communities.



The SDG&E system, includes its main 500/230 kV and 138/69 kV sub-transmission systems. The geographical location of the area is shown in the adjacent illustration. Its 500 kV system consists of the Southwest Powerlink (SWPL) and Sunrise Powerlink (SRPL) systems. The 230 kV transmission lines form an outer loop located along the Pacific coast and around downtown San Diego with an underlying 138 kV and 69 kV sub-transmission system. Rural customers in the eastern part of San Diego County are served by a sparse 69 kV system.

The ISO approved various transmission projects presented in chapter 8 for this area in previous planning cycles, which will maintain the area reliability and deliverability of resources while meeting policy requirement in the near future. Some of the major system additions are the Sycamore-Penasquitos 230 kV line, the 2nd Miguel-Bay Boulevard 230 kV line, the synchronous condensers at SONGS and San Luis Rey, the Southern Orange County Reliability Enforcement (SOCRE), the phase shifting transformers at Imperial Valley, and the Suncrest SVC (static VAR compensator) facility, and enhancements of existing remedial action schemes (RAS).

The interface of San Diego import transmission (SDIT) consists of SWPL, SRPL, the south of San Onofre (SONGS) transmission path, and the Otay Mesa-Tijuana 230 kV transmission tie with CENACE. The San Diego area relies on internal generation and import through SDIT to serve electricity customers. The area has a forecasted 1-in-10 peak sales load of 4,923 MW in 2029 after incorporating a load reduction of 322 MW of additional achievable energy efficiency (AAEE) and 0 MW of forecast behind-the-meter photovoltaic (BTM PV) generation production as the San Diego peak hour has shifted to HE19:00.

The area is forecast to have approximately 6,187 MW of grid-connected generation by the year 2029, including a total of 2,457 MW renewable generation and 206 MW energy storage resources. A total of 840 MW of conventional generation was recently constructed in the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the Encina generating plants.

2.9.2 Area-Specific Assumptions and System Conditions

The steady state and transient stability assessments on the SDG&E main and sub-transmission systems were performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the five base cases, stability model data and contingencies that were used in the assessments. In addition, specific assumptions on load of demand-side and resources of supply-side in the baseline and sensitivity scenarios are provided below and in Table 2.9-1.

Demand-Side Assumptions

The summer peak cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table below provides the load forecast assumptions including load reduction impact of BTM PV and AAEE on demand side. The load forecast provided by CEC are net demand values including load reduction and system losses. The summer light load and spring off-peak cases assume approximately 27 percent and 69 percent of the net peak load, respectively.

Supply-Side Assumptions

The table below also provides a summary of the supply-side assumptions modeled in the SDG&E main and sub-transmission systems assessments including conventional and renewable generation, and along with energy storage. A detailed list of existing generation in the area is included in Appendix A.

Transmission Assumptions

Transmission modeling assumptions on existing and previously planned transmission projects are consistent with the general assumptions described in section 2.3. In addition, it is assumed that the series capacitors at Miguel and Suncrest 500 kV stations are bypassed in the summer peak base and sensitivity cases.

Table 2.9-1: SDG&E load and generation assumptions

Case ID	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response*		Solar		Wind		Energy Storage		Geothermal		Thermal	
						Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	B1-21SP	Baseline	2021 Summer Peak Load	4740	69	1520	0	4,671	2	38	1,399	0	926	0	128	40	0	0	3,560	3,484
B2	B2-24SP	Baseline	2024 Summer Peak Load	4994	159	1748	0	4,835	2	38	1,499	0	926	667	206	40	0	0	3,560	2,088
B3	B3-29SP	Baseline	2029 Summer Peak Load	5245	322	2270	0	4,923	2	38	1,499	0	926	204	206	40	32	32	3,524	2,190
B4	B4-21LL	Baseline	2021 Spring Light Load (27% of the peak)	2481	19	1,520	1,201	1,261	2	38	1,399	1,184	926	722	128	-88	0	0	3,560	2
B5	B5-24OP	Baseline	2024 Spring Off-Peak (69% of the peak)	3446	110	1,748	0	3,336	2	38	1,499	0	926	741	206	-166	0	0	3,560	375
S1	S1-24SP HLOAD	Sensitivity	2024 High CEC Load Forecast & Peak-Shift	5410	159	1748	0	5,251	2	38	1,499	0	926	667	206	40	0	0	3,560	2,088
S2	S2-24OP HRPS	Sensitivity	2024 Spring off-peak with Heavy Renewable Output	5124	110	1748	1,678	3,336	2	38	1,499	1,439	926	741	206	-166	0	0	3,560	70
S3	S3-21SP HRPS	Sensitivity	2021 Summer peak with heavy renewable output	6199	69	1520	1,459	4,671	2	38	1,399	1,439	926	722	128	40	0	0	3,560	1,236

Note: Proxy Demand Response (DR) is modeled offline in starting cases.

Assessment Summary

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 steady state assessment of the baseline scenarios identified a number of thermal overload concerns under Category P1 to P7 contingencies in the SDG&E main and sub-transmission systems. The sensitivity scenarios assessment identified similar concerns compared to the baseline scenarios. The assessments confirmed that most of these concerns can be mitigated by previously approved projects and operational mitigations including operational procedures, congestion management, and remedial action schemes (RAS). The 30-minute emergency ratings of transmission facilities along with demand response and energy storage resources in the area can be relied upon under contingency to allow time needed for operational actions to redispatch conventional generation and preferred resources, and adjust the phase shifting transformers at Imperial Valley substation. The stability analysis performed did not identify any transient issues requiring mitigation. The only corrective mitigation requirement found to be needed is to address the overloads on various 69 kV lines between Escondido and San Luis Rey substations for the failure of a non-redundant relay at San Luis Rey 230 kV bus. Please refer to Appendix B for details on these concerns and associated mitigations.

2.9.3 Request Window Project Submissions

The ISO received a total of twelve project submittals through the 2019 request window submission for the SDG&E main and sub-transmission systems. Below is a description of each proposal followed by ISO comments and findings.

Imperial Smart Wire Solutions

Imperial Renewable LLC proposed an alternative to the S-Line series reactor project that was analyzed in Chapter 4 of the ISO 2018-2019 Transmission Plan, designed to reduce the LCR requirement in the San Diego-Imperial Valley area. The project proposes to install 25 Ω/phase of Smart Wires devices on the IID-owned 230 kV S-Line from El Centro to Imperial Valley substations when the previously approved S-Line upgrade project is completed. The project has an estimated cost of $15.8 million and an expected in-service date of December 2021.

The ISO can further consider this proposal once the design of the previously approved S-Line upgrade project is finalized, and presumably as a potential economic study request..

Suncrest-Sycamore Canyon 230 kV Transmission project

Horizon West Transmission, LLC (“HWT), former NextEra Energy Transmission West, LLC (NEET West) re-submitted its previously proposed Suncrest – Sycamore Canyon 230 kV transmission project, targeting thermal overloads in the Suncrest–Sycamore Canyon 230 kV path as a reliability need. The project proposes to build a new 27-mile 230 kV line from the first pole outside SDG&E’s Suncrest 230 kV substation to the last pole directly outside SDG&E’s Sycamore Canyon 230 kV substation. The project has an estimated cost of $75 million (excluding line termination costs) and a proposed in-service date of December 2024.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on the Suncrest–Sycamore Canyon 230 kV path can be eliminated by the existing TL23054/TL23055 RAS along with existing operational actions that rely upon the 30-minute ratings of the 230 kV lines to allow time to adjust the IV phase shifting transformers, redispatch conventional generation and preferred resources, in the baseline and sensitivity scenarios.

Sycamore Canyon Reliability Energy Storage

The Project was submitted in the 2018-2019 planning cycle, and again in this 2019-2020 planning cycle by Tenaska, Inc. as a reliability need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore Canyon 230 kV lines and Suncrest 500/230 kV transformers. The project was also re-submitted as a potential economic-driven project to reduce the LCR requirement for the San Diego sub-area. The proposed scope is to build a 350 MW/175~350 MWh battery energy storage system (BESS) and interconnect it to the SDG&E Sycamore Canyon substation. The project has an estimated cost of $127~157 million and a proposed in-service date of December 2023.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified in SWPL and SRPL can be eliminated by existing operational measures.

Lake Elsinore Advanced Pump Storage Project

ZGlobal, on behalf of the Nevada Hydro Company, resubmitted the Lake Elsinore Advanced Pump Storage (LEAPS) project as a reliability need to substantially eliminate the P6 thermal overload concerns identified on the Suncrest–Sycamore Canyon 230 kV path, having also submitted the project in the 2018-2019 transmission planning cycle.. The Project was also proposed as an economic-driven project to provide multiple economic benefits. The project consists of a 500/600 MW advanced pumped storage station and associated interconnection facilities. Two interconnection alternatives were proposed to connect the pumped storage facility to both the SCE 500 kV and the SDG&E 230 kV systems, or to the SDG&E 230 kV system only. The project has an estimated cost of $1.76~2.04 billion depending on the interconnection options and a proposed in-service year of 2025.

The ISO has not identifed a reliability need for this project. As discussed above, the power flow concerns identified in the SDG&E main system can be mitigated by existing operational measures.

Second 230 kV Bay Boulevard-Silvergate Transmission Line

San Diego Gas & Electric (SDG&E) proposed a project to build a 2nd 230 kV Bay Boulevard-Silvergate transmission line, targeting the P1 thermal overload concern on the Bay Boulevard-Silvergate 230 kV line TL23026 that was identified by SDG&E under its off-peak scenario with heavy northbound flow via the north of San Onofre 220 kV path from SDG&E to SCE. The project scope is to add second 230 kV line from Bay Boulevard to Silvergate substation with a minimum rating of 912/1176 MVA. The project has an estimated cost of $150~200 million and a proposed in-service date of June 2023.

The ISO review found that the two-hour short term emergency rating of Bay Boulevard-Silvergate 230 kV line provides enough time for the ISO market dispatch to reduce the loading level below its continuous rating. Hence, the ISO has not found a need for the second 230 kV Bay Boulevard-Silvergate transmission line.

Third *230 kV Encina-San Luis Rey Transmission Line*

SDG&E proposed building a third 230 kV line between Encina and San Luis Rey substations to address the P1 thermal overload concern on the TL23011A and TL23011B sections of the three-terminal Encina-San Luis-Palomar 230 kV line that was identified by SDG&E under the off-peak scenario with heavy northbound flow via the north of San Onofre 220 kV path. The project scope is to add a third 230 kV line between Encina and San Luis Rey substation by using the currently idle TL13802 line. The project has an estimated cost of $150~170 million and a proposed in-service date of June 2024.

The ISO 2017-2018 Transmission Plan identified the P1 thermal overload concern on TL23011A and TL23011B sections under similar operation condition and concluded that the ISO congestion management was sufficient to eliminate the overloads without resulting in significant congestion cost in the long run. Hence, the ISO did not find the need for the third 230 kV Encina-San Luis Rey transmission line project.

230kV Phase Shifters at Suncrest

SDG&E proposed adding phase shifting transformers at Suncrest, targeting the thermal overload concerns identified on the two 230 kV lines TL23054 and TL23055 between Suncrest and Sycamore Canyon substations in the baseline and sensitivity scenarios. The project scope is to add four phase shiftering transformers on TL23054 and TL23055 at the Suncrest 230 kV substation. The project has an estimated cost of $60~70 million and a proposed in-service date of June 2024.

The ISO did not identify a reliability need for this project. As discussed above, the power flow concerns identified in the SDG&E main system can be mitigated by existing operational measures.

San Luis Rey AIS 230kV Redundant Bus Differential Relay

SDG&E submitted a protection upgrade project installing a new redundant bus differential relay at San Luis Rey air insulated substation (AIS) 230 kV bus, targeting the P5 thermal overloads identified on several 69 kV lines between Escondido and San Luis Rey substations in the baseline and sensitivity scenarios. The project has an estimated cost of $850,000 and an expected in-service date of 2022.

The ISO has identified a reliability need for this project and concurs with SDG&E's proposed installation of a new redundant bus differential relay protection system for the San Luis Rey AIS 230 kV buses.

El Cajon-Garfield 69 kV (TL6925) Reconductor Project

This project was proposed by SDG&E as a reliability transmission solution to reconductor TL6925 El Cajon-Garfield 69 kV line and achieve a minimum continuous rating of 118MVA. The estimated cost of the project is between $8 million and $12 million, and the proposed in-service date is June, 2022.

The ISO has not identified a reliability need, on these non-BES facilities, for this project.

Ocean Range (TL693) Loop-in Project

This project was proposed by SDG&E as a reliability transmission solution to loop-in TL693 San Luis Rey-Melrose 69 kV line to the Ocean Ranch 69 kV substation. The estimated cost of the project is between $3 million and $6 million, and the proposed in-service date is 2020.

The ISO has not identified a reliability need for this project. The P1 thermal overload concerns can be mitigated by relying on generation re-dispatch.

Bay Boulevard-Imperial Beach (TL647) Reconductor Project

This project was proposed by SDG&E as a reliability transmission solution to reconductor TL647 Bay Boulevard-Imperial Beach 69 kV line and achieve a minimum continuous rating of 110 MVA. The estimated cost of the project is between $6 million and $10 million, and the proposed in-service date is 2022.

The ISO has not identified a reliability need for this project. The P1 thermal overload concerns can be mitigated by relying on generation re-dispatch or curtailment.

Chula Vista Energy Reliability Center

This project was proposed by Wellhead Power Development, LLC as a reliability transmission solution to develop a 50 MW, 200 MWh battery energy storage system project at the Otay 69 kV substation. The proposed in-service date is 2021.

The ISO has not identified a reliability need for this project. The P2.1 thermal overload concerns can be mitigated by relying on generation re-dispatch or curtailment.

2.9.4 Consideration of Preferred Resources and Energy Storage

As indicated earlier, projected amounts of up to 322 MW energy efficiency (AAEE) and 2,270 MW installed capacity of distributed BTM-PV self-generation were used in the study scenarios for the San Diego area. The BTM-PV self-generation reduces a total of 1793 MW of the San Diego load at HE16:00 on the southern California area peak hour, and 0 MW of the San Diego area peak load at HE19:00. The load reductions due to these preferred resources has shifted the San Diego peak load hour from HE16:00 to HE19:00, which avoided, deferred, or mitigated various significant reliability concerns identified in current and previous transmission planning cycles, including but not limited to:

- Various thermal overload concerns in SWPL and SRPL for various Category P1/P3/P6 contingencies
- Voltage instability in the San Diego and LA Basin for Category P3/P6 contingencies
- The south of San Onofre Safety Net taking action for Category P6 contingency
- Bay Boulevard–Silvergate-Old Town 230 kV path overloads for Category P6/P7 contingencies
- Friars-Doublett 138 kV line for Catwegory P6/P7 contingencies

- SCE's Ellis 220 kV south corridor for Category P6 contingency
- Otay Mesa-Tijuana 230 kV tie line for Category P6 contingency
- Cross-tripping the 230 kV tie lines with CENACE for Category P3/P6 contingencies

The operational and planned battery energy storage and demand response amounting to 166 MW and 40 MW, respectively, were used as potential mitigations in the base and sensitivity scenarios as needed. Utilization of the resources helped reduce some of the thermal overloads identified in the area.

In this planning cycle, no need for additional preferred resource and energy storage was identified as a cost-effective mitigation to meet reliability needs in the San Diego area. As alternatives to the recommended operational mitigation solutions, however, procuring additional amounts of preferred resources, such as Energy Efficiency, Demand Response, and energy storage in appropriate locations could be helpful to mitigate or reduce exposure to some of the reliability concerns.

2.9.5 Recommendation

The assessments identified a number of thermal overload concerns under Categories P1 to P7 contingencies in the SDG&E main and sub-transmission systems. In response to the ISO reliability assessment results and proposed alternative mitigations, a total of twelve project submissions were received through the 2019 request window. The ISO evaluated the alternatives and found a reliability need for one of the projects. Below is a summary of the recommendations for the SDG&E:

The ISO supports the San Luis Rey AIS 230 kV redundant bus differential relay project. The project is part the SDG&E's maintenance/upgrade program and does not require the ISO's approval.

2.9.5.1 Other Project that does not require ISO's approval

The San Luis Rey AIS 230 kV redundant bus differential relay project is an active project of the SDG&E's maintenance and upgrade program. The ISO has reviewed and agrees with the need for the project, but SDG&E does not need the ISO's approval to proceed.

Chapter 3

3 Policy-Driven Need Assessment

3.1 Background

In accordance with the May 2010 memorandum of understanding between the ISO and the California Public Utilities Commission (CPUC), and in coordination with the California Energy Commission (CEC), the CPUC develops the resource portfolios to be used by the ISO in its annual transmission planning process (TPP). The ISO utilizes the portfolios transmitted by the CPUC in performing reliability, policy and economic assessments in the TPP, with a particular emphasis on identifying policy-driven transmission solutions pursuant to the ISO tariff section 24.4.6.6.

The CPUC issued a decision[102] on February 8, 2018 which adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals. Subsequently, the CPUC issued a decision[103] on May 1, 2019 which recommended that the CAISO utilize the Preferred System Plan (PSP) adopted in this decision as the reliability base case and the policy-driven base case in its 2019-20 TPP. In order to make the PSP usable for the CAISO as a reliability and policy-driven base case, Commission staff updated the portfolio based on the latest available transmission input provided by the CAISO at the time. The decision also established two policy-driven sensitivity portfolios to be transmitted to the ISO to be used in the 2019-2020 TPP. While the base and sensitivity portfolios were developed considering potential statewide electricity sector GHG reductions to 46 MMT and 32 MMT respectively, the resulting portfolios delivered approximately 60 percent RPS results and 71 percent RPS results, respectively for the CAISO footprint.

The CPUC used the RESOLVE model for creating the portfolios studies as part of the 2019-2020 TPP. This model assumed the renewable resources under development with CPUC-approved contracts with the three investor-owned utilities to be part of the baseline assumptions while creating this portfolio.

3.2 Objectives of policy-driven assessment

Key objectives of the policy-driven assessment were:

- Evaluate transmission solutions (Category 1 and Category 2) needed to meet state, municipal, county or federal policy requirements or directives as specified in the Study Plan

102 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

103 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

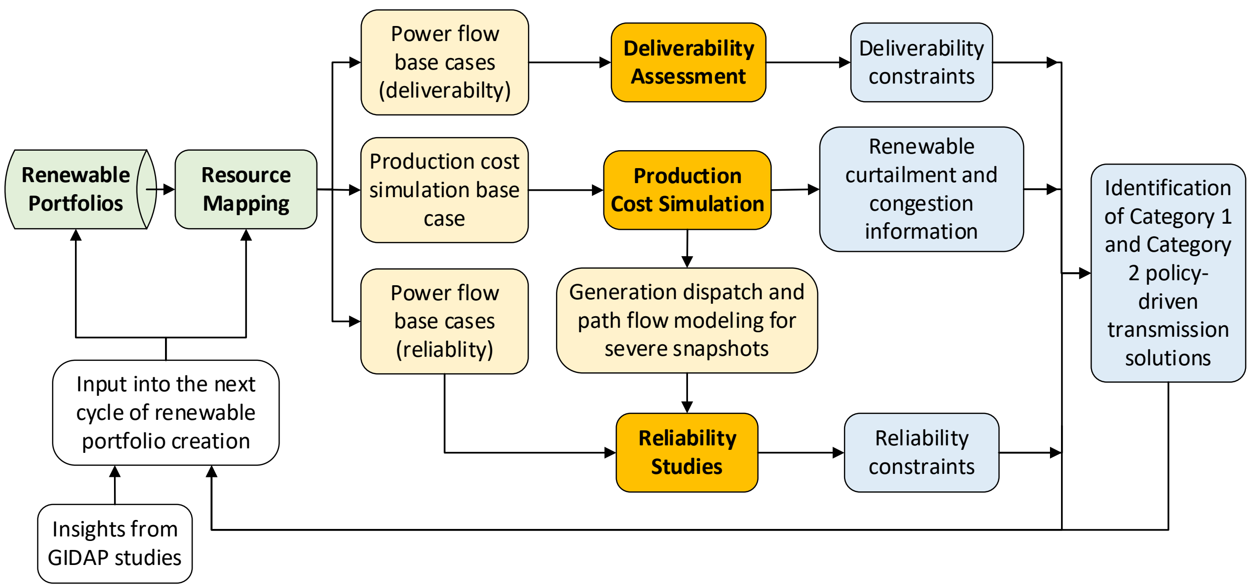
- Test the deliverability of resource amounts identified as full capacity deliverability status (FCDS)
- Analyze renewable curtailment data
- Capture reliability impacts

- Test the transmission capability estimates used in CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation

3.3 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies as illustrated in Figure 3.3-1. These studies are geared towards capturing the impact of renewable build out on transmission infrastructure, identifying any required upgrades and generating transmission input for the next set of renewable portfolios to be selected through the appropriate CPUC proceeding (currently the IRP proceeding).

Figure 3.3-1: Policy assessment methodology and study components



Production cost modeling simulation (PCM) study

Production cost modeling simulations were performed using the updated models to identify renewable curtailment and transmission congestion in the ISO BA system. Renewable curtailment can be caused by system constraints, such as over-generation and system ramping, or by transmission constraints. Two scenarios with different ISO export limitations were developed and simulated – (i) 2000 MW maximum net export from the ISO and (ii) no export limit from the ISO. The "no export limit" scenario may still have some renewable curtailment due to system constraints but should be relatively small. The difference of renewable curtailment between the first and the second scenarios therefore was used to be an approximation of renewable curtailment related to transmission constraints within California. Production cost simulations were used to create hourly snapshots of the system to be used for reliability studies which involve power flow simulations.

Reliability assessment of snapshots (power flow simulations)

Reliability studies were 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. Power flow contingency analysis was performed in order to capture any additional area-wide constraints or significant interconnection issues that need to be modeled in the production cost simulations in order to more accurately capture the renewable curtailment caused by transmission congestion.

Deliverability assessment

The deliverability test is designed for resource adequacy counting purposes 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 ISO performed the assessment following the on-peak Deliverability Assessment Methodology[104].

3.4 Key inputs and assumptions

The key inputs and assumptions for policy-driven assessment include transmission capability estimates for major renewable zones, renewable portfolios, transmission modeling assumptions and load assumptions.

3.4.1 Transmission modeling assumptions

The same transmission modeling assumptions used in ISO's Annual Reliability Assessments for NERC Compliance (all transmission projects approved by the ISO) were used in this analysis. Year-10 base cases used for 2018-2019 TPP annual reliability assessment were used as a starting point. Specific details are provided in section 2.3.

Transmission modeling assumptions used in economic planning database described in chapter 4 section 4.6 were used to develop the policy-driven production cost simulation model.

[104] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

3.4.2 Load modeling assumptions

The ISO identified severe conditions snapshots to be modeled based on high transmission system usage hours under high renewable dispatch in respective study areas, and the corresponding load levels were modeled in the respective power flow cases.

For deliverability studies performed as part of this policy-driven assessment, 2030 1-in-5 summer peak load and off-peak loads were tested.

3.4.3 Resource dispatch assumptions

For the reliability assessment, renewable resources were dispatched based on the identified snapshot.

For the deliverability assessment, renewable resource were dispatched according to the newly proposed deliverability methodology and dispatch assumptions.

For production cost modeling (PCM) simulations, the portfolio resources mapped to specific transmission substations were added to the ISO economic planning database described in chapter 4

3.4.4 Renewable Portfolios

As set out in Section 3.1, a base portfolio and two sensitivity portfolios were transmitted to the ISO to be used in the 2019-2020 TPP policy-driven assessment. The final portfolios are posted to the Commission's web site at: http://www.cpuc.ca.gov/General.aspx?id=6442460548.

Compared to the previous policy-driven base portfolio which was transmitted to the ISO by the CPUC during the 2016-2017 transmission planning process[105], the portfolios transmitted to the ISO as part of 2019-2020 TPP contain several significant changes in terms of resource classification and the nature of modeling/mapping data. The key changes are as follows:

- The CPUC's "RESOLVE" model was used instead of the RPS calculator to select portfolio resources.
- CEC staff developed the locational mapping of resources. In the past the ISO had relied on queued generation information for mapping portfolio resources to specific substations.
- The portfolios now include only the new generic (not contracted) resources that are incremental to the baseline resource set. In the past, portfolios were comprised of contracted and generic resources and only online resources were considered baseline. Contracted resources (online and planned) are now considered as baseline resources in RESOLVE model, so these resources are not part of the optimization that selects the portfolios.

[105] The CPUC also directed use of the 2016-2017 portfolio in the 2017-2018 transmission planning cycle, and only sensitivities, but no base case, was transmitted for use in the 2018-2019 transmission planning cycle.

- A mix of resources with Full Capacity Deliverability Status (FCDS) and Energy Only Deliverability Status (EODS) are selected as part of portfolios.

  Stand-alone "generic" energy storage is identified in all the portfolios but the location mapping for these resources is not available at this point.

A detailed breakdown of the three portfolios by zone, technology and deliverability status are shown in Table 3.4-1.

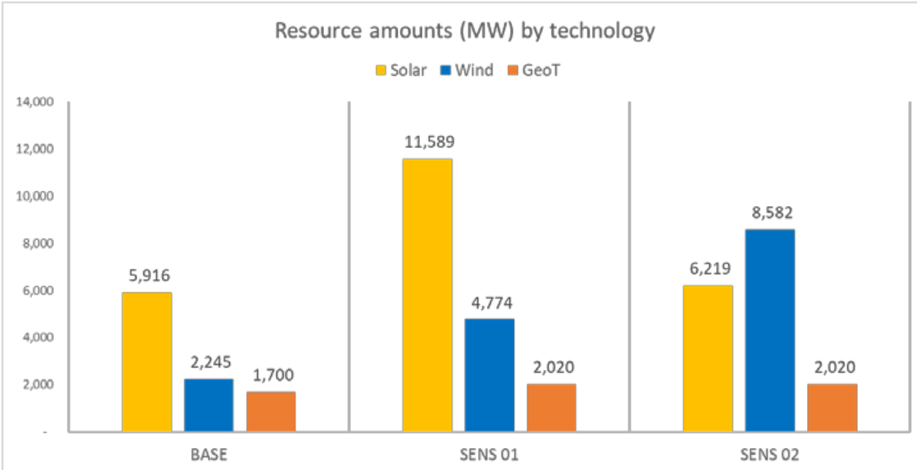
Table 3.4-1: Portfolio resource selection by zone, technology and deliverability status

Renewable zone	PCM and snapshot study capacity (MW)												Deliverability study capacity (MW)		
	BASE				SENS-01				SENS-02				BASE	SENS 1	SENS 2
	Solar	Wind	GeoT	Total	Solar	Wind	GeoT	Total	Solar	Wind	GeoT	Total			
Northern California	0		424	424	750		424	1,174	750		424	1,174	424	424	424
Solano	0	643	0	643	0	643	0	643	40	643	0	683	0	581	581
Central Valley and Los Banos	0	146	0	146	0	146	0	146	0	146	0	146	146	146	146
Westlands	0	0	0	0	2,699	0	0	2,699	1,116	0	0	1,116	0	1,996	413
Greater Carrizo	0	160	0	160	0	1095	0	1,095	0	1095	0	1,095	0	895	895
Tehachapi	1,013	153	0	1,166	1,013	153	0	1,166	1,013	153	0	1,166	1,166	1,166	1,166
Kramer and Inyokern	577	0	0	577	577	0	0	577	577	0	0	577	577	577	577
Riverside East and Palm Springs	1,320	42	0	1,362	2,842	42	0	2,884	577	42		619	360	360	42
Greater Imperial*	0	0	1276	1276	1,401	0	1276	2,677	1,401	0	1,276	2,677	624	624	624
Southern CA desert and Southern NV	3,006	0	0	3,006	2,307	442	320	3,069	745	0	320	1,065	802	802	320
None (Distributed Wind)	0	0	0	0	0	253	0	253	0	253	0	253	0	253	253
NW_Ext_Tx (Northwest wind)	0	601	0	601	0	1500	0	1,500	0	1,500	0	1,500	601	966	966
SW_Ext_Tx (Southwest wind)	0	500	0	500	0	500	0	500	0	500	0	500	500	500	500
New Mexico wind (new Tx)	0	0	0	0	0	0	0	0	0	2,250	0	2,250	0	0	326
Wyoming wind (New Tx)	0	0	0	0	0	0	0	0	0	2,000	0	2,000	0	0	481
TOTALS	**5,916**	**2,245**	**1,700**	**9,861**	**11,589**	**4,774**	**2,020**	**18,383**	**6,219**	**8,582**	**2,020**	**16,822**	**5,200**	**9,290**	**7,714**

Two sensitivity portfolios – sensitivity 1 (SENS-01) and sensitivity (SENS-02), shown in Figure 3.4-1, select approximately 86% and 70% more renewable resources than the base (BASE) portfolio. This higher renewable buildout is primarily driven by a more aggressive assumption of a 32 MMT GHG target used for the sensitivity portfolios compared to a GHG target of 42 MMT used for developing the base portfolio. The base portfolio and the two sensitivity portfolios were expected by the CPUC to align with 60% and 71% RPS respectively.

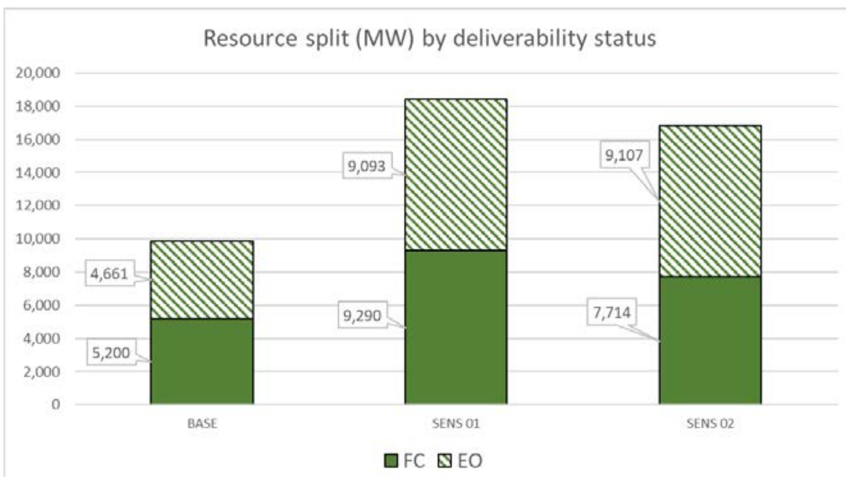
Sensitivity 1 portfolio contains significantly more solar resources than sensitivity 2 portfolio because sensitivity 1 portfolio is intended to represent a heavy in-state renewable development future which leans towards a high solar buildout; sensitivity 2 portfolio is intended to represent a significant reliance on out-of-state wind, primarily in Wyoming and New Mexico.

Figure 3.4-1: Comparison of portfolios by technology buildout



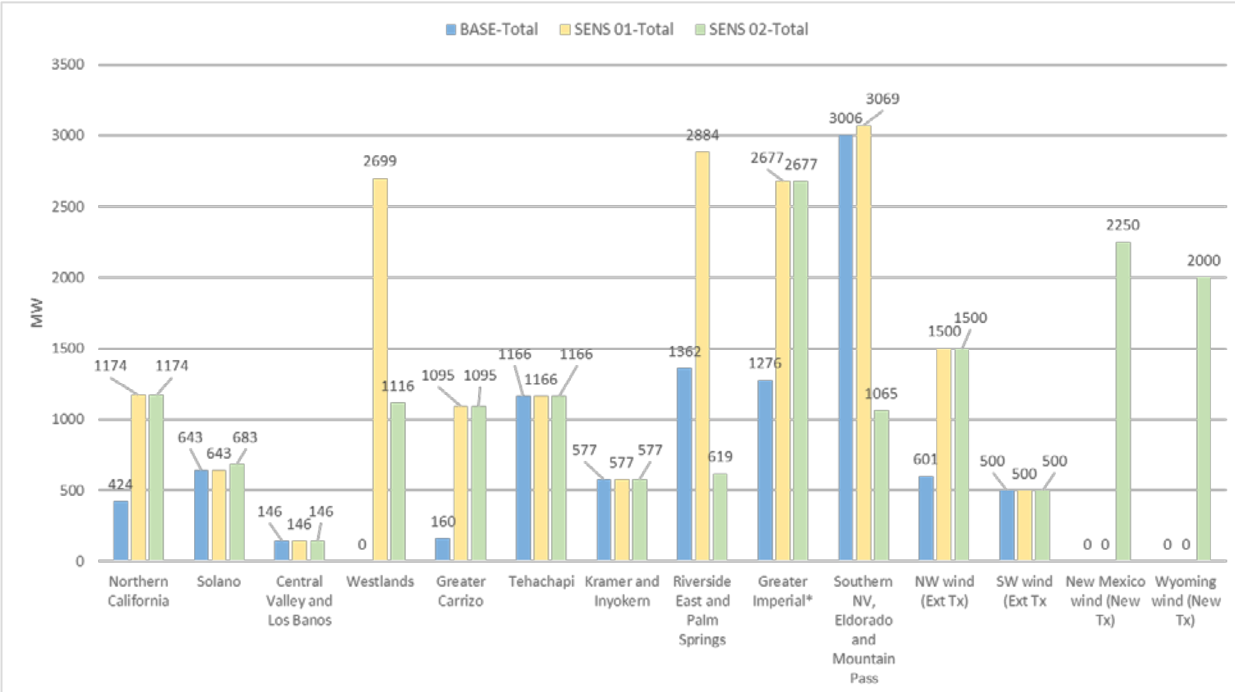
As shown in Figure 3.4-2, the ratio of FCDS to total (FC + EO) resources varies by less than 7% across the three portfolios (~52% of resources in the base portfolio are FCDS; ~51% of resources in sensitivity 1 portfolio are FCDS and ~46% resources in sensitivity 2 portfolio are FCDS)

Figure 3.4-2: Comparison of portfolios by deliverability status



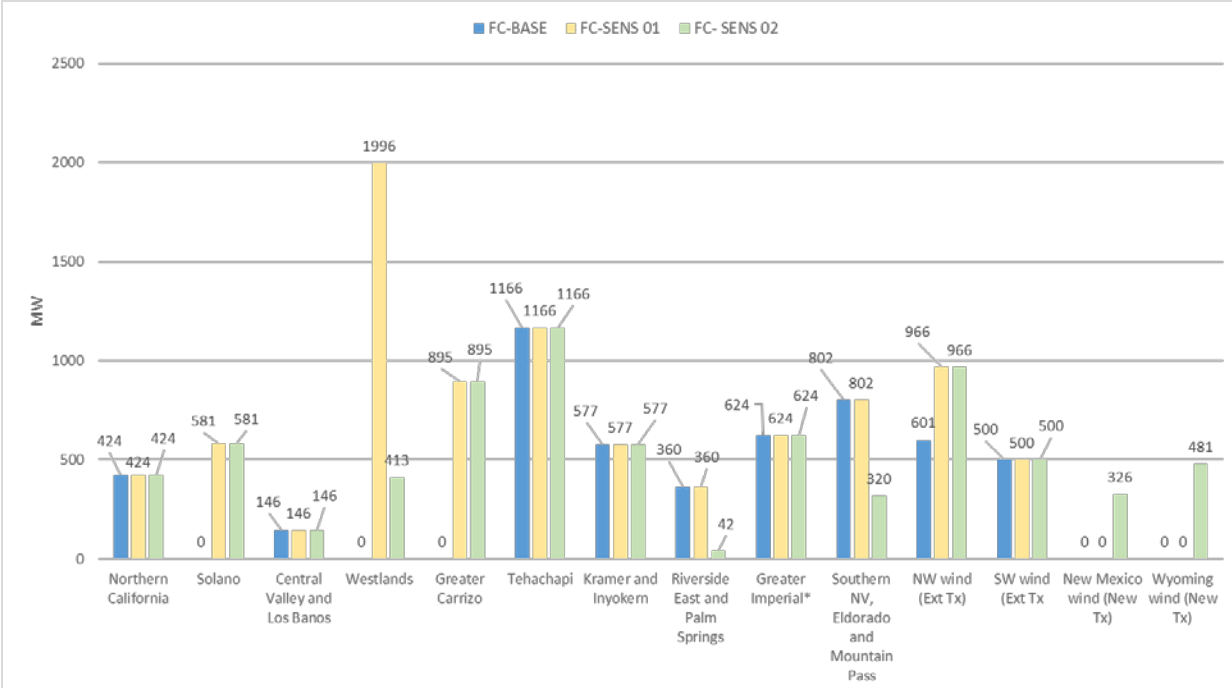
The zonal distribution of the total portfolio resources which include FCDS and EODS resources is shown in Figure 3.4-3. Total resource selection in Solano, Tehachapi, Kramer and Inyokern and SW wind (assumed by the CPUC to be delivered over existing out-of-state transmission) zones is constant across all three portfolios.

Figure 3.4-3: Total (FCDS + EODS) resource selection by location



As shown in Figure 3.4-4, the FCDS resource selection is unaffected by input assumptions in the three portfolios in case of the following zones: Northern California, Central Valley and Los Banos, Tehachapi, Kramer Inyokern, Greater Imperial and SW wind (assumed by the CPUC to be delivered over the existing out-of-state transmission).

Figure 3.4-4: FCDS resource selection by location



3.4.5 Mapping of portfolio resources to transmission substations

The portfolios are at a geographic scale that is too broad for transmission planning purposes, which requires more specific interconnection locations. The final allocation of the geographically-coarse resources to substations on the CAISO-controlled transmission grid was conducted by land-use experts at the CEC. The allocation is available on the CEC's website at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-MISC-03

The ISO relied on specific information received from IID as part of the annual TPP base case coordination and made certain changes to the modeling locations recommended by the CEC. The CEC staff had recommended the locations shown in Table 3.4-2 for modeling geothermal resources selected in all three portfolios:

Table 3.4-2: Geothermal resource locations recommended by the CEC

MW Assignment	Substation
1052	Bannister
160	El Centro
32	Highline

Based on the input received from IID during the planning base case building process about the likely location for geothermal resource development based on IID's interconnection studies, the ISO modeled the Imperial geothermal resources as shown in Table 3.4-3.

Table 3.4-3: Final modeling locations for Imperial geothermal resources

MW Assignment	Substation
622	Bannister 230 kV (IID)
622	Hudson Ranch 230 kV (connecting to IID's Midway 230 kV)

The objective of modeling generation projects connected to specific substations is not to endorse any particular generation project, but to streamline and focus the transmission analysis on the impact of certain amount of MW of generation modeled in the general area. In other words, transmission constraints to be mitigated within the TPP for an assumed portfolio generation build-out within a renewable zone should be independent of which competitively procured projects are built within that zone.

3.4.6 Transmission capability estimates and corresponding utilization in 42 MMT portfolio

One of the key inputs to the co-optimization performed by the RESOLVE tool used by the CPUC in portfolio development is a set of transmission capability estimates provided by the ISO for renewable zones in which candidate resources are selected. The estimated available transmission capability to support future renewable generation is monitored annually through the ISO transmission planning process. It is important to note that the transmission capability estimates are only one of the several deciding factors utilized for resources selection in the RESOLVE model. The ISO published a white paper[106] to describe the key sources of information and the methodology involved in the estimation of transmission capability for the specific purpose of providing input into portfolio development as part of the CPUC's IRP process.

Figure 3.4-5 through Figure 3.4-10 show the utilization of transmission capability estimates provided by the ISO as an input into 2017-2018 IRP by the three portfolios. The total available transmission capability amounts shown in these figures are net of any contracted future resources assumed in the RESOLVE baseline in respective zones.

Figure 3.4-5 and Figure 3.4-6 show how the base portfolio utilized the transmission capability estimates provided by the ISO. The estimated FCDS capability is fully utilized in the Greater Kramer, Southern NV-Eldorado-Mountain Pass and Greater Imperial zones while considerable surplus FCDS capability remains elsewhere. The estimated EODS capability is fully utilized in the Solano and Southern NV-Eldorado-Mountain Pass zones while considerable surplus EODS capability remains elsewhere.

[106] https://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf

Figure 3.4-5: Utilization of FCDS transmission capability estimates – Base portfolio

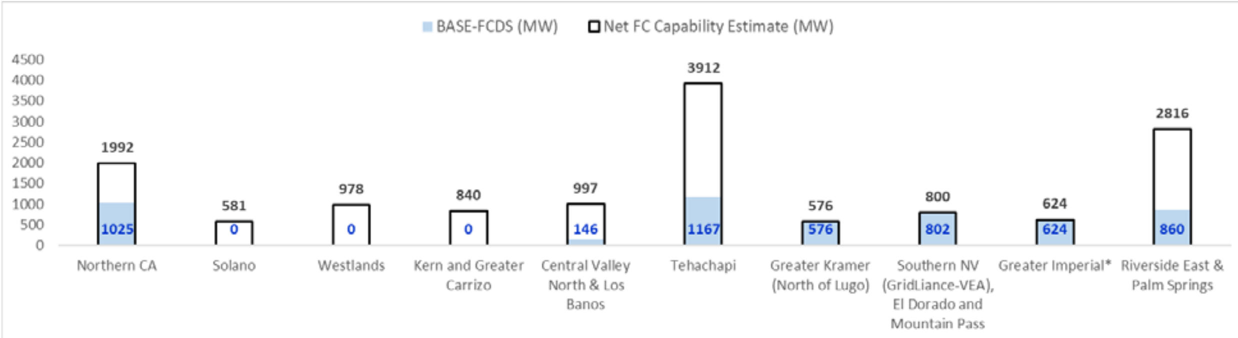


Figure 3.4-6: Utilization of EODS transmission capability estimates – Base portfolio

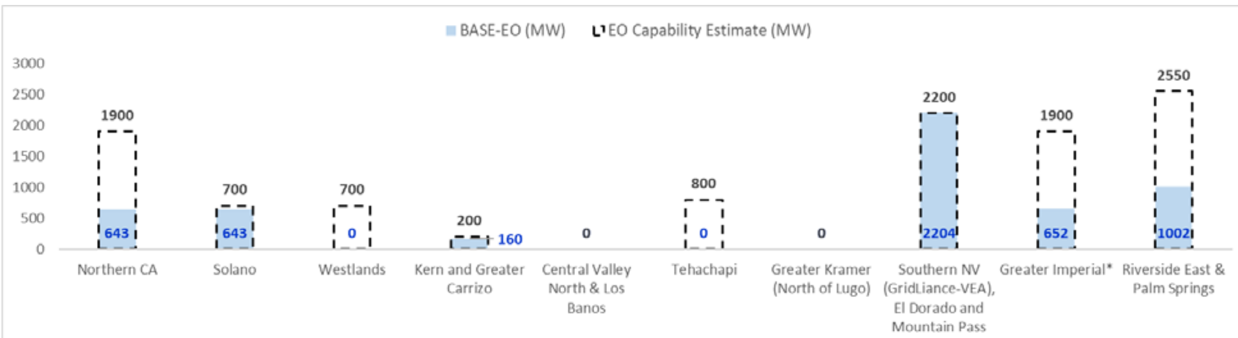


Figure 3.4-7 and Figure 3.4-8 show the utilization of transmission capability estimates in the sensitivity 1 portfolio. This portfolio selected more FCDS resources than the capability estimate in Westlands zone. The estimated FCDS capability is fully utilized in several zones leaving only a few other zones with surplus estimated FCDS capability. This is expected considering that the sensitivity 1 portfolio is intended to represent a heavy in-state renewable buildout – the same is true for the estimated EODS capability utilization.

Figure 3.4-7: Utilization of FCDS transmission capability estimates – Sensitivity 1 portfolio

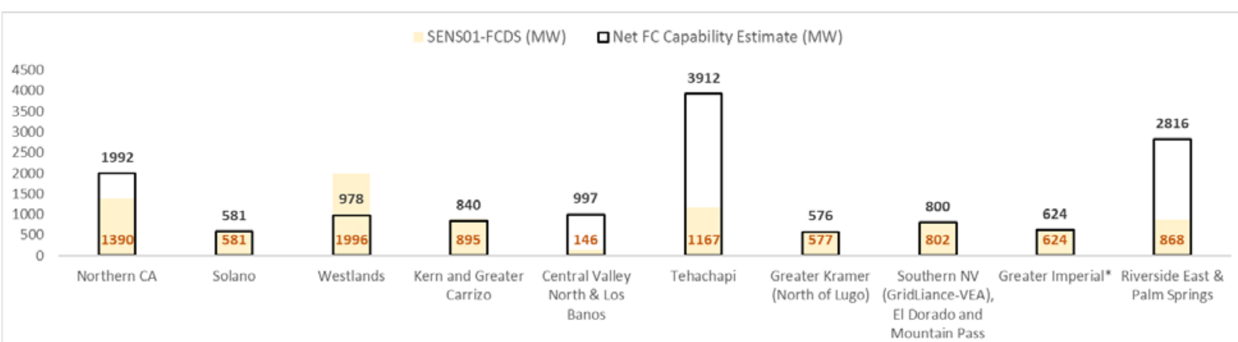


Figure 3.4-8: Utilization of EODS transmission capability estimates – Sensitivity 1 portfolio

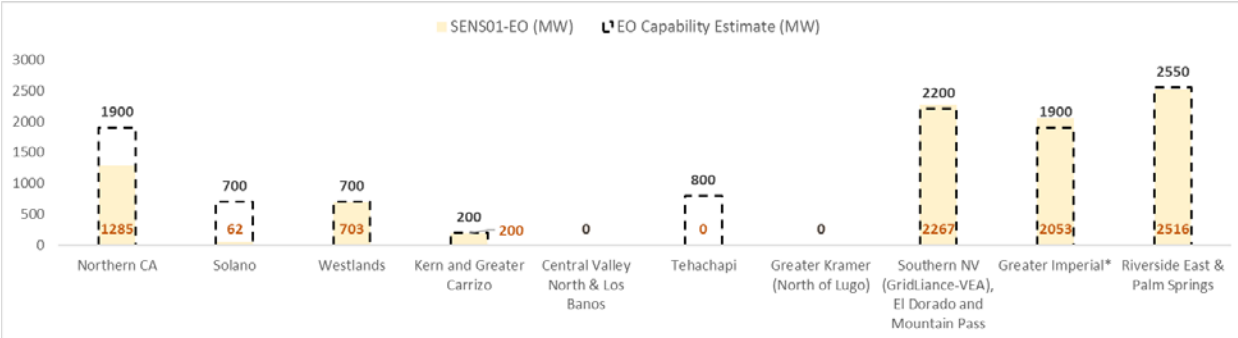


Figure 3.4-9 and Figure 3.4-10 show the utilization of transmission capability estimates in the sensitivity 2 portfolio. Transmission capability utilization in sensitivity 2 portfolio looks very similar to the utilization in Sensitivity 1 portfolio because the out-of-state wind resources selected in the sensitivity 2 portfolio deliver power into the same in-state zones as the heavy in-state sensitivity 1 portfolio.

Figure 3.4-9: Utilization of FCDS transmission capability estimates – Sensitivity 2 portfolio

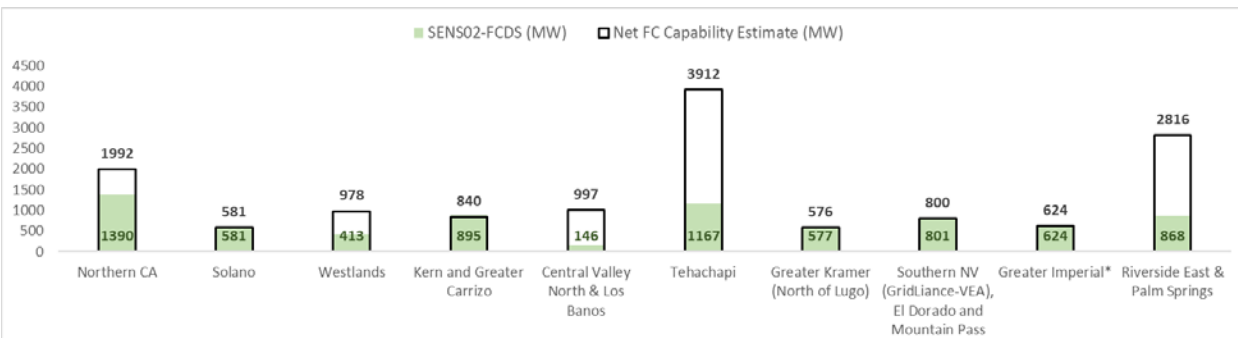
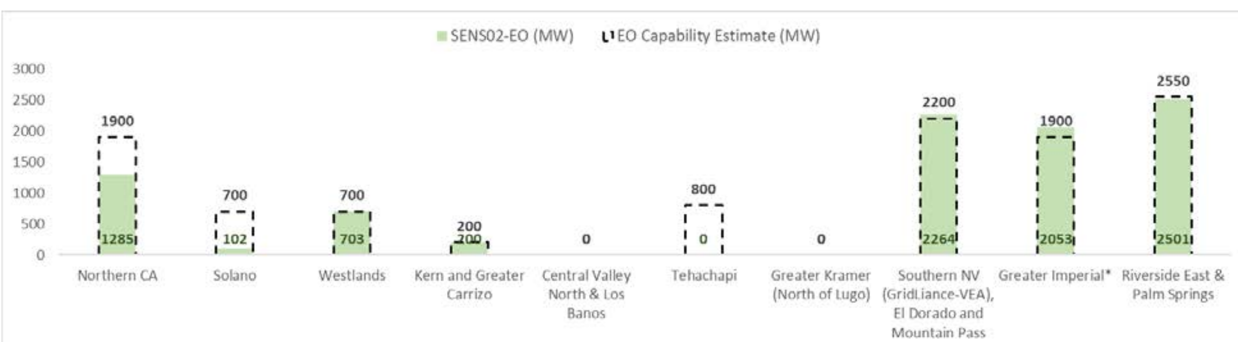


Figure 3.4-10: Utilization of EODS transmission capability estimates – Sensitivity 2 portfolio



3.5 Deliverability assessment

The key objectives of deliverability assessment of renewable portfolios are:

- Test deliverability of portfolio resource amounts identified as FCDS in accordance with the deliverability methodology as used in Generation Interconnection and Deliverability Allocation Procedures (GIDAP)
- Identify upgrades needed to ensure deliverability of resource amounts identified as FCDS in the commission-developed renewable portfolios
- Gain insights about FCDS transmission capability estimates and corresponding upgrade information to feed it back into IRP

3.5.1 Deliverability assessment methodology

The ISO performed the assessment following the on-peak Deliverability Assessment Methodology[107]. The main steps are described below.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool was used to identify potential deliverability problems. For each analyzed facility, an electrical circle was drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% or greater:

- Distribution factor (DFAX) = (Δ flow on the analyzed facility / Δ output of the generating unit) *100%

  or

- Flow impact = (DFAX * Full Study Amount / Applicable rating of the analyzed facility) *100%.

Load flow simulations were performed, which study the worst-case combination of generator output within each 5% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5% Circle were increased starting with units with the largest impact on the transmission facility. No more than twenty units were increased to their maximum output. In addition, no more than 1,500 MW of generation was increased. All remaining generation within the Control 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 more than 1,500 MW, the impact of the remaining amount of generation to be increased was considered using a Facility Loading Adder. The Facility Loading Adder was calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs was also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders was negative, the impact was set to zero and the flow on the analyzed facility without applying Facility Loading Adders was reported.

[107] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

3.5.2 Deliverability assessment assumptions and base case

The ISO developed a master base case for each portfolio for the on-peak deliverability assessment that modeled all the generating resources in the respective portfolio. Key assumptions of the deliverability assessment are described below.

Transmission

The ISO modeled the same transmission system as in the 2029 peak load base case used in the TPP reliability assessment.

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. The ISO assessed both wind and solar generations for maximum output of 50 percent exceedance production level during summer peak load hours for identification of deliverability constraints because the emphasis is on identifying wide-area issues that are likely to limit deliverability of large amounts of resources. The wind and solar generation exceedance production levels modeled in the deliverability assessment are shown in Table 3.5-1.

Table 3.5-1: Wind and Solar Generation 50% Exceedance Production Levels (percentage of installed capacity) in the Deliverability Assessment

Type	Area	50% Exceedance Level
Wind	SCE Northern & NOL	38%
	SCE Eastern	47%
	SDGE	37%
	PG&E NorCal	37%
	PG&E Bay Area (Solano)	47%
	PG&E Bay Area (Altamont)	32%
Solar	SCE Northern	92%
	SCE/GLW/VEA	93%
	SDGE	87%
	PG&E	92%

Import Levels

The ISO modeled imports at the maximum summer peak simultaneous historical level (2020 Maximum RA Import Capability) 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. Import target into CAISO from IID through IID-CAISO branch groups were increased from the 2020 MIC to support portfolio renewables mapped to IID system.

3.5.3 Deliverability assessment results

All three portfolios were studied as part of the 2018-2019 TPP policy-driven deliverability assessment. Renewable generation designated as FCDS in each portfolio was modeled with the maximum dispatch levels as shown in Table 3.5-1. EODS generation was not dispatched in this assessment.

3.5.3.1 SCE, GLW and VEA area deliverability results

All renewable zones in Southern California and zones outside of California that are likely to impact the deliverability assessment in the SCE, GLW and VEA study area are shown in Table 3.5-2.

Table 3.5-2: Renewable zones impacting deliverability out of the SCE, GLW and VEA study area

	Deliverability study capacity (MW)		
Renewable zone	BASE	SENS 01	SENS 02
Tehachapi	1,166 (1013 Solar + 153 Wind)	1,166 (1013 Solar + 153 Wind)	1,166 (1013 Solar + 153 Wind)
Kramer and Inyokern	577 Solar	577 Solar	577 Solar
Riverside East and Palm Springs	360 (318 Solar + 42 Wind)	360 (318 Solar + 42 Wind)	42 Wind
Greater Imperial*	624 GeoT	624 GeoT	624 GeoT
Southern CA desert and Southern NV	802 Solar	802 (40 Solar + 442 Wind + 320 GeoT)	320 GeoT
SW_Ext_Tx (Southwest wind)	500 Wind	500 Wind	500 Wind
New Mexico wind (new Tx)	0	0	326 Wind
Wyoming wind (New Tx)	0	0	481 Wind

With the resource mix specified in Table 3.5-2 modeled in each of the base cases developed for the three portfolios, the deliverability assessment identified the following constraints in the SCE, GLW and VEA study area:

VEA-NVE 138 kV constraint

The deliverability of renewable resources in the GLW and VEA areas is limited by thermal overloading of the Mercury Switch to Northwest 138 kV facilities owned by NV Energy caused by contingencies shown in Table 3.5-3. This constraint was identified in all three portfolios. All the contingencies listed in Table 3.5-3 have been previously identified in GIDAP to cause overloads and a RAS to trip generation has been identified as a mitigation. The RAS mitigation identified through GIDAP is adequate to ensure deliverability for the amount of resources identified as FCDS in all three portfolios. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-4, approximately 250 MW of renewable generation would be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-3: Deliverability assessment results – VEA-NVE 138 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Jackass Flats to Mercury Switch to Northwest 138 kV lines (including multiple NVE facilities)	Northwest – Desert View 230 kV	202% to 216%	179% to 193%	111% to 124%
	Innovation – Desert View 230 kV	173% to 187%	169% to 183%	110% to 124%
	Pahrump – Innovation 230 kV and Vista – Johnnie 138 kV	126%	105% to 113%	102% to 125%
	Pahrump – Innovation 230 kV and Pahrump – Vista 138 kV	<100%	101%	<100%

Table 3.5-4: VEA-NVE 138 kV deliverability constraint summary

Affected renewable zones	Southern NV (GLW-VEA)
Renewable MW affected	802 MW
Total generation behind the constraint	802 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	~250 MW

3.5.3.2 SDG&E area deliverability results

All the renewable zones in Southern California and zones outside of California that are likely to impact the deliverability assessment in the SDG&E study area are shown in Table 3.5-5.

Table 3.5-5: Renewable zones impacting deliverability out of SDG&E study area

	Deliverability study capacity (MW)		
Renewable zone	BASE	SENS 01	SENS 02
Riverside East and Palm Springs	360 (318 Solar + 42 Wind)	360 (318 Solar + 42 Wind)	42 Wind
Greater Imperial*	624 GeoT	624 GeoT	624 GeoT
SW_Ext_Tx (Southwest wind)	500 Wind	500 Wind	500 Wind
New Mexico wind (new Tx)	0	0	326 Wind

With the resource mix specified in Table 3.5-5 modeled in the base cases, the deliverability assessment identified the following constraints in the SDG&E study area:

Friars – Doublet Tap 138 kV constraint

The deliverability of renewable resources in the Greater Imperial zone is limited by thermal overloading of the Friars to Doublet Tap 138 kV line caused by the contingency shown in Table 3.5-6. This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to trip generation has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-7, approximately 239 MW of renewable generation would be expected to be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-6: Deliverability assessment results – Friars – Doublet Tap 138 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Friars-Doublet Tap 138 kV	Penasquitos-Old Town 230 kV and Sycamore-Penasquitos 230 kV	108%	109%	108%

Table 3.5-7: Friars – Doublet Tap 138 kV deliverability constraint summary

Affected renewable zones	Imperial
Renewable MW affected	406 MW
Total generation behind the constraint	1,969 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	239 MW

Silvergate – Old Town 230 kV constraint

The deliverability of renewable resources in the Greater Imperial zone is limited by thermal overloading of the Silvergate to Old Town 230 kV line caused by the contingencies shown in Table 3.5-8. This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to trip generation has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-9, approximately 1,960 MW of renewable generation would be expected to be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-8: Deliverability assessment results – Silvergate – Old Town 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Silvergate-Old Town 230 kV	Silvergate-Old Town-Mission 230 kv	110%	112%	110%
Silvergate-Old Town Tap 230 kV	Silvergate-Old Town 230 kV	112%	113%	111%

Table 3.5-9: Silvergate – Old Town 230 kV deliverability constraint summary

Affected renewable zones	Imperial
Renewable MW affected	2,385 MW
Total generation behind the constraint	4,585 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	1,960 MW

San Luis Rey – San Onofre 230 kV constraint

The deliverability of renewable resources in the Greater Imperial zone is limited by thermal overloading of the San Luis Rey to San Onofre 230 kV line No. 1 caused by the contingencies shown in this constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to trip generation has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-11, approximately 2,941 MW of renewable generation would be expected to be deliverable if the mitigation identified in GIDAP were not implemented.

This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to trip generation has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-11, approximately 2,941 MW of renewable generation would be expected to be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-10: Deliverability assessment results – San Luis Rey – San Onofre 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	103%	101%	102%

Table 3.5-11: San Luis Rey – San Onofre 230 kV deliverability constraint summary

Affected renewable zones	Imperial
Renewable MW affected	2,983 MW
Total generation behind the constraint	6,892 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	2,941 MW

Silvergate – Bay Boulevard 230 kV constraint

The deliverability of renewable resources in the Greater Imperial zone is limited by thermal overloading of the Silvergate to bay Boulevard 230 kV line caused by the contingencies shown in Table 3.5-13. This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to trip generation has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-13, 1,693 MW of renewable generation would be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-12: Deliverability assessment results – Silvergate – Bay Boulevard 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Silvergate-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1 and #2	116%	117%	116%
	Sycamore-Penasquitos 230 kV	109%	109%	109%

Table 3.5-13: Silvergate – Bay Boulevard 230 kV deliverability constraint summary

Affected renewable zones	Imperial
Renewable MW affected	2,385 MW
Total generation behind the constraint	4,459 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	1,693 MW

3.5.3.3 PG&E area deliverability results

Table 3.5-14 shows all the renewable zones in northern California and zones outside of California that are likely to impact the deliverability assessment in the PG&E study areas.

Table 3.5-14: Renewable zones impacting deliverability out of PG&E study areas

	Deliverability study capacity (MW)		
Renewable zone	BASE	SENS 01	SENS 02
Northern California	424 GeoT	424 GeoT	424 GeoT
Solano	0	581 Wind	581 Wind
Central Valley and Los Banos	146 Wind	146 Wind	146 Wind
Westlands	0	1,996 Solar	413 Solar
Greater Carrizo	0	895 Wind	895 Wind
NW_Ext_Tx (Northwest wind)	601 Wind	966 Wind	966 Wind

With the resource mix specified in Table 3.5-14 modeled in the base cases, the deliverability assessment identified the following constraints in PG&E study areas:

Round Mountain – Table Mountain 500 kV constraint

The deliverability of renewable resources in the Northern California zone mapped to the Round Mountain 230 kV bus is limited by thermal overloading of the Round Mountain to Table Mountain No. 1 and No. 2 230 kV lines caused by the contingencies shown in Table 3.5-15. This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to bypass series capacitors on the Round Mountain-Table Mountain #1 or #2 500 kV lines for outage/overload of either line has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in a RAS to trip generation for appropriate contingencies in order to achieve FCDS. As shown in Table 3.5-16, 20 MW of renewable generation would be deliverable if the RAS mitigation were not implemented.

Table 3.5-15: Deliverability assessment results – Round Mountain – Table Mountain 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Round Mountain-Table Mountain 500 kV Line # 1 or # 2	Round Mountain-Table Mountain Line # 1 or # 2	106	110	110
Round Mountain-Table Mountain 500 kV Line # 1 or # 2	Round Mountain-Table Mountain Line # 1 or # 2	106	110	110

Table 3.5-16: Round Mountain – Table Mountain 230 kV deliverability constraint summary

Affected renewable zones	Round Mountain
Renewable MW affected	424
Total generation behind the constraint	4145
Mitigation	Modify GIDAP RAS to drop Portfolio renewable generation
Deliverable renewable MW w/o mitigation	20 MW

Round Mountain – Cottonwood E. 230 kV constraint

The deliverability of renewable resources in the Northern California zone mapped to the Round Mountain 230 kV bus is limited by thermal overloading of the Round Mountain to Cottonwood E. 230 kV line caused by the contingency shown in Table 3.5-17. This constraint was identified in all three portfolios. Any representative generation modeled in the portfolios will need to participate in a RAS to trip generation for the appropriate contingency in order to achieve FCDS. As shown in Table 3.5-18, 252 MW of renewable generation would be deliverable if the RAS mitigation were not implemented.

Table 3.5-17: Deliverability assessment results – Round Mountain – Cottonwood E. 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Round Mountain-Cottonwood E 230 kV Line # 3	Round Mountain 500/230 kV T/F # 1	116	116	116

Table 3.5-18: Round Mountain – Cottonwood E. 230 kV deliverability constraint summary

Affected renewable zones	Round Mountain
Renewable MW affected	424
Total generation behind the constraint	1408
Mitigation	RAS to drop Portfolio renewable generation
Deliverable renewable MW w/o mitigation	252 MW

Delevan – Cortina 230 kV constraint

The deliverability of renewable resources in the Northern California zone mapped to the Round Mountain 230 kV bus is limited by thermal overloading of the Delevan to Cortina 230 kV line caused by the contingency of Round Mountain 500/230 kV transformer no. 1 shown in Table 3.5-19. This constraint was identified only in the base portfolio. Any representative generation modeled in the portfolios will need to participate in a RAS to trip generation for the appropriate contingency in order to achieve FCDS. As shown in Table 3.5-20, 186 MW of renewable generation would be deliverable if the RAS mitigation were not implemented.

Table 3.5-19: Deliverability assessment results – Delevan – Cortina 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Delevan-Cortina 230 kV Line	Round Mountain 500/230 kV T/F # 1	104		

Table 3.5-20: Delevan – Cortina 230 kV deliverability constraint summary

Affected renewable zones	Round Mountain
Renewable MW affected	424
Total generation behind the constraint	3906
Mitigation	RAS to drop Portfolio renewable generation
Deliverable renewable MW w/o mitigation	186 MW

Moss Landing – Los Aguilas 230 kV constraint

The deliverability of renewable resources in the Westlands zone is potentially limited by thermal overloading of the Moss Landing to Los Aguilas 230 kV line as shown in Table 3.5-21. This constraint was identified in all three portfolios. As long as the LCR requirement in Greater Bay area is met, this constraint is not expected to limit deliverability of resources identified in the three portfolios (Table 3.5-22).

Table 3.5-21: Deliverability assessment results – Moss Landing – Los Aguilas 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Moss landing-Las Aguilas 230 kV line	Base Case	106	109	111
	Moss Landing-Los Banos 500 kV line	105	112	108
	Tesla-Metcalf 500 kV Line	93	107	97

Table 3.5-22: Moss Landing – Los Aguilas 230 kV deliverability constraint summary

Affected renewable zones	Westland
Renewable MW affected	1,070
Total generation behind the constraint	3,000
Mitigation	Ensure that the LCR requirement is met in Greater Bay LCR Area
Deliverable renewable MW w/o mitigation	NA

Borden - Storey 230 kV constraint

The deliverability of renewable resources in the Westlands zone is limited by thermal overloading of the Borden to Storey 230 kV line caused by the contingencies shown in Table 3.5-23. This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and utilization of an existing series reactor at Wilson has been identified as a mitigation. As shown in Table 3.5-24, 289 MW of renewable generation would be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-23: Deliverability assessment results – Borden - Storey 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Borden-Storey # 1 230 kV line	Borden-Storey # 2 230 kV line	133	145	141
Borden-Storey # 2 230 kV line	Borden-Storey # 1 230 kV line	122	134	130

Table 3.5-24: Borden - Storey 230 kV deliverability constraint summary

Affected renewable zones	Westland
Renewable MW affected	1581
Total generation behind the constraint	4724
Mitigation	Insert Series Reactor at Wilson 230 kV/Area deliverability constraint in GIDAP Studies
Deliverable renewable MW w/o mitigation	289 (For worst overload)

GWF –Kingsburg 115 kV constraint

The deliverability of renewable resources in the Westlands zone is limited by thermal overloading of the Borden to Storey 230 kV line caused by the contingencies shown in Table 3.5-25. This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to trip generation has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-26, 695 MW of renewable generation would be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-25: Deliverability assessment results – GWF HEP – Contadina 115 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
GWF HEP-Contadina 115 kV / Contadina-Jackson Switching station/Jackson Switching Station to Kingsburg line	Base case	104	106	105
	Mustang-CSR09Swstation 230 kV line	106	112	107

Table 3.5-26: GWF HEP – Contadina 115 kV deliverability constraint summary

Affected renewable zones	Westland
Renewable MW affected	752
Total generation behind the constraint	854
Mitigation	RAS proposed in in GIDAP Studies
Deliverable renewable MW w/o mitigation	695 (For worst overload)

Dairyland - NewHall 115 kV constraint

The deliverability of renewable resources in the Westlands zone is limited by thermal overloading of the Dairyland – NewHall 115 kV line caused by the contingency shown in Table 3.5-27. This constraint was identified in all three portfolios. The same constraint has been previously identified in GIDAP and a RAS to trip generation has been identified as a mitigation. Any representative generation modeled in the portfolios will need to participate in this RAS in order to achieve FCDS. As shown in Table 3.5-28, 209 MW of renewable generation would be deliverable if the mitigation identified in GIDAP were not implemented.

Table 3.5-27: Deliverability assessment results – Dairyland – NewHall 115 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Dairyland-NewHall 115 kV line	Panoche-Mendota 115 kV line	104	104	104

Table 3.5-28: Dairyland – NewHall 115 kV deliverability constraint summary

Affected renewable zones	Westland
Renewable MW affected	226
Total generation behind the constraint	256
Mitigation	RAS proposed in GIDAP studies
Deliverable renewable MW w/o mitigation	209

Westlands area constraints observed only in the sensitivity portfolios

The deliverability of renewable resources identified in sensitivity portfolios in the Westlands zone is limited by thermal overloading of facilities as shown in Table 3.5-29.

Table 3.5-29: Deliverability assessment results – Westlands area Sensitivity only constraints

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 02
Wilson-Storey # 1 / # 2 230 kV lines	Wilson-Storey # 2/ # 1 230 kV lines	<100	104	<100
Gates-Mustang Switching Station # 1/ # 2 230 kV line	Gates-Mustang Switching Station # 2/ # 1 230 kV line	<100	101	<100
Gates- Calflat Switching Station 230 kV line	Midway-Caliente Switching Station # 1 & # 2 230 kV Lines	<100	105	113

Any representative generation modeled in these sensitivity portfolios will need to either participate in existing/proposed GIDAP RAS to trip generation or would rely on proposed GIDAP reconductor projects in order to achieve FCDS.

Gates 500/230 kV transformer banks constraint

As part of sensitivity 1 portfolio 1,400 MW of generation was modeled at the Gates 500 kV bus. Until the most recent interconnection cluster studies, most of the commercial interest near Gates was limited to the 230 kV system. Therefore the ISO tested the impact of modeling this one, 400 MW generation on the 230 kV system (SENS 01a) to gain insights about the impacts of this generation developing on the 230 kV system. Table 3.5-30 shows the Gates 500/230 kV transformer bank constraint.

Table 3.5-30: Deliverability assessment results – Gates 500/230 kV transformer banks constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS 01	SENS 01a
Gates bank # 11/12	Gates bank # 11/12	<100	<100	127

If the majority of generation in this zone develops on the 230 kV system then a deliverability upgrade such as a new Gates 500/230 kV bank as identified in GIDAP studies will be required to ensure FCDS for the portfolio resources.

3.6 Production cost simulation (PCM) study

3.6.1 PCM assumptions

The base portfolio and two sensitivity portfolios described in Section 3.4.4 were utilized for the PCM study during this 2019-2020 TPP policy-driven assessment. Details of PCM assumptions and development can be found in Chapter 4.

For each portfolio, two scenarios with different ISO net export limits were studied, a 2000 MW limit scenario and no export limit scenario, in order to estimate transmission related curtailment.

3.6.2 PCM results

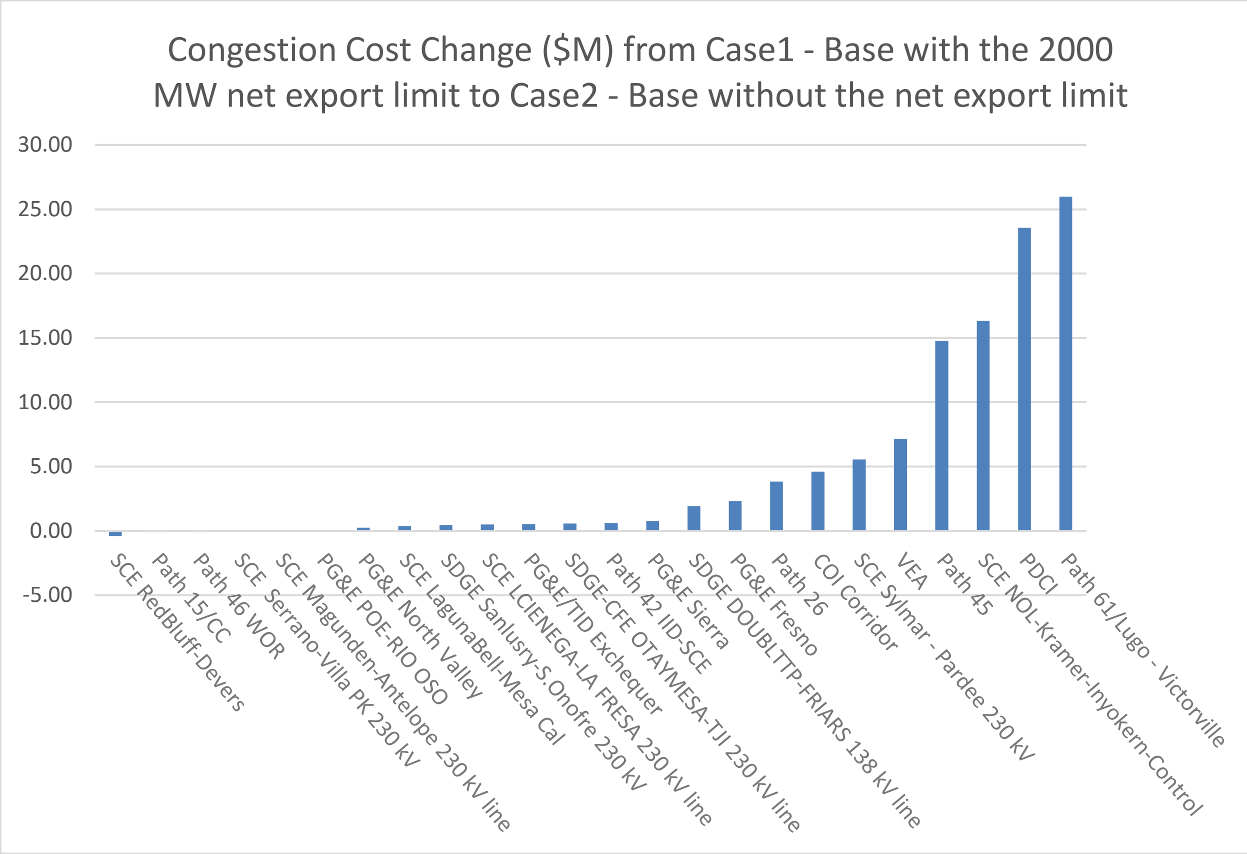
3.6.2.1 Congestion

Base Portfolio Congestion Results

The Base Portfolio was used in both the policy driven study and the economic driven study. The detailed congestion results of production cost simulation for the base portfolio are summarized in the economic assessment chapter (section 4.7.1).

Figure 3.6-1 shows the changes in congestion for the base portfolio from the scenario with the 2000 MW ISO export limit to the scenario with no export limit for the ISO. While most of the local transmission congestions remained unchanged or exhibited a slight change, congestion along major exporting corridors, such as PDCI, Path 45, and Path 61 increased.

Figure 3.6-1: Congestion changes for Base Portfolio between 2000 MW export limit and no export limit scenarios



Sensitivity 1 Portfolio Congestion Results

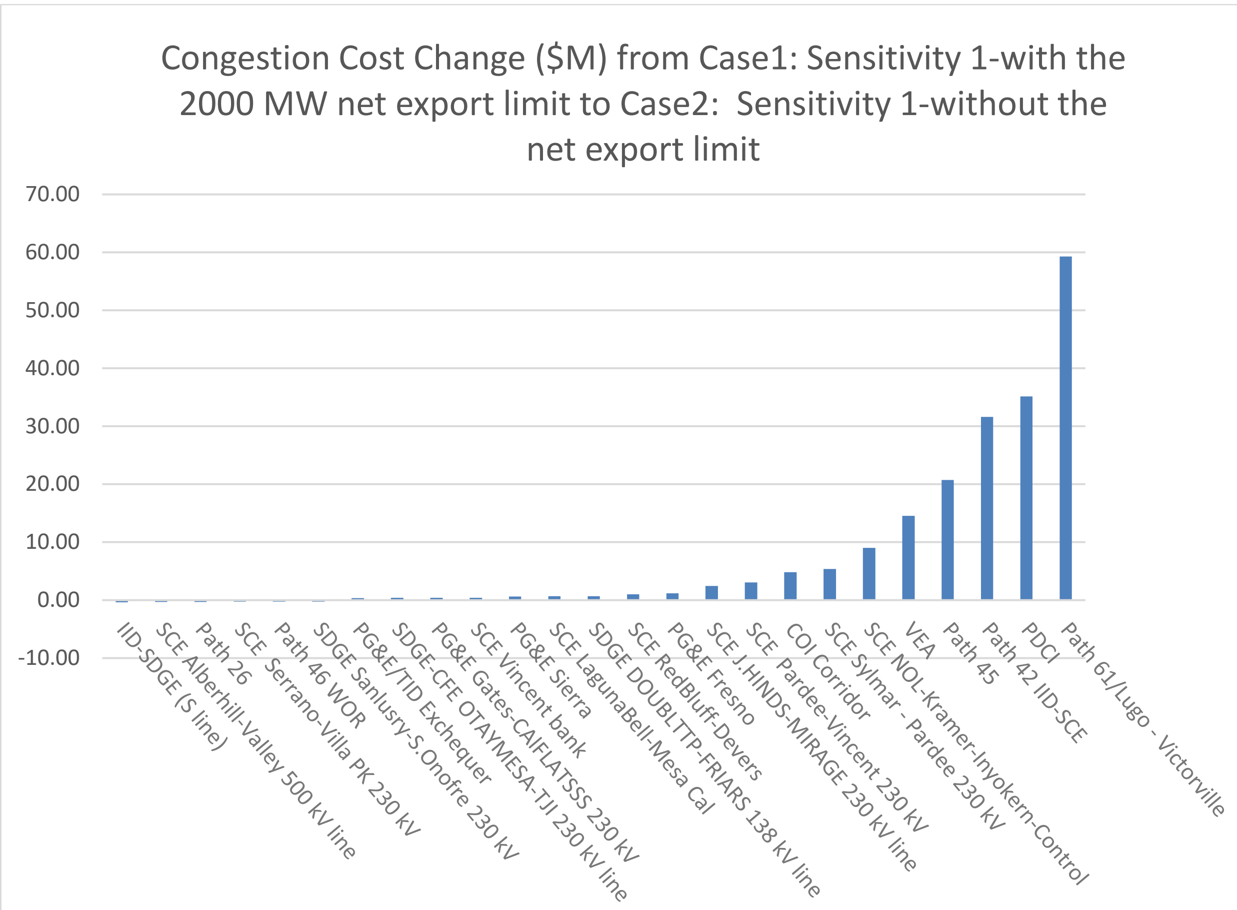
Table 3.6-1 lists the congestion summary results for the Sensitivity 1 portfolio scenario with the 2000 MW ISO net export limit. The constraints in this list are ranked in descending order of the total congestion cost.

Table 3.6-1: Congestion summary – Sensitivity 1 Portfolio with 2000 MW ISO net export limit

Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
Path 42 IID-SCE	50.00	1,060
COI Corridor	19.85	706
Path 26	5.29	257
VEA	5.17	1,017
PG&E/TID Exchequer	5.00	1,856
PDCI	4.41	583
SDGE DOUBLTTP-FRIARS 138 kV line	3.67	478
SCE Sylmar - Pardee 230 kV	3.50	267
SCE RedBluff-Devers	2.80	28
SDGE-CFE OTAYMESA-TJI 230 kV line	1.72	595
SCE Serrano-Villa PK 230 kV	1.41	10
IID-SDGE (S line)	1.40	94
PG&E Fresno	1.39	1,657
SCE NOL-Kramer-Inyokern-Control	1.05	517
SCE LagunaBell-Mesa Cal	1.04	27
Path 45	0.97	573
SDGE Sanlusry-S.Onofre 230 kV	0.45	32
SDGE IV-San Diego Corridor	0.41	14
SCE Alberhill-Valley 500 kV line	0.34	6
Path 46 WOR	0.27	22
San Diego	0.27	81
PG&E POE-RIO OSO	0.24	256
SCE J.HINDS-MIRAGE 230 kV line	0.15	42
PG&E Sierra	0.14	116
SCE LCIENEGA-LA FRESA 230 kV line	0.09	4
Path 61/Lugo - Victorville	0.05	5
Path 15/CC	0.05	6
PG&E North Valley	0.04	11
PG&E Gates-CAlFLATSSS 230 kV	0.02	5
SCE Pardee-Vincent 230 kV	0.02	3
PG&E Tesla-AEC 115 kV	0.01	2
PG&E GBA	0.01	10
Path 24	0.00	3

Assessing the Sensitivity 1 Portfolio revealed that congestion changes between the 2000 MW export limit and no export limit. As shown in Figure 3.6-2 the comparison between the scenarios show the changes in congestion for the Sensitivity 1 portfolio from the scenario with 2000 MW ISO export limit to the scenario without an export limit for the ISO. While most of local transmission congestions remained unchanged or exhibited a slight change, congestion along major exporting corridors, such as PDCI, Path 45, and Path 61 increased. About 1400 MW of solar generation was added in the Greater Imperial zone to the Sensitivity 1 portfolio, causing the congestion on Path 42 to increase compared to the base portfolio.

Figure 3.6-2: Congestion changes for Sensitivity 1 Portfolio between 2000 MW export limit and no export limit scenarios



Sensitivity 2 Portfolio Congestion Results

The congestion summary for the Sensitivity 2 Portfolio is shown in Table 3.6-2 which lists the congestion summary results of the for the Sensitivity 2 portfolio scenario with 2000 MW ISO net export limit. The constraints in this list are ranked in the descending order of total congestion cost.

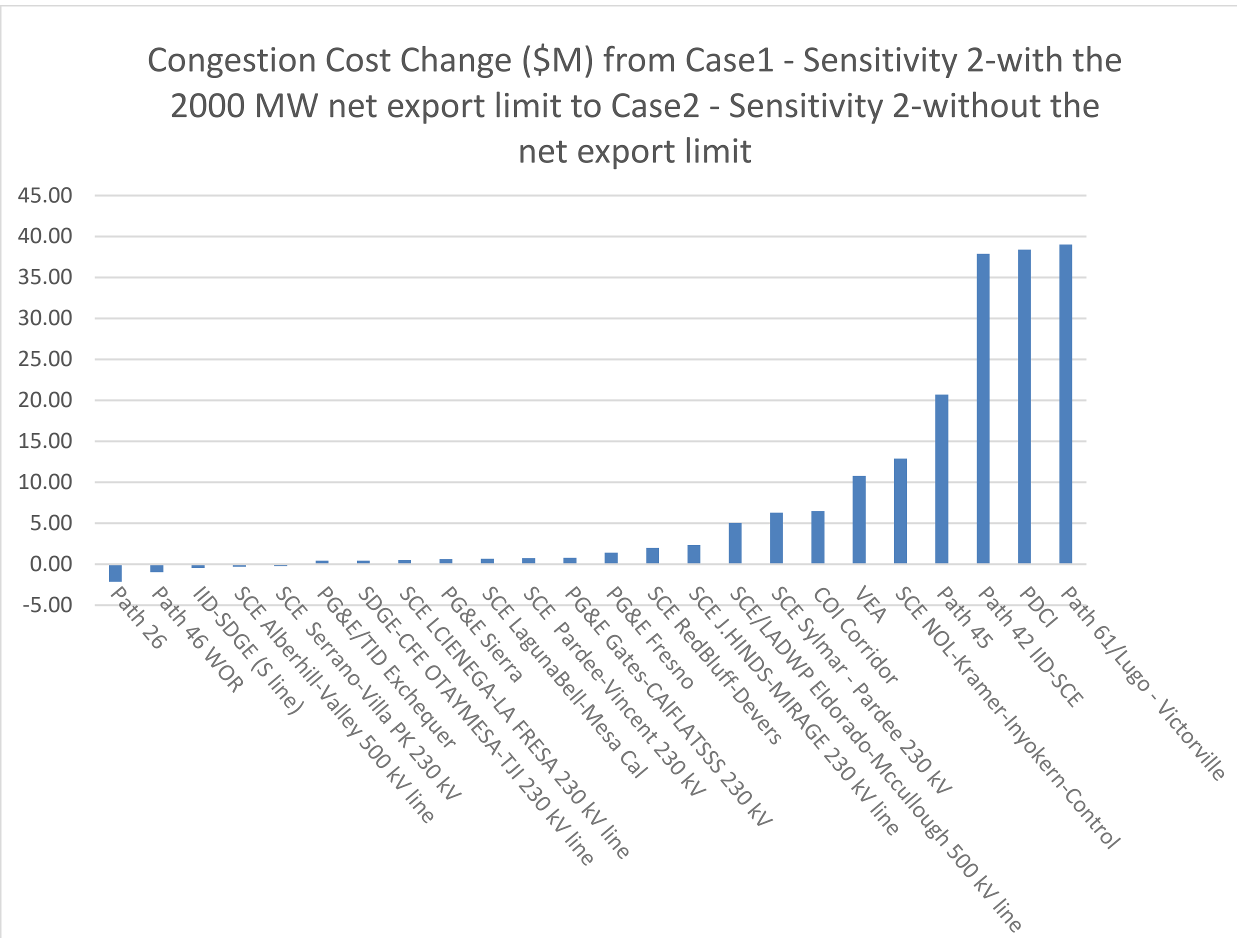
Table 3.6-2: Congestion summary – Sensitivity 2 Portfolio with 2000 MW ISO net export limit

Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
Path 42 IID-SCE	46.50	1,018
COI Corridor	18.89	637
Path 26	16.59	670
SDGE DOUBLTTP-FRIARS 138 kV line	5.82	615
PG&E/TID Exchequer	4.82	1,864
SCE RedBluff-Devers	4.35	44
PDCI	3.94	554
SCE Sylmar - Pardee 230 kV	3.16	278
SCE Serrano-Villa PK 230 kV	2.53	15
Path 46 WOR	2.22	73
IID-SDGE (S line)	2.14	157
PG&E Fresno	1.64	1,969
SCE NOL-Kramer-Inyokern-Control	1.47	448
SDGE-CFE OTAYMESA-TJI 230 kV line	1.44	530
SCE Alberhill-Valley 500 kV line	1.06	23
VEA	0.74	500
SCE LagunaBell-Mesa Cal	0.63	21
Path 45	0.55	394
SDGE IV-San Diego Corridor	0.39	17
Path 15/CC	0.34	25
SDGE Sanlusry-S.Onofre 230 kV	0.27	27
PG&E POE-RIO OSO	0.24	263
SCE LCIENEGA-LA FRESA 230 kV line	0.16	9
San Diego	0.15	70
PG&E Sierra	0.14	123
SCE/LADWP Eldorado-Mccullough 500 kV line	0.12	2
SCE J.HINDS-MIRAGE 230 kV line	0.12	37
SCE Mesa-Miraloma 500 kV line	0.07	1
PG&E North Valley	0.04	10
PG&E Gates-CAlFLATSSS 230 kV	0.04	19
Path 61/Lugo - Victorville	0.03	3
PG&E GBA	0.02	11
PG&E Tesla-AEC 115 kV	0.01	2

Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
Path 24	0.00	1

Congestion changes for the Sensitivity 2 Portfolio between the 2000 MW export limit and no export limit scenarios is shown in Figure 3.6-3 illustrates the changes in congestion for the Sensitivity 2 portfolio from the scenario with 2000 MW ISO export limit to the scenario without an export limit for the ISO. While most of local transmission congestions remained unchanged or exhibited a slight change, congestion along major exporting corridors, such as PDCI, Path 45, and Path 61 increased. Similar to the Sensitivity 1 results, due to the addition of solar generation in the Greater Imperial zone to the Sensitivity 2 portfolio, the congestion on Path 42 increased compared to the base portfolio.

Figure 3.6-3: Congestion changes for Sensitivity 2 Portfolio between 2000 MW export limit and no export limit scenarios



3.6.2.2 Curtailment

Base Portfolio Curtailment Results

The total wind and solar generation output and the total curtailment in the two scenarios in the base portfolio is shown in Table 3.6-3. Without enforcing an ISO net export limit, renewable curtailment reduced since the surplus generation can be exported to other regions. There were 2.34 TWh of curtailment in the ISO's system, which were caused mainly by transmission constraints.

Table 3.6-3: Wind and Solar generation and curtailment – Base Portfolio

Scenario	Base Portfolio with 2000 MW Net Export Limit	Base Portfolio without Net Export Limit
Total Wind and Solar Generation (TWh)	81.42	91.21
Total Curtailment (TWh)	12.12	2.34

The Wind and Solar generation and curtailment in Base Portfolio and No Export Limit Scenarios are shown in Figure 3.6-4 and Figure 3.6-5 and illustrates how the wind and solar generation output and curtailment by area for the 2000 MW Net Export Limit and No Export Limit scenarios vary, respectively. In terms of the magnitude of curtailment, the SCE Tehachapi, East of Lugo and Eastern areas had the most curtailment in the 2000 MW Net Export Limit scenario. In terms of percentage, the SCE East of Lugo and VEA areas had the highest percentages of curtailment, which was defined as curtailment divided by the summation of curtailment and generation output.

Figure 3.6-6: Curtailment changes between 2000 MW Net Export Limit and No Export Limit compares the curtailment by area between these two export limit scenarios. The SCE Tehachapi, East of Lugo and Eastern areas had the most reductions of renewable curtailment when the net export limit was relaxed. This was because the solar generation in these areas could export to other regions through adjacent tie lines.

Figure 3.6-4: Wind and Solar generation and curtailment in Base Portfolio – 2000 MW Net Export Scenario

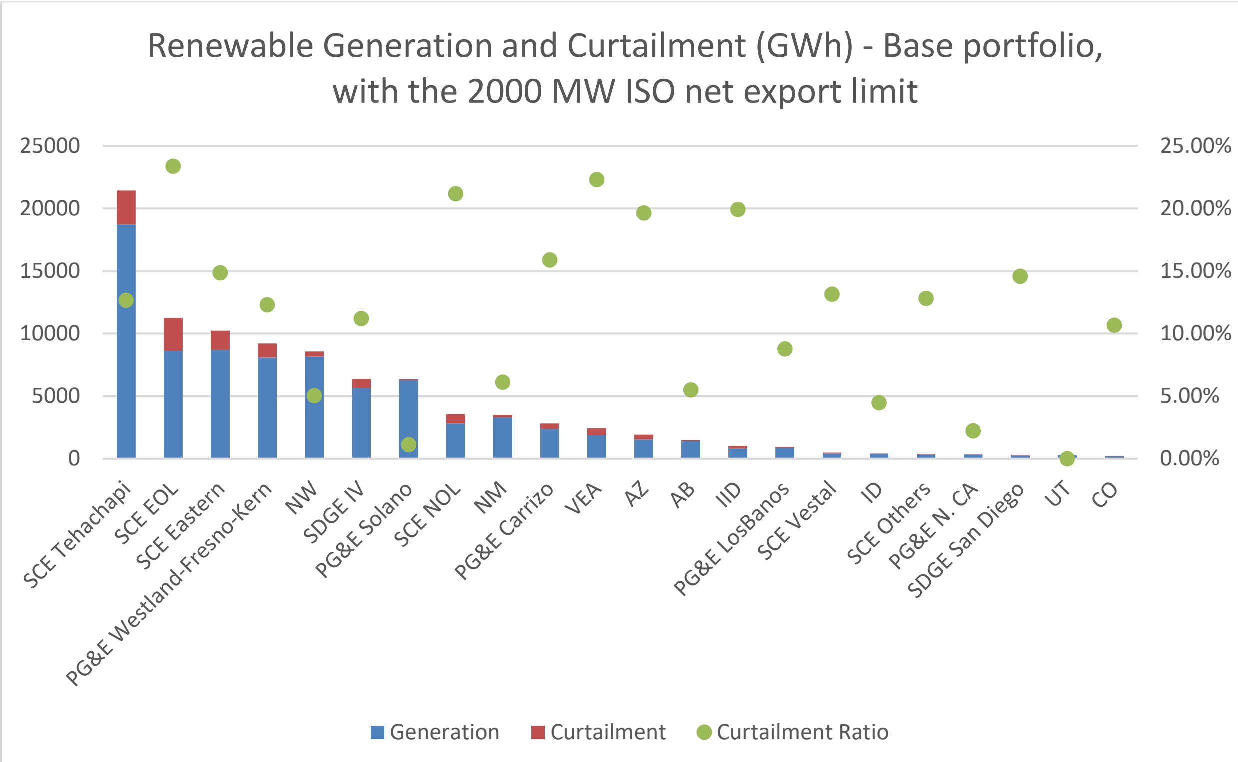


Figure 3.6-5: Wind and Solar generation and curtailment in Base Portfolio – No Export Limit Scenario

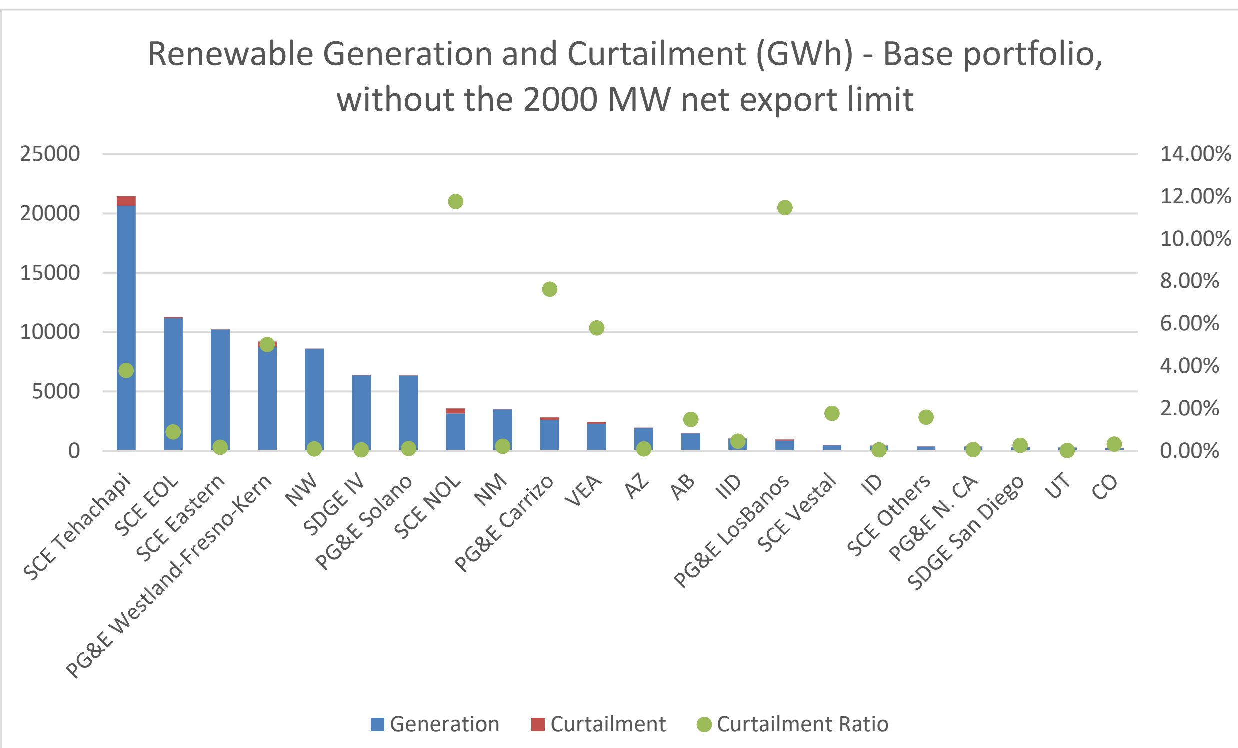
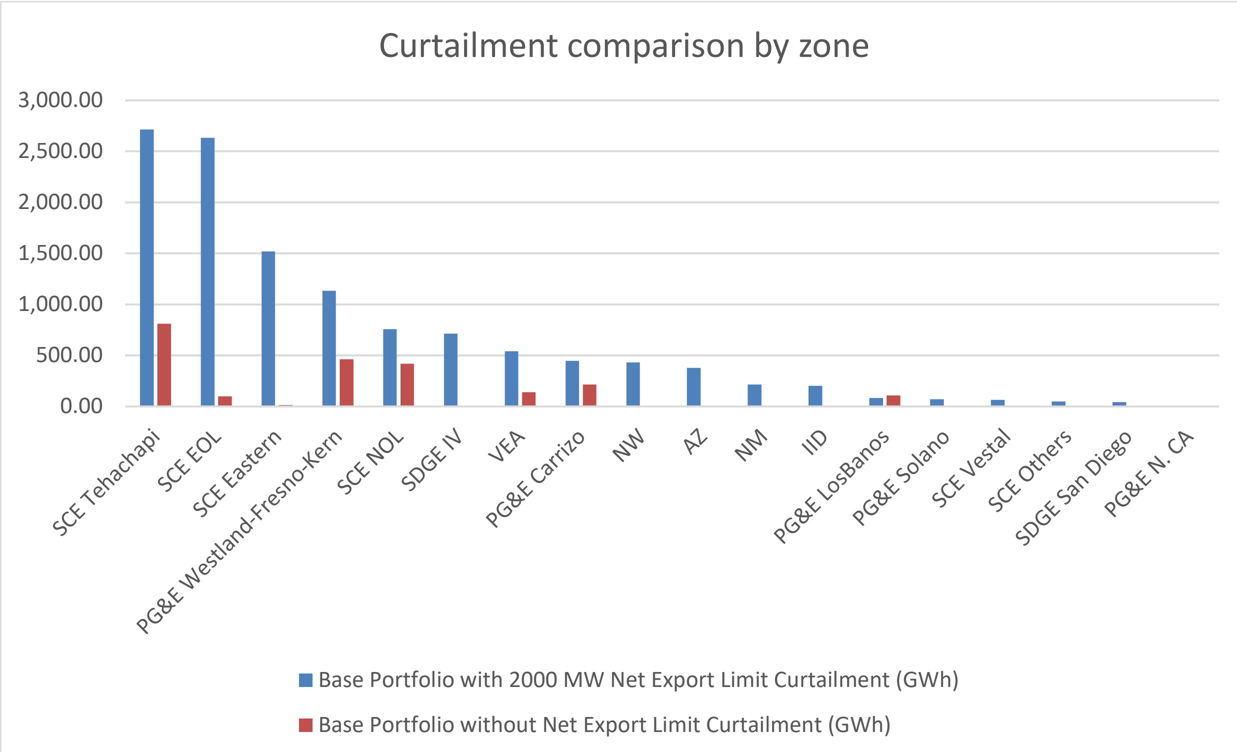


Figure 3.6-6: Curtailment changes between 2000 MW Net Export Limit and No Export Limit



Sensitivity 1 Portfolio Curtailment Results

Table 3.6-4 shows the total wind and solar generation output and the total curtailment in the two scenarios in the Sensitivity 1 portfolio. Without enforcing an ISO net export limit, renewable curtailment reduced since the surplus generation can be exported to other regions. There were 7.68 TWh of curtailment in the ISO's system, which were caused mainly by transmission constraints.

Table 3.6-4: Wind and Solar generation and curtailment – Sensitivity 1 Portfolio

Scenario	Sensitivity 1 with the 2000 MW net export limit	Sensitivity 1 without the net export limit
Total Wind and Solar Generation (TWh)	91.21	109.30
Total Curtailment (TWh)	25.77	7.68

Figure 3.6-4: Wind and Solar generation and curtailment in Base Portfolio – 2000 MW Net Export Scenario and Figure 3.6-8: Wind and Solar generation and curtailment in Sensitivity 1 Portfolio – No Export Limit Scenario show the wind and solar generation output and curtailment by area for the 2000 MW Net Export Limit and No Export Limit scenarios, respectively. In terms of the magnitude of curtailment, the SCE Tehachapi and Eastern areas and the PG&E Westland-Fresno-Kern area had the most curtailment in the 2000 MW Net Export Limit scenario. In terms of percentage, the IID area, and the SCE East of Lugo and North of Lugo

areas had the highest percentages of curtailment, which was defined as curtailment divided by the summation of curtailment and generation output .

Figure 3.6-9: Curtailment changes between 2000 MW Net Export Limit and No Export Limit shows the comparison of curtailment by area between these two export limit scenarios. The SCE Tehachapi, East of Lugo and Eastern areas had the most reductions of renewable curtailment when the net export limit was relaxed. This was because the solar generation in these areas could export to other regions through adjacent tie lines. The PG&E Westland-Fresno-Kern area had some reduction in curtailment but remained heavily curtailed.

Figure 3.6-7: Wind and Solar generation and curtailment in Sensitivity 1 Portfolio – 2000 MW Net Export Scenario

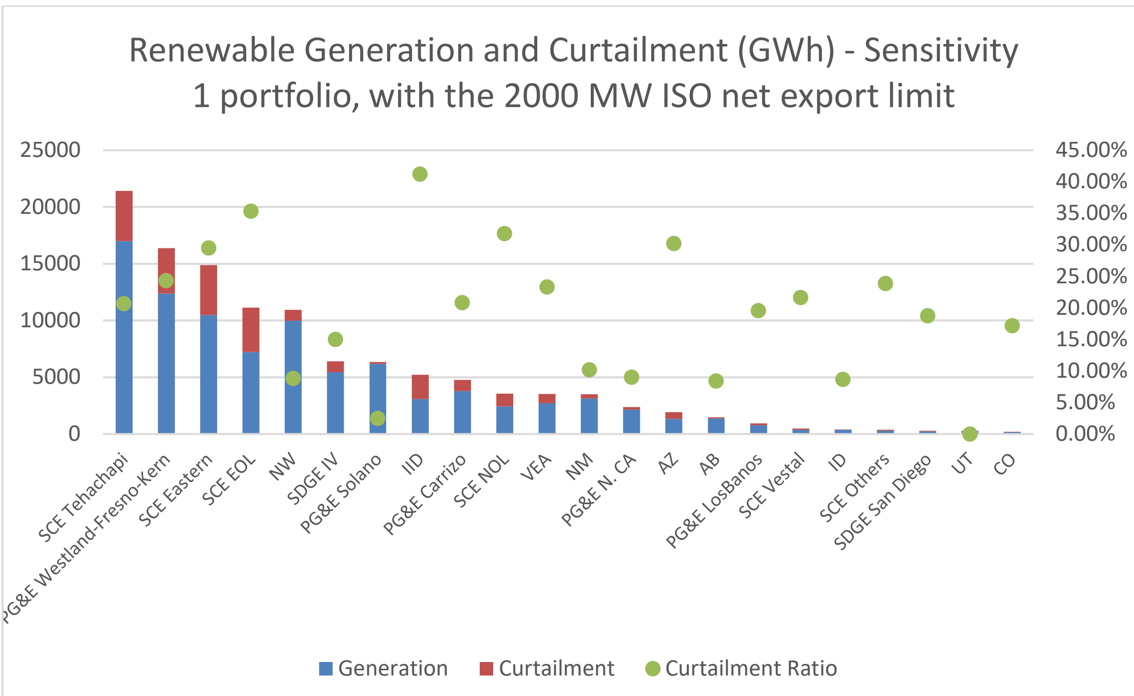


Figure 3.6-8: Wind and Solar generation and curtailment in Sensitivity 1 Portfolio – No Export Limit Scenario

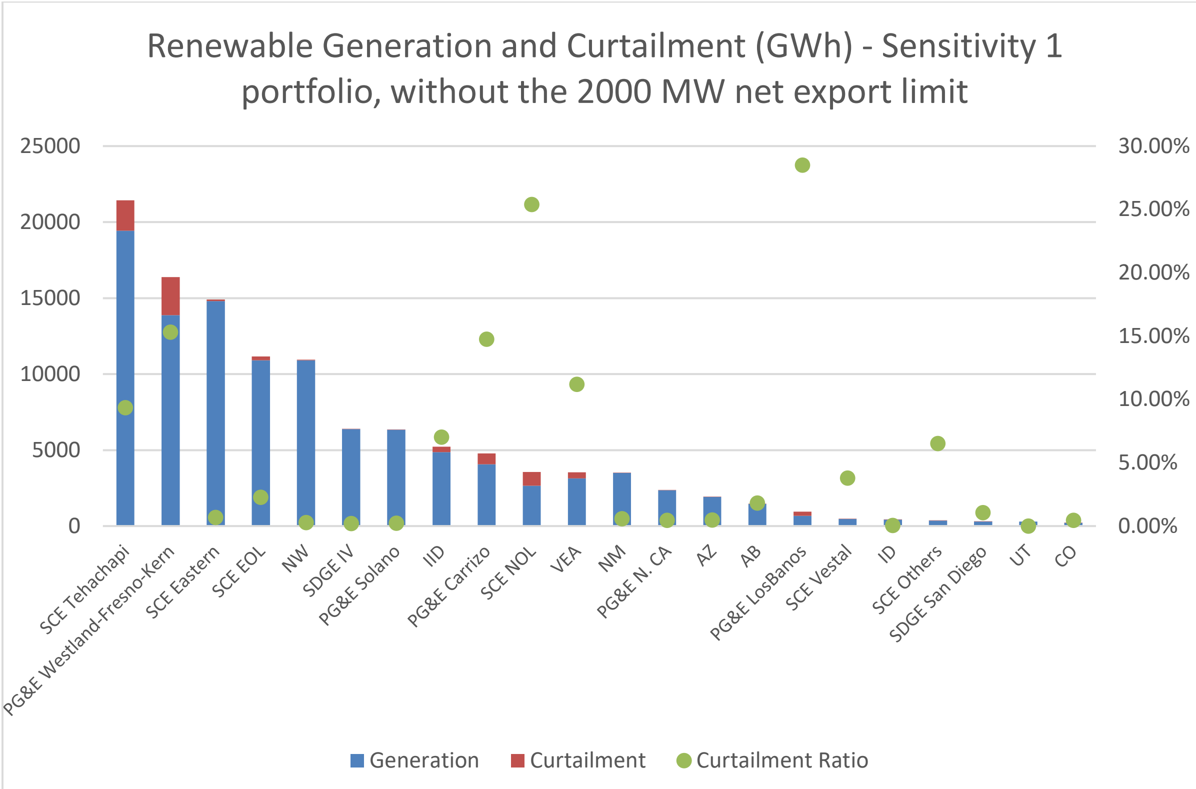
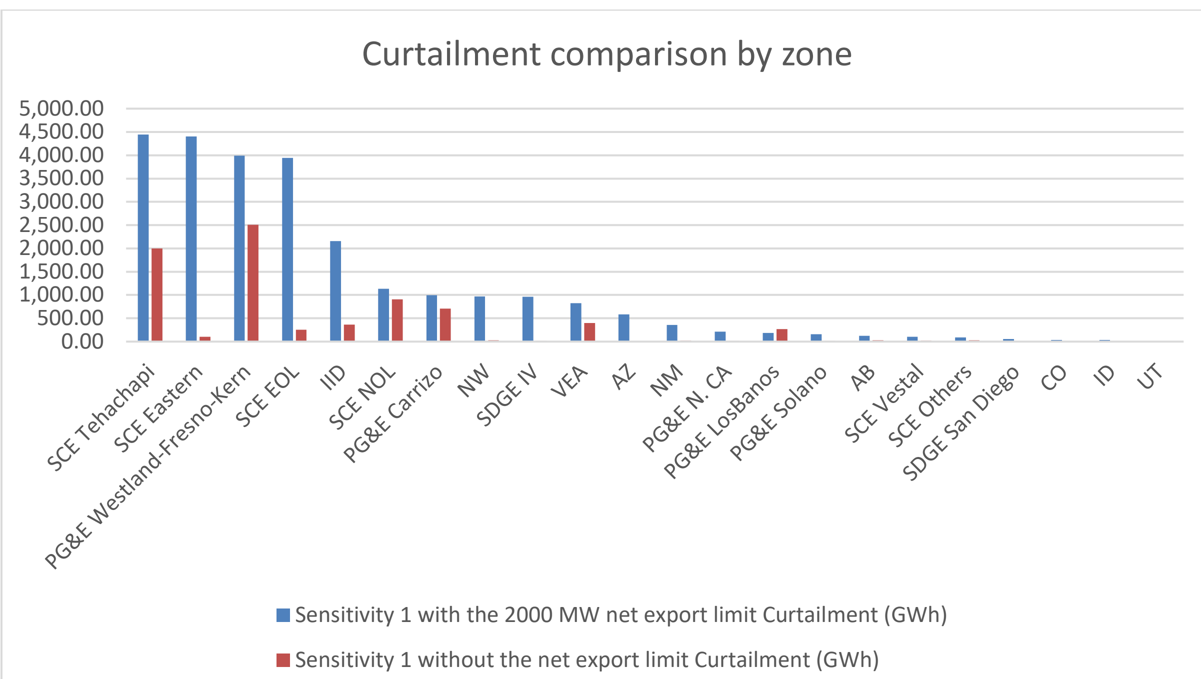


Figure 3.6-9: Curtailment changes between 2000 MW Net Export Limit and No Export Limit



Sensitivity 2 Portfolio Curtailment Results

Table 3.6-5: Wind and Solar generation and curtailment – Sensitivity 2 Portfolio shows the total wind and solar generation output and the total curtailment in the two scenarios in the Sensitivity 2 portfolio. Without enforcing an ISO net export limit, renewable curtailment reduced since the surplus generation can be exported to other regions. There were 7.04 TWh of curtailment in the ISO's system, which were caused mainly by transmission constraints.

Table 3.6-5: Wind and Solar generation and curtailment – Sensitivity 2 Portfolio

Scenario	Sensitivity 2 with the 2000 MW net export limit	Sensitivity 2 without the net export limit
Total Wind and Solar Generation (TWh)	93.88	112.00
Total Curtailment (TWh)	25.16	7.04

Figure 3.6-10: Wind and Solar generation and curtailment in Sensitivity 2 Portfolio – 2000 MW Net Export Scenario and Figure 3.6-11: Wind and Solar generation and curtailment in Sensitivity 2 Portfolio – No Export Limit Scenario show the wind and solar generation output and curtailment by area for the 2000 MW Net Export Limit and No Export Limit scenarios, respectively. In terms of the magnitude of curtailment, the SCE Tehachapi and Eastern areas and the PG&E Westland-Fresno-Kern area had the most curtailment in the 2000 MW Net Export Limit scenario. In terms of percentage, the IID area, and the SCE East of Lugo and North of Lugo areas had the highest percentages of curtailment, which was defined as curtailment divided by the summation of curtailment and generation output.

Figure 3.6-12: Curtailment changes between 2000 MW Net Export Limit and No Export Limit shows the comparison of curtailment by area between these two export limit scenarios. The SCE East of Lugo and Eastern areas had the most reductions of renewable curtailment when the net export limit was relaxed. This was because the solar generation in these areas could export to other regions through adjacent tie lines. The PG&E Westland-Fresno-Kern area and the SCE Tehachapi area had some reduction in curtailment, but remained heavily curtailed.

Figure 3.6-10: Wind and Solar generation and curtailment in Sensitivity 2 Portfolio – 2000 MW Net Export Scenario

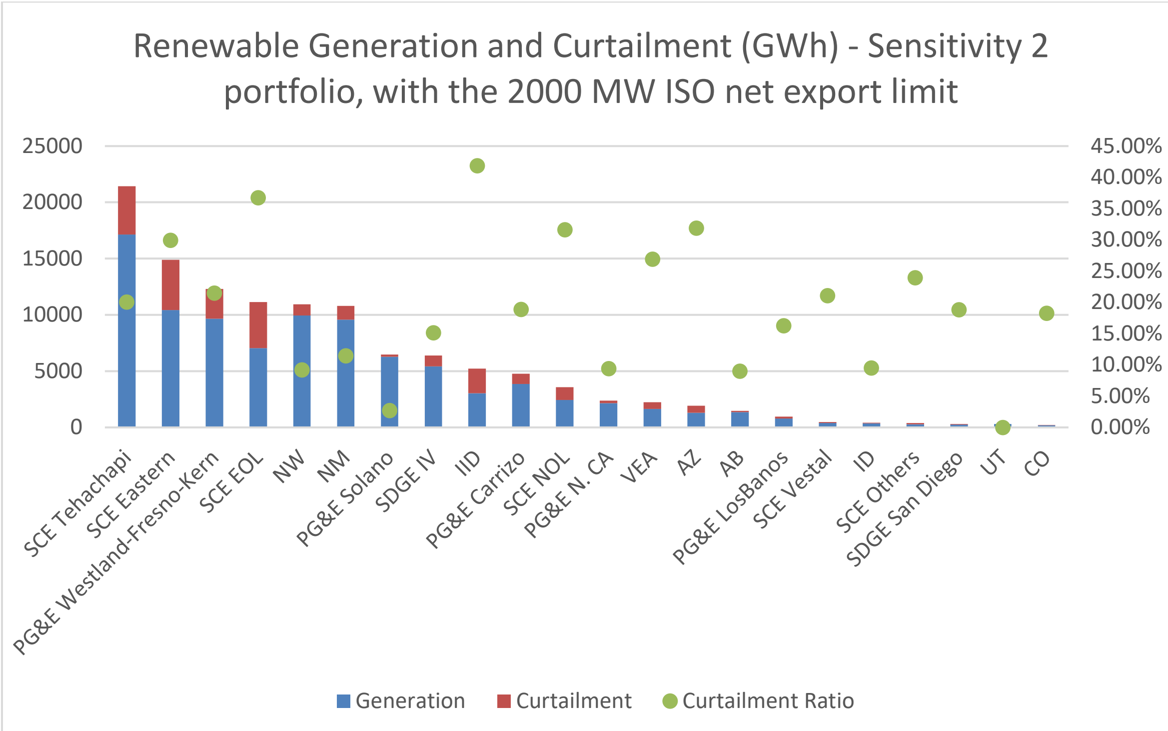


Figure 3.6-11: Wind and Solar generation and curtailment in Sensitivity 2 Portfolio – No Export Limit Scenario

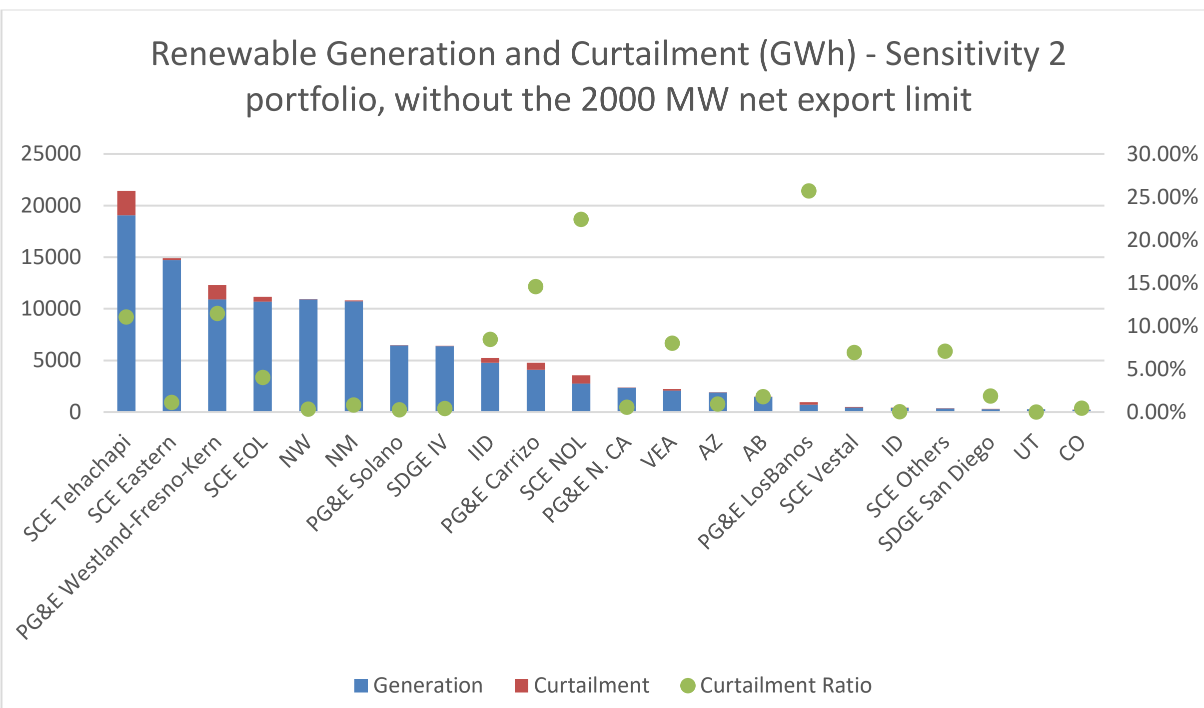
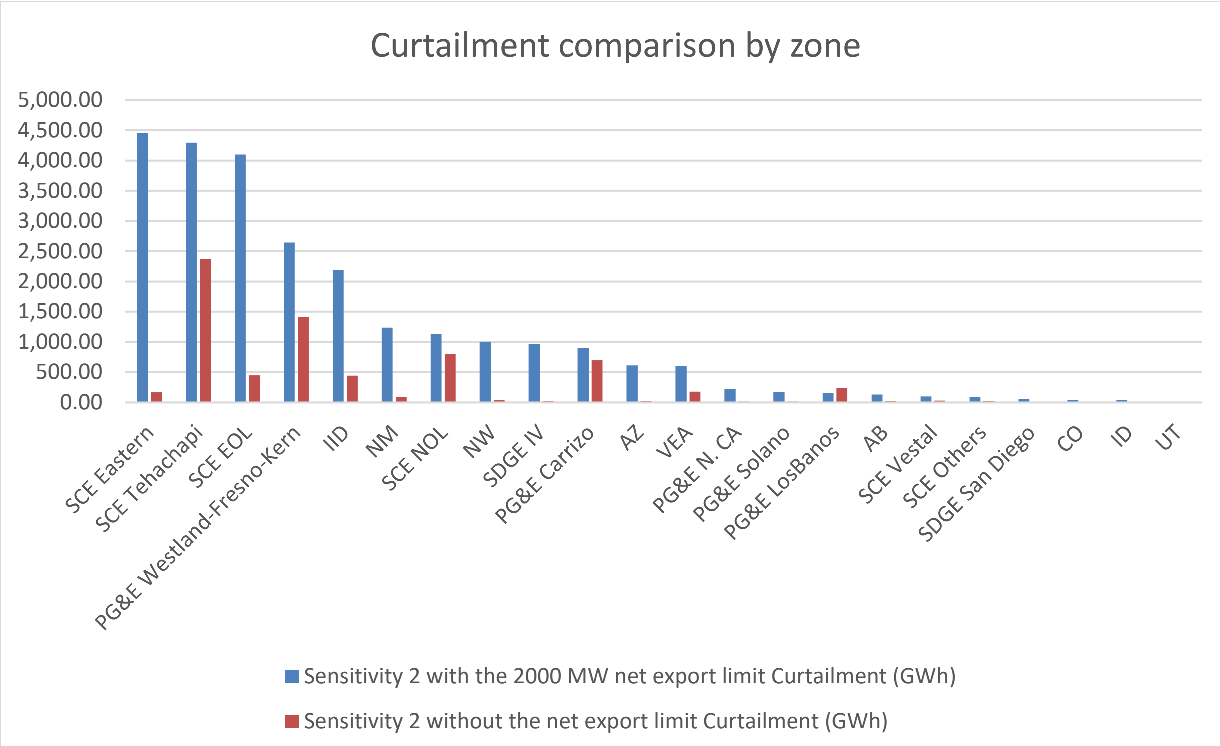


Figure 3.6-12: Curtailment changes between 2000 MW Net Export Limit and No Export Limit



3.7 Reliability assessment of snapshots

3.7.1 Starting base cases

The ISO utilized the 2029 summer peak base case developed for Northern California bulk system and Southern California Bulk system assessments described in Chapter 2 for the purpose of creating base cases for the snapshot study. The ISO team added the resources selected as part of the base, sensitivity #1 and sensitivity #2 portfolios as generic equivalent models to this consolidated ISO base case. The team relied on the resource mapping provided by the CEC staff as explained in Section 3.4.5.

3.7.2 Snapshot identification for power flow studies

Production cost simulations were 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. Hours that represent transmission system stress patterns for the snapshot study purpose were reviewed to aid in identifying transmission bottlenecks that would cause excessive renewable curtailment at times when system wide oversupply is unlikely.

Such hours tend to demonstrate the following attributes which form the critical factors for identification of study hours from the PCM output:

1. High renewable potential in the study area

   Hours with high renewable potential (dispatch + curtailment reported in PCM) were examined for the snapshot study because renewable dispatch in the PCM output reflects any curtailment that may have been caused by transmission congestion. The snapshot study intends to look at transmission bottlenecks before generation curtailment is applied to uncover issues that have not been captured in the PCM simulations.

2. Load levels at or above 65% to 70% of the hourly peak

   The hours analyzed under this snapshot study should capture a reasonable scenario for load and generation without coinciding with a system oversupply situation. Severe curtailment observed under scenarios when the system load is less than 65% can tend be attributed to an oversupply situation. Because the focus is on identifying hours when transmission bottlenecks are the sole cause of the renewable curtailment, it is prudent to focus on hours when the system load is greater than 65% of the annual peak. Depending on the study area, this criteria was applied to either the ISO BA load or to the study area load (Northern CA or Southern CA) or to both.

3. High imports into the study area

   In certain study areas such as Westlands and Northern CA, specific path flows indicate stressed transmission system. In case of import paths, oversupply conditions are less likely to occur during the hours from the PCM output that show high flows. This criteria was used to narrow down the list of candidate hours identified after applying the first three criteria.

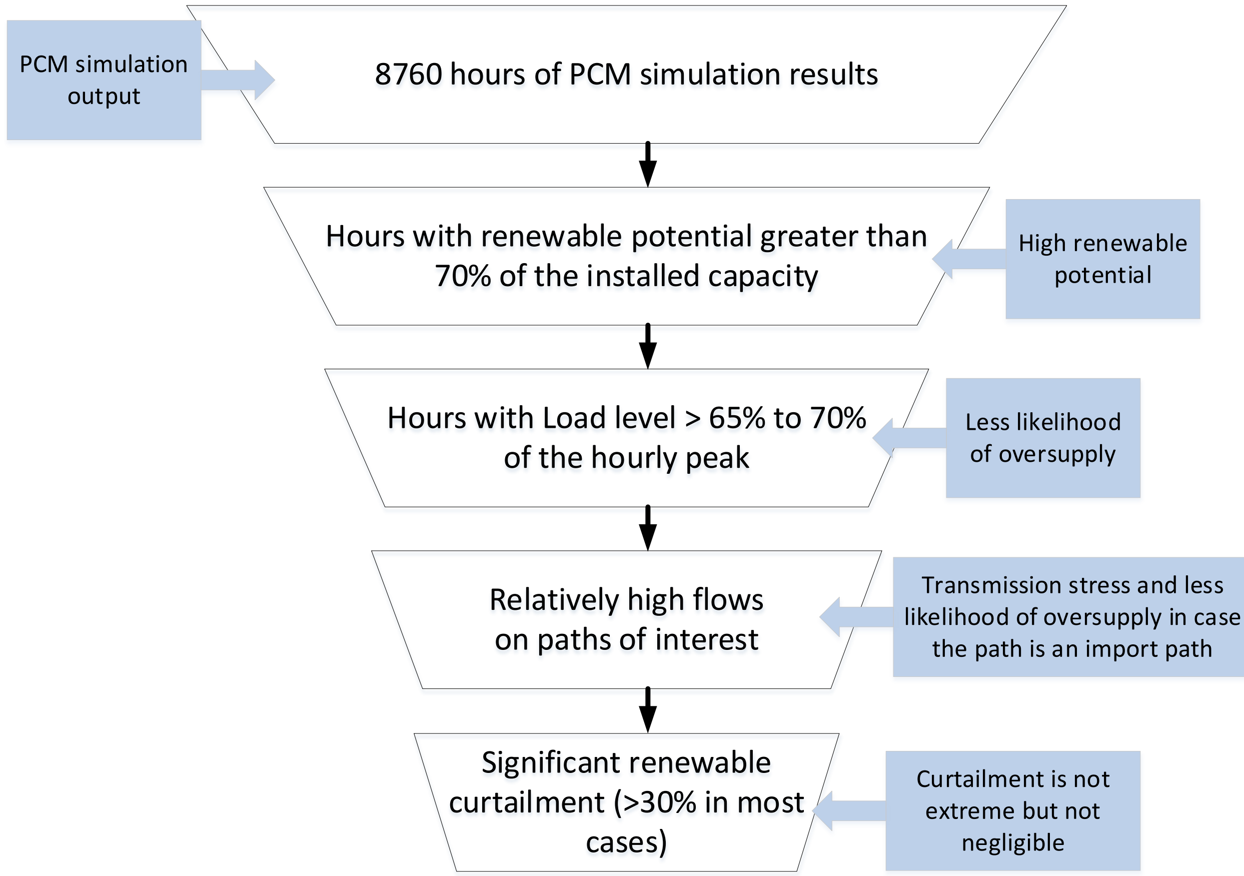
4. Renewable curtailment is neither extreme nor negligible

   After applying the first three criteria, the PCM output was examined for renewable curtailment in the study area or interest for each portfolio. In all study areas except for the Northern CA study area, the PCM simulation output showed a curtailment of more than 30% of the available renewable energy. The Northern CA area snapshot identification placed a higher weightage on finding an hour with high stressed path flows on Path 66 (COI), Path 26 and Path 15.

Compared to the two sensitivity portfolios the base portfolio consisted of significantly lower renewable buildout in the Northern and Central CA study areas. Therefore a snapshot study was not performed for the base portfolio in those areas.

The process followed for the identification of snapshots and the specific snapshots identified for the in-state and out-of-state portfolios to be studied for potential reliability issues are shown in Figure 3.7-1.

Figure 3.7-1: Snapshot selection for power flow studies



As a result, the hours shown in Table 3.7-1 were identified for the reliability assessment of snapshots for the three portfolios:

Table 3.7-1: Hours identified for reliability assessment of snapshots

	Northern CA and Southern PG&E	Southern CA
BASE	None	August 17 Hr Ending (HE) 12
SENS-01	March 08 HE 10	August 16 HE 12
SENS-02	July 20 HE 20	July 31 HE 15

A reliability assessment of the snapshots was performed based on a renewable resources dispatch that reflected the renewable potential (the PCM output level plus the curtailed amount) instead of the renewable output. The renewable curtailment in the production cost simulation could be due to ISO system-wide over-supply or transmission congestion. One of the key objectives of this snapshot assessment was to capture any area-wide constraints or significant interconnection issues that need to be modeled in the production cost simulations in order to more accurately capture the renewable curtailment caused by transmission congestion. Therefore, in order to identify such constraints for screening purposes, the renewable dispatch in power flow cases was based on the available renewable production before curtailment that resulted from the security constrained economic dispatch model. This approach to the selection and assessment of snapshots based on renewable potential provides insights about transmission constraints and interconnection issues that may not be (in some cases cannot be) captured in production cost simulations.

3.7.3 Power flow results

3.7.3.1 Summary of Northern CA portfolio reliability assessment

The reliability study was performed for the two sensitivity portfolios – SENS-01 and SENS-02 due to higher amount of total portfolio resources selected in these portfolios compared to the base portfolio. The reliability study was not conducted for the base portfolio as a part of the policy assessment as there was no significant generation within the northern califironia area requiring additional assessment behond the reliability assessment in chapter 2.

The study hour selected for the SENS-01 portfolio was the March 8th 2029 HE 10 snapshot which resulted in high South to North Path 15 flows (~4000 MW) and high South to North Path 26 flows (~2500 MW). The PG&E load was around 60% of the hourly peak and the total renewable potential (renewable dispatch plus curtailment) was between 70% and 75% in the Southern PG&E Area. This snapshot was selected in order to identify thermal issues in the Westlands, Los Banos and Carrizo zones.

The study hour selected for the SENS-02 portfolio was the July 20th 2029 HE 20 snapshot which resulted in high North to South Path 66 flows (~4347 MW), high South to North Path 26 flows(~2900 MW) and high wind generation (~74% of Pmax).This snapshot was selected in order to identify reliability issues around COI and Solano areas caused by conditions that are more severe than the ones studied as part of the deliverability studies.

A summary of resource nameplate amounts selected in Northern CA zones are shown in Table 3.7-2. These values were modeled in the respective base cases for the purpose of this reliability assessment.

Table 3.7-2: Summary of portfolio resources in Northern CA (nameplate MW)

Renewable zone	BASE			BASE-Total	SENS-01			SEN-01-Total	SENS-02			SEN-02-Total
	Solar	Wind	GeoT		Solar	Wind	GeoT		Solar	Wind	GeoT	
Northern California	0	0	424	424	750	0	424	1174	750	0	424	1174
Solano	0	643	0	643	0	643	0	643	40	643	0	683
Central Valley and Los Banos	0	146	0	146	0	146	0	146	0	146	0	146
Westlands	0	0	0	0	2699	0	0	2699	1116	0	0	1116
Greater Carrizo	0	160	0	160	0	1095	0	1095	0	1095	0	1095
NW wind (over existing Tx)	0	601	0	601	0	1500	0	1500	0	1500	0	1500

The major overloads that were observed for the SENS-01 portfolio are shown in Table 3.7-3. These overloads were primarily driven by renewable generation (existing, contracted and portfolio resources) after the case was P0-P1 contingency secured by reflecting curtailment of conventional generation.

Table 3.7-3: Reliability issues observed in Westlands and Carrizo zones

Limiting Element	Contingency	Type	SENS-01 Overload (%)	Renewable Zones Impacted	Potential Mitigation
Moss Landing-Las Aguillas 230kV Line	Base Case	P0	103%	Westlands	Ensure LCR requirement is met in Bay Area
Leprino Sw STa-GWF 115kV Line	P2-3:A14:19:_MUSTANGSS 230kV - Middle Breaker Bay 3	P2-3	115%	Westlands	Update 18RSMTRAS-04 RAS
GWF-Contandina 115kV Line	P2-3:A14:19:_MUSTANGSS 230kV - Middle Breaker Bay 3	P2-3	115%	Westlands	Update 18RSMTRAS-04 RAS
Jackson SS-Contandina 115kV line	P2-3:A14:19:_MUSTANGSS 230kV - Middle Breaker Bay 3	P2-3	115%	Westlands	Update 18RSMTRAS-04 RAS
Leprino Sw STa-GWF 115kV Line	P7-1:A14:4:_MUSTANGSS-GATES #1 230kV & MUSTANGSS-GATES #2 230kV	P7	157%	Westlands	Update 18RSMTRAS-04 RAS
GWF-Contandina 115kV Line	P7-1:A14:4:_MUSTANGSS-GATES #1 230kV & MUSTANGSS-GATES #2 230kV	P7	157%	Westlands	Update 18RSMTRAS-04 RAS
Jackson SS-Contandina 115kV line	P7-1:A14:4:_MUSTANGSS-GATES #1 230kV & MUSTANGSS-GATES #2 230kV	P7	157%	Westlands	Update 18RSMTRAS-04 RAS
Leprino SW Station-Henrietta 115kV Line	P7-1:A14:4:_MUSTANGSS-GATES #1 230kV &	P7	121%	Westlands	Update 18RSMTRAS-04 RAS

Limiting Element	Contingency	Type	SENS-01 Overload (%)	Renewable Zones Impacted	Potential Mitigation
	MUSTANGSS-GATES #2 230kV				
Henrietta 230/115kV TB	P7-1:A14:4:_MUSTANGSS-GATES #1 230kV & MUSTANGSS-GATES #2 230kV	P7	121%	Westlands	Update 18RSMTRAS-04 RAS
Kingsburg-Jackson SS #1 115kV Line	P7-1:A14:4:_MUSTANGSS-GATES #1 230kV & MUSTANGSS-GATES #2 230kV	P7	109%	Westlands	Update 18RSMTRAS-04 RAS
Kingsburg-Jackson SS #2 115kV Line	P7-1:A14:4:_MUSTANGSS-GATES #1 230kV & MUSTANGSS-GATES #2 230kV	P7	107%	Westlands	Update 18RSMTRAS-04 RAS
San Miguel- Estrella 70kV Line	P7-1:A14:14:_TEMPLETON-GATES 230kV & GATES-CALFLATSSS #1 230kV	P7	145%	Westlands	Proposed C12 GIP Upgrade to reconductor line. SPS not feasible due to many SPS in the Area
San Miguel- Coalinga 70kV Line	P7-1:A14:14:_TEMPLETON-GATES 230kV & GATES-CALFLATSSS #1 230kV	P7	127%	Westlands	Proposed C12 GIP Upgrade to reconductor line. SPS not feasible due to many SPS in the Area
Gates-CalFlats 230kV Line	P2-2:A20:26:_TEMPLETN 230kV Section 1D	P2-2	100%	Carrizo	C12 issue mitigated by ADNU/Carrizo SPS
Gates-CalFlats 230kV Line	P7-1:A15:16:_Caliente Sw Sta - Midway #1 & #2 230 kV Lines	P7	142%	Carrizo	C12 issue mitigated by ADNU
Gates-CalFlats 230kV Line	P7-1:A20:15:_MIDWAY-CALNTESS 230 kV Line No. 1 & 2	P7	142%	Carrizo	C12 issue mitigated by ADNU
Gates-CalFlats 230kV Line	P7-1:A10:14:_SOLARSS-CALNTESS 230 kV Line No. 1 & 2	P7	120%	Carrizo	Update Carrizo SPS
Morro Bay- Estrella 230kV Line	P7-1:A20:15:_MIDWAY-CALNTESS 230 kV Line No. 1 & 2	P7	106%	Carrizo	Update Carrizo RAS as per C12
Morro Bay- Estrella 230kV Line	P7-1:A15:16:_Caliente Sw Sta - Midway #1 & #2 230 kV Lines	P7	106%	Carrizo	Update Carrizo RAS as per C12

Limiting Element	Contingency	Type	SENS-01 Overload (%)	Renewable Zones Impacted	Potential Mitigation
Templeton-Paso Robles 70kV Line	P7-1:A20:12:_Morro Bay-CalFlats SS and Templeton-Gates 230 kV Lines	P7	100%	Carrizo	Update Carrizo SPS

Some of the reliability issues seen in the studies were also seen in the TPP reliability studies and the incremental impact of the sensitivity and renewable generation was not significant.

Key findings for the Northern CA and Westlands zone are:

- Localized issues that would limit renewable generation were identified in the reliability assessment of the portfolio resources in the Westlands zone.
- Reliability issues observed in the Westlands zone were caused by Normal system conditions as well as by contingencies involving breaker faults at Mustang 230 kV substation and double line outages of MUSTANGSS-GATES #1 230kV & MUSTANGSS-GATES #2 230kV
- Potential mitigations for these issues include (i) post-contingency generation curtailment, and (ii) remedial action schemes (RAS) to trip generation as result of a contingency.
- Either of the mitigation measures mentioned above are likely to result in renewable curtailment because curtailment of conventional generation in this area was found to not be adequate to mitigate the overloads listed in Table 3.7-4.

Key findings for the Northern CA and Carrizo zone are:

- Localized issues that would limit renewable generation were identified in the reliability assessment of the portfolio resources in the Carrizo zone.
- Reliability issues observed in the Carrizo zone were caused by contingencies involving breaker faults at Templeton 230 kV substation and double line (P7) outages out of Midway and Gates 230 kV stations.
- Potential mitigations for these issues include (i) post-contingency generation curtailment, (ii) remedial action schemes (RAS) to trip generation as result of a contingency and (iii) Reconductoring of line.
- Either of the mitigation measures mentioned above are likely to result in renewable curtailment because curtailment of conventional generation in this area was found to not be adequate to mitigate the overloads listed in Table 3.7-4.

Table 3.7-4 also shows major overloads that were observed for the SENS-02 portfolio. These overloads were primarily driven by renewable generation (existing, contracted and portfolio resources) after the case was P0-P1 contingency secured by reflecting curtailment of conventional generation.

Table 3.7-4: Reliability issues observed in Solano zone

Limiting Element	Contingency	Type	SENS-02 Overload (%)	Renewable Zones Impacted	Potential Mitigation
Vaca Dixon –Lambie 230 kV line	P2-3:A4:3:_BDLSWSTA 230KV - MIDDLE BREAKER BAY 2	P2-3	120%	Solano	Existing issue-Increased Curtailment of existing renewable generation will be required or a RAS to trip generation after the contingency
Lambie-Birdslanding 230 line	P2-3:A4:3:_BDLSWSTA 230KV - MIDDLE BREAKER BAY 2	P2-3	104%		

The 115 kV reliability issues seen in the studies were also seen in the TPP reliability studies and the incremental impact of the sensitivity and renewable generation was not significant. The 60 kV overloads seen in the study were Non-BES overloads and hence beyond the scope of this analysis.

Key findings for the Northern CA and Solano zones are:

- No area-wide transmission issue that would limit renewable generation was identified in the reliability assessment of the portfolio resources in the Northern CA region.
- Reliability issues observed in the Solano zone were caused by contingencies involving breaker faults at Birdslanding 230 kV substation.
- Potential mitigations for these issues include (i) post-contingency generation curtailment and (ii) remedial action schemes (RAS) to trip generation as result of a contingency.
- Either of the mitigation measures mentioned above are unlikely to result in renewable curtailment because curtailment of convention generation in this area was found to be adequate to mitigate the overloads listed in Table 3.7-4.

3.7.3.2 Summary of Southern CA portfolio reliability assessment

As shown in Table 3.7-1 are three separate snapshot hours were studied for evaluating the impact of portfolios on the Southern CA system.

A summary of resource nameplate amounts selected in Southern CA zones are shown in Table 3.7-5. These values were modeled in the respective base cases for the purpose of this reliability assessment.

Table 3.7-5: Summary of portfolio resources in Southern CA (nameplate MW)

Renewable zone	BASE			BASE -Total	SENS-01			SEN-01-Total	SENS-02			SEN-02-Total
	Solar	Wind	GeoT		Solar	Wind	GeoT		Solar	Wind	GeoT	
Tehachapi	1013	153	0	1166	1013	153	0	1166	1013	153	0	1166
Kramer and Inyokern	577	0	0	577	577	0	0	577	577	0	0	577
Riverside East and Palm Springs	1320	42	0	1362	2842	42	0	2884	577	42		619
Greater Imperial	0	0	1276	1276	1401	0	1276	2677	1401	0	1276	2677
Southern NV, Eldorado and Mountain Pass	3006	0	0	3006	2307	442	320	3069	745	0	320	1065
SW wind (assumed to deliver into Riverside East)	0	500	0	500	0	500	0	500	0	500	0	500
New Mexico wind (assumed to deliver into Riverside East)	0	0	0	0	0	0	0	0	0	2250	0	2250
Wyoming wind (assumed to deliver into Eldorado)	0	0	0	0	0	0	0	0	0	2000	0	2000

Reliability issues observed in Tehachapi

Based on the snapshots selected for the three portfolios, the existing, contracted and portfolio renewable resources in this zone were dispatched to 91%, 82% and 87% in the BASE, SENS-01 and SENS-02 portfolios respectively. No reliability issues were identified in the assessment of these snapshots in this zone.

Reliability issues observed in Kramer and Inyokern (Greater Kramer)

The major overloads that were observed when the portfolio resources along with existing and contracted resources in Kramer and Inyokern zones were dispatched close to 100 percent of their nameplate capacity in accordance with the snapshot hours selected for Southern CA region are shown in Table 3.7-6. Because all three portfolios have the exact same amount of portfolio resources and the same mapping information, the ISO studied slightly different generation dispatch in SENS-02 portfolio. Non-renewable generation in this zone was not dispatched in the BASE and SENS-01 portfolio; it was dispatched in SENS-02 portfolio to gain insights about whether curtailment of non-renewable generation would be adequate to address issues that are driven by conventional and renewable generation.

Table 3.7-6: Reliability issues observed in Kramer and Inyokern zones

Limiting Element	Contingency	Type	Overload (%)			Renewable Zones Impacted	Potential Mitigation
			BASE	SENS-01	SENS-02 (with non-renewables dispatched)		
Lugo 500/230 kV transformer bank 1 and 2	Base case	P0	<100%	<100%	125%	Greater Kramer	Overload in SENS-02 portfolio can be mitigated by curtailing non-renewable generation.
Lugo 500/230 kV transformer bank 1 or 2	Lugo 500/230 kV transformer bank 2 or 1	P1	123%	121%	179%	Greater Kramer	A RAS to trip generation is not adequate; pre-contingency curtailment of ~300 MW of renewable resources in conjunction with a RAS will mitigate this issue.
Victor - Lugo 230 kV no. 1, 2, 3 and 4	Base case	P0	<100%	<100%	122%	Greater Kramer and North of Victor	Overload in SENS-02 portfolio can be mitigated by curtailing non-renewable generation.
Victor - Lugo 230 kV no. 1 and 2	Several P1 and P7 contingencies (Worst: P7 of Victor - Ugo 230 kV line 3 and 4)	P1 and P7	107%	124%	182%	Greater Kramer and North of Victor	A RAS to trip generation is not adequate; pre-contingency curtailment of ~150 MW of renewable resources in conjunction with a RAS will mitigate this issue
Victor - Lugo 230 kV no. 3 and 4	Several P1 and P7 contingencies (Worst: P7 of Victor - Ugo 230 kV line 1 and 2)	P1 and P7	107%	124%	182%	Greater Kramer and North of Victor	A RAS to trip generation is not adequate; pre-contingency curtailment of ~150 MW of renewable resources in conjunction with a RAS will mitigate this issue
Kramer - Victor 230 kV no. 1 or 2	Kramer - Victor 230 kV no. 2 or 1	P1	103%	114%	116%	Greater Kramer and North of Kramer	Add future generation to the existing RAS to trip generation.

Key observations for the Kramer and Inyokern zone:

- The majority of resources in this zone were mapped to Kramer 230 kV substation based on the mapping work performed by the CEC staff.
- Reliability issues observed in this area provide an explanation for most of the renewable curtailment observed in the same area in PCM studies.
- High dispatch levels for the portfolio generation, and off-peak load levels combined with approximately 1,200 MW of behind-the-meter (BTM) solar generation modeled and dispatched for daytime snapshot hours in this zone resulted in several transmission constraints. The Kramer and Inyokern zones are radial generation pockets and therefore more susceptible to severe congestion of renewables with the projected levels of BTM solar development.
- The base case (NERC category P0) overloads in the SENS-02 portfolio were primarily driven by the dispatch of all the renewable resources coupled with the dispatch of the

non-renewable resources. Curtailment of non-renewable generation would be adequate to address these issues.

- Contingency overloads (under NERC category P1 and P7) would require pre-contingency curtailment of renewable resources in this zone under the conditions represented by the snapshots. Any combination of lower load, higher BTM generation and higher renewable potential for in-front-of-the-meter renewables would result in more severe curtailment.

Reliability issues observed in Riverside East and Palm Springs

Based on the snapshots selected for the three portfolios, the existing, contracted and portfolio renewable resources in this zone were dispatched to 93%, 85% and 95% in the BASE, SENS-01 and SENS-02 portfolios respectively. No reliability issues were identified in the assessment of these snapshots in this zone.

Reliability issues observed in Greater Imperial

Based on the snapshots selected for the three portfolios, the existing, contracted and portfolio renewable resources except the geothermal resources in this zone were dispatched to 73%, 71% and 86% in the BASE, SENS-01 and SENS-02 portfolios respectively. Geothermal resources were dispatched at 100% of the nameplate. Several base case (NERC category P0) and contingency (NERC category P1 and P7) overloads were observed on the 230 kV lines in the IID system under the conditions represented by the selected snapshot hours. IID needs to be involved in the detailed assessment of these issues if the portfolios developed as part of the IRP are likely to map resources to the IID system.

Reliability issues observed in Southern NV, Eldorado and Mountain Pass

The major overloads that were observed when the portfolio resources along with existing and contracted resources in Eldorado, Mountain Pass and Southern NV zones were dispatched close to 100 percent of their nameplate capacity in accordance with the snapshot hours selected for Southern CA region are shown in Table 3.7-7. The total amount of resources in these zones are comparable in all three portfolios, but the mapping of these resources within the GLW system varies from one portfolio to the other. The most noticeable difference is in the resources mapped to Innovation substation with 99 MW (all solar) in the BASE portfolio, 287 MW (40 MW solar + 220 MW geothermal + 27 MW wind) in SENS-01 portfolio and 287 MW (67 MW solar + 220 MW geothermal) in SENS-02 portfolio. Thus, SENS-01 and SENS-02 portfolios have mapped significantly more resources to Innovation 230 kV than the BASE portfolio. Other GLW substations such as Trout Canyon 230 kV, Gamebird 230 kV show corresponding reduction in the amount of resources mapped in SENS_01 and SEN-02 portfolio to account for increased resources at Innovation.

Table 3.7-7: Reliability issues observed in Eldorado, Mountain Pass and Southern NV zones

Limiting Element	Contingency	Type	Overload (%)			Renewable Zones Impacted	Potential Mitigation
			BASE	SENS-01	SENS-02		
Mercury to Northwest 138 kV lines (Most limiting facility overload)	Base Case	P0	104%	114%	108%	Southern NV	Portfolio allocation is within the originally estimated transmission capability. The overloads are caused by intra-zonal allocation of resources. Congestion management resulting in ~150 MW of renewable curtailment would mitigate this issue. Phase shifting transformers could also mitigate this issue but are not found to be needed.
	Several contingencies on GLW 230 kV system and VEA 138 kV system (Worst contingency: Northwest - Desert View 230 kV)	P1, P4 and P7	246%	268%	259%	Southern NV	A combination of congestion management and RAS. Alternatively, phase shifting transformer will mitigate this issue.
Jackass Flats - Mercury Switch 138 kV	Several P1, P4 and P7 contingencies on VEA's 138 kV and on GLW's 230 kV system (Worst: Vista - Johnnie 138 kV)	P1	134%	133%	128%	Southern NV	A combination of congestion management and RAS. Alternatively, phase shifting transformer will mitigate this issue.
Amargosa 230/138 kV transformer bank	Any of the Northwest - Desert View 230 kV, Innovation - Desert View, 230 kV, Sloan Canyon - Trout Canyon 230 kV	P1	124%	124%	115%	Southern NV	A combination of congestion management and RAS.
Pahrump 230/138 kV transformer bank 1 or 2	Pahrump 230/138 kV transformer bank 2 or 1	P1	109%	109%	119%	Southern NV	A combination of congestion management and RAS.
Pahrump 230/138 kV transformer bank 1 and 2	Several P4 contingencies (Worst: Pahrump 230/138 kV transformer bank + Pahrump - Innovation 230 kV)	P4	149%	124%	132%	Southern NV	A combination of congestion management and RAS.
Pahrump - Gamebird (proposed) 230 kV	Base case	P0	109%	<100%	<100%	Southern NV	Portfolio allocation is within the originally estimated transmission capability. The overloads are caused by intra-zonal allocation of resources. Congestion management resulting in ~100 MW of renewable curtailment would mitigate this issue.
	P1 of and P4 contingencies involving Trout Canyon - Sloan Canyon 230 kV	P1 and P4	139%	<100%	<100%	Southern NV	A combination of congestion management and RAS.

Limiting Element	Contingency	Type	Overload (%)			Renewable Zones Impacted	Potential Mitigation
			BASE	SENS-01	SENS-02		
Innovation - Desert View 230 kV	Base case	P0	<100%	103%	<100%	Southern NV	Portfolio allocation is within the originally estimated transmission capability. The overloads are caused by intra-zonal allocation of resources. Congestion management resulting in ~30 MW of renewable curtailment would mitigate this issue.
Sloan Canyon - Trout Canyon (proposed) 230 kV	P1 and P4 contingencies involving Pahrump - Gamebird (proposed) 230 kV	P1 and P4	139%	<100%	<100%	Southern NV	A combination of congestion management and RAS.
	P1, P4 and P7 contingencies involving Pahrump - Innovation 230 kV	P1, P4 and P7	139%	<100%	<100%	Southern NV	A combination of congestion management and RAS.

The key observations for the Eldorado, Mountain Pass and Southern NV zones are:

- In all three portfolios, approximately 2,300 MW of portfolio resources were mapped to Eldorado 500 kV substation. These resources do not contribute to the issues listed in Table 3.7-7.
- The base case (N-0) and contingency (NERC category P1, P4 and P7) transmission constraints observed in this area provide an explanation for a portion of the renewable curtailment observed in the PCM simulations which modeled all the resources at the same locations as those assumed for power flow modeling in the same area.
- Although the total amount of resources mapped to GLW system remains constant across the three portfolios, certain overloads vary across the portfolios due to a shift in the intra-zonal mapping. The results demonstrate that this system is more sensitive to the mapping location than several other zones in the ISO BA.
- The base case (N-0) overloads reported in Table 3.7-7 are caused by the intra-zonal distribution of the total zonal resources selected as part of the portfolios. In case of each of the three base case overloads, a modest renewable curtailment (30 MW to 150 MW) or relocation of resources to another part of Southern NV, Mountain Pass and Eldorado zone would mitigate the issue.
- All the issues identified under contingency conditions (NERC category P1, P4 and P7) can be mitigated by a combination of congestion management and by adding the future generation in this zone to RAS identified in GIDAP to trip generation under contingency conditions.

3.8 Transmission Plan Deliverability with Recommended Transmission Upgrades

As part of the coordination with other ISO processes and 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 12. An estimate of the generation deliverability supported by the existing system and approved upgrades is listed in Table 3.8-1 and Table 3.8-2[108]. 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, the transmission plan deliverability is greater than the MW amount of generation in the ISO interconnection queue up to and including queue cluster 12.

Table 3.8-1: Deliverability for Area Deliverability Constraints in Southern CA area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
East of Miguel constraint	Arizona	~5,091
	Imperial	
	Riverside East	
Imperial Valley transformer constraint	Imperial	~2,080
SDGE – Internal Area constraint	Imperial	~804
	Non-CREZ	
GLW-VEA Area Constraint	Southern NV	790
Desert Area Constraint	Riverside East	~5,041
	Arizona	
	Imperial	
Lugo AA Bank capacity limit	Kramer	~990

108 The transmission plan deliverability is estimated relative to the latest official renewable portfolio provided for TPP policy driven transmission need analysis. This portfolio was provided in 2019, so some amount of deliverability may have been utilized by renewable generation that has become operational.

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
	 San Bernardino - Lucerne	
Lugo - Pisgah 220kV flow limit	San Bernardino – Lucerne	~450
Kramer- Victor/Roadway -Victor South of Kramer flow limit	Kramer	~350
Victor-Lugo South of Kramer flow limit	Kramer	~690
Antelope – Vincent flow limit	Tehachapi Distributed Solar – SCE (Big Creek)	~6,000
Laguna Bell – Mesa flow limit	Non-CREZ - Ventura	~1,200
South of Magunden flow limit	Non-CREZ – Big Creek	~1,250
Whirlwind - Midway Southern California Constraint	Entire Southern California, Arizona, Neveda	~44,000

Table 3.8-2: Deliverability for Area Deliverability Constraints in PG&E area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
Gates 500/230 kV Bank #13	Westlands, Carrizo, non-CREZ	~4,051
12C1592-Templeton Sw Sta 230kV Line	Carrizo	~387
Gates-12C1592 Sw Sta 230kV Line	Westlands and Carrizo	~1,167
Gates-12C1593 Sw Sta-Midway 230kV Line	Westlands and Carrizo	~1842
California Flats Sw Sta-Gates 230kV Line	Westlands and Carrizo	662
Arco-Gates 230 kV Line	Westlands and Carrizo	~2,562
Gates-12C1590 Sw Sta 500 kV	Westlands	~3,790
Delevan 500/230 kV Substation	Northern California	~855
Humboldt-Trinity 115 kV Line	Non-CREZ	~0
Rio Oso-Lincoln (Rio Oso-SPI Jct) 115 kV Line	Non-CREZ	~0
12C1541 Sw Sta-Bellota 230 kV	Northern California	~2064
Vaca Dixon-Parkway 230 kV Line	Northern California	~2697

3.9 Summary of findings

A consolidated summary of how the three portfolios impact the three aspects of transmission system evaluation – deliverability, renewable curtailment and snapshot studies – in each transmission zone considered in the CPUC's portfolio development process are shown in Table 3.9-1.

Table 3.9-1: Summary of transmission impacts of the three portfolios at zonal level

Transmission zone	Deliverability assessment	Curtailment Ratio[109] (under ISO 2000 MW net export limit / under relaxed export limit)			Power flow snapshot simulation
	All three portfolios	**BASE** **13% / 3%**	**SENS-01** **22% / 7%**	**SENS-02** **21% / 6%**	
Northern California[110]	Several deliverability constraints listed in Section 3.5.3 were observed in all three portfolios. All these constraints can be mitigated by requiring the portfolio resources to participate in RASs to trip generation In case of SENS-01 portfolio, if most of the resources in Westlands develop on the 230 kV system then an upgrade such as a new Gates 500/230 kV bank will be required.	2% / 0%	9% / 0%	9% / 1%	Existing RAS or RAS identified in GIDAP studies to trip generation would be adequate. In absence of automatic tripping, congestion management will have to be used.
Solano		1% / 0%	3% / 0%	3% / 0%	A RAS to trip generation after the contingency is adequate. In absence of automatic tripping, congestion management will have to be used.
Central Valley and Los Banos		9% / 11%	20% / 29%	16% / 26%	No issues observed for the selected snapshot hours.
Westlands		12% / 5%	24% / 15%	21% / 11%	In SENS-01, RAS mitigation may not be adequate due to complexity of the required RAS. Resources selected in SENS-01 if developed at specific 230 kV locations will result in significant curtailment without an upgrade (identified in GIDAP cluster 12).
Greater Carrizo		16% / 8%	21% / 15%	19% / 15%	At resource levels selected in SENS-01, significant curtailment would be expected without an upgrade (identified in GIDAP cluster 12).
Tehachapi		13% / 4%	21% / 9%	20% / 11%	No issues observed for the selected snapshot hours.
Kramer and Inyokern (Greater Kramer)		21% / 12%	32% / 25%	32% / 22%	Significant transmission bottlenecks during daytime off-peak hours are likely to result in up to 500 MW of curtailment. This zone is very sensitive to the high amounts of BTM solar modeled in the base cases.

[109] Renewable curtailment in MWh divided by the renewable potential (sum of renewable curtailment and generation output) in MWh

[110] Northwest wind resources selected as portfolio resources are assumed to be delivered into this zone.

Transmission zone	Deliverability assessment	Curtailment Ratio[109] (under ISO 2000 MW net export limit / under relaxed export limit)			Power flow snapshot simulation
	All three portfolios	**BASE** **13% / 3%**	**SENS-01** **22% / 7%**	**SENS-02** **21% / 6%**	
Riverside East and Palm Springs[111]		15% / 0%	30% / 1%	30% / 1%	No issues observed for the selected snapshot hours.
Greater Imperial		20% / 0%	41% / 7%	42% / 8%	IID needs to be involved in the detailed assessment of transmission issues if the portfolios resources are likely to be mapped to the IID system
Southern NV, Eldorado and Mountain Pass[112]		22% / 6%	23% / 11%	27% / 8%	Minor base case overloads resulting in ~100 MW of curtailment. Issues observed under conditions can be mitigated by a combination of congestion management and RASs identified in GIDAP studies.

Key takeaways from the deliverability assessment, PCM simulations and power flow snapshot simulations of the three portfolios are:

- Deliverability assessment results demonstrate that no transmission upgrades beyond what have already been previously approved would be needed to support the base portfolio resources that were identified as FCDS resources. Generation representing portfolio resources will in certain zones have to participate in existing or previously identified RASs to trip generation under contingency conditions in order to achieve FCDS.
- In PCM simulations, Tehachapi, Southern NV, Eldorado and Mountain Pass and Riverside East zones experienced the highest amount of curtailment in the 2000 MW Net Export Limit scenario. The same zones showed the greatest reductions of renewable curtailment when the net export limit was relaxed. This was because the solar generation in these zones could export to other regions through adjacent tie lines.
- Amongst zones with more than 500 MW of resources selected in the portfolios –
  - Renewable resources in Greater Kramer zone in the base portfolio experienced a curtailment ratio of 21% in the 2000 MW net export limit scenario and 12% with the net export limit relaxed. The high curtailment ratio across all three portfolios is

[111] Southwest wind and New Mexico wind resources selected as portfolio resources are assumed to be delivered into this zone.

[112] Wyoming wind resources selected as portfolio resources are assumed to be delivered into this zone.

likely driven by ~1,200 MW of BTM solar modeled in this zone. Higher curtailment ratios in the sensitivity portfolios in this zone can be attributed in large part to oversupply because the portfolio buildout in this zone did not vary across the three portfolios.

- Renewable resources in Southern NV, Eldorado and Mountain Pass zone in the base portfolio experienced a curtailment ratio of 22% in the 2000 MW net export limit scenario and 6% with the net export limit relaxed.
- Renewable resources in Westlands and Greater Carrizo zones in the base portfolio experienced a curtailment ratio of 12% to 16% in the 2000 MW net export limit scenario and 5% to 8% with the net export limit relaxed. Higher curtailment ratios in the sensitivity portfolios in this zone can be attributed to (i) overall increased resource buildout resulting in more oversupply and (ii) the increased resource selection from the base portfolio to sensitivity portfolios in these zones causing transmission constraints to bind.
- Renewable resources in the Greater Imperial zone in the sensitivity portfolios experienced a curtailment ratio of ~41% in the 2000 MW net export limit scenario and 7% with the net export limit relaxed. These can be attributed to (i) overall increased resource buildout resulting in more oversupply and (ii) the increased resource selection in sensitivity portfolios comprising of 2,677 MW in the sensitivity portfolios in this zone causing transmission constraints to bind.

- The aforementioned observations regarding curtailment ratios point to zones in which resource build beyond a certain amount starts to increase the risk of significant renewable curtailment. Other zones such as Northern CA, Solano, Tehachapi and Riverside East / Palm Springs experienced significant curtailment ratios in the 2000 MW net export limit scenario but the curtailments significantly dropped in these zones when the net export limit was relaxed. The snapshot studies selected hours with high renewable potential, relatively high load (55 to 65%) to ensure that curtailment observed during the snapshot hours is not due only to oversupply. These studies confirmed the congestions observed on several paths in the PCM simulations.
  - In Northern CA (geographical region), the snapshot study results demonstrated the need for portfolio resources in Westlands, Solano and Greater Carrizo zones to participate in existing or new RASs and possibly trigger transmission upgrades in order to avoid excessive renewable curtailment.
  - In the Greater Imperial zone, the snapshot study results demonstrated the need to get IID involved in the detailed assessment of reliability issues if the portfolios developed as part of the IRP are likely to map resources to the IID system
  - In the rest of the Southern CA region, the snapshot study demonstrated the need for portfolio resources in Greater Kramer, Southern NV, Eldorado and Mountain Pass zones to participate in existing or new RASs and be subjected to congestion management under system conditions similar to the snapshot hours. In Greater Kramer zone the RAS may not be adequate to address the reliability

issues. Therefore, renewable resources in this zone may experience pre-contingency curtailment during conditions similar to or more severe than the ones modeled in the snapshot study.

3.10 Conclusions

The policy-driven assessment did not demonstrate a need for a new policy-driven transmission solution at this point. Therefore, the ISO is not recommending approval of any policy-driven transmission solution as part of the 2019-2020 TPP while reiterating that transmission projects previously approved would be needed to support the base portfolio officially transmitted by the CPUC as part of the 209-2020 TPP.

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 transmission solutions that may create opportunities to reduce ratepayer costs within the ISO.

Each year's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan. The studies used a production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and to assess benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. This type of economic benefit is normally categorized as an energy benefit or production benefit. 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.

Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling,
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analysis or to meet local capacity deficiencies,
- An "economic driven" transmission solution may be upsizing a previously identified reliability solution, or replacing that solution with a different project,
- Opportunities to reduce the cost of local capacity requirements – considering capacity costs in particular, and,
- Considering interregional transmission projects as potential alternatives to regional solutions to regional needs.

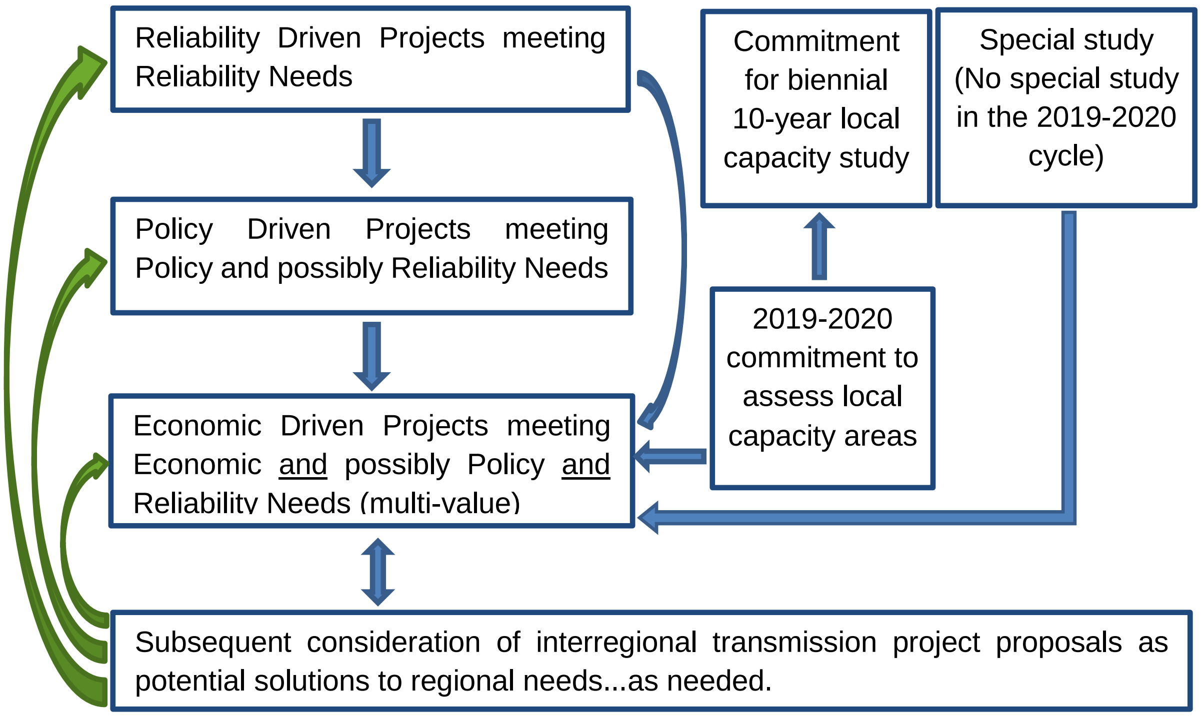
These more diverse drivers require a broader view of economic study methodologies and coordination between study efforts than in the past. As well, the economic assessment of the reduction or elimination of gas-fired generation in local capacity areas not studied last year was completed this year as an extension to the 2018-2019 Transmission Plan. Potential mitigations for the LCR areas and sub-areas that were not assessed in the 2018-2019 planning cycle were assessed using the assumptions, criteria and models consistent with the 2018-2019 planning cycle. During the course of the 2019-2020 trnasmission planning cycle, the ISO developed and sought FERC approval of changes to the local capacity requirements technical study criteria in the ISO tariff, and FERC approved those changes on January 17, 2020. Because the studies were prepared before the changes were approved, all studies were conducted using the pre-existing criteria. However, the ISO committed to considering any potential ramifications of the proposed changes prior to recommending approval of any transmission reinforcements for the benefit of reducing local capacity requirements, if the proposed changes could impact the need for the transmission reinforcement. None of the recommendations for approval of transmission reinforcements were impacted by the proposed – and ultimately approved – changes.

All transmission solutions identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation 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 ISO then performed the economic planning study to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the ISO. Selection of preferred solutions at "reliability" and "policy" stages are initially based on more conventional cost comparisons to meet reliability needs, *e.g*. capital and operating costs, transmission line loss savings, etc. As consideration of more comprehensive benefits, *e.g*. broader application of the TEAM, are conducted at the economic study stage, this can lead to replacing or upscaling a solution initially identified at the reliability or policy stage. The potential economic benefits are quantified as reductions of ratepayer costs based on the ISO Transmission Economic Analysis Methodology (TEAM).[113]

The above issues resulted in stronger interrelationships between studies conducted under different aspects of the transmission planning process. As a result, there are strong linkages and cross-references between different chapters, with the economic study process becoming somewhat of a central or core feature to the overall analysis. These interrelationships are captured to some extent in Figure 4.1-1.

[113] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Figure 4.1-1: Interrelationship of Transmission Planning Studies



The production cost modeling simulations discussed thus far focus primarily on the benefits of alleviating transmission congestion to reduce energy costs. Other benefits are also taken into account where warranted, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven. Local capacity benefits, *e.g*. reducing the requirement for local – and often gas-fired – generation capacity due to limited transmission capacity into an area can also be assessed and generally rely on powerflow analysis. This is discussed in section 4.2 below.

The more localized benefits discussed above were largely conceptualized around conventional transmission upgrades, with preferred resource procurement explored as an option where viable. With higher levels of renewable resource development and with the decline in the size of the gas-fired generation fleet, increased value is emerging for preferred resources, including storage, on a system basis regardless of local capacity and transmission congestion needs.

4.2 Technical Study Approach and Process

Different components of ISO ratepayer benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the “pre-project” and “post-project” study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit includes three components of ISO ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Second, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a transmission solution for importing energy 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 a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource.

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.

Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles. The calculation of these benefits is discussed in more detail below.

In the production benefit assessments, the ISO calculates ISO ratepayer’s benefits[114] as follows:

- *ISO ratepayer’s production benefit = (ISO Net Payment of the pre-upgrade case) – (the ISO Net Payment of the post-upgrade case)*
- *ISO Net Payment = ISO load payment - ISO generator net revenue benefiting ratepayer - ISO transmission revenue benefiting ratepayer*

The above calculation reflects the benefits to ISO ratepayers – offsetting other ISO ratepayer costs – of transmission revenues or generation profits from certain assets whose benefits accrue to ISO ratepayers. These include:

- PTO owned transmission;
- Generators owned by the utilities serving ISO’s load;
- Wind and solar generation or other resources under contract with an ISO load serving entity to meet the state renewable energy goal; and,
- Other generators under contracts of which the information is available for public may be reviewed for consideration of the type and the length of contract.

[114] WECC-wide societal benefits are also calculated to assess the overall reasonableness of the results and to assess the impact of the project being studied on the rest of the WECC-wide system, but not as the basis for determining whether the proejct is in the interests of the ISO ratepayer to proceed with. The WECC-wide societal benefits are assessed according to the following formula: *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*

How ISO ratepayer benefits relate to (and differ from) ISO production cost benefits are shown in Figure 4.2-1.

Figure 4.2-1: Ratepayer Benefits vs. Production Cost Savings

ISO Net Ratepayer Benefits from Production Cost Simulations are the sum of:	Types of Revenues and Costs calculated in Production Cost Studies	ISO "Production Cost" Savings are the sum of:
	Load Payments at Market Prices for Energy	
Yes	Reductions in ISO Ratepayer Gross Load Payments	
	Generation Revenues and Costs	
Yes	Increases in generator profits inside ISO for generators owned by or under contract with utilities or load serving entities, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
	Increases in merchant (benefits do not accrue to ratepayers) generator profits inside ISO, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
Yes	Increases in profits of dynamic scheduled resources under contract with or owned by utilities or load serving entities, being the sum of:	
	Increases in these dynamic scheduled resource revenues	
	Decreases in these dynamic scheduled resource costs	
	Transmission-related Revenues	
Yes	Increases in transmission revenues that accrue to ISO ratepayers	
	Increases in transmission revenue for merchant (e.g. non-utility owned but under ISO operational control) transmission	

In addition to the production and capacity benefits, any other benefits under TEAM— where applicable and quantifiable — can also be included. All categories of benefits identified in the TEAM document[115] and how they are addressed in the economic study process are summarized and set out in detail in Table 4.2-1.

115 Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.2-1: Summary of TEAM Benefit Categories

Categorization of Benefits (page 2 TEAM)	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
Production benefits: Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade.	In addition to production cost benefits themselves, focusing on ISO net ratepayer benefits;	Benefits focused on ISO net ratepayer benefits through production cost modeling.
	2.5.2 Transmission loss saving benefit (AND IN CAPACITY BENEFITS FOR CAPACITY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	Energy-related savings are reflected in production cost modeling results.
Capacity benefits: Benefits resulting from increased importing capability into the ISO BAA or into an LCR area. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.	2.5.1 Resource adequacy benefit from incremental importing capability A transmission upgrade can provide RA benefit when the following four conditions are satisfied simultaneously: • The upgrade increases the import capability into the ISO's controlled grid in the study years. • There is capacity shortfall from RA perspective in ISO BAA in the study years and beyond. • The existing import capability has been fully utilized to meet RA requirement in the ISO BAA in the study years. • The capacity cost in the ISO BAA is greater than in other BAAs to which the new transmission connects.	These benefits are considered where applicable; note that local capacity reduction benefits are discussed below. .
	2.5.2 Transmission loss saving benefit (AND IN PRODUCTION BENEFITS FOR ENERGY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	These benefits are considered, where applicable.

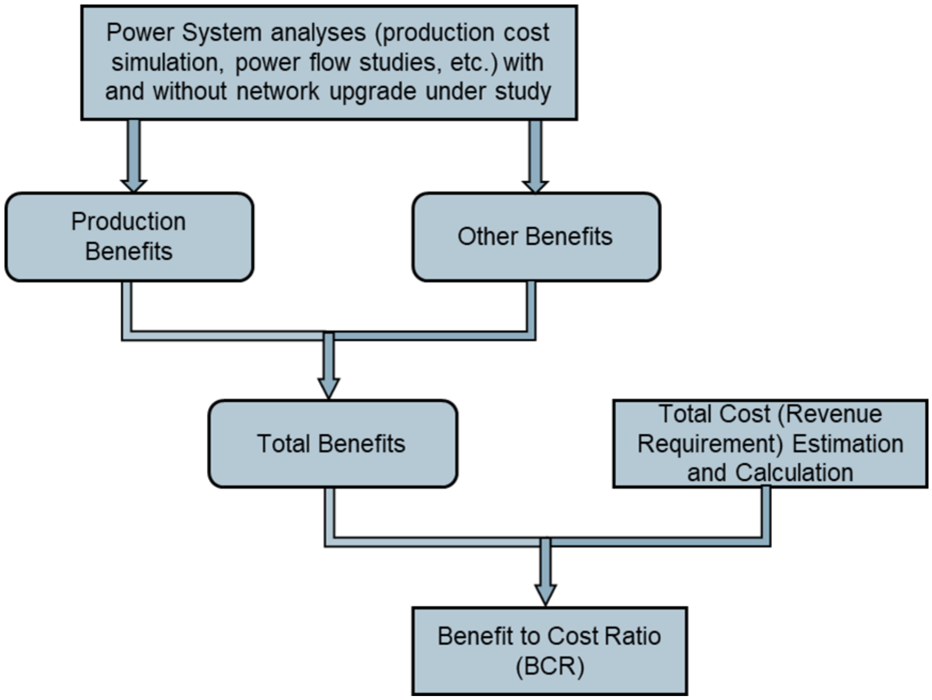
	2.5.3 Deliverability benefit Transmission upgrade can potentially increase generator deliverability to the region under study through the directly increased transmission capacity or the transmission loss saving. Similarly to the resource adequacy benefit as described in section 3.5.1, such deliverability benefit can only be materialized when there will be capacity deficit in the region under study. Full assessment for assessing the deliverability benefit will be on case by case basis.	This is primarily considered if the renewables portfolios identify the need for additional deliverability (as deliverability is used in TEAM and in ISO planning and generator interconnection studies) in which case the benefits may be policy benefits that have already been addressed in the development of portfolios, and further project development for this purpose for reducing local needs at this time is considered separately below.
	2.5.4 LCR benefit Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the CAISO controlled grid pay an annual fixed payment to the unit owner in exchange for the option to call upon the unit (if it is available) to meet local reliability needs. LCR units are used for both local reliability and local market power mitigation. LCR benefit is assessed outside the production cost simulation. This assessment requires LCR studies for scenarios with and without the transmission upgrades in order to compare the LCR costs. It needs to consider the difference between the worst constraint without the upgrade and the next worst constraint with the upgrade. The benefit of the proposed transmission upgrade is the difference between the LCR requirement with and without the upgrade.	LCR benefits are assessed, and valued according to prudent assumptions at this time given the state of the IRP resource planning at the time – and supported by the CPUC.
Public-policy benefit: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote area, or by avoiding over-build.	2.5.5 Public-policy benefit If a transmission project increases the importing capability into the ISO controlled grid, it potentially can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote areas. When there is a lot of curtailment of renewable generation, extra renewable generators would be built or procured to meet the goal of renewable portfolio standards (RPS). The cost of meeting the RPS goal will increase because of that. By reducing the curtailment of renewable generation, the cost of meeting the RPS goal will be reduced. This part of cost saving from avoiding over-build can be categorized as public-policy benefit.	With the current coordination of resource portfolios with the CPUC and CEC in place, these issues are addressed in the course of the portfolio development process.
Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as	2.5.6 Renewable integration benefit As the renewable penetration increases, it becomes challenging to integrate renewable	This can be considered as applicable, particularly for interregional transmission projects.

over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs.	generation. Interregional coordination would help mitigating integration problems, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs. A transmission upgrade that increases the importing and exporting capability of BAAs will facilitate sharing energy among BAAs, so that the potential over-supply and renewable curtailment problems within a single BAA can be relieved by exporting energy to other BAAs, whichever can or need to import energy. A transmission upgrade that creates a new tie or increases the capacity of the existing tie between two areas will also facilitate sharing A/S Sharing between the areas, if the market design allow sharing A/S. The total A/S requirement for the combined areas may reduce when it is allowed to share A/S. The lower the A/S requirement may help relieving over-supply issue and curtailment of renewable resources. It is worth noting that allowing exporting energy, sharing A/S, and reduced amount of A/S requirement will change the unit commitment and economic dispatch. The net payment of the CAISO's ratepayers and the benefit because of a transmission upgrade will be changed thereafter. However, such type of benefit can be captured by the production cost simulation and will not be considered as a part of renewable integration benefit.	Re-dispatch benefits would be included in the production cost savings in any event.
Avoided cost of other projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contribute to the benefit of the economic project.	2.5.7 Avoided cost of other projects If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contribute to the benefit of the economic project. Full assessment of the benefit from avoided cost is on a case-by-case basis.	This can be considered on a case by case basis, where applicable.

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement, as described in the TEAM document, of the project under study. To justify a proposed transmission solution, the ISO ratepayer benefit must be considered relative to the cost of the network upgrade. If the justification is successful, the proposed transmission solution may qualify as an economic-driven transmission solution. Note that other benefits and risks are taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven transmission solution.

The technical approach of economic planning study is depicted in Figure 4.2-2. 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 4.2-2: Technical approach of economic planning study



4.3 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 potential transmission solutions. In these studies, all costs and benefits are expressed in 2018 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net present values.

4.3.1 Cost analysis

In these studies, the “total cost” is considered to be the present value of the annualized revenue requirement 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 transmission solution, when necessary, the financial parameters listed in Table 4.3-1 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.

Table 4.3-1: 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	21.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2% and 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 1.3, reflective of a 7% real discount rate. This is an update to the 1.45 ratio set out in the ISO's TEAM documentation[116] that was based on prior experiences of the utilities in the ISO. The update reflects changes in federal income tax rates and more current rate of return inputs. It should be noted that this screening approximation is generally replaced on a case by case basis with more detailed modeling as needed if the screening results indicate the upgrades may be found to be needed.

As the "capital cost to revenue requirement" multiplier was developed on the basis of the long lives associated with transmission line, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and those levelized annual revenue requirements can be then compared to the annual benefits identified for those projects. This has the effect of the same comparative outcome, but adapts to both the shorter lifespans of battery storage and the varying lifespans of different major equipment within a battery storage facility that impact the levelized cost of the facility. This approach has been applied to the battery storage projects that received detailed analysis set out section 4.10.

[116] The ISO expects to update the TEAM documentation dated November 2, 2017 to reflect this change.

4.3.2 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 transmission solution. 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.[117]

When detailed analysis of a high priority study area is required, production cost simulation and subsequent benefits calculations are conducted for the 10th planning year - in this case, for 2029. For years beyond 2029 the benefits are estimated by extending the 2029 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 2029 = 0 percent (real); and.
- Benefits discount rate = 7 percent (real) with sensitivities at 5 percent as needed.

4.3.3 Cost-benefit analysis

Once the total cost and benefit of a transmission solution is determined a cost-benefit comparison is made. For a solution to qualify as an economic transmission solution under the tariff, 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. As discussed above, the traditional ISO approach is to compare the present value of annualized revenue requirements and benefits over the life of a project using standardized capital cost-to-revenue requirement ratios based on lifespans of conventional transmission. Given the relatively shorter lifespans anticipated for battery storage projects, battery storage projects can be assessed by comparing levelized annual revenue requirements to annual benefits. As indicated above, the ISO must also assess any other risks, impacts, or issues.

4.3.4 Valuing Local Capacity Requirement Reductions

As noted in chapter 1 and earlier in this chapter, the ISO recognizes that additional coordination on the long term resource requirements for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. This is particularly important in considering how to assess the value to

[117] 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.

ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas where, based on current planning assumptions, the gas-fired generation is sufficient to meet the local capacity needs. If there are sufficient gas-fired generation resources to meet the local capacity needs over the planning horizon, there is not a need for reliability-driven reinforcement; rather, the question shifts to the economic value provided by the reduction in local capacity requirement for the gas-fired generation. However, it cannot be assumed that gas-fired generation no longer required for local capacity purposes will not continue to be needed for system or flexible capacity reasons, albeit through competition with other system resources. While future IRP efforts are expected to provide more guidance and direction regarding expectations for the gas-fired generation fleet at a policy level, without that broader system perspective available at this time, the ISO has taken a conservative approach in assessing the value of a local capacity reduction benefit when considering a transmission reinforcement or other alternatives that could reduce the need for existing gas-fired generation providing local capacity. In this planning cycle, the ISO therefore applied the differential between the local capacity price and system capacity price to assess the economic benefits of reducing the need for gas-fired generation when considering both transmission and other alternatives.

It was also recognized that the basis for the local price may depend on the circumstances within the local capacity area, with several scenarios set out in Table 4.3-2.

Table 4.3-2: Scenarios for Consideration of Local Capacity Price Differentials

Scenario	Methodology (for this cycle)
If the local capacity area has a surplus of resources in the area and there is a reasonable level of competition in selling local RA capacity	The price differential between system and local capacity.
If there is only one (newer) generator in the area, and essentially no competition (or if all the units are needed and the oldest is still relatively new)	The price differential between system capacity and the full cost of service of the least expensive resource(s) may be the appropriate metric.
If there is only one older unit in the area that is heavily depreciated (or all the units are needed and if the newest is still relatively old)	Consider price the differential between the CPM soft offer cap and system capacity.*

Note *: If there is generation in an area or sub-area under an existing reliability must-run (RMR) contract, a sensitivity may be performed considering the difference between the cost of the RMR contract and the cost of system capacity.

These options are considered when needed on a case-by-case basis below and in the subsequent detailed analysis set out in section 4.10.

Northern California

For considering the benefits of local capacity requirement reductions in northern California, the differential between capacity north of Path 26 and local capacity was considered. The price of Greater Bay area generation local capacity based on the CPUC's most recent 2017 Resource Adequacy Report[118], which was published in August 2018, included a weighted average $2.22/kW-month for Greater Bay and $2.27/kW-month for the other PG&E areas. This results in

[118] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442458520

a $26,640/MW-Year and $27,240/MW-year price, respectively, for this capacity. Recognizing that local capacity in the Greater Bay area or the other PG&E local areas could also provide other benefits such as flexible and/or system capacity need, the net capacity values would be the difference between the local and system capacity price. The system weighted average is $2.09/kW-month, or $25,080/MW-year. Additionally, the CPUC also provided a system weighted average if the system resources are located in northern California (i.e., NP 26). The weighted average for system capacity value that is located in NP 26 is $2.15/kW-month, or $25,800/MW-year. The net capacity values for the Greater Bay and Other PG&E areas versus system or NP 26 resources are set out in Table 4.3-3 below.

Table 4.3-3: Net capacity values for the Greater Bay and Other PG&E areas versus system or NP 26 resources

	Net capacity values (local – system)	Net capacity values (local – NP 26 system resources)
Greater Bay Area	$1,560/MW-year	$840/MW-year
Other PG&E Areas	$2,160/MW-year	$1,440/MW-year

Southern California

For considering the benefits of local capacity requirement reductions in southern California, the differential between capacity south of Path 26 and local capacity was considered. The price of San Diego area generation local capacity based on the CPUC's most recent 2017 Resource Adequacy Report, which was published in August 2018, included a weighted average $3.18/kW-month for San Diego, $3.48/kW-month for the LA Basin area and $3.45/kW-month for Big Creek-Ventura. This results in a $38,160/MW-Year, $41,760/MW-year and $41,400/MW-year price, respectively, for this capacity. Recognizing that local capacity in these areas could also provide other benefits such as flexible and/or system capacity need, the net capacity values would be the difference between the local and system capacity price. The system weighted average is $2.09/kW-month, or $25,080/MW-year. Additionally, the CPUC also provided a system weighted average if the system resources are located in southern California (i.e., SP 26). The weighted average for system capacity value that is located in SP 26 is $1.59/kW-month, or $19,080/MW-year. The net capacity values for the Big Creek–Ventura, LA Basin and San Diego areas versus system or SP 26 resources are set out in Table 4.3-4 below.

Table 4.3-4: Net capacity values for the Southern California areas versus system or SP 26 resources

	Net capacity values (local – system)	Net capacity values (local – SP 26 system resources)
LA Basin	$16,680/MW-year	$22,680/MW-year
Big Creek–Ventura	$16,320/MW-year	$22,320/MW-year
San Diego	$13,080/MW-year	$19,080/MW-year

4.4 Study Steps of Production Cost Simulation in Economic Planning

While the assessment of capacity benefits normally uses the results from other study processes, such as resource adequacy and local capacity assessment, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost model development needs coordination with the entire WECC and management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database (also called production cost model or PCM) development and validation, simulation and congestion analysis, and production benefit assessment for congestion mitigation.

PCM development and validation mainly include the following modeling components:

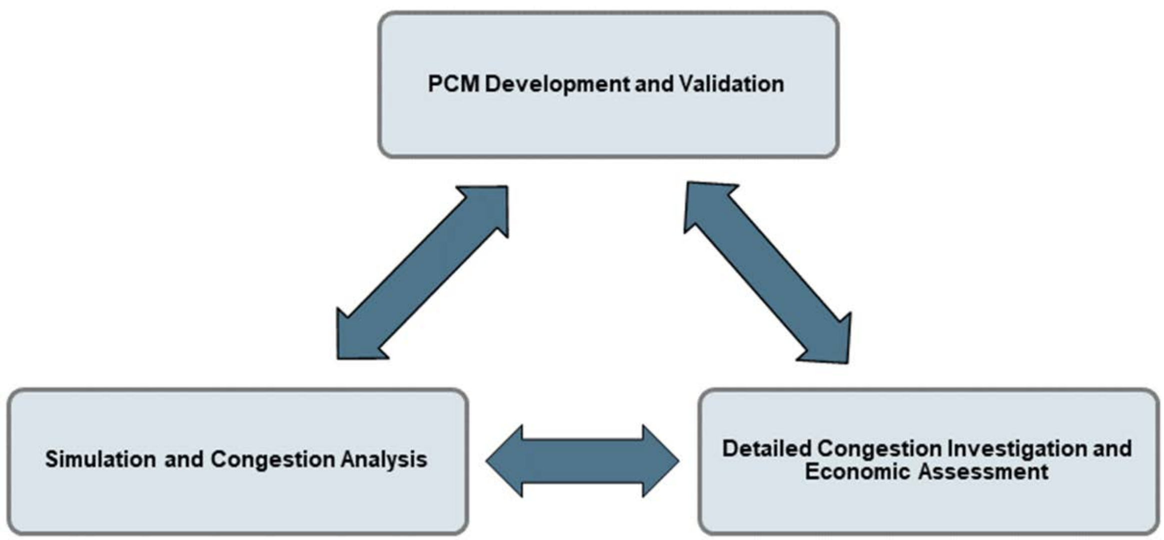
1. Network model (transmission topology, generator location, and load distribution)
2. Transmission constraint model, such as transmission contingencies, interfaces, and nomograms, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, energy storage model, renewable profiles, and renewable curtailment and price model.
4. Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers such as DG, DR, and EE.
5. Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission, etc.

Congestion analysis is based on production cost simulation that is conducted for each hour of the study year. Congestion can be observed on transmission line or transformers, or on interfaces or nomograms, and can be under normal or contingency conditions. In congestion analysis, all aspects of results may need to be investigated, such as locational marginal price (LMP), unit commitment and dispatch, renewable curtailment, and the hourly power flow results under normal or contingency conditions. Through these investigations, congestion can be validated, or some data or modeling issues can be identified. In either situation, congestion analysis is used for database validation. The simulated power flow pattern is also compared with the historical data for validation purpose, although it is not necessary to have identical flow pattern between the simulation results and the historical data. There are normally many iterations between congestion analysis and PCM development.

In the detailed congestion investigation and economic assessment step, the ISO quantifies economic benefits for each identified transmission solution alternative using the production cost simulation and other means. From the economic benefit information a cost-benefit analysis is conducted to determine if the identified transmission solution 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. In this step, the PCM and the congestion results are further validated.

Normally there are a number of iterations among these three steps through the entire economic planning study process. Figure 4.4-1 shows these components and their interaction.

Figure 4.4-1: Steps of production cost simulation in Economic planning



4.5 Production cost simulation tools and database

The ISO primarily used the software tools listed in Table 4.5-1 for this economic planning study.

Table 4.5-1: Economic Planning Study Tools

Program name	Version	Functionality
ABB GridView™	10.2.72	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 (8784 hours for leap year)

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO may also develop an optional 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five year period of benefits before the 10-year case becomes relevant.

4.6 ISO GridView Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the GridView PCM development for the economic planning study. The section also highlights the major ISO enhancements and modifications to the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) database that were incorporated into the ISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized in this document, but the final PCM is posted on the ISO's market participant portal once the study is finalized.

4.6.1 Modeling assumptions

The 2019-2020 TPP PCM development started from the last planning cycle's planning PCM, which used the ADS PCM as a starting database. The validated changes in the ADS PCM up to Phase II v2.0 were incorporated into the ISO planning PCM in 2019-2020 cycle. Using this database the ISO developed the base cases for the ISO TPP production cost simulation. These base cases included the modeling updates and additions, which followed the ISO unified planning assumptions and are described in this section.

4.6.2 Network modeling

The ADS PCM uses a nodal model to represent the entire WECC transmission network. However, the network model in the ADS PCM is based on a power flow case that is different from the ISO's reliability power flow cases developed in the current planning cycle. The ISO took a more comprehensive approach and modified the network model for the ISO's system to exactly match the reliability assessment power flow cases for the entire ISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and reliability assessment power flow cases. In conjunction with modeling local transmission constraints and nomograms, unit commitment and dispatch can accurately respond to transmission limitations identified in reliability assessment. This enables the production cost simulation to capture potential congestion at any voltage level and in any local area.

4.6.3 Load

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 California load data was drawn from the California Energy Demand Forecast 2018-2030, Revised Electricity Forecast adopted by California Energy Commission (CEC) on January 9, 2019.

Load modifiers, including DR, DG, and AAEE, were modeled as generators with hourly output profiles. The locations of the load modifiers were consistent with the reliability power flow cases.

4.6.4 Generation resources

Generator locations and installed capacities in the PCM are consistent with the 2019-2020 reliability assessment power flow case for 2029, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

4.6.5 Transmission constraints

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 ADS PCM 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 ADS PCM 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.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the ISO were modeled. These nomograms were developed in ISO's reliability assessments or identified in the operating procedures. In this planning cycle, critical constraints in the COI corridor that were identified in the reliability assessment were monitored and enforced in the planning PCM.

Scheduled maintenance of transmission lines was modeled based on historical data. Only the repeatable maintenances were considered. The corresponding derates on transmission capability were also modeled.

PDCI (Path 65) south to north rating was modeled at 1050 MW to be consistent with the operation limit of this path identified by LADWP, which is the operator of PDCI within California.

4.6.6 Fuel price and CO2 price

The forecasts of Natual Gas price and CO2 price were the same as in the ADS PCM, which are based on the CEC 2018 Integrated Energy Policy Report. The forecast of Coal prices were the same as in the ADS PCM. All prices are in 2018 real dollar.

4.6.7 Renewable curtailment price model

Through the course of the 2019-2020 planning cycle, the ISO consulted with stakeholders and refined its modeling of renewable generators for production cost modeling purposes. As a result, multi-block renewable generator models were used in the 2019~2019 planning cycle PCM. This model was applied to all ISO wind and solar generators. Each generator was modeled as five equal and separate generators (blocks) with identical hourly profiles, and each block's Pmax was 20% of the Pmax of the actual generator. Each block had a different curtailment price around $-25/MWh, as shown in Table 4.6-1.

Table 4.6-1: Multi-blocks renewable model

Block	Price ($/MWh)
1	-23
2	-24
3	-25
4	-26
5	-27

4.6.8 Battery cost model and depth of discharge

The ISO also refined its modeling of battery storage through the course of the 2019-2020 planning cycle, to reflect limitations associated with the depth of discharge of battery usage cycles (DoD or cycle depth) and replacement costs associated with the number of cycles and depth of discharge the battery is subjected to. In this planning cycle, the ISO developed an approach based on a flat average costs to develop the battery's operation cost.

$$Average\ Cost = \frac{Per\ unit\ replacement\ cost}{Cycle\ life * DoD * 2}$$

The 2025 forecast obtained from the DOE (DOE/Hydro Wires report, July 2019[119]) was used as the baseline assumptions for battery parameters:

- DoD: 80%
- Cycle life: 3500 cycles
- Per unit replacement cost: $189,000/MWh

With the above parameters, the average cost modeled in the planning PCM was $33.75/MWh.

4.7 Production Cost Simulation Results

4.7.1 Congestion results

Based on the economic planning study methodology presented in the previous sections, a congestion simulation of ISO transmission network was performed to identify which facilities in the ISO controlled grid were congested.

The results of the congestion assessment are listed in Table 4.7-1. Columns "Cost_F" and "Duration_F" were the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns "Cost_B" and "Duration_B" were the cost and duration of

119 https://www.sandia.gov/ess-ssl/wp-content/uploads/2019/07/PNNL_mjp_Storage-Cost-and-Performance-Characterization-Report_Final.pdf

congestion in the backward direction. The last two columns were the total cost and total duration, respectively.

Table 4.7-1: Potential congestion in the ISO-controlled grid in 2029

Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
Path 26 Corridor	P26 Northern-Southern California	14	3	14,172	586	14,187	589
COI Corridor	P66 COI	7,859	335	0	0	7,859	335
PDCI	P65 Pacific DC Intertie (PDCI)	0	0	5,988	696	5,988	696
PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-Merced M 115/70 kV xfmr	5,480	2,068	0	0	5,480	2,068
SDGE DOUBLTTP-FRIARS 138 kV line	DOUBLTTP-FRIARS 138 kV line, subject to SDGE N-2 SX-PQ + PQ-OT 230 kV with RAS	0	0	4,793	605	4,793	605
SCE Sylmar - Pardee 230 kV	PARDEE-SYLMAR S 230 kV line, subject to SCE N-1 Sylmar-Pardee 230 kV	0	0	4,664	299	4,664	299
SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #1	4,027	141	0	0	4,027	141
Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	3,519	78	3,519	78
VEA	PAHRUMP-CARPENTERCYN 230 kV line #1	0	0	2,803	357	2,803	357
SDGE-CFE OTAYMESA-TJI 230 kV line	OTAYMESA-TJI-230 230 kV line #1	0	0	1,732	595	1,732	595
SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #4	1,538	37	0	0	1,538	37
SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #2	1,511	43	0	0	1,511	43
PG&E Fresno	ORO LOMA-EL NIDO 115 kV line #1	1,372	208	0	0	1,372	208
COI Corridor	TM_VD_11-TM_VD_12 500 kV line #1	1,322	30	0	0	1,322	30
PG&E Fresno	HURONJ-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Excelsior 115 kV with SPS-Huron	46	1	1,229	1,281	1,275	1,282

Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #3	1,177	39	0	0	1,177	39
SCE RedBluff-Devers	DEVERS-DVRS_RB_21 500 kV line #2	0	0	1,096	17	1,096	17
Path 45	P45 SDG&E-CFE	273	194	822	446	1,095	640
SCE LagunaBell-Mesa Cal	LAGUBELL-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #2 and Mesa-Lighthipe 230 kV	0	0	1,009	22	1,009	22
COI Corridor	TABLE MT-TM_TS_11 500 kV line #1	856	17	0	0	856	17
PG&E Fresno	KETLMN T-GATES 70.0 kV line #1	768	1,562	0	0	768	1,562
Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500 kV	0	0	650	36	650	36
COI Corridor	RM_TM_11-RM_TM_12 500 kV line #1	574	15	0	0	574	15
Path 15/CC	GATES-GT_MW_11 500 kV line #1	84	4	445	17	529	21
SCE RedBluff-Devers	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	446	8	446	8
Path 42 IID-SCE	P42 IID-SCE	434	29	0	0	434	29
SCE NOL-Kramer-Inyokern-Control	P60 Inyo-Control 115 kV Tie	1	4	386	740	386	744
IID-SDGE (S line)	IMPRLVLY-ELCENTSW 230 kV line, subject to SDGE N-1 N.Gila-Imperial Valley 500 kV	0	0	375	39	375	39
PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-MrcdFLLs 70 kV	357	109	0	0	357	109
COI Corridor	RM_TM_21-RM_TM_22 500 kV line #2	350	13	0	0	350	13
COI Corridor	TM_TS_11-TM_TS_12 500 kV line #1	307	5	0	0	307	5
COI Corridor	TM_TS_12-TESLA 500 kV line #1	298	5	0	0	298	5
PG&E Fresno	RPNJ2-MANTECA 115 kV line #1	0	0	297	11	297	11

Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
PG&E POE-RIO OSO	POE-RIO OSO 230 kV line #1	286	268	0	0	286	268
PG&E Sierra	DRUM-BRNSWCKP 115 kV line #2	242	158	0	0	242	158
SCE J.HINDS-MIRAGE 230 kV line	J.HINDS-MIRAGE 230 kV line #1	185	51	0	0	185	51
San Diego	MELRSETP-SANMRCOS 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	0	0	178	78	178	78
VEA	JACKASSF-MERCRYSW 138 kV line #1	123	120	0	0	123	120
SDGE IV-San Diego Corridor	SUNCREST-SUNCREST TP2 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	123	4	0	0	123	4
Path 46 WOR	P46 West of Colorado River (WOR)	123	9	0	0	123	9
COI Corridor	TABLE MT-TM_VD_11 500 kV line #1	117	3	0	0	117	3
SDGE Sanlusry-S.Onofre 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	110	40	5	1	115	41
San Diego	SANLUSRY SC-MISSION 230 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	0	0	93	23	93	23
SDGE IV-San Diego Corridor	MIGUEL-MIGUELMP 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #2 with RAS	0	0	88	3	88	3
IID-SDGE (S line)	IMPRLVLY-ELCENTSW 230 kV line #1	0	0	87	5	87	5
SDGE IV-San Diego Corridor	SYCAMORE TP2-SYCAMORE 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	74	3	0	0	74	3
SCE NOL-Kramer-Inyokern-Control	KRAMER-VICTOR 230 kV line #1	70	3	0	0	70	3
SDGE IV-San Diego Corridor	SYCAMORE TP1-SYCAMORE 230 kV line, subject to SDGE	68	2	0	0	68	2

Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
	N-1 Sycamore-Suncrest 230 kV #2 with RAS						
VEA	TROUT CYN-SLOAN CYN 230 kV line #1	60	57	0	0	60	57
COI Corridor	ROUND MT-RM_TM_21 500 kV line #2	53	2	0	0	53	2
PG&E Fresno	LE GRAND-CHWCHLASLRJT 115 kV line #1	0	0	50	35	50	35
SCE Serrano-Villa PK 230 kV	SERRANO-VILLA PK 230 kV line, subject to SCE N-2 Serrano-Lewis #1 and Serrano-Villa PK #2 230 kV	46	1	0	0	46	1
COI Corridor	RM_TM_22-TABLE MT 500 kV line #2	41	2	0	0	41	2
SCE LCIENEGA-LA FRESA 230 kV line	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	29	2	29	2
PG&E North Valley	PEASE-HONC JT1 115 kV line #1	0	0	28	11	28	11
SDGE IV-San Diego Corridor	MIGUEL-MIGUELMP 500 kV line, subject to SDGE T-1 Miguel 500-230 kV #2 with RAS	24	1	0	0	24	1
PG&E Sierra	DRUM-DTCH FL1 115 kV line #1	15	14	0	0	15	14
COI Corridor	TM_VD_12-VACA-DIX 500 kV line #1	12	2	0	0	12	2
COI Corridor	ROUND MT-RM_TM_11 500 kV line #1	10	1	0	0	10	1
SCE NOL-Kramer-Inyokern-Control	CONTROL-INYOKERN 115 kV line #1	9	10	0	0	9	10
PG&E Fresno	HENTAP1-MUSTANGSS 230 kV line #1	0	0	9	1	9	1
SDGE Hoodoo Wash - N.Gila 500 kV line	HDWSH-N.GILA 500 kV line, subject to SDGE N-1 Hassayampa-NGila 500 kV #1	7	1	0	0	7	1
Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #1 500 kV	0	0	4	1	4	1
PG&E GBA	MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E	0	0	4	1	4	1

Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
	N-1 Mosslanding-LosBanos 500 kV						
PG&E Fresno	JACKSONSWSTA-WAUKENA_SS 115 kV line #1	0	0	2	24	2	24
PG&E Solano	TESLA-AEC_TP2 115 kV line #1	2	1	0	0	2	1
Path 61/Lugo - Victorville	P61 Lugo-Victorville 500 kV Line	0	0	2	1	2	1
Path 24	P24 PG&E-Sierra	2	1	0	0	2	1
PG&E Gates-CAlFLATSSS 230 kV	GATES-CALFLATSSS 230 kV line #1	0	0	0	1	0	1
PG&E Sierra	CHCGO PK-HIGGINS 115 kV line #1	0	1	0	0	0	1
PG&E North Valley	BRNSWKTP-DTCH FL2 115 kV line #1	0	0	0	1	0	1

The potential congestion across specific branch groups and local capacity areas is summarized in Table 4.7-2. The branch group or local area information was provided in the first column in Table 4.7-1. 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 were ranked based on the 2029 congestion cost.

Table 4.7-2: Aggregated potential congestion in the ISO-controlled grid in 2029

Aggregated congestion	Cost ($M) $M)M)	Duration (Hr)
Path 26 Corridor	18.36	704
COI Corridor	11.80	430
SCE NOL-Kramer-Inyokern-Control	8.72	1,017
PDCI	5.99	696
PG&E/TID Exchequer	5.84	2,177
SDGE DOUBLTTP-FRIARS 138 kV line	4.79	605
SCE Sylmar - Pardee 230 kV	4.66	299
PG&E Fresno	3.77	3,123
VEA	2.99	534
SDGE-CFE OTAYMESA-TJI 230 kV line	1.73	595
SCE RedBluff-Devers	1.54	25
Path 45	1.09	640
SCE LagunaBell-Mesa Cal	1.01	22
Path 15/CC	0.53	21
IID-SDGE (S line)	0.46	44
Path 42 IID-SCE	0.43	29
SDGE IV-San Diego Corridor	0.38	13
PG&E POE-RIO OSO	0.29	268
San Diego	0.27	101
PG&E Sierra	0.26	173
SCE J.HINDS-MIRAGE 230 kV line	0.18	51
Path 46 WOR	0.12	9
SDGE Sanlusry-S.Onofre 230 kV	0.11	41
SCE Serrano-Villa PK 230 kV	0.05	1
SCE LCIENEGA-LA FRESA 230 kV line	0.03	2
PG&E North Valley	0.03	12
SDGE Hoodoo Wash - N.Gila 500 kV line	0.01	1
PG&E GBA	0.00	1
PG&E Solano	0.00	1
Path 61/Lugo - Victorville	0.00	1
Path 24	0.00	1

4.7.2 Congestion analysis

In this planning cycle, investigations were conducted on the constraints that may have a large impact on the bulk system or the heavily congested areas, and showed recurring congestion. Specifically, these constraints selected for further analysis are shown in Table 4.7-3. The detailed analysis results are in section 4.10.

Table 4.7-3: Constraints selected for Detailed Investigation

Aggregated congestion or congestion	Cost (M$)	Duration (Hours)	Reason for selection
Path 26 corridor	18.36	704	Path 26 south to north congestion increased from previous planning cycles, and was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio.
PG&E Fresno Avenal area	0.77	1562	Kettleman Hills Tab to Gates 70 kV line congestion with long congestion hours
PG&E Fresno Huron to CalFlax 70 kV line	1.28	1282	Huron to Calflax 70 kV line congestion with relatively high congestion cost and long congestion hours
PG&E Fresno Oro Loma to El Nido 115 kV lines	1.37	208	Oro Loma to El Nido 115 kV line congestion with relatively high congestion cost
VEA Pahrump to Carpenter Canyon and Trout Canyon to Sloan Canyon 230 kV lines	2.86	414	Sloan Canyon to Pahrump 230 kV lines congestion with relatively high congestion cost

Congestions in were selected not solely based on congestion cost or duration, but by taking other considerations into account. Comparing the congestion and curtailment results, it was observed that some congestions with large cost or duration were driven by local renewable generators identified in the CPUC default renewable portfolio. Congestions in these areas were subject to change with further clarity of the interconnection plans of the future resources. Therefore, the congestions in these areas or zones were not selected for detail analysis in this planning cycle, particularly, SCE NOL area and RedBluff-Devers congestions, and Path 42 congestion.

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

COI corridor congestion in this planning cycle increased comparing with the last planning cycle, particularly on individual branches that are in the downstream of COI in north to south direction. Similarly to the local congestions discussed above, COI corridor congestion increased mainly due to the future generic renewable resources identified in the CPUC portfolio in Northwest areas and in Round Mountain area. The ISO will continue to monitor the congestion on COI corridor in future planning cycles.

Most of the observed Path 45 congestion was in the direction from CFE to ISO, which is mainly due to the natural gas price difference across the border. Other factors that may impact the congestion include the renewable generation development in Imperial Valley area and its representation in the future 50% renewable portfolio, and the CFE's generation and load modeling. Further clarity of such factors will be required before detailed investigations need to be conducted. The ISO will continue to monitor the congestion on Path 45 in future planning cycles.

Path 15 and Central California congestion was observed mainly from south to north direction, and largely related to both Path 26 flow in south to north direction and renewable modeling in PG&E Fresno area. Detailed economic assessment for mitigating the congestion was not conducted in this planning cycle since it requires further clarity of renewable modeling assumption in PG&E Fresno area and Southern California areas. The ISO will continuously and closely monitor and assess these congestions in the future planning cycles.

No detailed analyses on other congestions in Table 4.7-1 and were conducted as the congestions were not sufficient for justifying upgrades, based on either the studies in previous planning cycles or engineering judgement. They will be monitored in future planning cycles and will be studied as needed.

4.8 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. These economic study requests are distinct from the interregional transmission projects discussed in Chapter 5, but the interregional transmission projects discussed in Chapter 5 may be considered as options to meeting the needs identified though the economic planning studies.

Other economic study needs driven by stakeholder input have also been identified through other aspects of the planning process as well – those are also set out here, with the rationale for proceeding to detailed analysis where warranted.

The ISO's tariff and Business Practice Manual allows the ISO to select from economic study requests and other sources the high priority areas that will receive detailed study while developing the Study Plan, based on the previous year's congestion analysis. Recognizing that changing circumstances may lead to more favorable results in the current year's study cycle, the ISO has over the past number of planning cycles carried all study requests forward as potential high priority study requests, until the current year's congestion analysis is also available for consideration in finalizing the hi priority areas that will received detailed study. This additional review gives more opportunity for the study request to be considered, that can take into account on case by case basis the latest and most relevant information available.

Accordingly, the ISO reviewed each regional study or project being considered for detailed analysis, and the basis for carrying the project forward for detailed analysis as high priority economic planning studies – or not – is set out in this section. The section also describes how the study requests or projects selected for detailed analysis were studied, e.g. on a standalone basis or as one of several options of a broader area study. The received study requests were summarized in Table 4.8-1 and Table 4.8-2. Evaluations for the study requests for purposes of selecting the final list of high priority economic planning studies were included in the following subsections.

Table 4.8-1: Economic study requests

No.	Study Request	Submitted By	Location
1	Lake Elsinore Advanced Pumped Storage Project ("LEAPS")	Nevada Hydro Company	Southern California
2	California Transmission Project (CTP) updated with Pacific Transmission Expansion (PTE)	Cal Energy Development Company, LLC updated with Western Grid Development	Northern/Southern California
3	GLW/VEA service area transmission upgrade (includes Pahrump-Sloan Canyon Line Rebuild)	Gridliance West	Southern Nevada

4	Boardman to Hemingway 500 kV transmission project (B2H)	Idaho Power	Northwest (Oregon/Idaho)
5	SWIP-North	LS Power	Idaho/Nevada
6	Red Bluff to Mira Loma 500 kV line	NextEra Energy Resources (NEER)	Southern California
7	North Gila Imperial Valley #2 (NGIV2)	NGIV2, LLC	Arizona/California
8	Fresno Avenal area upgrade (Gates-Tulare Lake 70 kV line)	PG&E	Northern California

Table 4.8-2: Additional request window submissions that cited economic benefits

No.	Study Request	Submitted By	Location
1	Chula Vista Energy Reliability Center	Wellhead	Southern California
2	Suncrest - Sycamore 230 kV	Horizon West	Southern California
3	Red Bluff - Mira Loma 500 kV	Horizon West	Southern California
4	Sycamore Reliability Energy Storage	Tenaska	Southern California
5	Imperial Smart Wire Solution	Imperial Renewable	Southern California

4.8.1 Lake Elsinore Advanced Pumped Storage

The Nevada Hydro Company submitted the Lake Elsinore Advanced Pumped Storage project into the 2019-2020 transmission planning cycle through several venues:

- The project was first submitted to the ISO on March 13, 2019 on the basis of section 24.3.3 of the ISO's tariff, which provides an opportunity to provide input for consideration in the development of the draft Unified Planning Assumptions and Study Plan of, among other information, "Generation and other non-transmission alternatives, consistent with Section 24.3.2(a) proposed as alternatives to transmission solutions". The project was then submitted into the 2019 Request Window on October 15, 2019 purporting to address reliability needs in addition to providing other benefits. As set out in chapter 2 and noted below, the ISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by the operational measures. For this reason, the project was not found to be needed for reliability. The more comprehensive discussion of other potential benefits is provided below.

Study request overview

The LEAPS project is proposed to be located in Lake Elsinore, CA. Two interconnection options were originally submitted in 2018-2019 planning cycle, and re-submitted in this planning cycle.

Option 1: SCE/SDG&E Connection

- This option interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill[120] 500 kV substation and (ii) to SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation. If Alberhill is not approved, the connection point will be roughly one mile to the north-west at the proposed Lake Switchyard location.
- Approximate Project Cost = $2.04 billion

Option 2: SDG&E-only Connection

- Interconnecting to SDG&E's transmission by looping in the Talega – Escondido 230 kV line via the Case Springs 230 kV substation.
- Project Cost = $1.76 billion

Evaluation

The benefits described in the submission and ISO's evaluation of the economic study request are summarized in Table 4.8-3.

Table 4.8-3: Evaluating study request – Lake Elsinore Advanced Pumped Storage Project

Study Request: Lake Elsinore Advanced Pumped Storage Project		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Nevada Hydro stated that LEAPS can help to mitigate SDG&E local transmission constraints	The ISO's analysis in the last planning cycle found that although this project may help to mitigate congestion in some areas, it may adversely impact other areas. The analysis in the last planning cycle also found that there was not sufficient ratepayer's benefit compared to the potential cost of the project. No material change in circumstance that would change this result has been identified.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Nevada Hydo stated that LEAPS is an economic solution for integrating new renewables needed to meet the state GHG goal by 2030.	The analysis in the last planning cycle also found that there was not sufficient ratepayer's benefit compared to the potential cost of the project. No material change in circumstance that would change this result has been identified.
Local Capacity Area Resource requirements	Nevada Hydro stated that LEAPS provided LCR capacity equal to 500 MW for the San Diego area with an estimated benefit of $38 million annually for local capacity reduction.	The LCR reduction analysis in the last planning cycle found that there was not sufficient ratepayer's benefit compared to the potential cost of the project. No material change in circumstance that would change this result has been identified.

[120] The Alberhill Substation Project was denied without prejudice by the CPUC at its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF)

Study Request: Lake Elsinore Advanced Pumped Storage Project		
Benefits category	Benefits stated in submission	ISO evaluation
Increase in Identified Congestion	Nevada Hydro requested that the ISO to assess whether the project can further reduce congestion observed on the ISO grid.	Refer to earlier comment regarding “Identified Congestion”.
Integrate New Generation Resources or Loads	Nevada Hydro stated that LEAPS, like other transmission assets, enables better use of the existing transmission grid to interconnect projects needed to meet 50% criteria at lower overall cost to consumers because it reduces solar or wind overbuild capacity that will need to be procured by load-serving entities to meet their targets, as well as the associated interconnection cost.	The analysis in the last planning cycle also found that there was not sufficient ratepayer’s benefit compared to the potential cost of the project. No material change in circumstance that would change this result has been identified.
Other	LEAPS provide the full range of ancillary services, including flexible capacity for load following needed by ISO to manage the uncertainty in VER forecasts between Day Ahead schedules and Real Time operations. Market revenues from providing energy and these ancillary services are proposed to offset any revenue requirement from the project. LEAPS will provide reliability benefits by improving grid resiliency such as providing frequency response and voltage support to the grid. LEAPS will also mitigate ISO-identified overloads without having to rely on current mitigating measures include generation redispatch and/or load dropping.	The economic benefit of a number of the benefits discussed here are incorporated in the production simulation studies. The economic assessment in the last planning cycle also found that there was not sufficient ratepayer’s benefit compared to the potential cost of the project. No material change in circumstance that would change this result has been identified. No reliability requirements were identified in chapter 2 driving the need for the project.

Conclusion

No further assessment was conducted for this submitted study request in this planning cycle.

4.8.2 Pacific Transmission Expansion (PTE) HVDC Project[121]

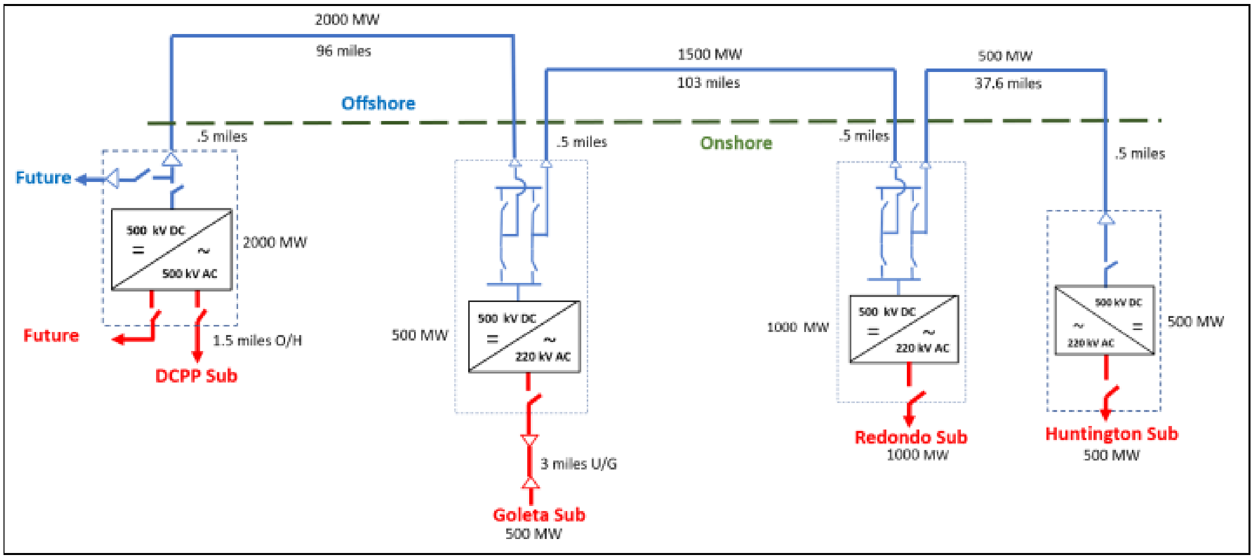
Study request overview

The proposed PTE includes a 500 kV HVDC submarine cable project that will utilize Voltage Source Converters (VSC) to interconnect with existing HVAC transmission facilities in both the Pacific Gas & Electric and Southern California Edison service areas is shown in Figure 4.8-1. The cable will be routed offshore of California in the Pacific Ocean and will have three segments, one between Diablo Canyon and Goleta substation with approximant length of 96

[121] PTE was formerly submitted as California Transmission Project (CTP) with different scope.

miles, one between Goleta and Redondo Beach at approximant length of 103 miles, and one between Redondo Beach and Huntington Beach at approximant length of 38 miles.

Figure 4.8-1: Submitted Configuration and Capacity for the PTE Project



The northern terminus of the PTE is proposed to be the Diablo Canyon 500 kV switching station and will utilize the two BAAH bay positions that will be vacated with the decommissioning of the Diablo Canyon Nuclear Power Plant. There will be one 2,000 MW VSC located at Diablo Canyon. There are three separate southern terminals for the PTE, one at SCE Goleta substation, one at Redondo Beach, and one at Huntington Beach. At both Goleta and Huntington Beach terminals, there will be one 500 MW VSC to enable connection to the SCE 220 kV substation and at Redondo Beach one 1,000 MW VSC.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-4.

Table 4.8-4: Evaluating study request – Pacific Transmission Expansion (PTE) HVDC Project

Study Request: Pacific Transmission Expansion HVDC Project		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	PTE will address specific PG&E area reliability issues found by the ISO in its preliminary reliability studies published on August 15, 2019. The ISO found 3 overloads on Path 26 which can be addressed by the PTE, The proposed mitigation is simply to reduce flow on Path 26, which would be accomplished through re-dispatch and/or exceptional dispatch resulting in higher costs. PTE as proposed, is in parallel	The project provides a parallel route to Path 26, and could address the identified congestion on Path 26.

	with Path 26, adding 2,000 MW of transfer capacity under steady state conditions.	
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	The project proponent states that the Project can provide a local capacity benefit to the LA Basin of 2,025 MW.	The proposed project connects to the ISO system at Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach. Diablo Canyon is not located in an LCR local capacity area. With the planned Pardee-Moorpark #4 230 kV circuit, there will no longer be a Moorpark local capacity sub-area requirement. However, the Santa Clara sub-area remains, and Goleta is located in that sub-area. Redondo Beach and Huntington Beach are located in the Western LA Basin LCR sub-area. The project could potentially provide LCR reduction benefits in the Western LA Basin and the Santa Clara sub-area.
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	The project proponent states that the Project can provide reactive power support at Goleta.	The proposed project includes VSC terminals at Goleta, so it could potentially provide reactive power support at Goleta.

Conclusion

The proposed project is an alternative for reducing Western LA Basin sub-area local capacity requirements, which was selected for detailed analysis in this transmission planning cycle as well for reducing Santa Clara sub-area local capacity requirements and potentially Path 26 congestion.

Path 26-related benefits and Santa Clara sub-area benefits are discussed in section 4.10.1 and section 4.1.1.2 respectively. Those benefits are included in the comprehensive assessment of the benefits of the proposed project in its consideration as an alternative in providing Western LA Basin sub-area benefits in section 4.10.13.

4.8.3 Gridliance West/VEA service area transmission upgrades

Study request overview

The proposed Gridliance West/VEA service area transmission upgrades include four segments as summarized below:

1. Pahrump – Sloan Canyon: Upgrade the existing Pahrump – Sloan Canyon 230 kV line to 926/1195 normal/emergency rating and connect to Carpenter Canyon and Trout Canyon;
2. Innovation – Desert View: Upgrade the existing Innovation – Desert View 230 kV line to 926/1195 normal/emergency rating and add second circuit at same rating;
3. Desert View – Northwest: Add a second 230 kV circuit Desert View – Northwest at 926/1195normal/emergency rating;
4. Pahrump – Innovation: Upgrade Pahrump – Innovation 230 kV to 926/1195 normal/emergency rating.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-5.

Table 4.8-5: Evaluating study request – Gridliance West/VEA service area transmission upgrades

Study Request: Gridliance West/VEA Service Area Transmission Upgrades		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Not addressed in submission	The Pahrump-Sloan Canyon segment of the proposed upgrades could address identified congestion on Pahrump-Sloan Canyon 230 kV line.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Gridliance West claimed that the proposed transmission upgrades can help to interconnect additional renewable resources at different locations in Southern Nevada.	The ISO's transmission planning studies model CPUC's renewable portfolios. The assumptions for the future resource locations are based the information provided in the CPUC's portfolios.
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	Not addressed in submission	No benefits identified by ISO
Other	Not addressed in submission	No benefits identified by ISO

Conclusion

The Pahrump-Sloan Canyon segment of the proposed transmission upgrades is an alternative to mitigating Pahrump-Sloan Canyon 230 kV line congestion, which has been selected for detailed analysis. The project has been included in that analysis. Please refer to section 4.10.5 below.

4.8.4 Boardman-Hemingway 500 kV transmission project (B2H)

Study request overview

Bonneville Power Administration (BPA), PacifiCorp, and Idaho Power jointly proposed to design, construct, operate and maintain a new 500 kV, single-circuit electric transmission line from a proposed substation near Boardman, Oregon to the Hemingway substation near Melba, Idaho – known as the Boardman to Hemingway Transmission Line Project or B2H Project. Idaho Power is leading the permitting process for the Project.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-6.

Table 4.8-6: Evaluating study request – Boardman to Hemingway 500 kV Transmission Project (B2H)

Study Request: Boardman to Hemingway 500 kV Transmission Project (B2H)		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	The project would relieve constraints north of the California-Oregon border, and could also be utilized to reduce the impact of major outages south of the California-Oregon border.	The project could help to migitage congestions of the 500 kV systems in Pacific Northwest.
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	No benefits identified by ISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	None	No benefits identified by ISO

Conclusion

No further economic assessment is conducted for this submitted project in this planning cycle.

The ISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Boardman, Oregon and Hemingway, Idaho, within the Columbia Grid (CG) and Northern Tier Transmission Group (NTTG) planning regions, respectively. Please refer to chapter 5 regarding the ITP process.

4.8.5 Southwest Intertie Project – North (SWIP-North)

The economic study request regarding the California-Oregon Intertie Day Ahead scheduling congestion and the Southwest Intertie Project – North (SWIP-North) project was submitted by LS Power Development, LLC.

Study request overview

The study request is based on the day-ahead market congestion experienced on COI over the last several years, citing ISO Department of Market Monitoring reports. These values exceed the market congestion observed in the real time market, as well as in past ISO production simulation studies.

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

The request is for ISO to consider scheduling congestion in its transmission economic planning production cost model, and study the benefits of approximately 1000 MW of bidirectional transmission capacity between Midpoint and Harry Allen, which would be available to the ISO market upon completion of construction of SWIP - North. The request also suggests the ISO to consider scenarios that combine SWIP-North with other out of sate transmission projects, which may compliment benefits of SWIP-North.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-7.

Table 4.8-7: Evaluating study request – COI Congestion and SWIP - North

Study Request: Southwest Intertie Project - North		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Request is for ISO to study congestion on California Oregon Intertie (COI) and Pacific AC Intertie (PACI)	Economic studies performed by the ISO have identified congestion on COI; these congestion costs did not change significantly from previous transmission plans; and were previously found not to be sufficient to warrant transmission solutions in previous transmission plans..
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	The ISO's transmission planning studies use CPUC's assumption for out of state resources
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

Study Request: Southwest Intertie Project - North		
Benefits category	Benefits stated in submission	ISO evaluation
Integrate New Generation Resources or Loads	Not addressed in submission	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	Study request recommends that ISO improve the study model to consider the 1000 MW of bidirectional transmission right that the project can provide to the ISO market. The request also suggests to study a full compliment of benefits from SWIP-North and other out of state projects.	Study scenarios of out of state projects, including SWIP-North, need to be developed in the Inter-regional planning (ITP) process. The transmission right model needs to be coordinated with the ADS PCM process to collectively and consistently consider the impact of modeling changes on the existing transmission right in the system and in the ADS PCM.

Conclusion

No further assessment was conducted for this submitted study request in this planning cycle.

The ISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Tier Transmission Group (NTTG) planning regions, respectively. Please refer to chapter 5 regarding the ITP process.

4.8.6 Red Bluff – Mira Loma 500 kV Transmission Project

Study request overview

The project was submitted by NextEra Energy Resources LLC as an economic study request and was also submitted into the 2019 Request Window as a potential reliability project by Horizon West Transmission, LLC. It involves the construction of a new 140-mile 500 kV transmission line between Red Bluff 500 kV substation and Mira Loma 500 kV substation. The project has an estimated cost of $850 million.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-8.

Table 4.8-8: Evaluating study request – Red Bluff – Mira Loma 500 kV Transmission Project

Study Request: Red Bluff – Mira Loma 500 kV Project		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	The project will address SCE's Desert Area constraints.	The project can help to mitigate potential congestion on RedBluff-Devers 500 kV line. However, the congestion on this corridor was not significant enough as identified in this planning cycle. See section 4.7.1. Studies in the last planning cycle also showed that mitigating this

Study Request: Red Bluff – Mira Loma 500 kV Project		
Benefits category	Benefits stated in submission	ISO evaluation
		congestion would not generate sufficient benefit compared to the expected cost of the project. No material change in circumstance that would materially affect these results has been identified.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The project can support integration of renewable generation for the ISO.	This project can help to deliver renewable energy in SCE's Riverside East area, but may adversely impact other areas.
Local Capacity Area Resource requirements	The Red Bluff-Mira Loma 500 kV Project will reduce the Eastern LA Basin LCR and is an added benefit of the project	The ISO's analysis in the last planning cycle found that although this line may help with the Eastern LA Basin voltage stability issue, reducing the Eastern LA Basin generation also adversely affects the overall LA Basin area LCR need. As a result the overall benefits are small compared to the expected cost of the project.
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	Not addressed in submission	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	The project will continue to support integration of the renewable generation; will minimize thermal overloads in the existing 230 kV and 500 kV system; will minimize congestion management cost; will enable significant amount of energy storage; will minimize generation curtailment; will complement integration of CAISO-approved projects; will improve votage profile	See "Identified Congestion", "Delivery of Location Constrained Resource Interconnection Generators", and "Local Capacity Area Resource requirements" above.

Conclusion

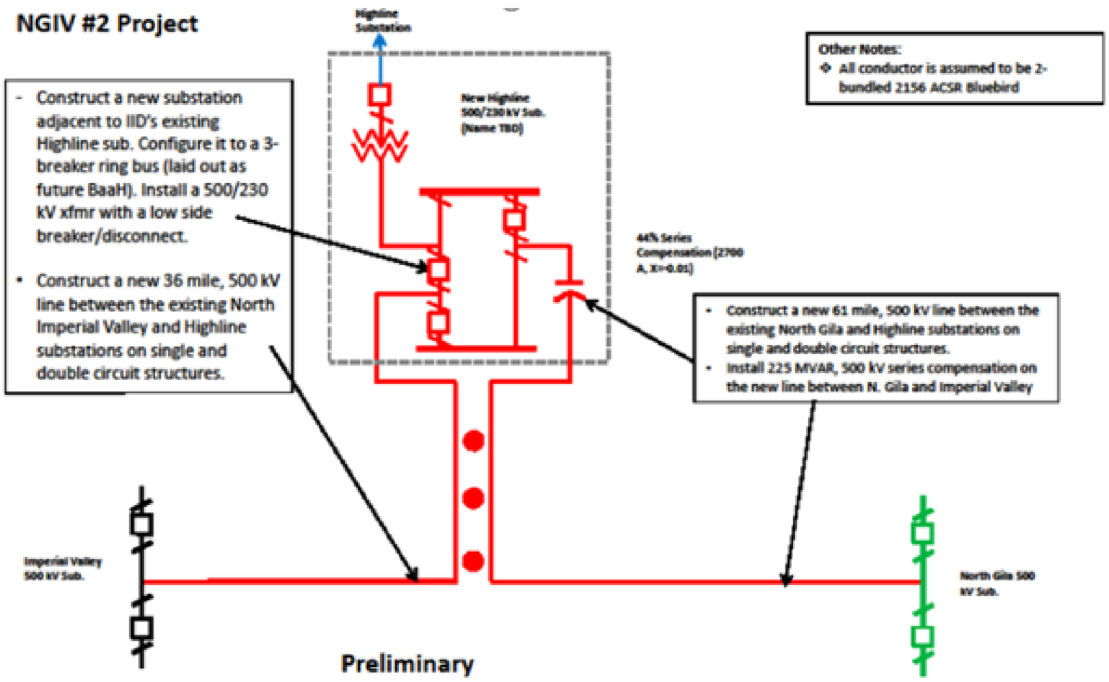
No further assessment was conducted for this submitted study request in this planning cycle.

4.8.7 North Gila Imperial Valley #2 (NGIV2)

Study request overview

NGIV2 is a new 500 kV line proposed from North Gila to Imperial Valley including two segments. The first segment is from North Gila 500 kV bus to the new Dunes 500 kV bus, which connects to the existing IID Highline 230 kV through a 500/230 kV transformer, and Dunes – Imperial Valley 500 kV. The Dunes 500/230 kV substation was formerly known as the Highline 500/230 kV substation in previous planning discussions. The preliminary one-line diagram of the submitted project is shown in Figure 4.8-2.

Figure 4.8-2: North Gila - Imperial Valley #2 500 kV Line Configuration



Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-9.

Table 4.8-9: Evaluating study request – North Gila Imperial Valley #2

Study Request: North Gila Imperial Valley #2		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	The project is expected to reduce congestion on the existing Southwest Power Link (SWPL).	There is no congestion identified in this planning cycle on the North Gila – Imperial Valley section of SWP. As shown in previous cycle's studies, the project will significantly increase congestion downstream of SWPL in east to west direction, increase congestion in the rest of SDG&E system.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The project will provide a new delivery point at the proposed Dunes 500/230 kV substation.	A new delivery point may not help to increase the deliverability of new generators, depending on the location of the binding constraints in the system. For this specifica area, the constraints are in the downstream system of the submitted project.
Local Capacity Area Resource requirements	The project will reduce LCR for the San Diego/Imperial Valley area	The ISO's 2018-2019 TPP has identified LCR reduction benefit of the submitted benefit.
Increase in Identified Congestion	Not addressed in submission	See "Identified Congestion" above

Integrate New Generation Resources or Loads	The project can increase diversity of the interrational energy resource zones	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	The project can make efficient use of existing available transmission corridors; provide additional capacity benefit under normal and emergency conditions for the southern portion of the CAISO system	The project can help to mitigate potential issues under North Gila – Imperial Valley N-1 contingency. However, its effectiveness may reduce as the recent approved upgrades are modeled, such as S-line upgrade. As described in section 4.9.11.3 of the ISO's 2018-2019 Transmission Plan, the reliability assessment demonstrated that the project would worsen the overload concerns identified in the San Diego import transmission and local 230 kV systems. This could potentially trigger reliability issues that need to be eliminated through additional capital investment.

Conclusion

No further assessment was conducted for this submitted study request in this planning cycle. Further, it may be necessary for the project – as now configured and given the interconnection via a new interconnection point to IID – to be considered as an interregional transmission project if revisited in future planning cycles.

4.8.8 Fresno Avenal area update (Gates-Tulare Lake 70 kV line)

Study request overview

Transmission congestion in the Fresno Avenal area, specifically Gates-Tulare Lake 70 kV line, prevents low cost energy from serving customers.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-10.

Table 4.8-10: Evaluating study request – Fresno Avenal area upgrade (Gates-Tulare Lake 70 kV line)

Study Request: Fresno Avenal area upgrade (Gates-Tulare Lake 70 kV line)		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	A cost effective solution that would mitigate congestion in the Fresno Avenal area can reduce consumer costs	Congestion in more than 1000 hour on Kettleman Hills Tap-Gates 70 kV , which is a section of Gates-Tulare Lake 70 kVe line, was observed in this planning cycle
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 is not expected to increase significantly over the planning horizon used in the Transmission Planning Process
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by ISO
Other	Not addressed in submission	No benefits identified by ISO

Conclusion

Based on the congestion analysis results and comments provided, the PG&E Fresno Avenal area congestion was selected for detailed analysis in this planning cycle. Please refer to section 4.10.2.

4.8.9 Potential Reliability Solutions with Potential Material Economic Benefits

The identification of reliability needs and potential mitigations to address those needs are set out in chapter 2. The identification of reliability needs includes the assessment of reliability needs expressed by stakeholders – who may have also submitted potential reliability request window submissions to address the concerns they identified - and the ISO's agreement or disagreement with those expressed concerns. The options to address various reliability needs can also include potential economic benefit. Generally, the determination of a reliability need and the selection of the preferred solution is addressed directly in chapter 2.

However, as noted in chapter 2, potential solutions can be proposed that require consideration of the potential for material economic benefits that would result in a revised or expanded solution being adopted as an economic-driven project that is also meeting the reliability need. A number of proposed projects were identified in chapter 2 as requiring further consideration of economic benefits and are set out in Table 4.8-11below:

Table 4.8-11: Projects proposed as reliability solutions with potential economic benefits[122]

Projects	Potential Economic Benefits
Chula Vista Energy Reliability Center (Wellhead)	This project is an alternative to mitigate reliability concerns identified by SDG&E. As discussed in chapter 2, a reliability need for this proposed solution was not identified. The congestion analysis (see section 4.7) did not identify congestion that this project can help to mitigate. Consequently, no further analysis was undertaken.
Suncrest-Sycamore 230 kV (Horizon West)	The proposed project purport to address some transmission reliability needs, which could otherwise cause some level of congestion. As discussed in chapter 2, a reliability need for this proposed solution was not identified. The congestion that the project could help to mitigate is relatively small (9 hours total) as identified in section 4.7. Consequently, no further analysis was undertaken
Red Bluff-Mira Loma 500 kV (Horizon West)	See section 4.8.6
Sycamore Reliability Energy Storage (Tenaska)	The proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, and was included as an alternative in the detailed analysis for the San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area in the last planning cycle. No further analysis was undertaken in this planning cycle since there is no material change in the area where the project would be located.
Imperial Smart Wire Solution (Imperial Renewable)	A similar project, which proposed a reactor instead of Smart Wires technology, was studied in the last planning cycle. Compared with that project, this Imperial Smart Wire Solution project may show an encouraging benefit to cost ratio for reducing the LCR need. The project will be considered in future planning cycles, once the design and configuration of the IID-owned S-Line upgrade is finalized.

[122] See chapter 2 for additional descriptions of the submitted projects. The table does not include projects submitted as also economic study requests, as those have already been addressed earlier in section 4.8.

4.9 Local Capacity Requirement Reduction Benefit Evaluation

Study requirement

In the 2018-2019 and continuing on in the 2019-2020 transmission planning cycle, the ISO undertook a review of the existing local capacity areas to examine the local capacity needs in the ISO footprint and identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas. This review went beyond the traditional local capacity technical studies, including the biennial 10 year local capacity technical studies that are part of the ISO's ongoing study process, by examining characteristics of requirements in more detail, and examining possible mitigations. These studies were conducted under the economic analysis framework, as there is currently not a basis for identifying solutions on a reliability basis or policy basis. If there are sufficient local resources to maintain reliability, reducing the use of those resources is not necessary to meet NERC or ISO planning standards. Further, there are no applicable federal or state policies at this time that necessitate planning for reduced local capacity levels beyond state policies for generation relying on coastal waters for once-through-cooling, and those needs have been addressed in previous transmission plans.

It was recognized that actual viable economic-driven opportunities may be unlikely, but that even if that was the case, examining and understanding the needs – and the load, generation and system characteristics driving those needs, could be valuable in future resource procurement processes outside of the ISO's transmission planning process. In particular, the information regarding local requirement characteristics in all areas, and the scope of upgrades necessary to effect reductions in the areas selected for detailed studies - even if not currently economic - would be helpful to state policy makers and regulatory agencies in considering future policy direction or resource planning decisions.

Recognizing that a thorough and comprehensive review of transmission and hybrid alternatives for all local capacity areas in a single planning cycle was unrealistic, the ISO targeted this expanded study on exploring and assessing alternatives to eliminate or materially reduce requirements in "at least half" of the existing areas and sub-areas in the first year (the 2018-2019 transmission planning cycle) and completing the analysis in this subsequent planning cycle. The local capacity areas and sub-areas to be studied were prioritized based on the attributes of the gas-fired generation to provide other system benefits and on the gas-fired generation being located in disadvantaged communities.

This analysis therefore provided an overview of the local capacity requirements on the ISO system in greater depth than traditional local capacity requirements technical studies.

The studies were essentially carried out in two phases. The first phase consisted of:

- Examining the needs in all areas and sub-areas, with the characteristics of the needs being set out in more detail, which both provides the necessary information to inform consideration of other resource alternatives to meet the needs, and allowed the prioritization of the "more than half" areas and sub-areas for which transmission and hybrid mitigations would be explored.

- Prioritizing the areas and sub-areas, and selecting the "more than half" for which alternatives would be developed.
- Identifying and testing transmission and hybrid alternatives for that subset. The ISO did not studied the economics of "resource substitution", e.g. replacing one form of local capacity resource with another, as that is a resource procurement decision falling under the CPUC's procurement processes.

The ISO selected the "more than half" areas for study of mitigations for last year's efforts, by screening existing areas and sub-areas, filtering out those that were already on the path to being eliminated, and prioritizing the remainder to select the half that would receive in-depth analysis.

There are currently 10 active local capacity areas, and 53 distinct requirements considering both areas and sub-areas. This number will decrease to 41 distinct requirements by 2026 due to new already-approved transmission projects that will completely eliminate the LCR need in 12 sub-areas. A subset of the 41 remaining areas and sub-areas were selected for further study of potential economic-driven transmission solutions, through the prioritization process based on:

- Local areas and sub-areas with announced retirements or units being mothballed that were not previously studied. The studies for these areas and sub-areas need to have a higher priority due to potential pending retirements.
- Local resources located in disadvantaged communities. Higher priority to local areas and sub-areas that rely on resources located in these communities.
- Type of resources. Higher priority will be given to local areas and sub-area that rely on resources that use natural gas and/or petroleum.
- Age of resources. Reduce reliance on old resources close to the end of their useful life. Reduction of resources (other than hydro, solar and wind) over 40 year old has priority.

As a result of the prioritization effort, 23 distinct area and sub-area needs were selected in the 2018-2019 TPP for consideration of transmission and hybrid alternatives, representing over 50% of total.

The ISO completed the second phase in this planning cycle, by assessing the remaining areas. The areas and sub-areas studied in the 2019-2020 TPP, consisting of the remaining areas or sub-areas that relied at least to some extent on gas-fired generation are shown in Table 4.9-1. Areas and sub-areas that rely only on existing hydro generation were not studied.

As discussed in Chapter 6, alternatives to eliminate or materially reduce local capacity requirements in the selected areas and sub-areas were developed, exploring not only the most limiting conditions and issues, but often exploring the "next level" of limitation that would be binding once the most limiting conditions were addressed.

Many of those alternatives are quite complex, relatively costly, and require further coordination with the CPUC's integrated resource planning framework and the longer term needs for gas-fired generation for system purposes before recommendations could be seriously considered. However, some of the less expensive and more modest upgrades identified do warrant further consideration as potential economic-driven transmission projects in this planning cycle, as well as other upgrades proposed by stakeholders that warrant detailed analysis.

The review described in Chapter 6 was conducted as an extension of the previous years' efforts, and relied on the information and base cases developed in that cycle and based on the local capacity technical study criteria in effect at the time.. Any areas that were considered potential economic study requests deserving detailed study as potential high priority study requests were then considered below, using the current planning cycle's study assumptions.

Evaluation and Conclusions

Of the areas and sub-areas examined in this cycle, the subset identified in Table 4.9-1 were selected for further detailed economic study for potential economic-driven recommendations, set out in section 4.10.

Table 4.9-1: Selection of Areas and Sub-areas for Examination of Alternatives and for Detailed Economic Analysis

Areas and sub-areas selected for examination of potential alternatives – "more than half" of the areas and sub-areas.		Areas and sub-areas selected for detailed economic analysis in section 4.10
1	Humboldt	*selected for detailed economic analysis – subsection 4.10.6*
	Stockton	
2	- Stanislaus	
3	- Tesla-Bellota	*selected for detailed economic analysis – subsection 4.10.7*
4	- Weber	
	Greater Bay Area	
5	- Llagas (Update)	*selected for detailed economic analysis – subsection 4.10.8*
6	- Oakland	
7	- Contra Costa	*selected for detailed economic analysis – subsection 4.10.9*
8	- Overall	
	Fresno	
9	- Coalinga	*selected for detailed economic analysis – subsection 4.10.10*
10	- Overall	
	Kern	
11	- South Kern PP	*selected for detailed economic analysis– subsection 4.10.11*
12	- Overall (if needed)	
	Big Creek/Ventura	
13	- Santa Clara	*selected for detailed economic analysis – subsection 4.10.12.*
14	- Overall	*selected for detailed economic analysis– subsection 4.10.12*
	LA Basin	
15	- El Nido	*selected for detailed economic analysis – subsection 4.10.13*

16	- Western LA Basin	*selected for detailed economic analysis – subsection 4.10.13*
	- Overall (in conjunction with Western reduction)	*Evaluated for impacts to local capacity requirement for the overall area*
17	San Diego/Imperial Valley (combined with LA Basin)	*Evaluated for impacts to local capacity requirement for the area*

4.10 Detailed Investigation of Congestion and Economic Benefit Assessment

The ISO selected the branch groups and study areas listed in Table 4.10-1 for further assessment as high priority studies after evaluating identified congestion, considering potential local capacity reduction opportunities and stakeholder-proposed reliability projects citing material economic benefits, and reviewing stakeholders' study requests, consistent with tariff section 24.3.4.2.

Facilities identified as potential mitigations in those study areas include stakeholder proposals from a number of sources; request window submissions citing economic benefits, economic study requests, and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements.

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.10-1 for ease of tracking where and how these stakeholder proposals were addressed.

The detailed analysis also considers other ISO-identified potential mitigations which have been listed in Table 4.10-1 as well.

Table 4.10-1: Detailed Economic Benefit Investigation

Detailed investigation	Alternative	Proposed by	Reason
Congestion			
Path 26 Corridor	PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach)	PTE	A parallel path to Path 26 and can potentially reduce congestion on Path 26
PG&E Fresno Avenal area Gates toTulare Lake 70 kV line	Reconductoring Kettleman Hills Tap to Gates 70 kV line	PG&E	Potentially mitigate or reduce the identified congestion
PG&E Fresno Huron to CalFlax 70 kV line	Reconductoring Huron to Calflax 70 kV line	ISO	Potentially mitigate or reduce the identified congestion
PG&E Fresno Oro Loma to El Nido 115 kV lines	Reconductoring Oro Loma to El Nido 115 kV line	ISO	Potentially mitigate or reduce the identified congestion
VEA Sloan Canyon to Pahrump 230 kV lines	Reconductoring the existing Sloan Canyon to Pahrump 230 kV lines;	GLW	Potentially mitigate or reduce the identified congestion
	Reconductoring Sloan Canyon to Pahrump 230 kV lines and install two phase shifters between the VEA and NVE 138 kV systems	ISO	Potentially mitigate or reduce the identified congestion
Local Capacity Reduction Study Areas			
PG&E Humboldt area	Build a new Humboldt to Trinity 115 kV line	ISO	Potentially reduce local capacity requirements
PG&E Stockton Tesla-Bellota sub-area	Reconductoring the overloaded lines in the Tesla to Manteca area (~50 miles) and Stanislaus to Manteca area (~150 miles)	ISO	Potentially reduce local capacity requirements

Detailed investigation	Alternative	Proposed by	Reason
	Build a new Weber to Manteca 230 kV line and reconductoring number of lines in the Tesla to Manteca area (~25 miles) and the Stanislaus to Manteca area (~100 miles)	Horizon West	Potentially reduce local capacity requirements
	Build a new Westside to Kasson 230 kV line and reconductoring number of lines in the Sanislaus to Manteca area (~75 miles)	ISO	Potentially reduce local capacity requirements
PG&E Greater Bay Area Llagas sub-area	Loop the Metcalf-Llagas 115 kV line into the Morgan Hill substation	PG&E	Potentially reduce local capacity requirements
PG&E Greater Bay Area Contra Costa sub-area	Reconductoring Tesla-Delta Switch Yard 230 kV line	ISO	Potentially reduce local capacity requirements
	Delta Reliability Energy Storage - add a new 4-hour and 75 MW energy storage at Delta substation	Tenaska	Potentially reduce local capacity requirements
	Tesla-Delta Switchyard 230 kV line reactance project with Smart Wires device	Smart Wires	Potentially reduce local capacity requirements
PG&E Fresno Coalinga sub-area	Install a 25 MVAr capacitor at Coalinga 70 kV	ISO	Potentially reduce local capacity requirements
	Install a new Gates 230/70 kV transformer	ISO	Potentially reduce local capacity requirements
PG&E Kern South Kern PP sub-area	SPS to shed 75 MW of load at Stockdale A substation for the loss of any combination of Midway-Kern PP 230 kV lines	ISO	Potentially reduce local capacity requirements
Big Creek–Ventura area	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	Potentially reduce local capacity requirements and Reliability need
Big Creek–Ventura area /Santa Clara sub-area	PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach)	PTE	Potentially reduce local capacity requirements
	Install a 79 MVAR, 230 kV shunt capacitor at Goleta Substation and upgrading multiple towers and terminal equipment on Santa–Clara Vincent, Santa Clara–Pardee, and Santa Clara–Moorpark No.1 & 2 230 kV lines to achieve ratings of 494 MVA (normal)/665 MVA (emergency)	ISO/SCE	Potentially reduce local capacity requirements
Western sub-area (LA Basin)	PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach).	PTE	Potentially reduce local capacity requirements.
El Nido sub-area (LA Basin)	Install 350 MW BESS in El Nido sub-area	ISO	Potentially reduce local capacity requirements
	Upgrade La Fresa – La Cienega 230 kV line (12 mi.)	ISO	Potentially reduce local capacity requirements
	Install 350 MW BESS in Nido and 350 MW in Western LA Basin sub-areas	ISO	Potentially reduce local capacity requirements

Detailed investigation	Alternative	Proposed by	Reason
	Install BESS in Nido and Upgrade Mesa – Laguna Bell 230 kV line	ISO	Potentially reduce local capacity requirements
	Install 350 MW BESS in Nido sub-area and Install 3 Ω Line Series Reactor on the Mesa-Laguna Bell 230 kV line	ISO	Potentially reduce local capacity requirements
	Upgrade La Fresa – La Cienega 230 kV line and Install 3 Ω Line Series Reactor on the Mesa – Laguna Bell 230 kV line	ISO	Potentially reduce local capacity requirements

This study step consists of conducting detailed investigation and modeling enhancements as needed. To the extent that economic assessments for potential transmission solutions are needed, the production benefits and other benefits of potential transmission solutions are based on the ISO's Transmission Economic Analysis Methodology (TEAM)[123], and potential economic benefits are quantified as reductions of ratepayer costs.

In addition to the production benefit, other benefits were also evaluated as needed. As discussed in section 4.2, other benefits are also taken into account on a case by case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven.

All costs and payments provided in this section are in 2018 real dollars.

Scope of Study Alternatives

Finally, it is important to reiterate that all regional transmission solutions – other than modifications to existing facilities, are subject to the ISO's competitive solicitation process as set out in the ISO's tariff. So, while many projects have been submitted with narrowly defined project scopes, the ISO is not constrained to only study those scopes without modification, or to study the projects exclusively on the basis under which the proponent suggested.

4.10.1 Path 26 Corridor Congestion and PTE HVDC Project

Congestion analysis

The production cost modeling results demonstrated congestion occurring on Path 26 corridor mainly when the flow was from south to north. Renewable generators in Southern California identified in the CPUC renewable portfolio were the main driver of the Path 26 corridor congestion. The details of the Path 26 corridor congestion are shown in Table 4.10-2.

[123] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.10-2: Path 26 corridor congestion

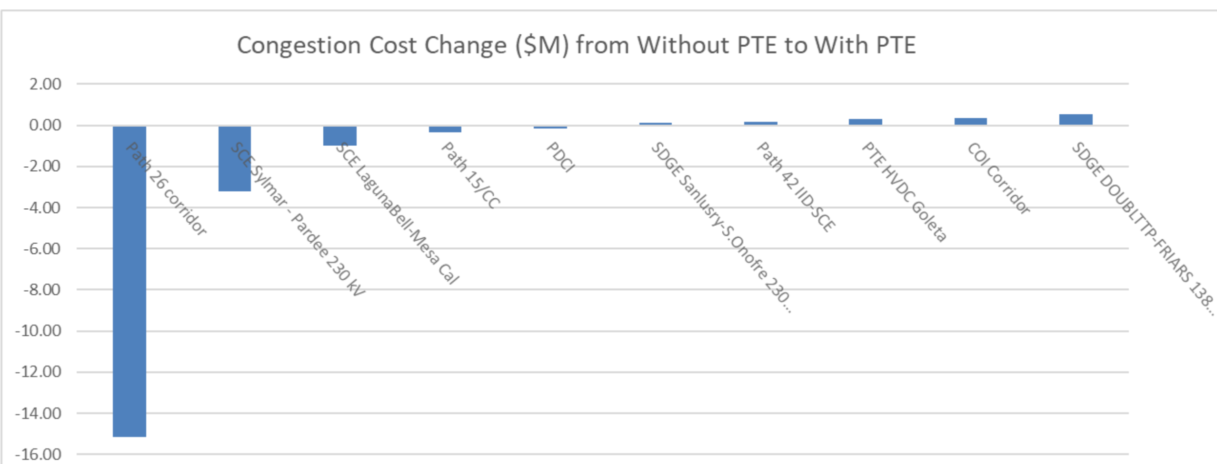
Constraints Name	Congestion Costs ($M)	Congestion Duration (Hrs)
P26 North to South (4000 MW path ration)	0.01	3
P26 South to North (3000 MW path rating)	14.17	586
From MW_WRLWND_31 to MW_WRLWND_32 500 kV line #3	3.52	78
From MW_WRLWND_32 to WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500 kV	0.65	36
From MW_WRLWND_32 to WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #1 500 kV	0	1

Congestion mitigation alternatives

A stakeholder-submitted alternative to mitigate the Path 26 corridor congestion was considered, which is a multi-terminals offshore HVDC project comprising three segments and four terminals at Diablo Canyon, Goleta, Redondo Beach, and Huntingon Beach. The details of this alternative can be found in section 4.8.2.

The PTE project provides a parallel path to Path 26, therefore the Path 26 congestion can be reduced by modeling the PTE project. SCE's local area congestions, such as Sylmar to Pardee congestion and Mesa Cal to Laguana Bell congestion, are reduced. The congestion change that resulted from modeling the PTE project are shown in Figure 4.10-1.

Figure 4.10-1: Congestion changes with PTE project modeled



Production benefits

The production benefit of the PTE project for ISO's ratepayers and the production cost savings are shown in Table 4.10-3.

Table 4.10-3: Production Benefits for the PTE HVDC project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	7,732.7	7,743.6	-10.8
ISO generator net revenue benefiting ratepayers	3,445.9	3,467.4	21.5
ISO transmission revenue benefiting ratepayers	167.1	147.8	-19.2
ISO Net payment	4,119.8	4,128.4	-8.5
WECC Production cost	14,784.1	14,776.8	7.3

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

The total production cost benefit of the PTE project to the ISO ratepayers is -$8.5 million based on the production cost simulation results in this planning cycle, which is the summation of the changes of load payment, generator net revenue, and transmission revenue. The production cost simulation results showed that modeling the PTE project results in an increase in load payment and an increase in generator net revenue. Transmission revenue benefiting ratepayers reduced because congestion cost reduced with modeling the PTE project.

The PTE project was identified as an alternative to reducing LCR in some local areas in the SCE's system. The detailed LCR reduction assessment for the PTE project can be found in section 0 and section 4.10.13. The cost estimation and the benefit to cost ratio calculation for the PTE project are also described in section 4.10.13, where the LCR reduction in El Nido and Western LA Basin sub-areas is assessed.

4.10.2 PG&E Fresno Avenal Area Gates to Tulare Lake 70 kV line

Congestion analysis

Congestion on the Gates to Tulare Lake 70 kV line, specifictly the section between Kettleman Hills Tap to Gates, was observed in this planning cycle. The congestion occurs from Kettleman Hills Tap to Gates mainly in the hours when solar generation output is high, especially in the months when the summer rating of the line is applied. Figure 4.10-2 and Figure 4.10-3 show the hourly average flow from Kettleman Hills Tap to Gates in the months when the winter rating and the summer rating are applied, respectively.

Figure 4.10-2: Hourly average flow on Kettleman Hills Tap to Gates 70 kV line – months with winter rating applied

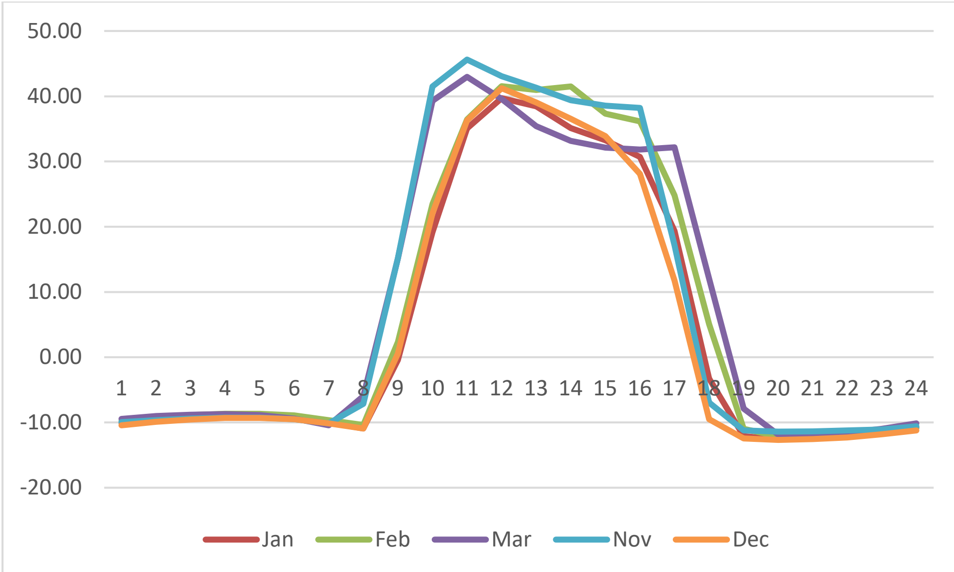
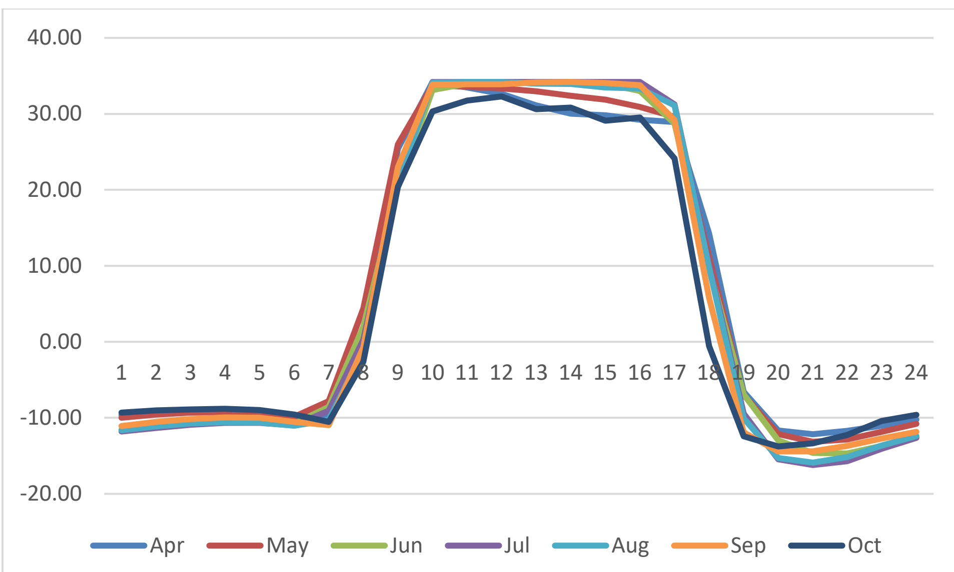


Figure 4.10-3: Hourly average flow on Kettleman Hills Tap to Gates 70 kV line – months with summer rating applied



Congestion mitigation alternaltives

A reconductoring of the Kettleman Hills Tap to Gates 70 kV line to a higher rating was assessed. Production cost simulation result showed that the reconductoring can mitigate the congestion of the Kettleman Hills Tap to Gates 70 kV line.

Production benefits

The production benefit of reconductoring Kettleman Hills Tap to Gates 70 kV line for ISO's ratepayers and the production cost savings are shown in Table 4.10-4.

Table 4.10-4: Production Benefits for Reconductoring Kettleman Hills Tap to Gates 70 kV line

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	7,732.7	7,730.6	2.1
ISO generator net revenue benefiting ratepayers	3,445.9	3,444.3	-1.5
ISO transmission revenue benefiting ratepayers	167.1	166.9	-0.2
ISO Net payment	4,119.8	4,119.4	0.4
WECC Production cost	14,784.1	14,788.6	-4.5

Note that ISO ratepayer "savings" are a <u>decrease</u> in load payment, but an <u>increase</u> in ISO generator net revenue benefiting ratepayers and an <u>increase</u> in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a <u>decrease</u> in overall production cost. A negative saving is an incremental cost or loss.

<u>Cost estimates</u>

The capital cost of the reconductoring was estimated at about $11 million based on the length of the line and the PG&E's per unit cost[124] that has been derived for generation interconnection study. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $11 million capital translates to a total cost of $14.3 million.

<u>Benefit to Cost Ratio</u>

The present value of the sum of the production cost and capacity benefits above are shown in Table 4.10-5 and were calculated on a 40 year project life followed by the calculation of the benefit to cost ratio.

Table 4.10-5: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

PG&E Fresno Kettleman Hills Tap to Gates 70 kV Reconductoring	
Production cost savings ($million/year)	0.4
Capacity saving ($million/year)	0.0
Capital cost ($million)	11.0
Discount Rate	7%
PV of Production cost savings ($million)	5.7
PV of Capacity saving ($million)	0.0

[124] http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Total benefit ($million)	5.7
Total cost (Revenue requirement) ($million)	14.3
Benefit to cost ratio (BCR)	0.4

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the benefit to cost ratio was not sufficient for the ISO to find the need for the reconductoring of the Kettleman Hills Tap to Gates 70 kV line. It should be noted that the congestion on this line is related to several key factors including the local load profile and the local solar generator output. The ISO will coordinate with PG&E to investigate these key factors in future planning cycles.

This congestion will be monitored and investigated in future planning cycles.

4.10.3 PG&E Fresno Area Huron to Calflax 70 kV line

Congestion analysis

Congestion on the Huron to Calflax 70 kV line under an N-2 contingency of Panoche to Excelsior 115 kV lines was observed in this planning cycle. The congestion occurs mainly from Calflax to Huron in the hours when solar generation output is high, especially in the months when the summer rating of the line is applied. The hourly average flow from Huron to Calflax in the months when the winter rating and the summer rating are applied, respectively are shown in Figure 4.10-4 and Figure 4.10-5.

Figure 4.10-4: Hourly average flow on Huron to Calflax 70 kV line – months with winter rating applied

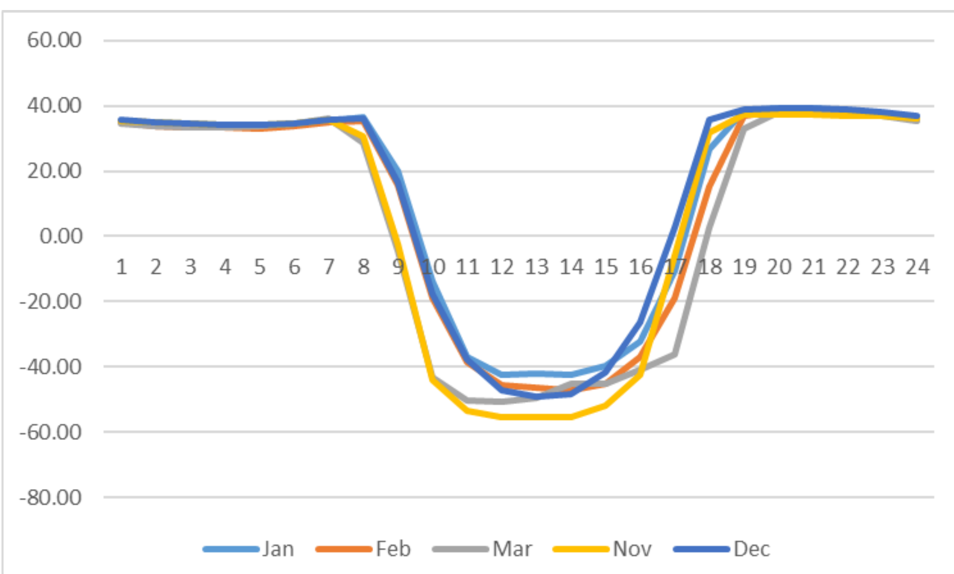
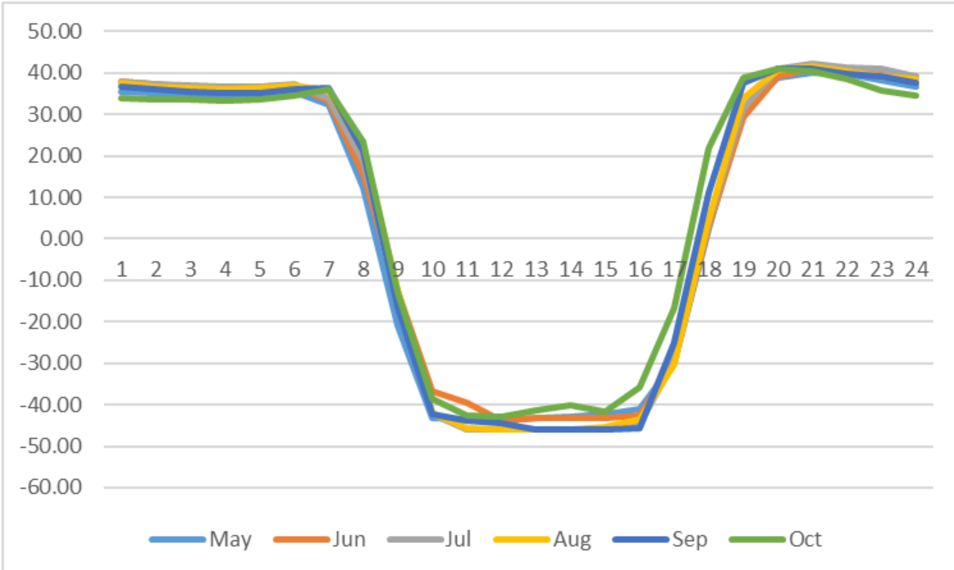


Figure 4.10-5: Hourly average flow on Huron to Calflax 70 kV line – months with summer rating applied



Congestion mitigation alternaltives

A reconductoring of the Huron to Calflax 70 kV line was assessed. Production cost simulation result showed that the reconductoring can mitigate the congestion of the Huron to Calflax 70 kV line.

Production benefits

The production benefit of reconductoring Huron to Calflax 70 kV line for ISO's ratepayers and the production cost savings are shown in Table 4.10-6.

Table 4.10-6: Production Benefits for Reconductoring Huron to Calflax 70 kV line

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	7,732.7	7,731.1	1.6
ISO generator net revenue benefiting ratepayers	3445.9	3,446.7	0.9
ISO transmission revenue benefiting ratepayers	167.1	166.2	-0.9
ISO Net payment	4,119.8	4,118.2	1.6
WECC Production cost	14,784.1	14,784.8	-0.7

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Cost estimates

The capital cost of the reconductoring was estimated at about $12 million based on the length of the line and the PG&E's per unit cost[125] that has been derived for generation interconnection study. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $12 million capital translates to a total cost of $15.6 million.

Benefit to Cost Ratio

The present value of the sum of the production cost and capacity benefits are shown in Table 4.10-7. These benefits were calculated on a 40 year project life followed by the calculation of the benefit to cost ratio.

Table 4.10-7: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

PG&E Fresno Huron to Calflax 70 kV Reconductoring	
Production cost savings ($million/year)	1.6
Capacity saving ($million/year)	0.0
Capital cost ($million)	12.0
Discount Rate	7%
PV of Production cost savings ($million)	22.6
PV of Capacity saving ($million)	0.0
Total benefit ($million)	22.6
Total cost (Revenue requirement) ($million)	15.6
Benefit to cost ratio (BCR)	1.45

Conclusions

The benefit to cost ratio is about 1.45, which provides sufficient economic justification. However, The ISO decided to not recommend the reconductoring of the Huron to Calflax 70 kV line for approval as economic driven project in this planning cycle for the following reasons:

- The congestion on the Huron to Calflax 70 kV line was observed in the simulation results under an N-2 contingency of the Panoche to Excelsior 115 kV lines, which have multiple segments. The ISO will continue to coordinate with PG&E to further evaluate whether this contingency is a credible N-2 contingency and whether there are any other alternatives such as SPS to mitigate the congestion under contingency.
- The congestion may be affected by the assumptions of local load and generators and their profiles. The ISO will coordinate with PG&E to further investigate these affecting factors.

This congestion will be monitored and investigated in future planning cycles.

[125] http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

4.10.4 PG&E Fresno Area Oro Loma to El Nido 115 kV line

Congestion analysis

Congestion on the Oro Loma to El Nido 115 kV line was observed in this planning cycle. The congestion occurs in the direction from Oro Loma to El Nido in the hours when solar generation output is high in the months when the summer rating of the line is applied. Congestion was observed in total 208 hours in the production cost simulation results.

Congestion mitigation alternaltives

In this planning cycle, a reconductoring of the sections of the Wilson to El Nido 115 kV line was approved as a reliability upgrade, which was modeled in the planning PCM. In the Oro Loma to El Nido congestion study, a reconductoring of the Oro Loma to El Nido 115 kV line was assessed, and the reconductoring was assumed to use to the same conductor rating as of the upgraded Wilson to El Nido 115 kV line.

The production cost simulation results showed that the reconductoring can partially mitigate the congestion on the Oro Loma to El Nido 115 kV line. The congestion hours reduced from 208 hours to 73 hours. Higher reconductoring rating can migitage the congestion on the Oro Loma to El Nido line, but would cause congestions in the downstream system, including the El Nido to Wilson 115 kV line.

Production benefits

The production benefit of reconductoring Oro Loma to El Nido 115 kV line for ISO's ratepayers and the production cost savings are shown in Table 4.10-8.

Table 4.10-8: Production Benefits for Reconductoring Oro Loma – El Nido 115 kV line

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	7732.7	7733.4	-0.6
ISO generator net revenue benefiting ratepayers	3445.9	3443.9	-2.0
ISO transmission revenue benefiting ratepayers	167.1	166.1	-0.9
ISO Net payment	4119.8	4123.4	-3.5
WECC Production cost	14784.1	14788.0	-3.9

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Conclusions

The reconductoring of the Oro Loma to El Nido 115 kV line does not provide positive benefit to ISO ratepayers. The study results do not support pursuing a reconductoring of the Oro Loma to

El Nido 115 kV line at this time. The Oro Loma to El Nido 115 kV congestion and its potential reconductoring will be reevaluated in future planning cycles with further clarity of Wilson to El Nido upgrade implementation.

4.10.5 GridLiance West/VEA Area

Congestion analysis

The production cost simulation results in this planning cycle demonstrate congestion occurring in the GridLiance West (GLW)/VEA area. Renewable generators in the GLW/VEA area and in the SCE's Eldorado and Ivanpah areas are the main drivers of the congestion. The loop flow caused by the interchange between the Nevada Energy (NVE) and the ISO systems also contributes to the congestion. A summary of the congestion in the GLW/VEA area is shown in Table 4.10-9.

Table 4.10-9: GLW/VEA area congestion

Congestion	Congestion cost ($M)	Congestion duration (Hr)
From Carpenter Canyon to Pahrump 230 kV line	2.80	357
From Jackass Flats to Mercury 138 kV line	0.12	120
From Trout Canyon to Sloan Canyon 230 kV line	0.06	57

Congestion mitigation alternatives

Two alternatives to mitigating the identified congestion were assessed:

- Alternative 1: The economic study request of reconductoring Sloan Canyon to Pahrump 230 kV line, which includes three sections from Sloan Canyon to Trout Canyon, from Trout Canyon to Carpenter Canyon, and from Carpenter Canyon to Pahrump.
- Alternative 2: Combining Alternative 1 and the installation of two phase shifters between the VEA and NVE's 138 kV systems, specifically on the Lathrop Wells to Jackass Flats 138 kV line and on the Innovation to Mercury 138 kV line. This alternative was identified in the ISO's generation interconnection studies. It can help to limit the loop flow between the NVE and the ISO systems.

Production cost simulation results showed that Alternative 1 can mitigate the congestion on all of the sections of the Sloan Canyon to Pahrump 230 kV line, but slightly increase the congestion on Jackass Flats to Mercury 138 kV line. Alternative 2 can mitigate all congestions listed in Table 4.10-9.

Production benefits

The production cost savings were shown in Table 4.10-10 for the two alternatives.

Table 4.10-10: Production Benefits for GLW/VEA upgrades

		Alternative 1 - Reconductoring		Alternative 2 - Reconductoring plus Phase Shifters	
	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	7732.7	7720.0	12.7	7732.4	0.3
ISO generator net revenue benefiting ratepayers	3445.9	3440.7	-5.1	3450.6	4.7
ISO transmission revenue benefiting ratepayers	167.1	164.5	-2.6	164.1	-2.9
ISO Net payment	4119.8	4114.8	5.0	4117.7	2.1
WECC Production cost	14784.1	14790.5	-6.5	14785.2	-1.1

Cost estimates

The current cost estimate from GLW is $96.4 million for the proposed Sloan Canyon to Pahrump reconductoring. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $96.4 million capital translates to a total cost of $125.3 million for Alternative 1.

The current cost estimate for a 138 kV phase shifter is $4.5 million based on VEA's per unit cost[126] . The capital cost of two phase shifters is $9 million. Applying the ISO's screening factor of 1.3, the total cost of the two 138 kV phase shifters is $11.7 million, which results in the total cost $137 million for Alternative 2.

Benefit to Cost Ratio

The present value of the sum of the production cost and capacity benefits is shown in Table 4.10-11. These values were calculated based on a 40 year project life followed by the benefit to cost ratio calculation.

[126] http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Table 4.10-11: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

GLW/VEA upgrades		
	Alternative 1 - Reconductoring	Alternative 2 - Reconductoring plus Phase Shifters
Production cost savings ($million/year)	5.0	2.1
Capacity saving ($million/year)	0.0	0.0
Capital cost ($million)	96.4	105.4
Discount rate	7%	7%
PV of Production cost savings ($million)	69.1	29.1
PV of Capacity saving ($million)	0.0	0.0
Total benefit ($million)	69.1	29.1
Total cost (Revenue requirement) ($million)	125.3	137.0
Benefit to cost ratio (BCR)	0.55	0.21

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the benefit to cost ratio was not sufficient for the ISO to find a need for either transmission upgrade Alternative 1 or 2 in the GLW/VEA area in this planning cycle. This area will continue to be monitored and investigated in future planning cycles with further clarity of the resource assumption and development in the VEA area and the SCE's Ivanpah, Mountain Pass, and Eldorado areas.

4.10.6 Humboldt Area Local Capacity Reduction Study

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Humboldt area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2019-2020 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Humboldt area is in Appendix G, section 3.2.1.

The project would consist of the following:

- Build a new Humboldt to Trinity 115 kV line.

Production benefits

The new Humboldt to Trinity 115 kV line is not expected to provide production benefits. No congestion was identified in the Humboldt area in this planning cycle.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Humboldt area. The local capacity requirement for gas-fired generation in the Humboldt area was eliminated resulting in a reduction of approximately 170 MW.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and “north of path 26 system” resources. For the Humboldt area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions in the Humboldt area is valued based on the cost range for the Humboldt area is shown in Table 4.10-12.

Table 4.10-12: Humboldt LCR area Reduction Benefits

Build a new Humboldt to Trinity 115 kV line		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Humboldt area) (MW)	170	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.37	$0.24

Cost estimates:

The planning estimate cost for this alternative is $318 million. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO’s screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the “total” cost”, for a total of $413.4 million.

Benefit to Cost Ratio

The benefit to cost ratios are shown in Table 4.10-13 and were calculated from the present value of the capacity benefits tabulated in Table 4.10-12. based on a 50 year project life.

Table 4.10-13 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Build a New Humboldt to Trinity 115 kV line		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.37	$0.24
Capital Cost Estimate ($ million)	$318	
Benefit to Cost		
PV of Savings ($million)	$5.07	$3.38
Estimated "Total" Cost (screening) ($million)	$413.4	
Benefit to Cost	0.01	0.01

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Humboldt area for system reasons is achieved.

4.10.7 Stockton Area Tesla-Bellota Sub-area Local Capacity Reduction Study

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Stockton Tesla-Bellota sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2019-2020 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Tesla-Bellota sub-area is in Appendix G, section 3.2.4.5. The alternatives consist of the following:

- Alternative 1: Reconductoring the overloaded lines in the Tesla to Manteca area (~50 miles) and Stanislaus to Manteca area (~150 miles).
- Alternative 2: Build a new Weber to Manteca 230 kV line and reconductoring number of lines in the Tesla to Manteca area (~25 miles) and the Stanislaus to Manteca area (~100 miles).
- Alternative 3: Build a new Westside to Kasson 230 kV line and reconductoring number of lines in the Sanislaus to Manteca area (~75 miles).

Production benefits

All three alternatives are not expected to provide production benefits. No congestion was identified in the Tesla-Bellota sub-area in this planning cycle.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Tesla-Bellota sub-area. The local capacity requirement for gas-fired generation in the Tesla-Bellota sub-area was reduced resulting in a reduction of approximately 365 MW.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and “north of path 26 system” resources. For the Tesla-Bellota sub-area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions of the Alternative 3, which has the lowest cost among the three alternatives, in the Tesla-Bellota sub-area is shown in Table 4.10-14. The benefit is valued based on the cost range for the Tesla-Bellota sub-area.

Table 4.10-14: Tesla-Bellota LCR Sub-area Reduction Benefits

Tesla-Bellota Sub-area Alternative 3: new Westside to Kasson 230 kV line and reconductoring number of lines in the Sanislaus to Manteca area		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	365	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.79	$0.53

Cost estimates:

The planning estimate cost for the Alternative 3 is $117 million. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO’s screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the “total” cost”, for a total of $152 million.

Benefit to Cost Ratio

The present value of the capacity benefits shown in Table 4.10-14 are shown in Table 4.10-15. These values were calculated based on a 50 year project life for the range of the cost estimates.

Table 4.10-15 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Tesla-Bellota Sub-area Alternative 3: new Westside to Kasson 230 kV line and reconductoring number of lines in the Sanislaus to Manteca area		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.79	$0.53
Capital Cost Estimate ($ million)	$318	
Benefit to Cost		
PV of Savings ($million)	$10.88	$7.25
Estimated “Total” Cost (screening) ($million)	$152	
Benefit to Cost	0.07	0.05

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Tesla-Bellota sub-rea for system reasons is achieved.

4.10.8 Greater Bay Area Llagas Sub-area Local Capacity Reduction Study

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Greater Bay Area Liagas sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2019-2020 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Llagas sub-area is in Appendix G, section 3.2.5.2. The alternatives would consist of the following:

Loop the Metcalf-Llagas 115 kV line into the Morgan Hill substation.

Production benefits

This alternative is not expected to provide production benefits. No congestion was identified in the Llagas sub-area in this planning cycle.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Humboldt area. The local capacity requirement for gas-fired generation in the Llagas sub- area was reduced resulting in a reduction of approximately 75 MW.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and “north of path 26 system” resources. For the Llagas sub-area, these translated to values of $1,560/MW-year and $840/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions in the Llagas sub-area is valued based on the cost range for the Llagas sub-area is shown in Table 4.10-16.

Table 4.10-16: Llagas LCR Sub-area Reduction Benefits

Metcalf-Llagas loop-in to Morgan Hill substation		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	75	
Capacity value (per MW-year)	$1,560	$840
LCR Reduction Benefit ($million)	$0.12	$0.06

Cost estimates:

The planning estimate cost for the loop-in of the Metcalf to Llagas line into the Morgan Hill substation is $7 million. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO’s screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the “total” cost”, for a total of $9.1 million.

Benefit to Cost Ratio

The present value of the capacity benefits shown in Table 4.10-16 are shown in Table 4.10-17. These values were calculated based on a 50 year project life for the range of the cost estimates

Table 4.10-17 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Metcalf-Llagas loop-in to Morgan Hill substation		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.12	$0.06
Capital Cost Estimate ($ million)	$7	
Benefit to Cost		
PV of Savings ($million)	$1.61	$0.87
Estimated “Total” Cost (screening) ($million)	$9.1	
Benefit to Cost	0.18	0.10

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Liagas sub-rea for system reasons is achieved.

4.10.9 Greater Bay Area Contra Costa Sub-area Local Capacity Reduction Study

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Greater Bay Area Contra Costa sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2019-2020 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Contra Costa sub-area is in Appendix G, section 3.2.5.7. The alternatives would consist of the following:

- Alternative 1: Reconductoring Tesla-Delta Switch Yard 230 kV line.
- Alternative 2: Delta Reliability Energy Storage - add a new 4-hour and 75 MW energy storage at Delta substation.
- Alternative 3: Tesla-Delta Switchyard 230 kV line reactance project with Smart Wires device.

Production benefits

The alternatives are not expected to provide production benefits. No congestion was identified in the Contra Costa sub-area in this planning cycle.

<u>Local Capacity Benefits:</u>

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Humboldt area. The local capacity requirement for gas-fired generation in the Contra Costa sub-area was reduced or mitigated resulting in a reduction of approximately 668 MW with the Alternative 1,672 MW with the Alternative 2, and 1275 MW with the Alternative 3, respectively.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and "north of path 26 system" resources. For the Contra Costa sub-area, these translated to values of $1,560/MW-year and $840/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions in the Contra Costa sub-area are shown in Table 4.10-18, Table 4.10-19 and Table 4.10-20. The benefit of local capacity reductions in the Contra Costa sub-area is valued based on the cost range for the Contra Costa sub-area.

Table 4.10-18: Contra Costa LCR Sub-area Reduction Benefits – Alternative 1

Alternative 1: Reconductoring Tesla-Delta Switch Yard 230 kV line		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	668	
Capacity value (per MW-year)	$1,560	$840
LCR Reduction Benefit ($million)	$1.04	$0.56

Table 4.10-19: Contra Costa LCR Sub-area Reduction Benefits – Alternative 2

Alternative 2: Delta Reliability Energy Storage (75 MW, 4-hour)		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	672	
Capacity value (per MW-year)	$1,560	$840
LCR Reduction Benefit ($million)	$1.05	$0.56

Table 4.10-20: Contra Costa LCR Sub-area Reduction Benefits – Alternative 3

Alternative 3: The Tesla-Delta Switchyard 230 kV line reactance		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	1275	
Capacity value (per MW-year)	$1,560	$840
LCR Reduction Benefit ($million)	$1.99	$1.07

Cost estimates:

The planning estimate cost for the reconductoring of the Tesla to Delta Switch Yard 230 kV line is $30 million, and the estimate cost for the Delta Reliability Energy Storage is $149 million based on the request window submittal. These are estimated costs at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $39 million for the reconductoring of the Tesla to Delta Switch Yard 230 kV line, and for a total of $193.7 million for the Delta Reliability Energy Storage.

Benefit to Cost Ratio

The present value of the capacity benefit for the reconductoring of the Tesla-Delta 230 kV line is shown in Table 4.10-21. These values were calculated based on a 40 year project life.

Table 4.10-21 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 1: Reconductoring Tesla-Delta Switch Yard 230 kV line		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$1.04	$0.56
Capital Cost Estimate ($ million)	$30	
Benefit to Cost		
PV of Savings ($million)	$14.38	$7.74
Estimated "Total" Cost (screening) ($million)	$39	
Benefit to Cost	0.37	0.20

The benefit to cost ratios for the Delta-Reliability Energy Storage project is shown in Table 4.10-22. These values were calculated using the annual capacity benefit from the local capacity reduction and the levelized cost for the project, as described in section 4.3.3.

Table 4.10-22 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 2: Delta Reliability Energy Storage (75 MW, 4-hour)				
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus NP 26	
Net LCR Saving ($million/year)	$1.05		$0.56	
Capital Cost				
Capacity (MW)	75			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$149		$149
Capital Cost $/kW	$1,660	$1,987	$1,660	$1,987
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$30	$36	$30	$36
Benefit to Cost				
Savings ($million/year)	$1.05	$1.05	$0.56	$0.56
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$30	$36	$30	$36
Benefit to Cost	0.04	0.03	0.02	0.02

Note 1: The Lazard Capital Cost and Lazard Levelized Fixed Cost were based on "Lazard's Levelized Cost of Storage Analysis - Version 4.0, November 2018. https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

Note 2: The Proponent Provided Capital Cost in $/kW was determined by dividing the Proponent Provided Capital Cost by the Capacity of the project.

Note 3: The Proponent Provided Levelized Fixed Cost was estimated by multiplying the ratio of the Proponent Provided Capital Cost divided by the Lazard provided Capital Cost times the $/kW-year Lazard Provided Levelized Fixed Cost.

The present value of the capacity benefit for the smart wire device on the Tesla-Delta Switch Yard 230 kV line is shown in Table 4.10-23. These values were calculated based on a 40 year project life.

Table 4.10-23 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 3: The Tesla-Delta Switchyard 230 kV line reactance		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$1.99	$1.07
Capital Cost Estimate ($ million)	$14.4	
Benefit to Cost		
PV of Savings ($million)	$27.43	$14.77
Estimated “Total” Cost (screening) ($million)	$18.7	
Benefit to Cost	1.47	0.79

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

The Tesla-Delta Switchyard 230 kV line reactance project provides significant reduction in Contra Costa sub-area’s capacity requirement, however the need of the same resources towards satisfying the overall Greater Bay Area requirement still needs to be evaluated. The evaluation will be part of the 2021 LCR study which will also include the recently changed LCR criteria. Furthermore Marsh Landing units 3 and/or 4 are currently required for black start purposes, therefore the benefit to cost ratio may need to be adjusted. For these reasons this alternative is not recommended for approval at this time.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Contra Costa sub-rea for system reasons is achieved.

4.10.10 Fresno Area Coalinga Sub-area Local Capacity Reduction Study

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Fresno Coalinga sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2019-2020 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Coalinga sub-area is in Appendix G, section 3.2.6.3. The alternatives would consist of the following:

- Alternative 1: Install a 25 MVAr capacitor at Coalinga 70 kV.
- Alternative 2: Install a new Gates 230/70 kV transformer.

Production benefits

The two alternatives are not expected to provide production benefits. No congestion was identified in the Coalinga sub-area in this planning cycle.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Humboldt area. The local capacity requirement for gas-fired generation in the Coalinga sub-area was reduced resulting in a reduction of approximately 4 MW with the Alternative 1 and 17 MW with the Alternative 2.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and "north of path 26 system" resources. For the Coalinga sub-area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions of the Alternative 2 in the Coalinga sub-area is shown in Table 4.10-24. These values are based on the cost range for the Coalinga sub-area.

Table 4.10-24: Coalinga LCR Sub-area Reduction Benefits

Coalinga Sub-area Alternative 2: New Gates 230/70 kV transformer		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	17	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.04	$0.02

Cost estimates:

The planning estimate cost for the Alternative 2 is $44 million. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $57.2 million.

Benefit to Cost Ratio

The benefit to cost ration of the proposed alternative is shown In Table 4.10-25. These values are based on the capacity benefits shown in Table 4.10-24 and are calculated on a 50 year project life.

Table 4.10-25 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Coalinga Sub-area Alternative 2: new Gates 230/70 kV transformer		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.04	$0.02
Capital Cost Estimate ($ million)	$44	
Benefit to Cost		
PV of Savings ($million)	$0.51	$0.34
Estimated “Total” Cost (screening) ($million)	$57.2	
Benefit to Cost	0.01	0.01

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Coalinga sub-rea for system reasons is achieved.

4.10.11 Kern Area South Kern Sub-area Local Capacity Reduction Study

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the South Kern sub-area that the ISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2019-2020 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the South Kern sub-area is in Appendix G, section 3.2.7.2. The alternatives would consist of the following:

- SPS to shed 75 MW of load at Stockdale A substation for the loss of any combination of Midway-Kern PP 230 kV lines (#1, #3, and #4).

Production benefits

This alternative is not expected to provide production benefits. No congestion was identified in the South Kern sub-area in this planning cycle.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Humboldt area. The local capacity requirement for gas-fired generation in the South Kern sub-area was mitigated resulting in a reduction of approximately 80 MW.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and "north of path 26 system" resources. For the South Kern sub-area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions in the South Kern sub-area is shown in Table 4.10-26. These values are based on the cost range for the South Kern sub-area.

Table 4.10-26: South Kern LCR Sub-area Reduction Benefits

South Kern Sub-area SPS		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	80	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.17	$0.12

Cost estimates:

The planning estimate cost for the South Kern sub-area SPS is $10 million. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $13 million.

Benefit to Cost Ratio

The present value of the capacity benefits for the South Kern LCR Sub-area is shown in Table 4.10-27. These values are based on the benefits reduction shown in Table 4.10-26 and are calculated based on a 50 year project life.

Table 4.10-27: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

South Kern Sub-area SPS		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.17	$0.12
Capital Cost Estimate ($ million)	$10	
Benefit to Cost		
PV of Savings ($million)	$2.38	$1.59
Estimated "Total" Cost (screening) ($million)	$13	
Benefit to Cost	0.18	0.12

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

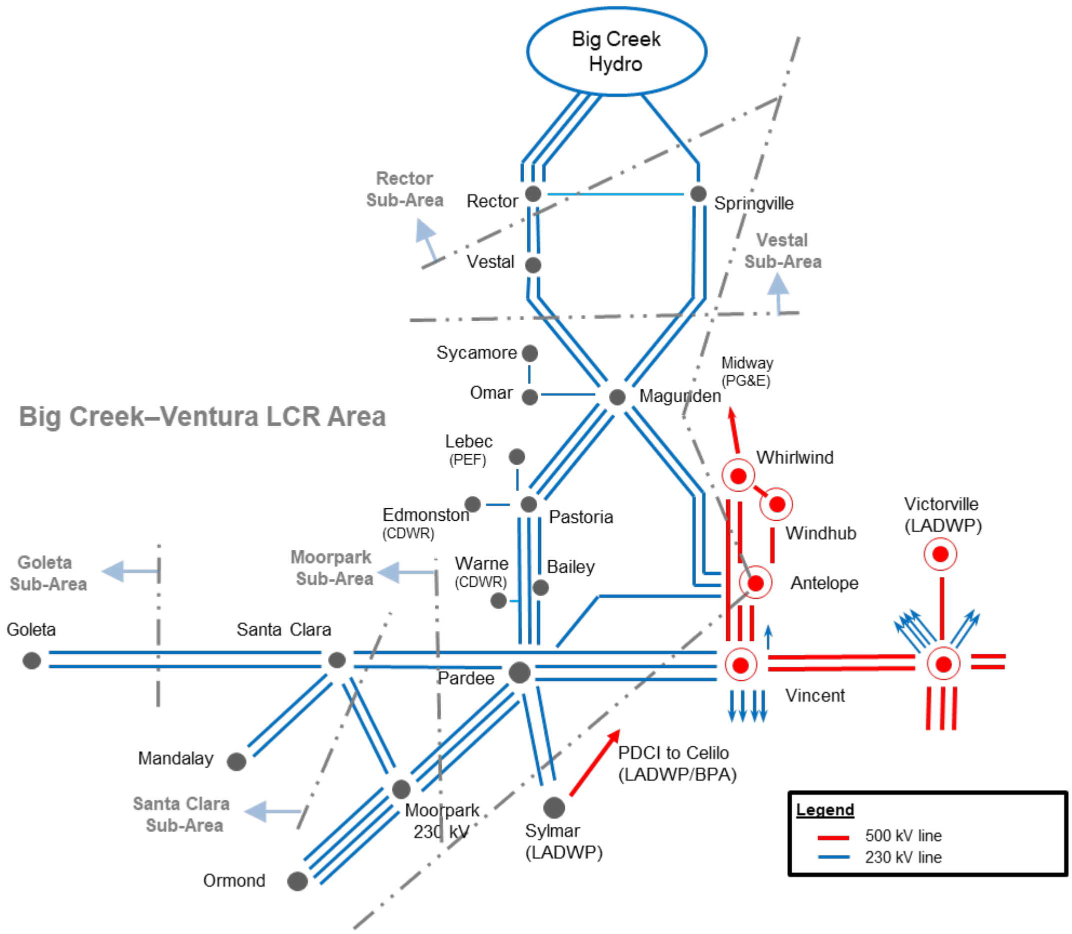
Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the South Kern sub-rea for system reasons is achieved.

4.10.12 Big Creek-Ventura Area and Santa Clara Sub-area Local Capacity Reduction Study

Figure 4.10-6 shows an overview of the Big Creek–Ventuara area.

Figure 4.10-6: Big Creek–Ventura Area Transmission System



Gas-fired local capacity is declining significantly in the Big Creek-Ventura (BCV) area. Mandalay (560 MW) was retired in 2018 and Ormond Beach (1500 MW) is scheduled to retire at the end of 2020[127]. Ellwood (54 MW) is assumed to retire when its short-term contract expires.

In the 2017-2018 transmission planning cycle, the ISO approved the Pardee-Moorpark 230 kV Transmission Project (ISD 12/31/2021) as an alternative to gas-fired local capacity that is needed to serve customers in the Ventura and Santa Barbara counties. SCE is in the process of procuring 195 MW/780 MWh of energy storage resources as shown in Table 4.10-28 to meet the remaining local capacity need in the Santa Clara and Goleta sub-areas.

[127] While the possibility of extending the OTC compliance for several units due to system wide requirements is emerging, this plan is based on the original assumptions that all OTC generation complies with its current scheduled compliance plans.

Table 4.10-28: SCE Santa Clara Procurement Results

Project	Technology	Capacity (MW)	Duration (Hour)	Connection	Online Date
Swell SC	Lithium Ion Batteries	14.0	4.0	Santa Clara 66 kV	1/1/2021
Strata Saticoy	Lithium Ion Batteries	100.0	4.0	Santa Clara 66 kV	12/1/2020
Ormat Vallecito	Lithium Ion Batteries	10.0	4.0	Goleta 66 kV	12/1/2020
AltaGas Goleta	Lithium Ion Batteries	40.0	4.0	Goleta 66 kV	12/1/2020
EGP Hollister	Lithium Ion Batteries	10.0	4.0	Goleta 66 kV	3/1/2021
Painter	Lithium Ion Batteries	10.0	4.0	Goleta 66 kV	3/1/2021
Silverstrand	Lithium Ion Batteries	11.0	4.0	Santa Clara 66 kV	3/1/2021

Assessment of gas-fired generation requirement

An assessment of expected gas-fired generation requirement in the Big Creek/Ventura area is shown in Table 4.10-29. These values are based on the results of the 2028 local capacity study that is included as Appendix G of the 2018-2019 transmission plan. The table indicates that the Rector, Vestal, Goleta and Moorpark sub-areas will have no gas-fired generation requirement in 2028 because of the availability of sufficient hydro resources, the on-going procurement of preferred resources, or the completion of the approved Moorpark–Pardee transmission project. In the Santa Clara sub-area all of the remaining gas-fired generation in the area will be needed to meet 2028 LCR. In the greater Big Creek-Ventura area, less than 26 percent or 436 MW of existing gas-fired generation will be needed for local resource adequacy. The ongoing Santa Clara sub-area procurement is expected to reduce the gas fired generation requirement in the greater Big-Creek–Ventura area to approximately 14 percent or 241 MW.

Table 4.10-29: Assessment of Gas-fired Generation Requirement in the Big Creek/Ventura Area

Sub-Area	2028 LCR (MW)	2028 Resource Capacity (MW, NQC)			2028 Gas-fired Generation Local Capacity Requirement	
		Total	Non Gas-fired	Gas-fired	MW	Percent of Gas
Rector	N/A	1,028	1,028	0	0	0%
Vestal	465	1,205	1,151	54	0	0%
Goleta	42	7	7(35)	0	0	0%
Santa Clara	318	199	15(119)	184	184	100%
Moorpark	0	223	39	184	0	0%
Overall Big Creek Ventura	2251	3511	1815	1696	436	26%

Note: (1) Values in parenthesis indicate deficiency to be filled by ongoing SCE RFP
(2) 2028 resource capacity excludes Ellwood (54 MW) and Ormond Beach (1491 MW)

Three alternatives were considered to reduce LCR in the Big Creek–Ventura area and/or Santa Clara sub-area

1. Pardee-Sylmar No. 1 and No. 2 230 kV Line Rating Increase Project
2. Pacific Transmission Expansion (PTE) HVDC Project
3. Santa Clara Area Upgrades

4.1.1.1 Pardee-Sylmar 230 kV Line Rating Increase Project

The project involves upgrading terminal equipment at Pardee and Sylmar to increase the rating of the Pardee-Sylmar No. 1 and No.2 230 kV lines to 1287/1737 MVA (145% increase in emergency ratings). The project was submitted by SCE as a reliability project. The estimated cost is $15.4 million. SCE’s estimate for its portion of the work is $2.76 million based on the unit cost guide. LADWP’s estimate for its portion of the work is $12.6 million based on a similar project. The proposed in-service date is May 2025 based on the timing of the identified reliability need.

Production benefits

The production benefit of upgrading the Pardee to Sylmar 230 kV line for ISO’s ratepayers and the production cost savings are shown in Table 4.10-30.

Table 4.10-30: Production Benefits for Pardee to Sylmar 230 kV Line Rating Increase Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	7,732.7	7,727.0	5.7
ISO generator net revenue benefiting ratepayers	3,445.9	3,445.7	-0.1
ISO transmission revenue benefiting ratepayers	167.1	163.1	-3.9
ISO Net payment	4,119.8	4,118.2	1.7
WECC Production cost	14,784.1	14,778.7	5.4

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Local Capacity Benefits:

Local capacity analysis was performed for the greater Big Creek–Ventura area and Santa Clara sub-area with the Pardee-Sylmar 230 kV project modeled using the 2028 LCR study power flow model from the previous planning cycle. The results including the limiting facility, the critical contingency and the resulting LCR are shown in Table 4.10-31.

Table 4.10-31: LCR assessment results for the Pardee-Sylmar 230 kV Line Rating Increase Project

Area/Sub-area	Category	Limiting Facility	Contingency	LCR (MW)
Status Quo				
BCV	C	Sylmar-Pardee #1 or #2 230 kV line	ugo–Victorville 500 kV line and one Sylmar–Pardee 230 kV line	2,251
Santa Clara	D	Voltage collapse	ardee–Santa Clara 230 kV and Moorpark–Santa Clara 230 kV DCTL	318
Pardee-Sylmar Line Rating Increase Project				
BCV	C	Antelope 500/230 kV #1 or #2 transformer	PDCI Monopole and one Antelope 500/230 kV Tr.	1,414
Santa Clara	Same as Status Quo			

The project reduces Big Creek–Ventura area LCR by 837 MW but does not affect Santa Clara area LCR as shown in Table 4.10-32.

Table 4.10-32: Potential LCR Reduction - Pardee-Sylmar 230 kV Project

Alternatives	Capacity (MW)		
	Total	Non-Gas	Gas
Status Quo			
Overall BCV LCR Requirement	2,251	1,815	436
Santa Clara LCR Requirement	318	15 (119)[1]	184
Pardee-Sylmar 230 kV Project			
Overall BCV LCR Requirement	1,414	1,230	184[2]
Reduction	837	585	252
Santa Clara LCR Requirement	318	15 (119)[1]	184
Reduction	0	0	0

Notes: (1) Values in parenthesis indicate deficiency to be filled by ongoing SCE RFP

(2) The Pardee-Sylmar 230 kV Rating Increase Project can eliminate reliance on gas-fired generation to meet local capacity need in the greater BigCreek–Ventura area. However, the 184 MW of existing gas-fired resources located in the Santa Clara Sub-area will continue to be needed to meet the sub-area need.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between the cost of local and system resources and between the cost of local and south of path 26 system resources. For the Big Creek-Ventura area, these translate into of $16,320/MW-year and $22,320/MW-year respectively.

The economic benefit resulting from the local capacity reduction associated with the Pardee-Sylmar 230 project is shown in Table 4.10-33. The present value of the capacity benefits are calculated based on a 40 year project life.

Table 4.10-33: LCR Reduction Benefits for Pardee-Sylmar 230 kV Line Rating Increase Project

Pardee-Sylmar 230 kV Line Rating Increase Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR capacity reduction (MW)	837	
Capacity value (per MW-year)	$16,320	$22,320
Annual LCR reduction benefit ($million/year)	$13.7	$18.7
Present value of LCR reduction benefit ($million)	$182	$249

Cost estimates:

The total cost of the project is estimated at $15.36 million. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, the project cost translates into $20 million in present value of revenue requirement.

Benefit to Cost Ratio

The benefit to cost ratio for the project is calculated in to range from 10.3 to 13.6 as shown in Table 4.10-34. The economic analysis also included evaluation of advancing the project by two years based on the achievable in-service date of May 2023. The results show an NPV of $23.4–$31.9 million in favor of advancing the project.

Table 4.10-34: Benefit to Cost Ratio (Ratepayer Benefits per TEAM)

Pardee-Sylmar 230 kV Line Rating Increase Project		
PV of Prod. Benefit ($ million)	$23	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
PV of LCR Savings ($million)	$182	$249
PV Revenue Req. ($ million)	$20.0	
Benefit to Cost	10.3	13.6
Benefit of Advancing ISD		
NPV of advancing ISD by 2 years($ million)	$23.4	$31.9

4.1.1.2 Pacific Transmission Expansion (PTE) HVDC Project

The Pacific Transmission Expansion (PTE) Project was submitted by Western Grid Development LLC. PTE is a 2000 MW HVDC project with a northern terminal at Diablo and three southern terminals including a 500 MW terminal connecting to the Goleta substation in the Big Creek–Ventura area. The project cost is estimated at $1,850 million. The project was submitted by Western Grid Development LLC. The proposed ISD is December 2026.

Due to the location of the three southern terminals, the project affects LCR in both the Big Creek–Ventura and LA Basin areas. This section only assesses the project's impact on the Big Creek–Ventura LCR. The projects impact on the LA Basin area LCR as well as the combined benefit to cost ratio for the project is addressed in the section 4.10.13 below taking into account the LCR reduction benefits identified for the project in this section.

<u>Production benefit</u>

Please see section 4.10.1 above.

<u>Local Capacity Benefits:</u>

Local capacity analysis was performed for the greater Big Creek–Ventura area and Santa Clara sub-area with the Pacific Transmission Expansion project modeled using the 2028 LCR study power flow model from the previous planning cycle. The results including the limiting facility, the critical contingency and the resulting LCR are shown in Table 4.10-35.

Table 4.10-35: LCR assessment results for the Pacific Transmission Expansion Project

Area/Sub-area	Category	Limiting Facility	Contingency	LCR (MW)
Status Quo				
BCV	C	Sylmar-Pardee #1 or #2 230 kV line	Lugo–Victorville 500 kV line and one Sylmar–Pardee 230 kV line	2,251
Santa Clara	D	Voltage collapse	Pardee–Santa Clara 230 kV and Moorpark–Santa Clara 230 kV DCTL	318
Pacific Transmission Expansion (PTE) Project				
BCV	C	Sylmar–Pardee #1 or #2 230 kV line	Lugo–Victorville 500 kV and one Sylmar–Pardee 230 kV line	1,858
Santa Clara/Goleta	C	Low Goleta 230 kV voltage	PTE and Santa Clara Goleta 230 kV	70

The project reduces Big Creek–Ventura area LCR by 393 MW and the Santa Clara sub-area LCR by 184 MW as shown in Table 4.10-36.

Table 4.10-36: Potential LCR Reduction (*Big Creek–Ventura Portion*) - Pacific Transmission Expansion Project

Alternatives	Capacity (MW)		
	Total	Non-Gas	Gas
Status Quo			
Overall BCV LCR Requirement	2,251	1,815	436
Santa Clara LCR Requirement	318	15 (119)[1]	184
Pacific Transmission Expansion Project			
Overall BCV LCR Requirement	1,858	1,815	43
Reduction	393	0	393
Santa Clara LCR Requirement	70	15 (55)[1]	0
Reduction	248	64	184
Notes: (1) Values in parenthesis indicate deficiency to be filled by ongoing SCE procurement.			

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between the cost of local and system resources and between the cost of local and south of path 26 system resources. For the Big Creek-Ventura area, these translate into $16,320/MW-year and $22,320/MW-year respectively.

The economic benefit resulting from the potential LCR reduction in the Big Creek–Ventura area associated with the Pacific Transmission Expansion project is shown in Table 4.10-37. The present value of the capacity benefits are calculated based on a 50-year project life.

Table 4.10-37: LCR Reduction Benefits for Pacific Transmission Expansion Project *(Big Creek–Ventura Portion)*

Pacific Transmission Expansion Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR capacity reduction (MW)	393	
Capacity value (per MW-year)	$16,320	$22,320
Annual LCR reduction benefit ($million/year)	$6.4	$8.8
Present value of LCR reduction benefit ($million)	$88.5	$121.0

Cost estimates:

The total cost of the project is estimated at $1,850 million. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, the project cost translates into a present value of revenue requirement of $2,405 million.

Benefit to Cost Ratio

The LCR reduction benefits of the project in the LA Basin area along with its overall BCR are presented in Alternative 7 in section 4.10.13.

4.1.1.3 Santa Clara Area Upgrades

The scope of the Santa Clara Area Upgrades alternative includes installing a 79 MVAR, 230 kV shunt capacitor at Goleta Substation and upgrading multiple towers and terminal equipment on Santa–Clara Vincent, Santa Clara–Pardee, and Santa Clara–Moorpark No.1 & 2 230 kV lines to achieve ratings of 494 MVA (normal)/665 MVA (emergency), which represents an increase of up to 135% in emergency ratings. The total cost of the project is $12.3 million of which $3.3 is for installation of the shunt capacitor and $9.0 million for the line rating upgrades. The ISD is 4 years from approval (April 2024). This alternative was identified by CAISO with input from SCE.

Local Capacity Benefits:

Local capacity analysis was performed for the greater Big Creek–Ventura area and Santa Clara sub-area with the Santa Clara Area Upgrades alternative modeled using the 2028 LCR study power flow model from the previous planning cycle. The results including the limiting facility, the critical contingency and the resulting LCR are shown in Table 4.10-38.

Table 4.10-38: LCR assessment results for Santa Clara Area Upgrades

Area/Sub-area	Category	Limiting Facility	Contingency	LCR (MW)
Status Quo				
BCV	C	Sylmar-Pardee #1 or #2 230 kV line	Lugo–Victorville 500 kV line and one Sylmar–Pardee 230 kV line	2,251
Santa Clara	D	Voltage collapse	Pardee–Santa Clara 230 kV and Moorpark–Santa Clara 230 kV DCTL	318
Santa Clara Area Upgrades				
BCV	Same as Status Quo			
Santa Clara	D	Voltage collapse	Pardee–Santa Clara 230 kV and Moorpark–Santa Clara 230 kV DCTL	270

The project reduces Santa Clara sub-area LCR by 48 MW but does not affect Big Creek–Ventura area LCR as shown in Table 4.10-39.

Table 4.10-39: Potential LCR Reduction - Santa Clara Area Upgrades

Alternatives	Capacity (MW)		
	Total	Non-Gas	Gas
Status Quo			
Overall BCV LCR Requirement	2,251	1,815	436
Santa Clara LCR Requirement	318	15 (119)[1]	184
Santa Clara Area Upgrades			
Overall BCV LCR Requirement	2,251	1815	436
Reduction	0	0	0
Santa Clara LCR Requirement	270	15 (119)[1]	136
Reduction	48	0	48
Notes: (1) Values in parenthesis indicate deficiency to be filled by ongoing SCE procurement			

Since a significant portion of the Santa Clara area LCR will be derived from the 195 MW/780 MWh energy storage resources being procured, a simplified hourly analysis was performed for the peak day to confirm LCR energy requirements will be met and to ensure there is sufficient off-peak energy to reliably charge the batteries. For this purpose P-V analysis was performed as shown in Figure 4.10-7 to establish the area load limit with the Santa Clara Area Upgrades and the associated gas-fired LCR reduction modeled. The analysis was performed with energy storage resources offline so the impacts of charging and discharging can be examined on an hourly basis. The load limit along with the area load shape is then used to estimate the LCR energy need from storage and the energy available for charging as shown in Figure 4.10-8. The analysis assumes energy storage efficiency of 85%.

The results of the hourly analysis indicate that the LCR energy need with the Santa Clara Area Upgrades modeled does not exceed the total capability of the energy storage resources being procured and that the area will have sufficient off-peak capability to charge the batteries[128].

Figure 4.10-7: Santa Clara area P-V analysis

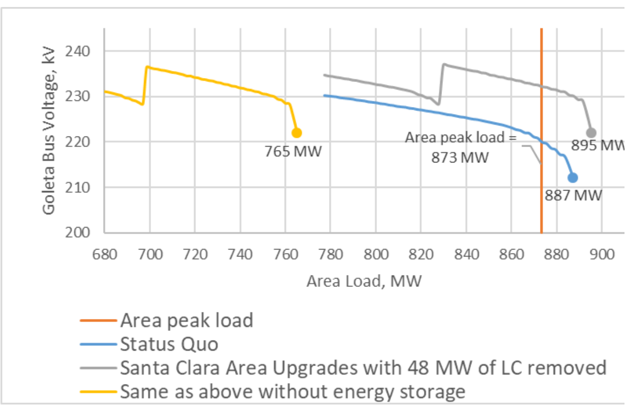
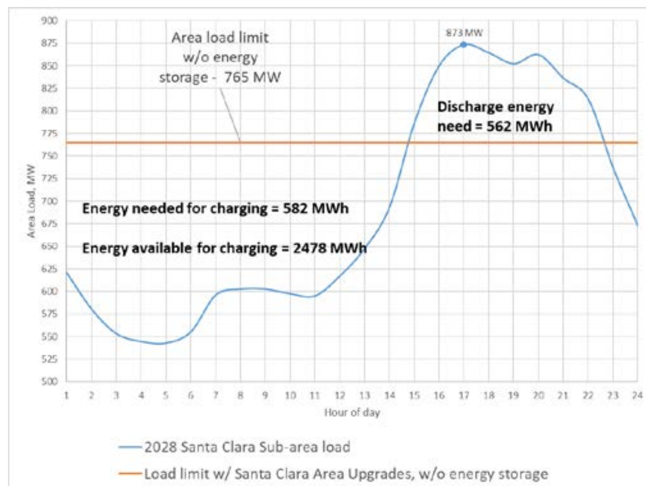


Figure 4.10-8: Santa Clara area energy storage analysis



As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between the cost of local and system resources and between the cost of local and south of Path 26 system resources. For the Big Creek-Ventura area, these translated to values of \$16,320/MW-year and \$22,320/MW-year respectively.

The economic benefit resulting from the local capacity reduction associated with the Santa Clara Area Upgrades is shown in Table 4.10-40. The present value of the capacity benefits are calculated based on a 50 year project life. Since the project reduces Santa Clara sub-area LCR but does not affect the overall Big Creek–Ventura area LCR and since capacity cost differential

[128] The additional step of validating the results of the hourly spreadsheet-type analysis using hourly power flow analysis is not considered necessary given the results of the simplified analysis above indicate the availability of substantial LCR and charging energy margin.

between LCR sub-area capacity and LCR area capacity is not available, the economic value of the LCR reduction in the Santa Clara sub-area is considered to be zero at this time.

Table 4.10-40: LCR Reduction Benefits for Santa Clara Area Upgrades

Santa Clara Area Upgrades		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR capacity reduction (MW)	0 (48 MW)[1]	
Capacity value (per MW-year)	\$16,320	\$22,320
Annual LCR reduction benefit (\$million/year)	--	--
Present value of LCR reduction benefit (\$million)	--	--
Notes: (1) Value in parenthesis indicates LCR reduction in the Santa Clara sub-area		

Cost estimates:

The total cost of the project is estimated at \$12.3 million. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, the project cost translates into \$16.0 million in present value of revenue requirement.

Benefit to Cost Ratio

The benefit to cost ratio for the project is considered to be zero at this time given the LCR reduction is only in a sub-area as noted above. This is shown Table 4.10-41.

Table 4.10-41: Benefit to Cost Ratio (Ratepayer Benefits per TEAM)

Santa Clara Area Upgrades		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
PV of LCR Savings (\$million)	--	--
PV Revenue Req. (\$ million)	\$16.0	
Benefit to Cost Ratio	--	--

Conclusions

Three alternatives were evaluated to reduce local capacity in the Big Creek-Ventura area and/or Santa Clara sub-area. Below is a summary of the results for each alternative.

The Pardee–Sylmar 230 kV reliability project has a cost of $15.4 million and reduces Big Creek-Ventura area LCR by 837 MW. The economic evaluation indicates a net present value (NPV) for the project of $185 million–$252 million and a benefit-cost ratio of 10.3–13.6. The economic analysis also included evaluation of advancing the project by two years based on the achievable in-service date of May 2023. The results show an NPV of $23.4–$31.9 million in favor of advancing the project. Reliability assessment along with recommendation for this reliability project can be found in section 2.7.5.

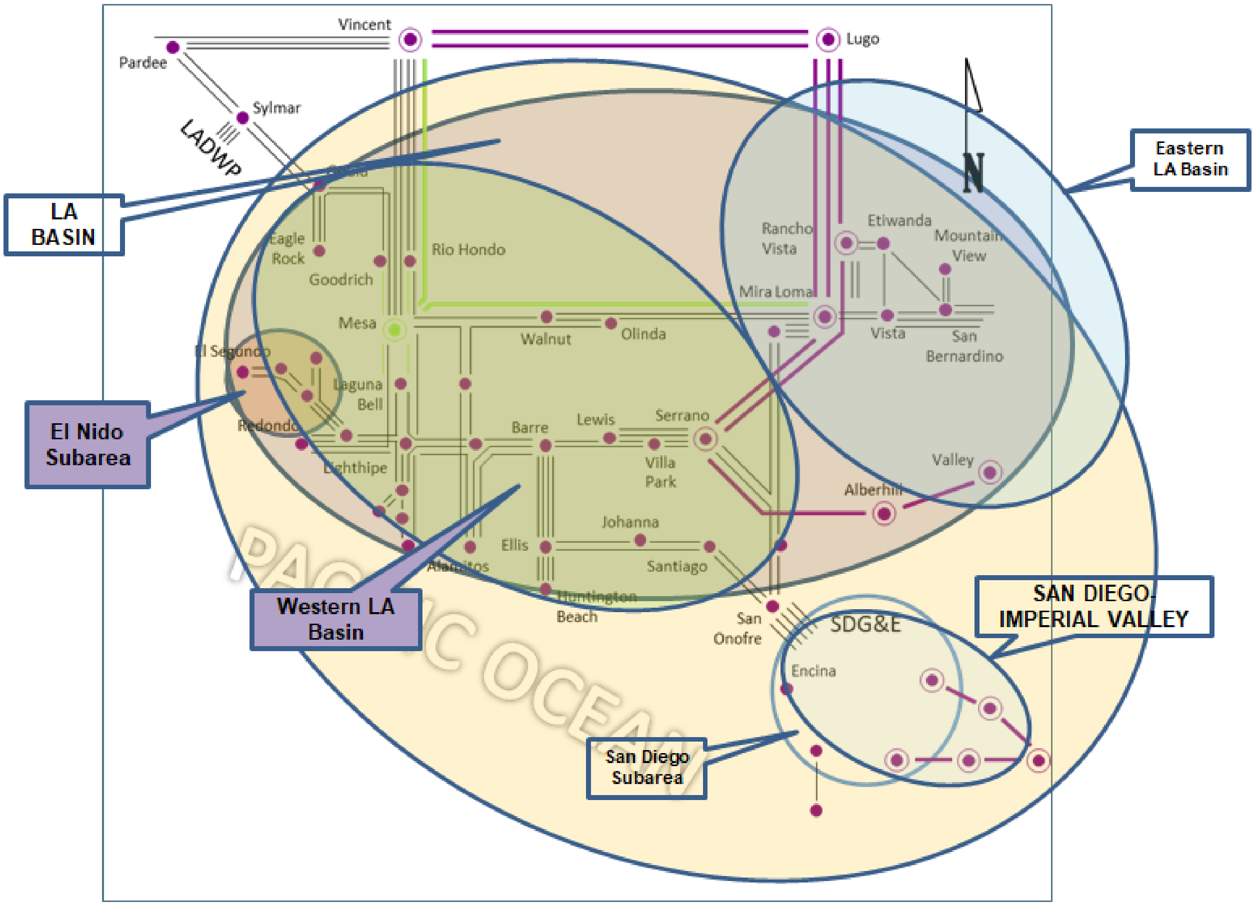
The Pacific Transmission Expansion (PTE) project has a cost of $1,850 million and affects LCR in both the Big Creek–Ventura and LA Basin areas due to the location of its three southern terminals. The project reduces Big Creek–Ventura area and Santa Clara sub-area LCR by approximately 393 MW and 184 MW, respectively. The LCR reduction benefits of the project in the Western LA Basin sub-area along with its overall BCR are presented in the Alternative 7 discussion in section 4.10.13.

The Santa Clara Area Upgrades alternative has a cost of $12.3 million. The project reduces Santa Clara sub-area LCR by approximately 48 MW but does not affect LCR in the greater Big Creek–Ventura area. Since cost differential between sub-area LCR capacity and area LCR capacity is not available, the economic value of the LCR reduction in the Santa Clara sub-area and hence the BCR of the alternative is deemed to be zero at this time.

4.10.13 El Nido and Western LA Basin Sub-areas Local Capacity Reduction Study

El Nido, shown in Figure 4.10-9, is a sub-area within the Western LA Basin. Western LA Basin is a sub-area within the LA Basin LCR area. The following diagram provides the context of these two sub-areas within the overall LA Basin area.

Figure 4.10-9: Single line diagram of the LA Basin and San Diego-Imperial Valley LCR and sub LCR areas



__Recap of El Nido sub-area local capacity requirement (2028)__

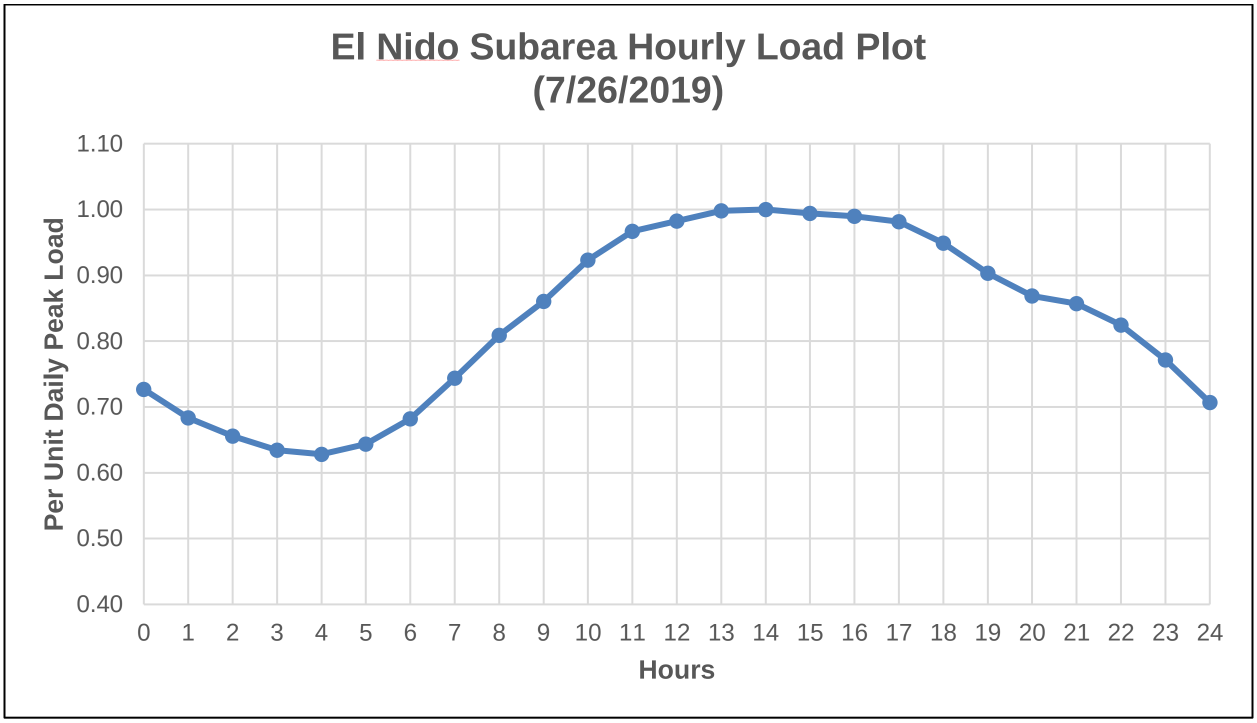
The results for this assessment are summarized in Table 4.10-42. For further details, please refer to Appendix G of this 2019-2020 Transmission Plan.

Table 4.10-42: 2028 LCR Need and Transmission Constraint in the El Nido sub-area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2028	First Limit	C	Thermal loading on La Fresa-La Cienega 230 kV line	La Fresa – El Nido #3 & 4 230 kV lines	400 MW
2028	N/A	B	None	Various contingencies	No requirements

An hourly load plot representing a typical peak summer day for the El Nido sub-area is shown in Figure 4.10-10.

Figure 4.10-10: El Nido sub-area hourly load plot on a peak summer day



Recap of the Western LA Basin sub-area local capacity requirement (2028)

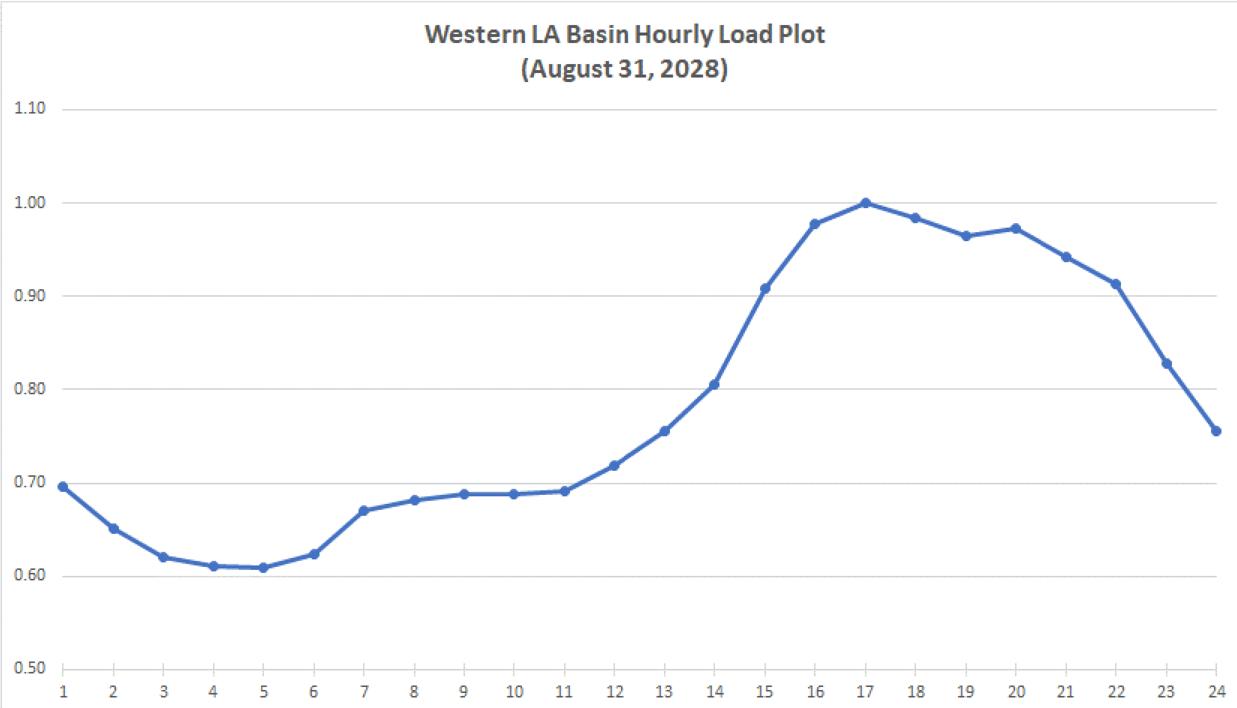
The results for this assessment are summarized in Table 4.10-43. For further details, please refer to Appendix G of the Transmission Plan.

Table 4.10-43: 2028 LCR Need and Transmission Constraint in the Western LA Basin sub-area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2028	First Limit	C	Thermal loading on the Mesa-Laguna Bell #1 230 kV line	Mesa – Redondo #1 230 kV line, followed by Mesa - Lighthipe 230 kV line, or vice versa	3,912
2028	N/A	B	None-binding	Multiple combinations possible	N/A

A plot for the load in the Western LA Basin sub-area is shown in Figure 4.10-11. The results are similar to the overall SCE area as the load in this area comprises nearly half of the total SCE load (~ 46%).

Figure 4.10-11: Western LA Basin sub-area hourly load plot on a peak summer day



<u>Recap of the Eastern LA Basin sub-area local capacity requirement (2028)</u>

For further details, please refer to Appendix G of the Transmission Plan. Although this sub-area is not part of the remaining areas for LCR reduction study in this planning cycle as it was evaluated in the previous 2018-2019 planning cycle, the LCR need for this sub-area is included as the evaluation of the Western LA Basin causes interaction with the Eastern LA Basin sub-area LCR need and to the overall LA Basin. The impact to the Eastern LA Basin LCR need is evaluated after the El Nido and Western LA Basin sub-area gas-fired generation reduction was evaluated. The results are shown in Table 4.10-44.

Table 4.10-44: 2028 LCR Need and Transmission Constraint in the Eastern LA Basin sub-area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2028	First Limit	C	Post-transient voltage stability	Serrano-Valley 500 kV line, followed by Devers – Red Bluff 500 kV #1 and 2 lines	2,678
2028	N/A	B	None-binding	Multiple combinations possible	N/A

Recap of the overall San Diego – Imperial Valley local capacity requirement (2028)

For further details, please refer to Appendix G of the Transmission Plan. Although this area is not part of the remaining areas for LCR reduction study in this planning cycle as it was evaluated in the previous planning cycle, the LCR need for this area is included as the evaluation of the Western LA Basin causes interaction with the overall San Diego-Imperial Valley area LCR need. The impact to the overall San Diego – Imperial Valley area LCR need is evaluated after the El Nido and Western LA Basin sub-area gas-fired generation reduction was evaluated. These result are shown in Table 4.10-45.

Table 4.10-45: 2028 LCR Need and Transmission Constraint in the San Diego – Imperial Valley Area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2028	First Limit (No Solar Generation Due to Load Peaking at 8 p.m.)	B/C	El Centro 230/92 kV transformer thermal loading	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500 kV line (N-1)	3,977 MW

CAISO-Considered LCR Reduction Solutions and Request Window Project Submittal

The ISO examined a number of potential transmission options for reducing the gas-fired generation requirements in the El Nido and Western LA Basin sub-areas. The transmission options identified by the ISO would be expected to have minimal environmental impact and be relatively low cost given the economic study parameters relied upon in this 2019-2020 planning cycle. The following table provides a list of potential solutions that the ISO evaluated to further reduce the local gas-fired generation need in the El Nido and Western LA Basin sub-areas. The alternatives are summarized in Table 4.10-46.

Table 4.10-46: Study Alternatives for Reducing Local Gas-Fired Generation in the El Nido and Western LA Basin sub-areas

	Name of Solutions	Submitter	Submission date	Target LCR reduction areas	500 kV Voltage	230 kV Voltage	DC Voltage (425 kV)	Estimated costs ($ million)
1	Install 350 MW BESS in El Nido sub-area	CAISO	2019-20 TPP	El Nido		√		$ 581
2	Upgrade La Fresa – La Cienega 230 kV line (12 mi.)	CAISO	2019-20 TPP	El Nido		√		$ 104
3	Install 350 MW BESS in Nido and 350 MW in Western LA Basin sub-areas	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$ 1,162
4	Install BESS in Nido and Upgrade Mesa – Laguna Bell 230 kV line	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$ 631
5	Install 350 MW BESS in Nido sub-area and Install 3 Ω Line Series Reactor on the Mesa-Laguna Bell 230 kV line	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$ 596
6	Upgrade La Fresa – La Cienega 230 kV line and Install 3 Ω Line Series Reactor on the Mesa – Laguna Bell 230 kV line	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$119
7	Pacific Transmission Expansion HVDC Project	Western Grid Development, LLC	10/15/2019	Big Creek/Ventura LCR area and Western LA Basin	√	√		$ 1,850

Production benefits

Alternatives 1 and 2 from Table 4.10-46 are not expected to provide production benefits. No congestion was identified in the El Nido sub-area. Alternatives 3 through 6 may provide marginal production benefits in the Western LA Basin as congestion was identified for the Mesa – Laguna Bell 230kV. However, the congestion cost was relatively low ($1.01 million) and occurred only 22 hours in a year. Alternative 7 (PTE project alternative) was evaluated and was determined that there was no production cost benefit associated with the proposed project (see Table 4.10-3). Based on the production cost study, no benefit was identified with the addition of the PTE project.

Local Capacity Benefits:

The following are assessments to determine local capacity benefits associated with seven alternatives listed in the table above.

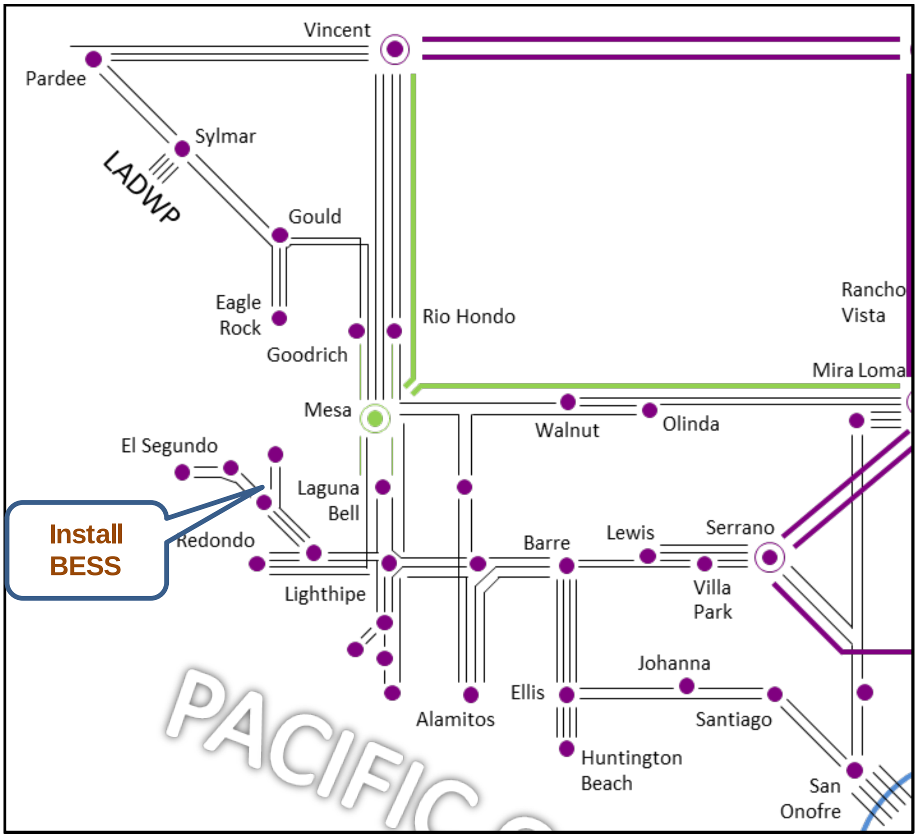
Alternative 1 - Install 350 MW battery energy storage system (BESS) in the El Nido sub-area

A single line diagram of the vicinity of Alternative 1 is shown in Figure 4.10-12.

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the El Nido sub-area. The local capacity requirement for gas-fired generation in the El Nido sub area was reduced by approximately 337 MW. However, reducing the LCR need in the El Nido sub-area by installing 350 MW BESS also causes a net reduction of 50 MW for the Western LA Basin sub-area, 0 MW impact to the Eastern LA Basin sub-area and 10 MW adverse impact to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 10 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido sub-area, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-12: Single line diagram of the vicinity of Alternative 1



Description of Alternative #1 and determination of local capacity benefits:

- Install BESS at the following locations: 200 MW at La Cienega and 150 MW at El Nido substations or vicinity
- Amount of gas-fired generation capacity reduction in El Nido sub-area: 337 MW
- Net amount of gas-fired generation reduction in the Western LA Basin: 50 MW
- Adverse impact to Eastern LA Basin LCR: 0 MW (assuming system readjustment to Devers voltage schedule to provide more VAR output from Devers SVC)
- Adverse impact to the San Diego – Imperial Valley LCR: -10 MW

In Table 4.10-47, the net benefit of local capacity reductions of the Alternative 1 in the El Nido sub-area is valued based on the cost range for southern California area.

Table 4.10-47: El Nido sub-area Net LCR Reduction Benefits for Alternative 1

	Alternative 1: Install 350 MW BESS in El Nido sub-area	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
Net LCR reduction benefit (Western LA Basin) (MW)	50	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.8	$1.1
LCR increase (Eastern LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
LCR increase (San Diego-Imperial Valley) (MW)	-10	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.1	-$0.2
Net LCR Saving ($million/year)	$6.3	$8.6

Cost estimates:

The planning estimate cost for the Alternative 1 is $581 million, using Lazard unit costs. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Benefit to Cost Ratio

The levelized fixed cost as compared to the savings associated with the capacity benefits are shown in Table 4.10-48. The benefit to cost ratios were calculated for the range of the local capacity benefits.

Table 4.10-48: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 1: Install 350 MW in the El Nido Sub-area		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$6.3	$8.6
Capital Cost		
Capacity (MW)	350	
Capital Cost Source	Lazard	Lazard
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Benefit to Cost		
Savings ($million/year)	$6.3	$8.6
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Benefit to Cost	0.05	0.06

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs versus SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources. The benefit to cost ratio is less than 1, indicating that this option is not economic based on local capacity benefits.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the El Nido sub-area for system reasons is achieved.

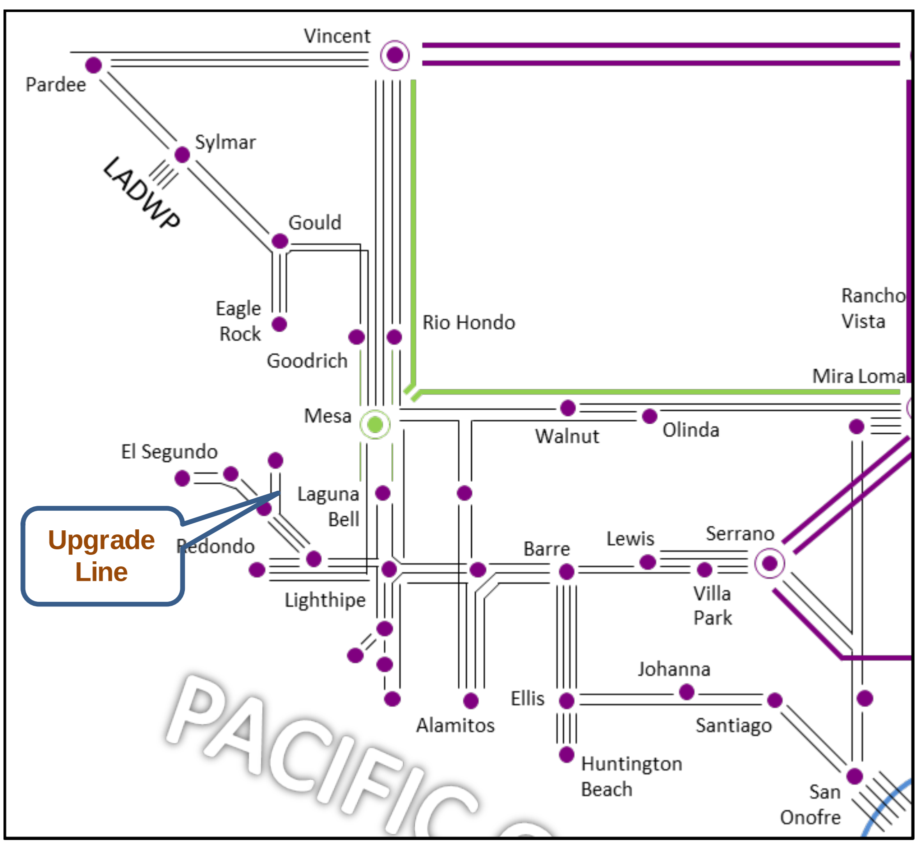
<u>Alternative 2 - Upgrade La Fresa – La Cienega 230 kV Line in the El Nido sub-area</u>

A single line diagram of the vicinity of Alternative 2 is shown in

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the El Nido sub-area. The local capacity requirement for gas-fired generation in the El Nido sub area was reduced by approximately 337 MW. However, reducing the LCR need in the El Nido sub-area by upgrading the La Fresa – La Cienega 230kV line also causes a net adverse impact of 531 MW for the Western LA Basin sub-area LCR need, 84 MW LCR impact to the Eastern LA Basin sub-area and 0 MW adverse impact to the San Diego-Imperial Valley LCR area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the El Nido, Western LA Basin and Eastern LA Basin sub-areas, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $13,080/MW-year and $19,080/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-13: Single line diagram of the vicinity of Alternative 2



Description of Alternative 2 and determination of local capacity benefits:

- Upgrade La Fresa – La Cienega 230 kV line (12 mi.) to higher capacity (i.e., 787 MVA normal, 1062 MVA emergency)
- Amount of gas-fired generation capacity reduction in El Nido sub-area: 337 MW
- Net amount of adverse impact to the Western LA Basin LCR need: -531 MW
- Adverse impact to Eastern LA Basin LCR: -84 MW
- Adverse impact to the San Diego – Imperial Valley LCR: 0 MW (after factoring impacts to Western and Eastern LA Basin above)

The net benefit of local capacity reductions of the Alternative 2 in the El Nido sub-area is shown in Table 4.10-49. These values are based on the cost range for southern California area.

Table 4.10-49: El Nido sub-area Net LCR Reduction Benefits for Alternative 2

	Alternative 2: Upgrade La Fresa - La Cienega 230 kV Line	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR increase (Western LA Basin) (MW)	-531	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$8.9	-$12.0
LCR increase (Eastern LA Basin) (MW)	-84	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$1.4	-$1.9
LCR increase (San Diego-Imperial Valley) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	-$4.6	-$6.3

Note: negative value for net LCR saving translates to an increase in LCR cost.

Cost estimates:

The planning estimate cost for this alternative is $104 million. This is an estimated cost based on SCE transmission unit cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $135 million. Please note that this estimate does not include a contingency cost at this time.

Benefit to Cost Ratio

The present value of the capacity benefits are shown in Table 4.10-50. These values are calculated based on a 40-year[129] project life.

Table 4.10-50: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 2: Upgrade La Fresa - La Cienega 230 kV Line		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	-$4.6	-$6.3
PV of LCR Savings ($million)	($61.82)	($84.06)
Capital Cost		
Capital Cost Estimate ($ million)	$104	
Estimated "Total" Cost (screening) ($million)	$135	
Benefit to Cost		
PV of Savings ($million)	($61.82)	($84.06)
Estimated "Total" Cost (screening) ($million)	$135.20	
Benefit to Cost	-0.46	-0.62

[129] Upgrades on existing transmission facilities are assumed to have 40-year project life in the economic evaluation.

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources. The benefit to cost ratio is less than 1, indicating that this option is not economic based on local capacity benefits.

Conclusions

Further consideration may be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the El Nido sub-area for system reasons is achieved.

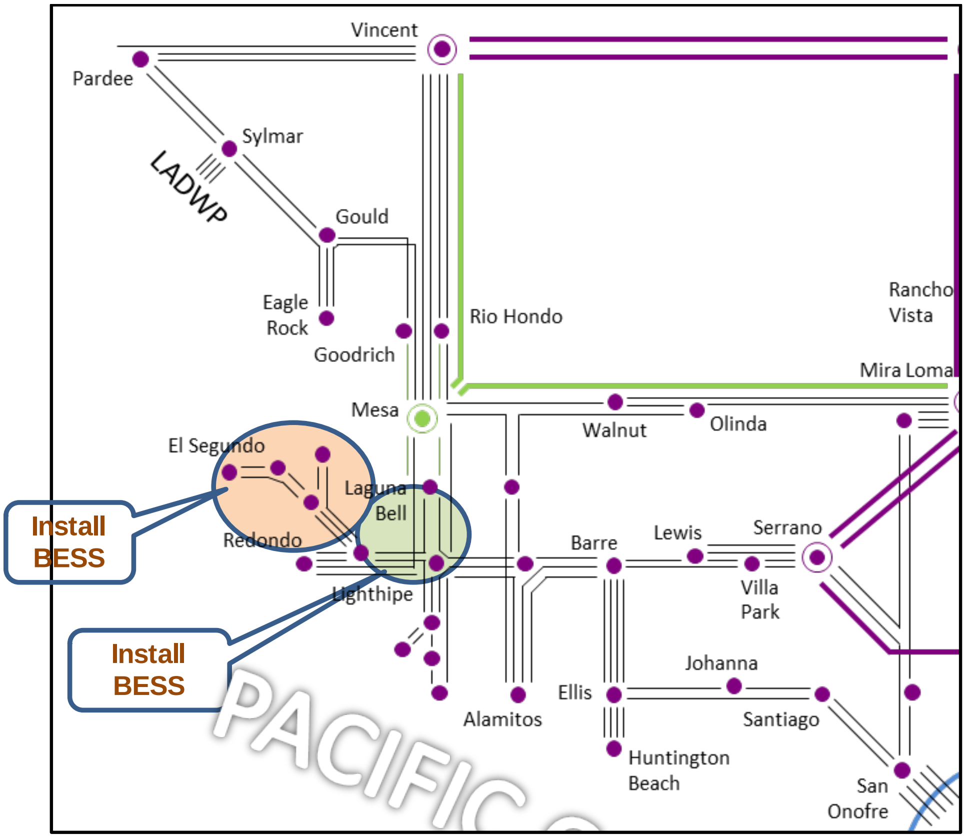
Alternative 3 - Install a total of 700 MW of battery energy storage system in the El Nido and Western LA Basin sub-areas

A single line diagram of the vicinity of Alternative 3 is shown in Figure 4.10-14.

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the El Nido and Western LA Basin sub-areas. The local capacity requirement for gas-fired generation in the El Nido sub area was reduced resulting in a reduction of approximately 337 MW. Additionally, approximately 670 MW of local capacity requirement for gas-fired generation was reduced for the Western LA Basin sub-area. Reducing local capacity requirements in the El Nido and Western LA Basin causes an adverse impact of 42 MW to the Eastern LA Basin sub-area LCR need and about 35 MW adverse impact to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 35 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido, Western LA Basin and Eastern LA Basin sub-areas, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $13,080/MW-year and $19,080/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-14: Single line diagram of the vicinity of Alternative 3



Description of Alternative 3 and determination of local capacity benefits:

- Install a total of 700 MW BESS at the following locations:
    - 200 MW at La Cienega and 150 MW at El Nido substations or vicinity (load side)
    - 200 MW at Laguna Bell, 100 MW at La Fresa and 50 MW at Del Amo
- Amount of gas-fired generation capacity reduction in El Nido sub-area: 337 MW
- Net amount of gas-fired generation reduction in the in the Western LA Basin: 670 MW
- Adverse impact to Eastern LA Basin LCR: - 42 MW (assume system readjustment to Devers voltage schedule to provide more VAR output from Devers SVC)
- Adverse impact to the San Diego – Imperial Valley LCR: - 35 MW

The net benefit of local capacity reductions of the Alternative 3 in the El Nido and Western LA Basin sub-areas is shown in Table 4.10-51. These values are based on the cost range for southern California area.

Table 4.10-51: El Nido and Western LA Basin sub-areas Net LCR Reduction Benefits for Alternative 3

	Alternative 3: Install BESS in El Nido and Western LA Basin Sub-areas	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (Eastern LA Basin) (MW)	-42	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$0.7	-$1.0
LCR increase (San Diego-Imperial Valley) (MW)	-35	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.5	-$0.7
Net LCR Saving ($million/year)	$15.6	$21.2

Cost estimates:

The planning estimate cost for the Alternative 3 is $1,162 million, using Lazard unit cost. This is an estimated cost at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Benefit to Cost Ratio

The levelized fixed cost as compared to the savings associated with the capacity benefits are shown in Table 4.10-52. The benefit to cost ratios were calculated for the range of the local capacity benefits.

Table 4.10-52: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 3: Install BESS in the El Nido and Western LA Basin Sub-areas		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$15.6	$21.2
Capital Cost		
Capacity (MW)	700	
Capital Cost Source	Lazard	Lazard
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$276	$276
Benefit to Cost		
Savings ($million/year)	$15.6	$21.2
Estimated Levelized Fixed Cost (screening) ($million/year)	$276	$276
Benefit to Cost	0.06	0.08

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the El Nido sub-area for system reasons is achieved.

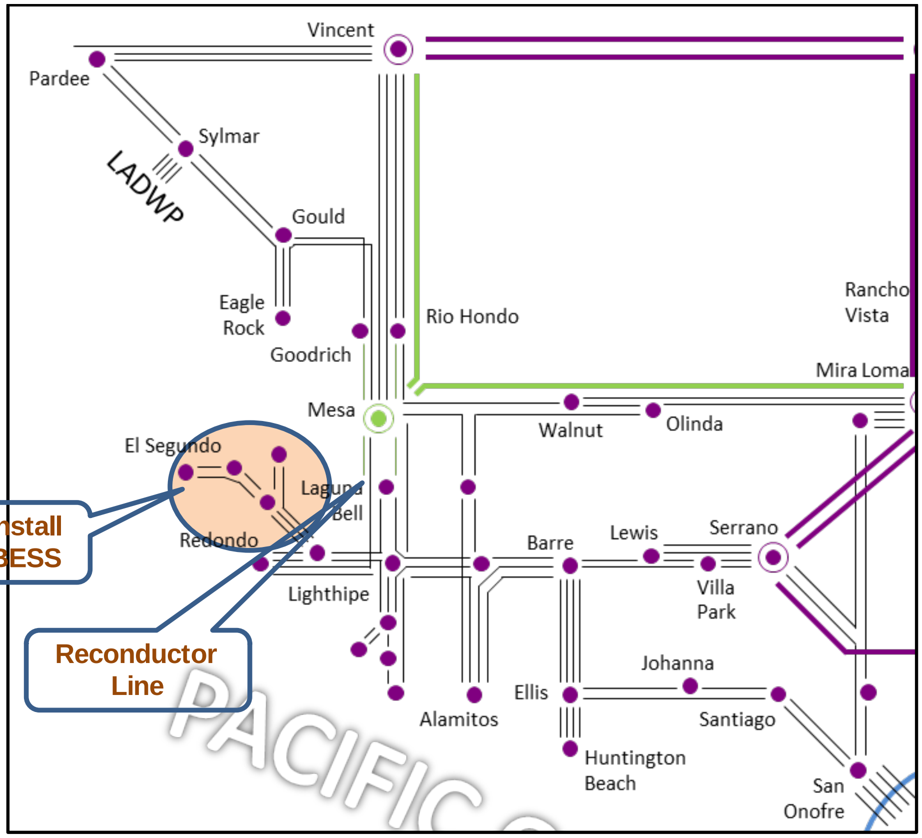
<u>Alternative 4 - Install 350 MW battery energy storage system in the El Nido sub-area and Upgrade Mesa – Laguna Bell 230kV Line</u>

A single line diagram of the vicinity of Alternative 4 is shown in Figure 4.10-15.

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the El Nido and Western LA Basin sub-areas. The local capacity requirement for gas-fired generation in the El Nido sub area was reduced resulting in a reduction of approximately 337 MW. Additionally, approximately 670 MW of local capacity requirement for gas-fired generation was reduced for the Western LA Basin sub-area. Reducing local capacity requirements in the El Nido and Western LA Basin causes an adverse impact of 126 MW to the Eastern LA Basin sub-area LCR need and about 70 MW adverse impact to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 70 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido, Western LA Basin and Eastern LA Basin sub-areas, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $13,080/MW-year and $19,080/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-15: Single line diagram of the vicinity of Alternative 4



Description of Alternative 4 and determination of local capacity benefits:

- Install 350 MW BESS at the following locations:
  - 200 MW at La Cienega and 150 MW at El Nido substations or vicinity (downstream)
- Upgrade 5.6-mi of Mesa-Laguna Bell 230 kV line to 1574 MVA normal, 2123 MVA emergency
- Amount of gas-fired generation capacity reduction in El Nido sub-area: 337 MW
- Net amount of gas-fired generation reduction in the in the Western LA Basin : 670 MW
- Adverse impact to Eastern LA Basin LCR: - 126 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 70 MW

The net benefit of local capacity reductions of the Alternative 4 in the El Nido and Western LA Basin sub-areas is shown in Table 4.10-53. These values are based on the cost range for the southern California area.

Table 4.10-53: El Nido and Western LA Basin sub-areas Net LCR Reduction Benefits for Alternative 4

	Alternative 4: Install BESS in El Nido sub-area and Reconductor Line in Western LA Basin	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (adverse impact) in the Eastern LA Basin (MW)	-126	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$2.1	-$2.9
LCR increase (San Diego-Imperial Valley) (MW)	-70	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.9	-$1.3
Net LCR Saving ($million/year)	$13.8	$18.6

Cost estimates:

The planning estimate cost for the Alternative 4 includes the following:

- $581 million, using Lazard unit cost, for 350 MW of BESS in the El Nido sub-area
- $50 million for reconductoring of the Mesa-Laguna Bell 230kV line, using SCE transmission unit cost
- The total cost for installing the BESS and reconductoring line is $631 million.

This estimated cost would need to be refined further if there is further interest and consideration of this alternative.

Benefit to Cost Ratio

The levelized fixed cost as compared to the savings associated with the capacity benefits.are shown in Table 4.10-54. The benefit to cost ratios were calculated for the range of the local capacity benefits.

Table 4.10-54: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 4: Install 350 MW in the El Nido Sub-area and Reconductor in the Western LA Basin Sub-area		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$13.8	$18.6
PV of LCR Savings ($million)	$190.2	$257.3
Capital Cost (BESS)		
Capacity (MW)	350	
Capital Cost Source	Lazard	Lazard
Capital Cost ($ million)	$581	$581
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Capital Cost (Reconductor Line)		
Capital Cost Estimate ($million)	$50	
Estimated "Total" Cost (screening) ($million)	$65	
Estimated Annual Cost (screening) ($million/year)	$5	
Benefit to Cost		

Savings ($million/year)	$14	$19
Estimated Annual Cost ($million/year)	$143	$143
Benefit to Cost	0.10	0.13

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the El Nido sub-area for system reasons is achieved.

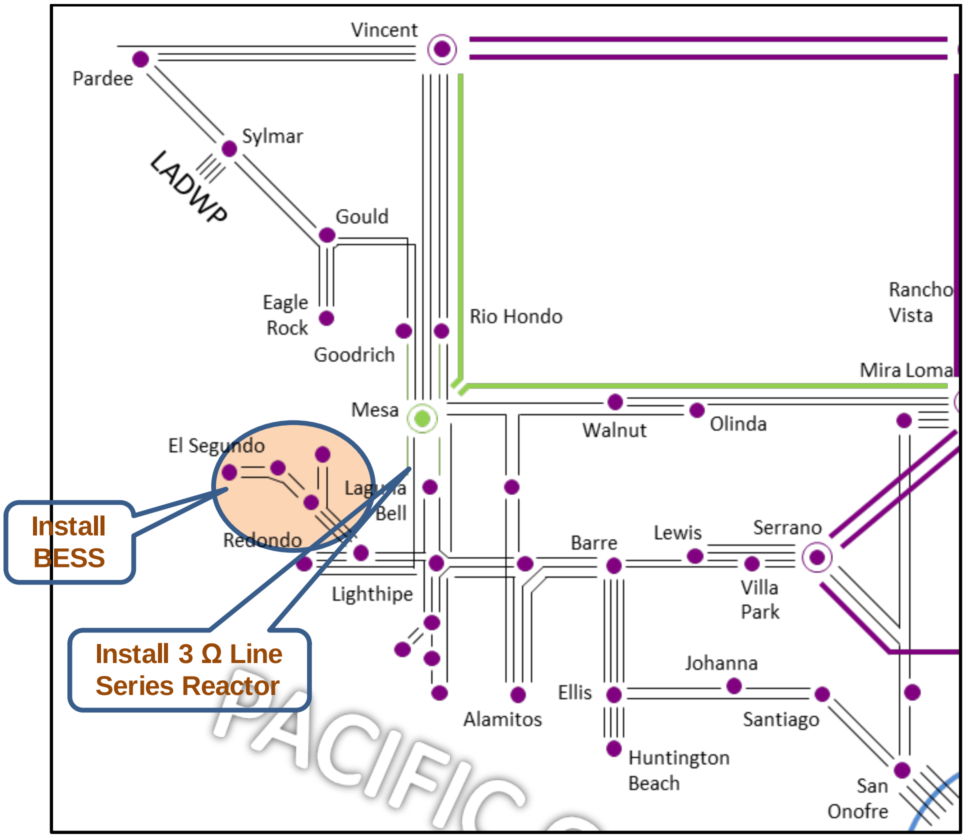
Alternative 5 - Install 350 MW battery energy storage system (BESS) in the El Nido sub-area and 3 Ω line series reactor on the Mesa-Laguna Bell 230 kV line

A single line diagram of the vicinity of Alternative 5 is shown in Figure 4.10-16.

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the El Nido and Western LA Basin sub-areas. The local capacity requirement for gas-fired generation in the El Nido sub area was reduced resulting in a reduction of approximately 337 MW. Additionally, approximately 670 MW of local capacity requirement for gas-fired generation was reduced for the Western LA Basin sub-area. Reducing local capacity requirements in the El Nido and Western LA Basin causes an adverse impact of 0 MW to the Eastern LA Basin sub-area LCR need and about 70 MW adverse impact to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 70 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido, Western LA Basin and Eastern LA Basin sub-areas, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $13,080/MW-year and $19,080/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-16: Single line diagram of the vicinity of Alternative 5



Description of Alternative 5 and determination of local capacity benefits:

- Install 350 MW BESS at the following locations:
  - o 200 MW at La Cienega and 150 MW at El Nido substations or vicinity (load side)
- Install 3 Ω line series reactor on the Mesa-Laguna Bell 230 kV line
- Amount of gas-fired generation capacity reduction in El Nido sub-area: 337 MW
- Net amount of gas-fired generation reduction in the in the Western LA Basin : 670 MW
- Adverse impact to Eastern LA Basin LCR: 0 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 70 MW

The net benefit of local capacity reductions of the Alternative 5 in the El Nido and Western LA Basin sub-areas is shown in Table 4.10-55. These values are based on the cost range for southern California area.

Table 4.10-55: El Nido and Western LA Basin sub-areas Net LCR Reduction Benefits for Alternative 5

	Alternative 5: Install BESS in El Nido Sub-area and Line Series Reactor in Western LA Basin	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (Eastern LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
LCR increase (San Diego-Imperial Valley) (MW)	-70	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.9	-$1.3
Net LCR Saving ($million/year)	$15.9	$21.5

Cost estimates:

The planning estimate cost for the Alternative 5 includes the following:

- $581 million, using Lazard unit cost, for 350 MW of BESS in the El Nido sub-area
- $15 million for installing 3 Ω line series reactor on the Mesa-Laguna Bell 230kV line, using previous similar project cost
- The total cost for installing the BESS and reconductoring line is $596 million.

This estimated cost would need to be refined if there is further interest and consideration of this alternative.

Benefit to Cost Ratio

The levelized fixed cost as compared to the savings associated with the capacity benefits are shown in Table 4.10-56. The benefit to cost ratios were calculated for the range of local capacity benefits.

Table 4.10-56: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 5: Install 350 MW in the El Nido Sub-area and Line Series Reactor on 230 kV Line in Western LA Basin		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$15.9	$21.5
PV of LCR Savings ($million)	$219.2	$296.8
Capital Cost (BESS)		
Capacity (MW)	350	
Capital Cost Source	Lazard	Lazard
Capital Cost ($ million)	$581	$581
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Capital Cost (Install 3 Ω Line Series Reactor)		
Capital Cost Estimate ($million)	$15	
Estimated "Total" Cost (screening) ($million)	$20	
Estimated Annual Cost (screening) ($million/year)	$1	
Benefit to Cost		

Savings ($million/year)	$16	$22
Estimated Annual Cost ($million/year)	$139	$139
Benefit to Cost	0.11	0.15

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the El Nido sub-area for system reasons is achieved.

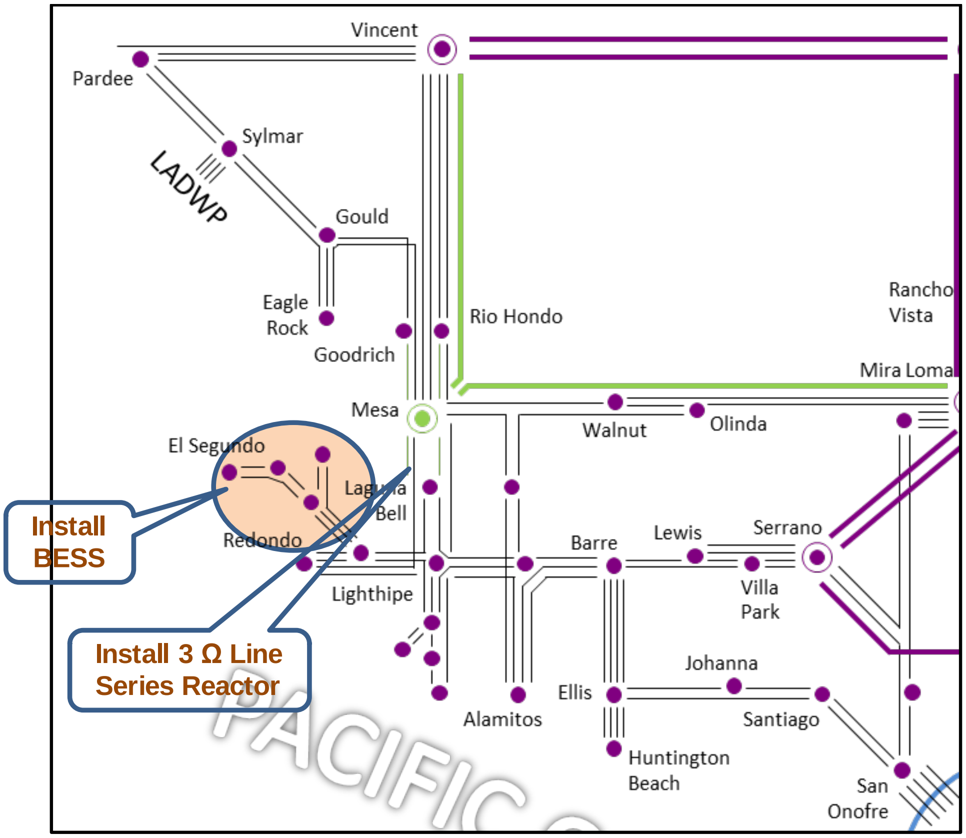
Alternative 6 - Upgrade La Fresa-La Cienega 230 kV Line and Install Line Series Reactor on the Mesa – Laguna Bell 230 kV Line

A single line diagram of the vicinity of Alternative 6 is shown in Figure 4.10-17.

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the El Nido and Western LA Basin sub-areas. The local capacity requirement for gas-fired generation in the El Nido sub area was reduced resulting in a reduction of approximately 337 MW. Additionally, approximately 670 MW of local capacity requirement for gas-fired generation was reduced for the Western LA Basin sub-area. Reducing local capacity requirements in the El Nido and Western LA Basin causes an adverse impact of 206 MW to the Eastern LA Basin sub-area LCR need and about 120 MW adverse impact to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 120 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido, Western LA Basin and Eastern LA Basin sub-areas, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $13,080/MW-year and $19,080/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-17: Single line diagram of the vicinity of Alternative 6



Description of Alternative 6 and determination of local capacity benefits:

- Reconductor 12-mile La Fresa – La Cienega 230 kV line
- Install 3 Ω line series reactor on the Mesa-Laguna Bell 230 kV line
- Amount of gas-fired generation capacity reduction in El Nido sub-area : 337 MW
- Net amount of gas-fired generation reduction in the in the Western LA Basin: 670 MW
- Adverse impact to Eastern LA Basin LCR: - 206 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 120 MW

The net benefit of local capacity reductions of the Alternative 6 in the El Nido and Western LA Basin sub-areas is shown in Table 4.10-57. These values are based on the cost range for southern California area.

Table 4.10-57: El Nido and Western LA Basin sub-areas Net LCR Reduction Benefits for Alternative 6

	Alternative 6: Reconductor 230 kV Line in El Nido Sub-area and Install Line Series Reactor on 230 kV Line in Western LA Basin	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (Eastern LA Basin) (MW)	-206	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$3.4	-$4.7
LCR increase (San Diego-Imperial Valley) (MW)	-120	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$1.6	-$2.3
Net LCR Saving ($million/year)	$11.8	$15.9

<u>Cost estimates:</u>

The planning estimate cost for the Alternative 6 includes the following:

- $104 million, using SCE transmission unit cost, for reconductoring La Fresa-La Cienega 230kV line in the El Nido sub-area
- $15 million for installing 3 Ω line series reactor on the Mesa-Laguna Bell 230kV line, using previous similar project cost
- The total cost for installing the BESS and reconductoring line is $119 million.

This estimated cost would need to be refined further if there is further interest and consideration of this alternative.

Benefit to Cost Ratio

The present value of the capacity benefits is shown in Table 4.10-58. These values are based on a 40-year[130] project life.

Table 4.10-58: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 6: Reconductor 230 kV Line in El Nido Sub area and Install Line Series Reactor on 230 kV Line in Western LA Basin		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$11.8	$15.9
PV of LCR Savings ($million)	$157.2	$211.67
Capital Cost		
Capital Cost Estimate ($ million)	$119	
Estimated “Total” Cost (screening) ($million)	$155	
Benefit to Cost		
PV of Savings ($million)	$157.2	$211.67
Estimated “Total” Cost (screening) ($million)	$154.70	
Benefit to Cost	1.02	1.37

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only

130 Upgrades on existing transmission facilities are assumed to have 40-year project life in the economic evaluation.

marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the El Nido sub-area for system reasons is achieved.

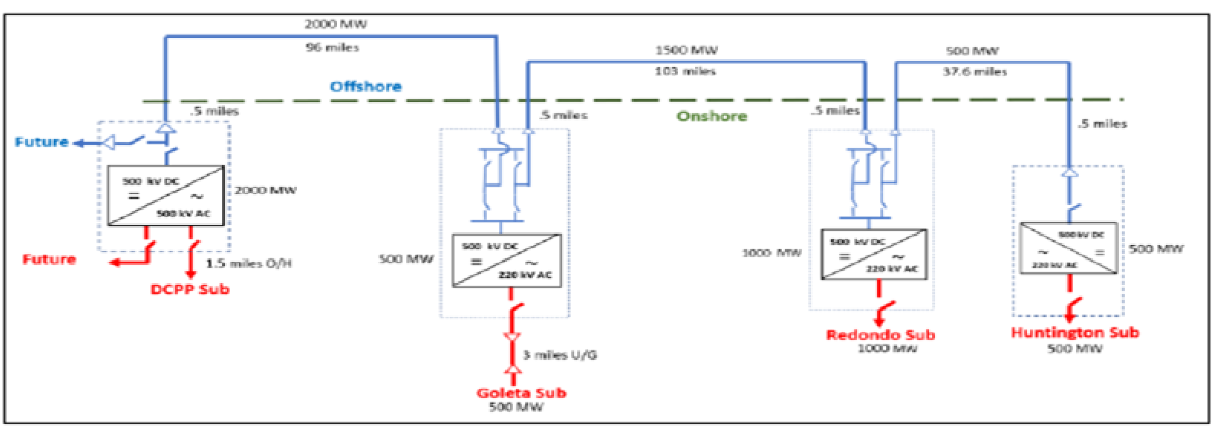
Alternative 7 - Proposed Pacific Transmission Expansion HVDC Project

A single line diagram of the proposed Pacific Transmission Expansion HVDC Project is shown in Figure 4.10-18.

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Big Creek-Ventura LCR area and the Western LA Basin sub-area. The local capacity requirement for gas-fired generation in the Big Creek-Ventura area was reduced by 393 MW, and 1,889 MW for the Western LA Basin sub-area. Reducing local capacity requirements in the Western LA Basin causes an adverse impact of 149 MW to the Eastern LA Basin sub-area LCR need and about 140 MW adverse impact to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 140 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido, Western LA Basin and Eastern LA Basin sub-areas, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $13,080/MW-year and $19,080/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2019-2020 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-18: Proposed Pacific Transmission Expansion HVDC Project



Description of Alternative 7 and determination of local capacity benefits:

- This option is proposed by the Western Grid Development, LLC
- Scope of proposed project:
    - Install four Voltage Source Converter stations, rated 2000 MW (500 kV DC/AC), 1000 MW (500 kV DC / 230 kV AC), two 500 MW (500 kV DC / 230 kV AC)
    - Install 500 kV DC submarine cables connecting Diablo Canyon switchyard to Goleta, Redondo Beach and Huntington Beach substations
- Amount of gas-fired generation reduction in the Big Creek-Ventura area: 393 MW
- Amount of gas-fired generation capacity reduction in El Nido sub-area: 0 MW
- Amount of gas-fired generation reduction in the Western LA Basin sub-area: 1,889 MW
- Adverse impact to Eastern LA Basin LCR: - 149 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 140 MW

The net benefit of local capacity reductions of the Alternative 7 in the Big Creek/Ventura area and Western LA Basin sub-area is shown in Table 4.10-59. These values are based on the cost range for southern California area.

Table 4.10-59: Big Creek/Ventura area and Western LA Basin sub-area Net LCR Reduction Benefits for Alternative 7

-	Alternative 7: Pacific Transmission Expansion HVDC Project	
	Local/CPM versus System Capacity	Local/CPM versus SP 26
LCR Reduction Benefit (Big Creek/Ventura) (MW)	393	
Capacity value (per MW-year)	$16,320	$22,320
LCR Reduction Benefit ($million)	$6.4	$8.8
	Local versus System Capacity	Local versus SP 26
LCR Reduction Benefit (El Nido) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$0.0	$0.0
LCR reduction benefit (Western LA Basin) (MW)	1,889	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$31.5	$42.8
LCR increase (Eastern LA Basin) (MW)	-149	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$2.5	-$3.4
LCR increase (San Diego-Imperial Valley) (MW)	-140	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$1.8	-$2.7
Net LCR Saving ($million/year)	$33.6	$45.6

Cost estimates

The cost estimate provided by the project sponsor is $1,850 million for the proposed project. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", translates to a total cost of $2,405 million.

Benefit to Cost Ratio

The present value of the sum of the production cost and capacity benefits are shown in Table 4.10-60. These values are based on a 50 year project life[131]..

Table 4.10-60: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 7: Pacific Transmission Expansion HVDC Project		
Production Cost Modeling Benefits		
Total PCM Benefits ($million/year)	-8.5	
Present Value of Production Cost Savings ($million)	-117.31	
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$33.6	$45.6
PV of LCR Savings ($million)	$463.8	$628.8
Capital Cost		
Capital Cost Estimate ($ million)	$1,850	
Estimated "Total" Cost (screening) ($million)	$2,405	
Benefit to Cost		

[131] For new transmission projects, the project life is assumed to be 50-year in the economic evaluation.

PV of Savings ($million)	$346.5	$511.5
Estimated "Total" Cost (screening) ($million)	$2,405	
Benefit to Cost	0.14	0.21

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Conclusions

The economic benefits of the Pacific Transmission Expansion project are not sufficient on a standalone basis to support the project as an economic-driven transmission project based on the findings in the 2019-2020 transmission planning studies. The project provides benefits for which the ISO is valuing with conservative assumptions at this time, due to uncertainty regarding the future reliance on gas-fired generation for system and flexible needs. The ISO expects that dialogue will continue as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement, and as system needs for other attributes the project may provide are further assessed.

4.11 Summary and Recommendations

The ISO conducted production cost modeling simulations in this economic planning study and grid congestion was identified and evaluated; the congestion studies helped guide the specific study areas that were considered for further detailed analysis. Other factors, including the ISO's commitment to consider potential options for reducing the requirements for local gas-fired generation capacity, and prior commitments to continue analysis from previous years' studies, also guided the selection of study areas.

The ISO then conducted extensive assessments of potential economic transmission solutions consisting of production cost modeling and assessments of local capacity benefits. These potential transmission solutions included stakeholder proposals received from a number of sources; request window submissions citing economic benefits, economic study requests, and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements. Alternatives also included interregional transmission projects as set out in chapter 5. Overall, 15 areas, sub-areas, and transmission paths were studied. This entailed consideration of 25proposals and alternatives.

The study results in this planning cycle were heavily influenced by certain ISO planning assumptions driven by overall industry conditions. In particular, the longer term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined, in the CPUC's integrated resource planning process, but actionable direction regarding the need for these resources for those purposes is not yet available. The uncertainty regarding the extent to which gas-fired generation will be needed to meet those system and flexible capacity requirements necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements. The ISO accordingly placed values on benefits associated with reducing local gas-fired generation capacity requirements primarily on the difference between the relevant local area capacity price and system capacity prices. This conservative assumption was a key difference between the economic benefits calculated in this study, and the economic assessments stakeholders provided in support of their projects. The ISO recognizes that the capacity value of many of these projects will need to be revised when actionable direction on the need for gas-fired generation for system and flexible needs is available.

The ISO's focus on ratepayer benefits, rather than broader WECC-wide societal benefits, was another difference between a number of stakeholder proposals.

A number of stakeholder proposals for battery storage projects cited the ISO's stakeholder initiative regarding how storage procured as a regulated cost of service transmission asset (or SATA) could also access market revenues when not needed for reliability. This initiative has been placed on hold to consider further refinements to the ISO's storage participation model. The ISO nonetheless assessed the economic benefits they could provide, assuming that if appropriate, procurement could also be investigated as market-based local capacity resources through CPUC procurement processes. However, the same conservative assumptions regarding local capacity benefits were applied.

The overall economic planning study results in the 2019-2020 planning cycle are summarized in Table 4.11-1.

Table 4.11-1: Summary of economic assessment in the 2019-2020 planning cycle

Congestion or study area	Alternative	Benefits Consideration	Economic Justification
Path 26 corridor, Big Creek/Ventura LCR area, Western LA Basin sub-area	PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach)	Production cost ratepayer benefits and local capacity benefits not sufficient	No
PG&E Fresno Avenal area	Kettleman Hills Tap to Gates 70 kV line reconductoring)	Production cost ratepayer benefits not sufficient	No
PG&E Fresno area	Huron to CalFlax 70 kV line reconductoring	Production cost ratepayer benefits not sufficient	No
PG&E Fresno area	Oro Loma to El Nido 115 kV line reconductoring	Production cost ratepayer benefits sufficient	No
GLW/VEA	Sloan Canyon to Pahrump 230 kV line reconductoring	Production cost ratepayer benefits not sufficient	No
GLW/VEA	Sloan Canyon to Pahrump 230 kV line reconductoring and Phase Shifters between VEA and NVE's 138 kV systems	Production cost ratepayer benefits not sufficient	No

Congestion or study area	Alternative	Benefits Consideration	Economic Justification
PG&E Humboldt area	Build a new Humboldt to Trinity 115 kV line	Local capacity benefits not sufficient	No
PG&E Stockton Tesla-Bellota sub-area	Reconductoring the overloaded lines in the Tesla to Manteca area (~50 miles) and Stanislaus to Manteca area (~150 miles)	Local capacity benefits not sufficient	No
	Build a new Weber to Manteca 230 kV line and reconductoring number of lines in the Tesla to Manteca area (~25 miles) and the Stanislaus to Manteca area (~100 miles)	Local capacity benefits not sufficient	No
	Build a new Westside to Kasson 230 kV line and reconductoring number of lines in the Sanislaus to Manteca area (~75 miles)	Local capacity benefits not sufficient	No
PG&E Greater Bay Area Llagas sub-area	Loop the Metcalf-Llagas 115 kV line into the Morgan Hill substation	Local capacity benefits not sufficient	No
PG&E Greater Bay Area Contra Costa sub-area	Reconductoring Tesla-Delta Switch Yard 230 kV line	Local capacity benefits not sufficient	No
	Delta Reliability Energy Storage - add a new 4-hour and 75 MW energy storage at Delta substation	Local capacity benefits not sufficient	No
	Tesla-Delta Switchyard 230 kV line reactance project with smart wire device	Local capacity benefits is sufficient with consider the the local resource adequancy capacity cost, but not sufficient with considers the system resource adequacy capacity cost	No
PG&E Fresno Coalinga sub-area	Install a 25 MVAr capacitor at Coalinga 70 kV	Local capacity benefits not sufficient	No
	Install a new Gates 230/70 kV transformer	Local capacity benefits not sufficient	No
PG&E Kern South Kern PP sub-area	SPS to shed 75 MW of load at Stockdale A substation for the loss of any combination of Midway-Kern PP 230 kV lines (#1, #3, and #4)	Local capacity benefits not sufficient	No
Big Creek/Ventura area and Santa Clara sub-area	Pardee-Sylmar 230 kV Line Rating Increase Project	Production benefit and Local capacity benefits sufficient	Yes
	Install a 79 MVAR, 230 kV shunt capacitor at Goleta Substation and upgrading multiple towers and terminal equipment on Santa–Clara Vincent, Santa Clara–Pardee, and Santa Clara–Moorpark No.1 & 2 230 kV lines to achieve ratings of 494 MVA (normal)/665 MVA (emergency)	Local capacity benefits not sufficient	No

Congestion or study area	Alternative	Benefits Consideration	Economic Justification
El Nido sub-area and Western LA sub-area	Install 350 MW BESS in El Nido sub-area	Local capacity benefits not sufficient	No
	Upgrade La Fresa – La Cienega 230 kV line (12 mi.)	Local capacity benefits not sufficient	No
	Install 350 MW BESS in Nido and 350 MW in Western LA Basin sub-areas	Local capacity benefits not sufficient	No
	Install BESS in Nido and Upgrade Mesa – Laguna Bell 230 kV line	Local capacity benefits not sufficient	No
	Install 350 MW BESS in Nido sub-area and Install 3 Ω Line Series Reactor on the Mesa-Laguna Bell 230 kV line	Local capacity benefits not sufficient	No
	Upgrade La Fresa – La Cienega 230 kV line and Install 3 Ω Line Series Reactor on the Mesa – Laguna Bell 230 kV line	Local capacity benefit is marginally sufficient. However, the need for the same resources toward satisfying the entire Southern California or the ISO overall system capaciy requirements still needs to be evaluated. The evaluation will be part of the upcoming transmission planning process, therefore no alternative is recommended for approval at this time.	No (see explanation in the column at left)

In summary, one transmission solution – the Pardee to Sylmar 230 kV line Rating Increase Project, estimated to cost about $20 million – was found to have sufficient economic benefits. This project is evaluated and recommended for approval as a reliability project in chapter 2 and the economic benefits warrant pursuing an earlier in-service date to achieve the economic benefits as soon as possible.

Several paths and related projects will be monitored in future planning cycles to take into account further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources and gas-fired generation supporting California’s renewable energy goals.

Chapter 5

5 Interregional Transmission Coordination

The ISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with FERC Order No. 1000. The ISO's 2019-2020 transmission planning cycle was completed during the odd-year portion of the 2018-2019 interregional transmission coordination cycle. The ISO hosted its 2018-2019 ITP submission period in the first quarter of 2018 in which proponents submitted six ITP proposals to the ISO for consideration in the ISO's 2018-2019 TPP. The ISO considered all ITP proposals in its 2018-2019 TPP and did not identify an ISO need for the proposed ITPs. Consistent with the Order No. 1000 Common Interregional Tariff, the ISO was not required to consider the proposed ITPs beyond the ISO's 2018-2019 TPP planning cycle. Commensurate with this outcome, no further consideration of the submitted ITPs was required in the 2019-2020 TPP.

5.1 Background on the Order No. 1000 Common Interregional Tariff

FERC Order No. 1000 broadly reformed the regional and interregional planning processes of public utility transmission providers. While instituting certain requirements to clearly establish regional transmission planning processes, Order No. 1000 also required improved coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. Since the final rule was issued, the ISO has continued to collaborate with neighboring transmission utility providers and Western Planning Regions (WPRs) across the Western Interconnection through a coordinated process for considering interregional projects.

Early on in the interregional transmission coordination process the WPRs developed certain business practices for the specific purpose of providing stakeholders visibility and clarity on how the WPRs would engage in interregional coordination activities among their respective regional planning processes. Commensurate with each WPR's regional arrangement with their members, these business practices were incorporated into their regional processes to be followed within the development of their regional plans. For the ISO, these business practices have been incorporated into the ISO's Business Practice Manual (BPM) for the Transmission Planning Process.

Commensurate with past interregional transmission coordination cycles, the ISO continued to play a leadership role in Order 1000 processes within the ISO's planning region, through direct coordination with the other WPRs and representing and supporting interregional coordination concepts and processes in public forums such as WECC. The WPRs have actively engaged to resolve conflicts and challenges that have arisen since the first coordination cycle was initiated in 2016. The ISO and other WPRs have continued to consider and forge new opportunities to facilitate coordination among its stakeholders and neighboring planning regions for the benefit of interregional coordination.

5.2 Interregional Transmission Projects

Interregional Transmission Projects have been considered in this transmission planning process on the basis that:

- The ITP must electrically interconnect at least two Order 1000 planning regions;
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO's transmission planning process;
- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region; and,
- When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

5.3 Interregional Transmission Coordination per Order No. 1000

Overall, the interregional coordination requirements established by Order No. 1000 are fairly straight-forward. In general, the interregional coordination order requires that each WPR (1) commit to developing a procedure to coordinate and share the results of their planning region's regional transmission plans to provide greater opportunities for the WPRs to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost effectively than separate regional transmission facilities; (2) develop a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions; (3) establish a formal agreement to exchange among the WPRs, at least annually, their planning data and information; and finally (4) develop and maintain a website or e-mail list for the communication of information related to the interregional transmission coordination process.

On balance, the ISO fulfills these requirements by following the processes and guidelines documented in the BPM for the Transmission Planning Process and through its development and implementation of the TPP.

5.3.1 Procedure to Coordinate and Share ISO Planning Results with other WPRs

During each planning cycle the ISO predominately exchanges its interregional information with the other WPRs in two ways: (1) an annual coordination meeting hosted by the WPRs; and (2) a process by which ITPs can be submitted to the ISO for consideration in its TPP. While the annual coordination meetings are organized by the WPRs, one WPR is designated as the host for a particular meeting and in turn, is responsible for facilitating the meeting. The annual coordination meetings are generally held in February of each year, but in no event later than March 31. Hosting responsibilities are shared by the WPRs in a rotational arrangement that has been agreed to by the WPRs. The ISO hosted the 2018 meeting and NTTG is hosting the 2019 meeting.

In general, the purpose of the coordination meeting is to provide a forum for stakeholders to discuss planning activities of the west, including a review of each region's planning process, its needs and potential interregional solutions, update on Interregional Transmission Project (ITP) evaluation activities, and other related issues. It is important to note that the ISO and ColumbiaGrid planning processes are annual while the planning processes of NTTG and WestConnect are biennial. To address this difference in planning cycles, the WPRs have agreed to annually share the planning data and information that is available at the time the annual interregional coordination meeting is held; divided into an "even" and "odd" year framework. Specifically, the information which the ISO shares is shown in Table 5.3-1.

Table 5.3-1: Annual Interregional Coordination Information

Even Year	Odd Year
Most recent draft transmission plan	Most recent draft transmission plan
ITPs that: Were being considered within the previous odd year draft transmission plan; That are being considered within the previous odd year draft transmission plan for approval and/or awaiting "final approval" from the relevant planning regions; and, That have been submitted for consideration in the even year transmission plan.	ITPs that: Were being considered within the previous even year draft transmission plan; and, That were considered in the even year draft transmission plan and approved by the ISO Board for further consideration within the odd year draft transmission plan.

5.3.2 Submission of Interregional Transmission Projects to the ISO

As part of its TPP the ISO provides a submission window during which proponents may submit their ITPs into the ISO's annual planning process within the current interregional coordination cycle. The submission window is open from January 1st through March 31st of every even numbered year. Interregional Transmission Projects will be considered by the WPRs on the basis that:

- The ITP must electrically interconnect at least two Order 1000 planning regions;
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO's transmission planning process;
- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region; and,

- When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

An ITP submittal must include specific technical and cost information for the ISO to consider during its validation/selection process of the ITP. In order for the ISO to consider a proponent's project as an ITP, it must have been submitted to and validated by at least one other WPR. Once the validation process has been completed, each WPR is then considered to be a Relevant Planning Region. All Relevant Planning Regions consider the proposed ITP in their regional process. For the ISO, validated ITPs will be included in the ISO's Transmission Planning Process Unified Planning Assumptions and Study Plan for the current planning cycle and evaluated in that year's transmission planning process.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

5.3.3 Evaluation of Interregional Transmission Projects by the ISO

Once the submittal and validation process has been completed, the ISO shares its planning data and information with the other Relevant Planning Regions and develops a coordinated evaluation plan for each ITP to be considered in its regional planning process. The process to evaluate an ITP can take up to two years where an "initial" assessment is completed in the first or even year and, if appropriate, a final assessment is completed in the second or odd year. The assessment of an ITP in a WPR's regional process continues until a determination is made as to whether the ITP will/will not meet a regional need within that Relevant Planning Region. If a WPR determines that an ITP will not meet a regional need within its planning region, no further assessment of the ITP by that WPR is required. Throughout this process, as long as an ITP is being considered by at least two Relevant Planning Regions, it will continue to be assessed as an ITP for cost allocation purposes; otherwise, the ITP will no longer be considered within the context of Order No. 1000 interregional cost allocation. However, if one or more planning regions remain interested in considering the ITP within its regional process even though it is not on the path of cost allocation, it may do so with the expectation that the planning region(s) will continue some level of continued cooperation with other planning regions and with WECC and other WECC processes to ensure all regional impacts are considered.

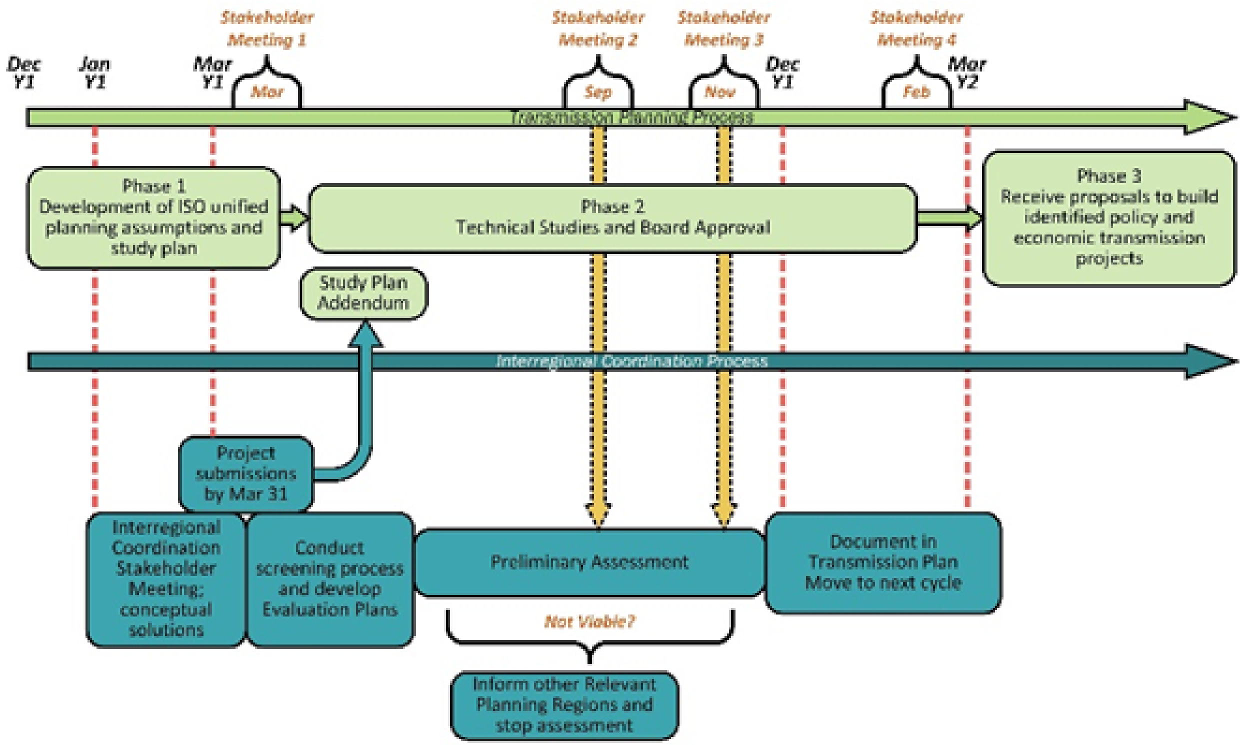
5.3.3.1 Even Year ITP Assessment

The even year ITP assessment begins when the relevant planning regions initiate the coordinated ITP evaluation process. This evaluation process constitutes the relevant planning regions' formal process to identify and jointly evaluate transmission facilities that are proposed to be located in planning regions in which the ITP was submitted. The goal of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP that will be used by all relevant planning region(s) in their individual evaluations of the ITP(s). The relevant planning regions are required to complete the ITP evaluation process within 75 days after the ITP submittal deadline of March 31 during which a lead planning region is selected for each ITP proposal to develop and post for ISO stakeholder review, a coordinated ITP evaluation process plan for each ITP. Once the ITP evaluation plans are finalized, each relevant planning region independently considers the ITPs that have been submitted into its regional planning process.

As with the other relevant planning regions, the ISO assesses the ITP proposals under the ISO tariff. As illustrated in the ISO shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the ISO manages its assessment of an ITP proposal across the two year interregional coordination cycle in two steps. During the even year, the ISO makes a preliminary assessment of the ITP and once it completes that task, ISO must consider whether or not consideration of the ITP should continue into the next ISO planning cycle (odd year interregional coordination process). That determination can be made based on a number of factors including economic, reliability, and public policy considerations.

Figure 5.3-1: Even Year Interregional Coordination Process

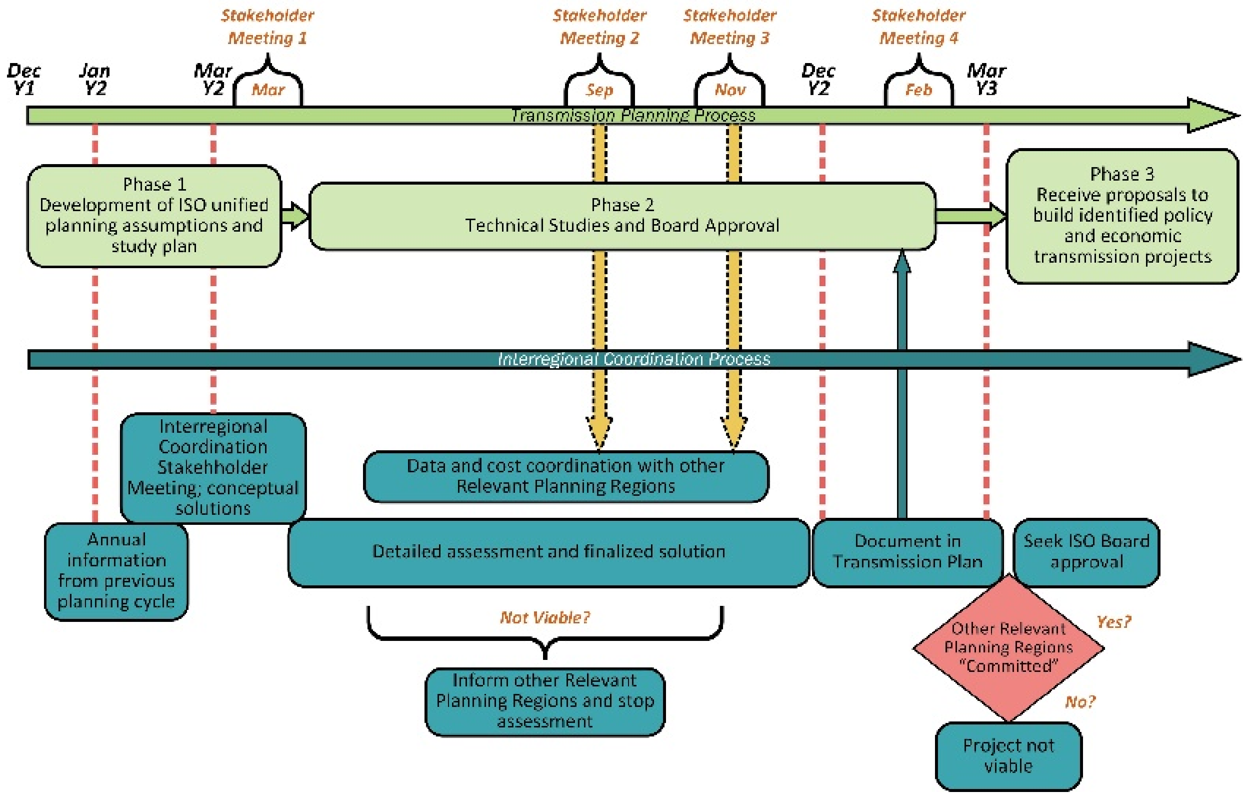


The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation to continue or not continue assessment of the ITP in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission plan.

5.3.3.2 Odd Year ITP Assessment

A recommendation in the even year transmission plan to continue assessing an ITP will initiate consideration of the ITP in the following, or odd year transmission planning cycle and as such, will be documented in the odd year transmission planning process, unified planning assumptions, and study plan. Similar to the even year coordination process shown in Figure 5.3-1, the ISO will follow the odd year interregional coordination process shown in Figure 5.3-2.

Figure 5.3-2: Odd Year Interregional Coordination Process



During the odd year planning cycle the ISO will conduct a more in-depth analysis of the project proposal, which will include consideration of the timing in which the regional solution is needed and the likelihood that the proposed interregional transmission project will be constructed and operational in the same timeframe as the regional solution(s) it is replacing. The ISO may also determine the regional benefits of the interregional transmission project to the ISO that will be used for purposes of allocating any costs of the ITP to the ISO.

If the ISO determines that the proposed ITP is a more efficient or cost effective solution to meet an ISO-identified regional need and the ITP can be constructed and operational in the same timeframe as the regional solution, the ISO will then consider the ITP as the preferred solution in the ISO transmission plan. The ISO will document its analysis of the ITP and the other regional transmission solutions.

Once the ISO selects an ITP in the ISO transmission plan the ISO will coordinate with the other relevant planning regions to determine if the ITP will be selected in their regional plans and whether or not a project sponsor has committed to pursue or build the project. Based on the information available, the ISO may inform the ISO Board on the status of the ITP proposal and if appropriate, seek approval from the board to continue working with all relevant parties associated with the ITP to determine if the ITP can viably be constructed. Determining viability may take several years during which time the ISO will continue to consider the ITP it its transmission planning process and if appropriate, select it as the preferred solution. The ISO may seek ISO Board approval to build the ITP once the ISO receives a firm commitment to construct the ITP.

5.4 Formation of Northern Grid

Since the first interregional transmission coordination cycle was initiated, four WPRs have closely coordinated the development of the necessary processes, protocols, and guidelines that were required to fully implement the requirements of Order No. 1000 and the Order No. 1000 Common Interregional Tariff. During 2019 two WPRs, the Northern Tier Transmission Group and ColumbiaGrid, have decided to merge into a single WPR which will be called Northern Grid. Northern Grid has adopted the Order No. 1000 Common Interregional Tariff as is but for changes necessary to effectively incorporate Northern Grid into the common tariff language. No tariff changes were required by the ISO or WestConnect for Northern Grid to become a WPR.

The incorporation of Northern Grid into the common tariff language became effective January 1, 2020. Commensurate with that decision, the Northern Tier Transmission Group and ColumbiaGrid were no longer considered a WPR. It is important to note however, that the coordination guides and protocols that have been developed over the last two interregional coordination cycles have been effective in ensuring transparency and comparability of the existing ITP coordination process remains in place and will continue forward to future interregional transmission coordination cycles. Beginning in 2020 the ISO and WestConnect will continue to engage with Northern Grid on interregional transmission coordination activities.

5.5 WECC Anchor Data Set

For a great deal of its history, WECC has provided data collection, coordination, and validation services for its members. Historically, this work has focused on power flow and stability models and data and has produced an annual power flow and stability base case data bank that is available to all members. However, since the mid-1990’s many WECC members began to consider transmission oriented, security constrained economic assessments (production cost modeling) in their planning processes. While power flow and stability models and tools remain the critical system performance tool for assessing system reliability, FERC Orders No. 890 and No. 1000 had within them embedded certain economic assessment requirements that transmission providers were obligated to meet. As a result, a need for west wide coordination, collection, and validation of production cost data has arisen. Although WECC has been proactive in its engagement to support its members in this area, a consistent and repeatable process for engaging and coordinating its member’s information, in particular the Western Planning Regions, was seen to be lacking.

Order 1000 requires that each Western Planning Region, following its Order 1000 regional process, develop its own regional plan. Similarly, WECC completes their annual study program which considers reliability and adequacy across the western interconnection. Although the focus of the Order 1000 regional planning process and WECC’s study program process are not necessarily the same, the Western Planning Regions recognized that the need for a common dataset of power flow and production cost information and a consistent and repeatable process for coordinating their data with WECC was in the best interest of the Western Planning Regions and WECC. To this end, in early 2016 the Western Planning Regions collaborated with WECC to develop the WECC Anchor Data Set (ADS). The objective of the ADS is to provide an avenue for the Western Planning Regions to coordinate data included in their Order 1000 regional plans with WECC and their stakeholders to facilitate a consistent and complete data for the benefit of all users.

5.6 Development of the ADS

Developing and implementing the ADS is a significant undertaking for WECC as its intended objective is to “re-write” its data collection process to include production cost information and clearly link power flow and load and resource information with the production cost information. The WECC Reliability Assessment Committee (RAC) formed the ADS Task Force which was actively engaged in implementation of the ADS and charged with considering and proposing any recommended changes that may need to be considered to facilitate the successful implementation of the ADS.

In October 2019 the ADS Task Force completed its work and reported its findings to the RAC[132]. As required by RAC, the ADS Task Force developed a process work flow through which the ADS process could be implemented. The ADS Task Force also prepared an initial draft of the ADS Process Guide whose purpose was to document the ADS process and generally describe its foundational requirements.

At this point, the full development of the ADS rests with the RAC and WECC and it expected to continue throughout 2020. The ISO supports developing and implementing the ADS and will remain engaged in the ADS development process through standing WECC subcommittees and workgroups. The ADS remains the best representative approach to addressing existing and ongoing data inconsistencies and applications, while facilitating a common dataset that accurately represents the regional plans of the WPRs. Each year the ISO builds over 100 power flow cases to perform its reliability assessment of the ISO controlled grid as well as a detailed production cost model dataset from which it performs economic, policy, and other “special studies”. Clearly, significant ISO resources are committed to developing these study models during each planning cycle and, as such, their accuracy is of paramount importance to that process. The ISO believes that the successful development and implementation of the ADS will yield, through a consistent and repeatable process, better coordinated and more accurate datasets that will maximize their use and minimize errors in WPR regional and WECC assessments.

132 https://www.wecc.org/Administrative/DeShazo%20-%20ADSTF%20Transmittal%20Letter_October%202019.pdf?Web=1

Chapter 6

6 Other Studies and Results

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan and are 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. The studies have not been addressed elsewhere in the transmission plan. These presently include the reliability requirements for resource adequacy studies, both short term and long term, the long-term congestion revenue rights (LT CRR) simultaneous feasibility test studies, a system frequency response assessment, and a flexible capacity deliverability assessment.

6.1 Reliability Requirement for Resource Adequacy

Section 6.1.1 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, being the local capacity technical analysis and the resource adequacy import allocation study. The local capacity technical analysis addressed the minimum local capacity area requirements (LCR) on the ISO grid. The resource adequacy import allocation study established the maximum resource adequacy import capability to be used in 2020. Upgrades that are being recommended for approval in this transmission plan have therefore not been taken into account in these studies.

6.1.1 Local Capacity Requirements

The ISO conducted short- and long-term local capacity technical (LCT) analysis studies in 2019. A short-term analysis was conducted for the 2020 system configuration to determine the minimum local capacity requirements for the 2020 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 May 1, 2019. For detailed information on the 2020 LCT Study Report please visit:

http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2024 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years respectively. The 2024 LCT Study Report was published on May 1, 2019 and for detailed information please visit:

http://www.caiso.com/Documents/Final2024Long-TermLocalCapacityTechnicalReport.pdf

The ISO also conducts a ten-year local capacity technical study every second year, as part of the annual transmission planning process. The ten-year LCT studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide an indication of whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding and, per agreement between state agencies, they are done on every other year cycle.

The most recent ten-year LCR study was initiated in the 2018-2019 transmission planning process. The ISO undertook a comprehensive study of local capacity areas last year and that extended into this planning cycle, examining both the load shapes and characteristics underpinning local capacity requirements, and evaluating alternatives for those needs even if it is unlikely that the economic benefits alone would outweigh the costs. A number of these alternatives received detailed economic evaluations in this planning cycle, as set out in chapter 4, to assess if they should be approved as economic-driven transmission solutions.

For detailed information about the 2028 long-term LCT study results, please refer to the stand-alone report in the Appendix G.

As shown in the LCT study reports and indicated in the LCT study manual, that the ISO prepares each year setting out how that year's LCT studies will be performed, 12 load pockets are located throughout the ISO-controlled grid as shown in Table 6.1-1; however only 10 of them have local capacity area requirements as illustrated in Figure 6.1-1.

Table 6.1-1: List of Local Capacity Areas and the corresponding service territories within the ISO Balancing Authority Area

No	LCR Area	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
12	Metropolitan Water District	MWD

Figure 6.1-1: 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 130 MW. In contrast, the requirements of the Los Angeles Basin are approximately 7,000 MW. The short-term and long-term LCR needs from this year's studies are shown in Table 6.1-2.

Table 6.1-2: Local capacity areas and requirements for 2020 and 2024

LCR Area	LCR Capacity Need (MW)	
	2020	2024
Humboldt	130	132
North Coast/North Bay	742	706
Sierra	1,764	1,304
Stockton	629	675
Greater Bay Area	4,550	4,395
Greater Fresno	1,694	1,711
Kern	465	152
Los Angeles Basin	7,364	6,260
Big Creek/Ventura	2,410	2,577
Greater San Diego/Imperial Valley	3,895	4,025
Valley Electric	0	0
Metropolitan Water District	0	0
Total	23,643	21,937

Notes:

For more information about the LCR criteria, methodology and assumptions please refer to the ISO LCR manual.[133]

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

For more information about the 2024 LCT study results, please refer to the report posted on the ISO website.

[133] "Final Manual 2020 Local Capacity Area Technical Study," November 23, 2018, http://www.caiso.com/Documents/2020LocalCapacityRequirementsFinalStudyManual.pdf .

6.1.2 Resource adequacy import capability

The ISO has established the maximum resource adequacy (RA) import capability to be used in year 2020 in accordance with ISO tariff section 40.4.6.2.1. These data can be found on the ISO website[134]. The entire import allocation process[135] is posted on the ISO website.

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 2029.

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

http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2020-2029.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2022 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. The ISO also notes that upgrades proposed to the IID-owned 230 kV S Line will increase deliverability out of the Imperial area overall and including from IID. The allocation of that deliverability in the future will be available to support deliverability of generation connecting either to the ISO controlled grid or the IID system based on the application of the ISO's tariff and business practices.

[134] "California ISO Maximum RA Import Capability for year 2020," available on the ISO's website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2020.pdf .

[135] See general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

6.2 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

6.2.1 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.

6.2.2 Data Preparation and Assumptions

The 2019 LT CRR study leveraged the base case network topology used for the annual 2020 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 section 8 of this 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 two seasons (with season 1 being January through March and season 3 July through September) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as save cases for further review and record-keeping.

The ISO regional transmission engineering group and CRR team must closely collaborate to ensure that all data used were validated and formatted correctly. The following criteria were used to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs:

- SFT is completed successfully;
- the worst case base loading in each market run does not exceed 60 percent of enforced branch rating;
- there are overall improvements on the flow of the monitored transmission elements.

6.2.3 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.

6.2.4 Conclusions

The SFT studies involved four market runs that reflected two three-month seasonal periods (January through March and July through September) 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 July 2019 that there are no existing released LT CRRs at-risk" that require further analysis. Thus, the transmission projects and elements approved in the 2019-2020 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.

6.3 Frequency Response Assessment and Data Requirements

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.

Over past planning cycles, the ISO conducted a number of studies to assess the adequacy of forecast frequency response capabilities, and those studies also raised broader concerns with the accuracy of the generation models used in our analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

The ISO has therefore been conducting studies and model collection and validation efforts over the past several years to identify priority areas for improving generation modeling in power flow and stability analysis. This effort is critical both due to identified areas of concern with the models and data presently available, as well as the increasing requirements in NERC mandatory standards.

The work conducted in the time frame of the 2017-2018 planning cycle have focused primarily on data collection and model validation. During 2018, the ISO undertook an effort to collect accurate modeling data from the generation owners. In response to the ISO requests, numerous data was received and many generation models were updated. These updates were reported to WECC and were included in the WECC Dynamic Master File. The frequency response study was performed with the use of the updated generation models for the units for which the updated models were received.

In addition, the ISO Business Practice Manual (BPM) has been updated to include requirements to generation modeling data submittals. The ISO Tariff Section 24.8.2 requires “Participating Generators [to] provide the CAISO on an annual or periodic basis in accordance with the schedule, procedures and in the form required by the Business Practice Manual any information and data reasonably required by the CAISO to perform the Transmission Planning Process. . . .” Section 10 of the BPM establishes both: (1) what information and data must be submitted; and (2) the schedule, procedures, and format for submitting that information and data.

The ISO requires generating unit models in the GE-PSLF format and other technical information from participating generators, as identified in the generator data template that was developed by the ISO in 2018. Generator data templates for different categories of participating generators will be posted on the ISO website. The generator resource list identifying all participating generators by data category and submission phase also can be accessed on the ISO website. The BPM includes sanctions to the Generation Owners for not providing the requested data in time.

In the subsections below, the progress achieved and issues to be considered going forward has been summarized, as well as the background setting the context for these efforts and the study results.

6.3.1 Frequency Response and Over generation issues

The ISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in subsequent years, using the latest dynamic stability models. In the 2019-2020 transmission planning cycle the potential impact of inverter-based resources (IBR) providing frequency response was also studied.

Reliability Standard BAL-003-1.1 (Frequency Response and Frequency Bias Setting)

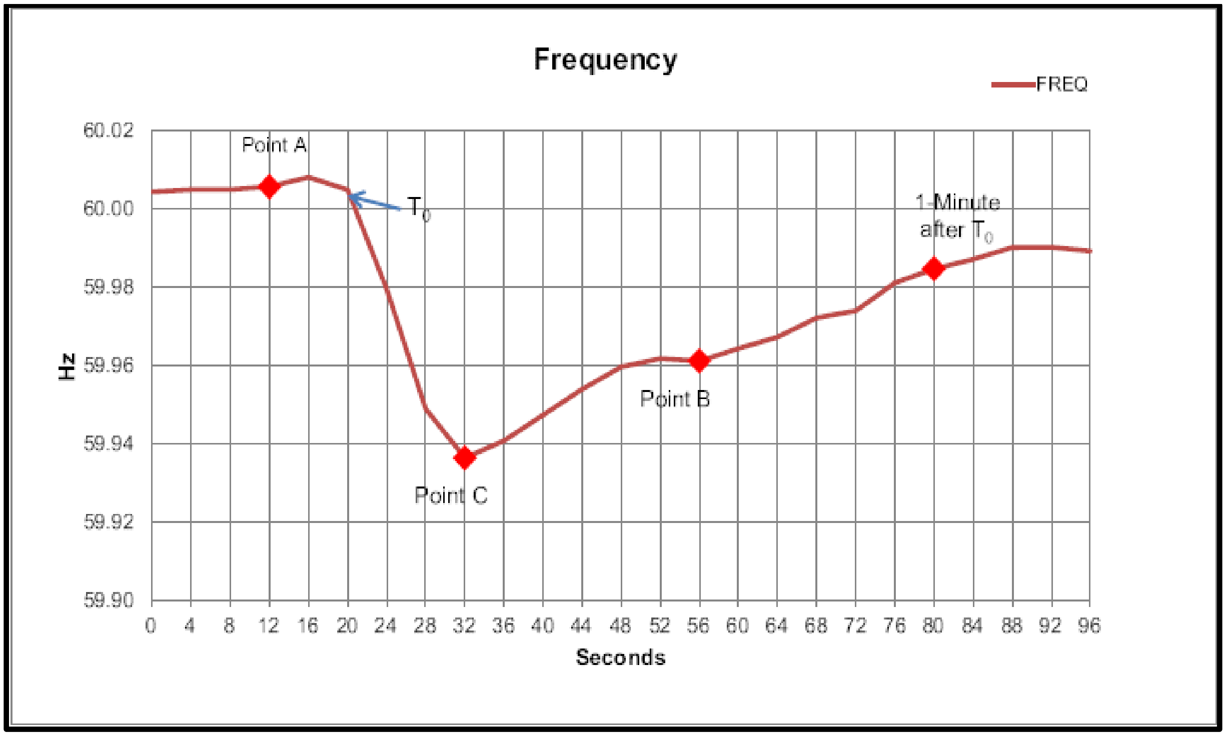
On November 12, 2015 FERC approved Reliability Standard BAL-003-1.1 (Frequency Response and Frequency Bias Setting), as submitted by North American Reliability Corporation (NERC). This standard was an update of the Standard BAL-003-1 that created an obligation for balancing authorities, including the ISO, to demonstrate sufficient frequency response to disturbances that result in decline of the system frequency by measuring actual performance against a predetermined frequency response obligation.

NERC has established the 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 (2,740 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 a 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-003-1.1 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.

A generic system disturbance that results in frequency decline, such as a loss of a large generating facility is illustrated in Figure 6.3-1. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 6.3-1: Illustration of Primary Frequency Response



The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

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-003-1.1 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 257.4 MW/0.1 Hz. It remained the same for 2017. For 2019, the Western Interconnection FRO was also calculated as 858 MW/0.1 Hz, according to the NERC 2018 Frequency Response Annual Analysis. Maximum delta frequency for the Western Interconnection for 2019 was calculated by NERC as 0.248 Hz. For 2018, it was calculated as 0.280 Hz.

The NERC frequency response annual analysis report that specifies Frequency Response Obligations of each interconnection can be found on the NERC website[136].

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-003-1.1 for all operating conditions.

[136] "2018 Frequency Response Annual Analysis," November 2018, https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2018%20Frequency%20Reponse%20Annual%20Analysis%20Info%20Filing.pdf#search=Frequency%20Response%20annual%20analysis

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.

Generation Headroom

Another metric that was evaluated in the ISO studies 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 capacity 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 responsive 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.

2018-2019 Transmission Plan Study Results

As in the previous ISO frequency response studies, the 2018-2019 Transmission Plan study concentrated on the primary frequency response, which occurs automatically prior to the AGC or operator actions. The contingency studied was an outage of two Palo Verde nuclear units, which is the most critical credible contingency in regards to frequency deviation. This contingency was studied in dynamic stability simulations for 60 seconds for all PG&E Bulk system cases in the 2018-2019 planning process. The most critical case that showed the lowest frequency appeared to be the 2023 Spring off-Peak sensitivity case with high renewable and low gas generation output. This case had relatively low level of conventional generation, which may present a challenge in meeting the FRO. Therefore, this case was studied in more detail. Section 6.3.2 of the 2018-2019 Transmission Plan illustrates the results of the study with the following being the conclusions of the study.

- The initial study results indicated acceptable frequency performance both within WECC and the ISO for the base case studied (Spring Off-Peak of 2023 with high renewable generation dispatch). Both WECC and the ISO frequency response was above the obligation specified in BAL-003-1.1.
- However, with lower commitment of the frequency-responsive units, frequency response from the ISO may fall below the Frequency Response Obligation specified by NERC. The study showed that when the headroom on the responsive units was decreased, frequency response of the ISO was insufficient.

- In the future when more inverter-based renewable generation will come online, frequency response from the ISO will most likely become insufficient.
- Compared to the ISO's actual system performance during disturbances, the study results seem optimistic because actual frequency responses for some contingencies were lower than the dynamic model indicated. Therefore, a thorough validation of the models needs to be performed to ensure that governor response in the simulations matches their response in the real life. The issue that was observed in real system operation was withdrawal of the governor response that was not observed in the simulations.

6.3.2 FERC Order 842

On February 15, 2018 FERC issued Order 842 that requires newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. Based on FERC Order 842, all generators including wind and solar generators that execute an LGIA on or after May 15, 2018 are required to provide frequency response. While FERC Order 842 doesn't specify any headroom requirement, it is expected that under spring off peak conditions with significant solar generation, the solar generation will be curtailed and therefore new solar units that are capable of frequency response will have the headroom to be able to change MW output upward as well as downward.

6.3.3 2019-2020 Transmission Plan Study

The primary focus of the studies conducted in the 2019-2020 transmission planning cycle was to assess the contribution that inverter-based resources could provide to frequency response. A number of existing IBRs connected to the ISO footprint have primary frequency response (PFR) capability but other than for a few units, the PFR capabilities of the IBRs are not enabled. There are currently around 18 GW of existing installed IBRs across the ISO, which is forecasted to reach 26 GW by year 2024. Considering the subset of existing IBRs with frequency response required and enabled, and new IBRs which are required to provide primary frequency response per FERC Order 842, it is expected that the PFR capability of the IBRs would be beneficial to system recovery from frequency events and to meet the ISO Frequency Response Obligation (FRO).

Both existing and future IBRs with primary frequency response obligations, at the ISO's operation direction, could be curtailed such that headroom is available for upward PFR. This study assessed the impact of enabling the PFR capability of the IBRs on system frequency response, providing headroom is available.

In addition to enabling PFR capabilities, the ISO is considering modifications to the interconnection requirements for IBR connected to the ISO's footprint. Specifically, the ISO is considering changing the frequency deadband and the droop settings requirements for IBRs to drive faster frequency response. A study was required to determine the impact of the above changes on system frequency response, with the test being the simulation of the tripping of two Palo Verde units. Given the size of these units, the trip causes sufficient frequency decline in the simulation and facilitates comparison of the output of different generating units. This is the test the ISO performs to forecast compliance with the requirements of NERC's BAL-003-1 standard.

Study Scope

The scope of the 2019-2020 Transmission Plan study was to test the impact of enabling PFRs; the IBR PFR capability were enabled in this study in 3 groups:

1. To establish a baseline, frequency response of the system following the tripping of two Palo Verde units was calculated without enabling the PFR of any of the IBRs except those that currently are already enabled.
2. The PFR of all the new IBRs that coming online between now and year 2024 was enabled assuming 8% headroom is available on all solar units (approximating the units that will be obligated under FERC Order 842 to be capable and provide primary frequency response when headroom is available).
3. In addition to new units, the PFR of 60% of the existing IBRs was enabled; it is assumed that approximately 60 % of the existing IBRs have the capability to provide primary frequency response; however the control features are not required under their generator interconnection agreements to be activated.

In addition to enabling PFR as described above, the ISO also studied the impact of changing the droop and frequency deadband settings to achieve improved frequency response contributions and performance. The current droop and deadband requirements are 5% and ±0.036 Hz. The study assessed changes to the droop and deadband requirements for new IBRs to 4% and ±0.0167 Hz, respectively as illustrated in the study scenarios below.

The year 2024 spring off peak case was considered for this study to simulate system frequency response in an early afternoon in April. Due to low load and high solar generation it is expected that majority of gas units in the ISO to be offline and therefore would not provide frequency response.

Study Scenarios

Currently around 18 GW of IBRs (solar, wind, storage) are connected to the ISO transmission system. Based on CPUC baseline portfolio, it is expected that the total installed capacity of IBRs to reach 26 GW by 2024. The study scenarios considered in this study are simulating the system response under spring off peak conditions in the middle of the day in April in year 2024.

An 8% headroom was assumed to be available in the spring in California as renewable generation is often curtailed due to excess generation in the middle of the day. Therefore to test a stressed case, the ISO assumed in all the scenarios in this study that transmission-connected solar generation was dispatched at 92%, wind generation was offline, and storage units were fully charge and therefore they were modelled online but dispatched at zero. All the Behind-the-Meter PV (BTM-PV) resources were dispatched at maximum and did not provide any frequency response.

The following scenarios were considered in this study. More information on each of the scenarios is provided in Table 6.3-1: Study Scenarios for Frequency Response Study.

Baseline (Base): This scenario is the continuation of the status quo in which only few existing IBRs with total capacity of around 1 GW provide frequency response. The rest of IBRs will not provide any frequency response.

- Scenario 1 (SC1): The assumption in this scenario is that all new IBRs installed between now and year 2024 will provide frequency response with 5% droop and ±0.036 Hz deadband.
- Scenario 2 (SC2): Compared to SC1, the only change is that in this scenario the new IBRs have 4% droop.
- Scenario 3 (SC3): Compared to SC1, the only change is that in this scenario the new IBRs have ±0.0167 Hz deadband.
- Scenario 4 (SC4): Compared to SC1, in this scenario the new IBRs have 4% droop and ±0.0167 Hz deadband.
- Scenario 5 (SC5): In all the above scenarios, the existing IBRs do not provide frequency response. In SC5 it was assumed that the frequency response capability of around 60% of the existing IBRs that have such capability is activated with 5% droop and ±0.036 Hz.
- Scenario 6 (SC6): Compared to SC5, in this scenario all the IBRs with frequency response capability have 4% droop and ±0.0167 Hz deadband.

Table 6.3-1: Study Scenarios for Frequency Response Study

	Study Scenarios						
	Base	SC1	SC2	SC3	SC4	SC5	SC6
PFR enabled for existing IBRs?	Yes for a few units	Yes for a few units	Yes for a few units	Yes for a few units	Yes for a few units	**Yes for 60%**	**Yes for 60%**
Existing IBRs and other gens droop	5%	5%	5%	5%	5%	5%	5%
Existing IBRs and other gens deadband (Hz)	±0.036	±0.036	±0.036	±0.036	±0.036	±0.036	±0.036
PFR enabled for new IBRs?	No	Yes	Yes	Yes	Yes	Yes	Yes
New IBRs droop	n/a	**5%**	**4%**	5%	**4%**	5%	**4%**
New IBRs deadband (Hz)	n/a	**±0.036**	±0.036	**±0.0167**	**±0.0167**	±0.036	**±0.0167**

Sensitivity Study

With the solar dispatch at 92% and BTM-PV dispatched at maximum in the middle of spring with low load in California, the total export in the study case was around 8,500 MW which is significantly more than typical high export of around 2,000 MW.

To reduce the export to values in line with historical data, a sensitivity study was performed in which the transmission connected solar generation was curtailed to bring the export from 8,500

MW down to around 2,300 MW. The headroom of the solar units was around 40% following the curtailments in the sensitivity scenario.

Study Results

Baseline Study Case (8% headroom)

The system frequency and the total ISO generation output following the trip of two Palo Verde units for the baseline case and under all the scenarios are shown in Figure 6.3-2 and Figure 6.3-3 respectively.

These results indicate that by just enabling the frequency response of the new units coming online between now and year 2024 (SC1 to SC4), the system recovers from frequency events faster and settles at higher frequencies. This is true even with 5% droop and ±0.036 Hz deadband but the ISO generation provides more support in scenarios with 4% droop and ±0.0167 Hz deadband.

Another major improvement in the frequency recovery occurs when the frequency response of around 60% of the existing units that have the capability, are enabled.

It should be noted that if the PFR of the existing capable units and all the future IBRs are activated, the ISO's frequency response may far exceed the required FRO value which is around 250 MW/0.1 Hz. The exceedance will be higher with 4% droop and ±0.0167 Hz deadband.

Sensitivity Study Case (~40% headroom)

The system frequency and the total ISO generation output following the trip of two Palo Verde units for the baseline case and under all the scenarios are shown in Figure 6.3-4 and Figure 6.3-5 respectively.

Compared to the base study case, the total ISO generation output almost doubles and therefore frequency recovery is faster and at higher value. The exceedance of the ISO response compared to its FRO is higher in this sensitivity case.

Figure 6.3-2: System Frequency Response Under Baseline Case (8% headroom)

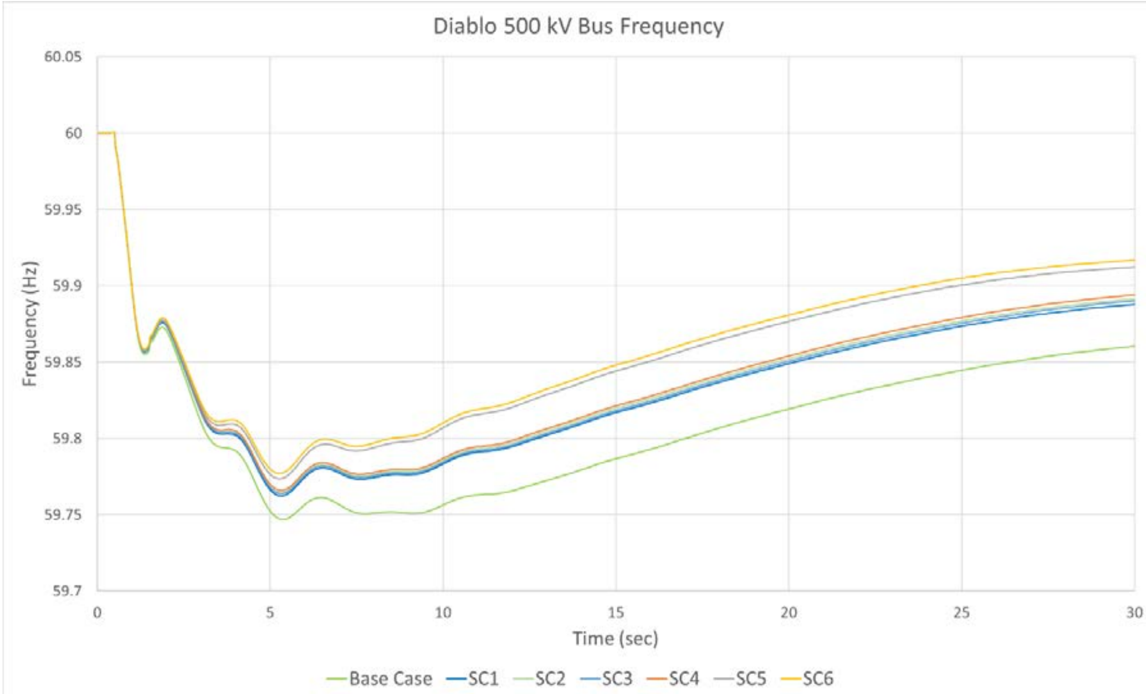


Figure 6.3-3: Total Output of ISO Generators Under Baseline Case (8% headroom)

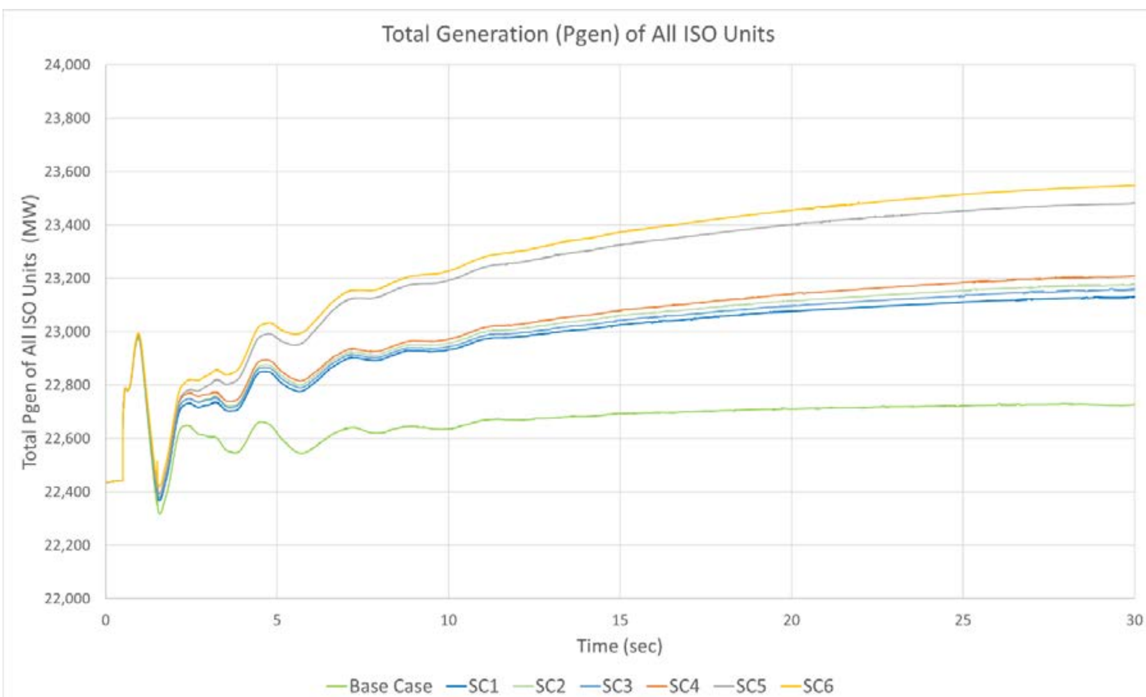


Figure 6.3-4: System Frequency Response Under Sensitivity Case (~40% headroom)

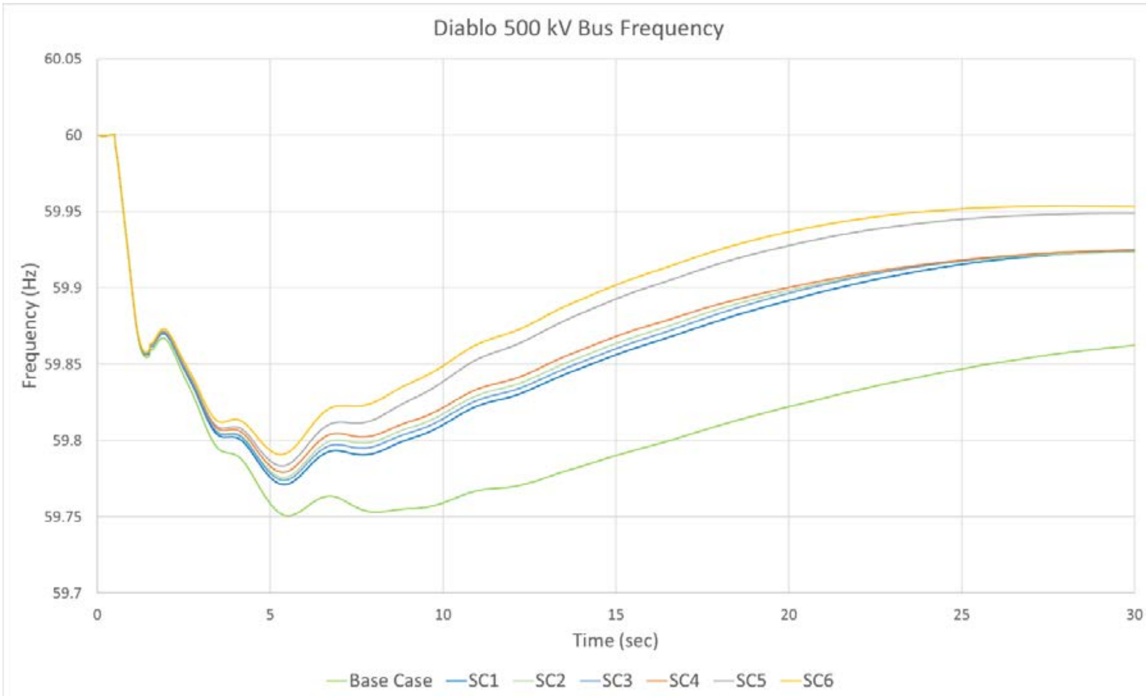
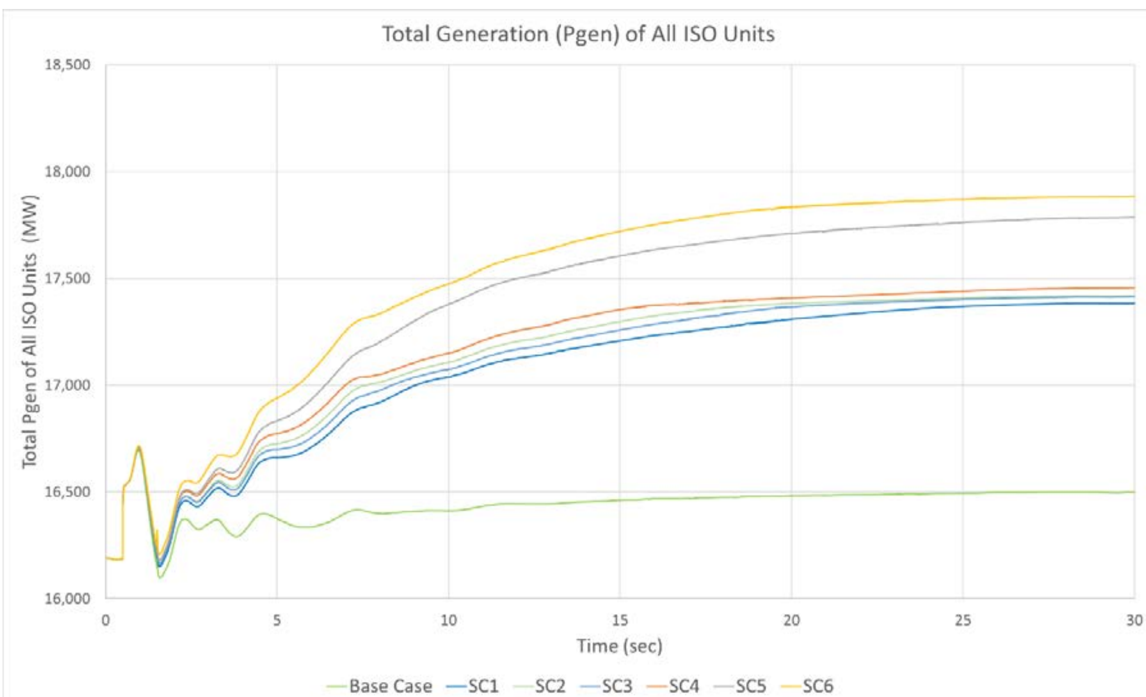


Figure 6.3-5: Total Output of ISO Generators Under Baseline Case (~40% headroom)



Conclusions and Recommendations

This study indicates that ISO system response to major frequency events such as two Palo Verde units improves when IBRs have headroom and their frequency response are enabled.

The studies illustrate that the ISO is forecast to meet and even exceed its Frequency Response Obligation (FRO) of 250 MW/0.1 Hz with the frequency response of new IBRs enabled per FERC Order 842 and would be further improved with approximate 60% of existing IBRs enabled while they have headroom due to curtailment. As illustrated above the changes to the deadband and droop settings have modest benefits for the frequency response.

With regards to the ISO FRO requirements, it is sufficient to meet FRO just by enabling the PFR even with current values for droop and deadband however the ISO generation output will increase with the proposed 4% droop and ±0.0167 Hz deadband.

6.3.3.1 Progress in Updating Models

The ISO has continued to work with Transmission Owners to collect the needed information from generators, and this effort has raised a number of challenges. The various standards requirements obligating the provision of validated data are complex:

NERC requires all generators connected to the Bulk Electric System and greater than 20 MVA (single unit) or 75 MVA (generating plant) comply with NERC data standards, and provide updated data at least every 10 years. However the NERC dynamic data validation standards only apply to generating units that are greater than 75 MVA, which appears to capture about 80% of grid-connected generation in the ISO footprint.

The WECC generating unit validation policy applies to generators greater than 10 MVA, which would address a further 17%.

The ISO also has certain tariff rights to generator information. Under the ISO Tariff Section 24.8.2, ISO can request generator modeling data on an annual or periodic basis, as identified in the ISO BPM for Transmission Planning Process. The ISO has added a new Section 10 to the BPM describing the process which is set to receive, validate and update generator modeling data used in the ISO transmission planning and reliability studies. This process addresses requirements for all ISO participating generators. The new section of the BPM includes participating generators classification according to which the data is requested and provided.

Participating generator modeling requirements identify five different categories of operational generating units. Each operational generating unit is identified and categorized by their ISO market Resource ID. Aggregate resources are identified and categorized by the parent market Resource ID. These categories are:

- Category 1 - Participating generators connected to the Bulk Electric System (BES):
    - Individual generating unit with nameplate capacity greater than 20 MVA, or
    - Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 75 MVA.
- Category 2 – Participating generators connected to facilities 60 kV and above, and not covered in category 1:

- Individual generating unit with nameplate capacity greater than 10 MVA, or
- Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 20 MVA.

- Category 3 - Participating generators connected to BES or facilities above 60KV with generation output lower than the category 1 or 2 modeling requirement thresholds.
  - Individual generating unit with nameplate capacity less than 10 MVA, or
  - Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity less than 20 MVA.
- Category 4 - Non-Net Energy Metered (non-NEM) participating generator connected to non-BES facilities below 60KV, but explicitly modelled as an individual generating unit in transmission planning power flow and stability studies.
- Category 5 - Non-Net Energy Metered (non-NEM) participating generator connected to non-BES facilities below 60KV, modelled as an aggregate resource in transmission planning power flow and stability studies.

The ISO and PTOs are actively pursuing validated modeling data from all generators. The ISO has developed a data template that is being sent to the generation owners. The data templates have to be completed by generator owners for successful submission of data. They may also require submission of supporting documents. The data are submitted to the ISO based on the instructions in the BPM. The data requirements to each category of the generators are also described in the BPM.

The ISO continues to send a data request letter to the participating generators, as set out in the schedule within the BPM, identifying the specific data requirements for the generating unit. The data request letter contains instructions for the participating generator to identify the applicable category and phase of their resource, associated data requirements, compliance deadline, and process to submit data to the ISO and applicable PTO.

The process of the data collection is on-going and is being implemented in several stages. It was started in May 2019 with the data requests for the Category 1 generation units with the completion of the process for all the units planned for September of 2022.

Generating units that achieve commercial operation after September 1, 2018, are to submit the required generator modeling data within one hundred and twenty calendar days of achieving commercial operation in the ISO market. The required data is identified in the generator data template provided to the participating generator upon achieving commercial operation.

Under the ISO Tariff section 37.6.2, the ISO can apply penalty of $500/day for failure to submit requested data. The criteria for applying sanctions are listed in BPM. The penalty is to be applied to Scheduling Coordinator associated with resource ID of generating unit.

6.3.4 Next Steps

Efforts will continue to collect modeling data. 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 updated 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.

6.4 Flexible Capacity Deliverability

6.4.1 Background

In conjunction with the CPUC annual Resource Adequacy proceeding (R.11-10-023), the ISO developed the flexible resource adequacy criteria and must-offer obligation (FRACMOO) through a stakeholder process in 2014. The flexible capacity is the capacity that can be ramped to match net load ramping that becomes an operating challenge as more and more variable energy resources are added to the system. The ISO determines annually the flexible capacity need of the ISO system. The ISO system need is then allocated to each of the local regulatory authorities (LRAs) responsible for load in the ISO balancing authority area.

The capacity of resources that can be counted on to meet the flexibility need is called Effective Flexible Capacity (EFC). Currently, the deliverability of EFC is based on the resource's Net Qualifying Capacity (NQC). The deliverability test for determining NQC is under summer peak conditions and it provides enough assurance that flexible resources are deliverable at the end of the ramping during summer months. Initially, it was assumed that the summer peak condition reasonably represents the stressed operating scenario to deliver the full output of the flexible resources to the ISO aggregate load. Therefore, the NQC could be counted as the upper limit of the EFC. With more and more renewable generation in operation, actual data reveals that the highest system ramping need occurs during weekend, non-summer months, instead of summer peak days. This trend raises a concern with the existing approach when resource ramping during the non-summer season is constrained by the transmission capability. As an initial effort to address this concern, the ISO developed a methodology and tested the deliverability of flexible capacity in the 2019-2020 TPP cycle.

6.4.2 Deliverability Requirement for Flexible Capacity

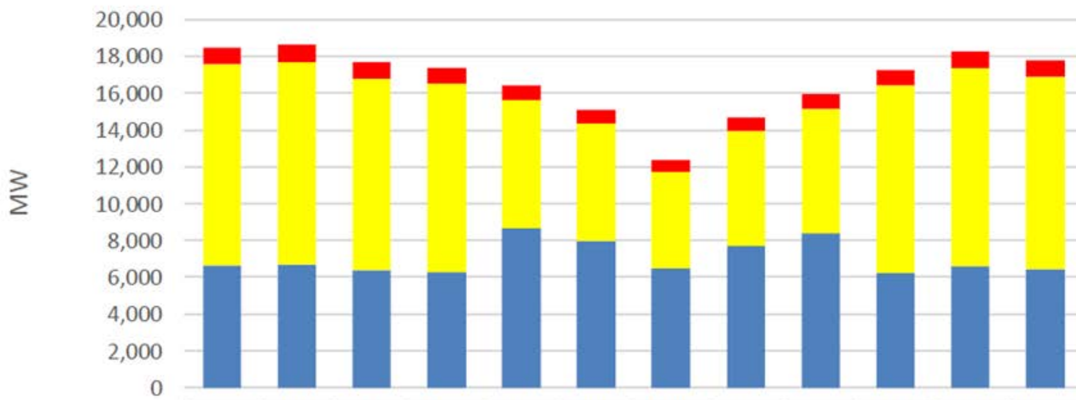
The deliverability of flexible capacity shall mean that the output of a flexible resource could be ramped through its Effective Flexible Capacity range simultaneously with other flexible resources in the same generator pocket to meet the system net load ramping needs without being constrained by the transmission capability.

6.4.2.1 Seasonal Deliverability Requirement

The ISO flexible capacity need assessment has shown that the system-wide total flexible capacity need is the highest in the non-summer months. The 2020 flexible capacity needs[137] are shown in Figure 6.4-1. The base flexible capacity need is 36 percent of the total system need for the non-summer months and 53 percent for the summer months. The time period for peak and super-peak flexible capacity is HE16 through HE20 for both summer and non-summer months. It has been observed that the increase in grid connected solar and incremental behind-the-meter solar will reduce the secondary net load ramp in the non-summer months, but will increase the primary net load ramp.

[137] http://www.caiso.com/Documents/Final2020FlexibleCapacityNeedsAssessment.pdf

Figure 6.4-1: ISO System-Wide Flexible Capacity Needs in Each Category for 2020



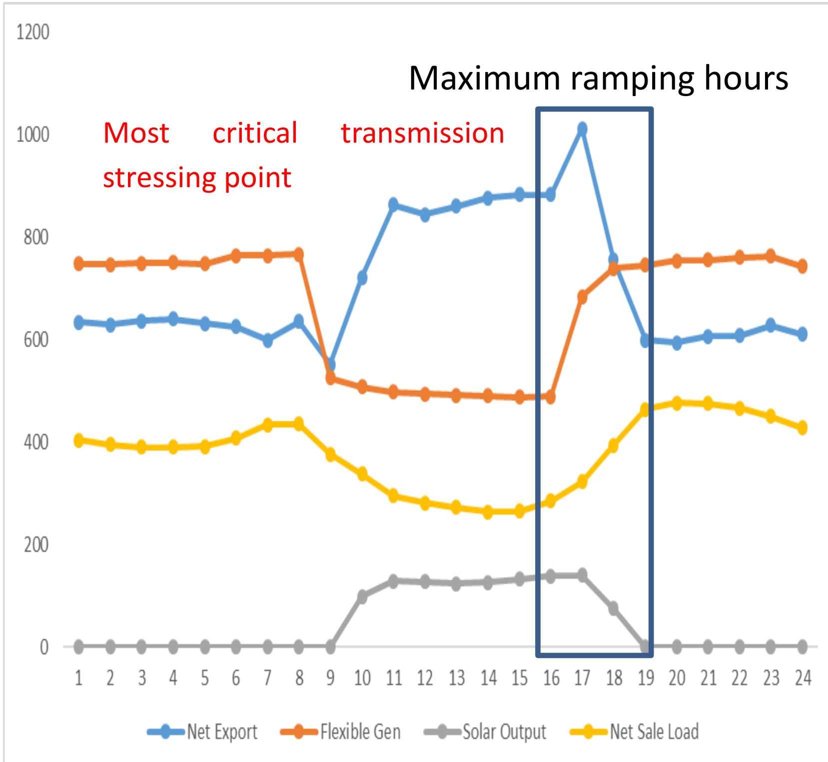
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	925	931	885	869	822	756	617	733	798	863	913	890
Peak Flexibility	10,900	10,974	10,428	10,240	6,970	6,406	5,230	6,218	6,766	10,174	10,758	10,493
Base Flexibility	6,675	6,721	6,387	6,271	8,652	7,951	6,491	7,718	8,398	6,231	6,589	6,426

The flexible capacity needs to be deliverable in all the months, especially the non-summer months to meet the highest system-wide need. The seasonal difference between non-summer and summer could drive quite different generation pockets from the transmission capacity perspective. Even for the same generation pockets, the transmission could be stressed more in the non-summer season than in the summer season.

6.4.2.2 Deliverability along the Net Load Ramping Curve

Along the maximum net load ramping curve, the system condition transitions from low load and high renewable output to high load and low renewable output. The most stressed condition for the generation pocket, from a transmission capability perspective, varies depending on the mix and profiles of the load and resources inside the pocket. The flexible capacity needs to be deliverable along the entire ramping curve, not only at the starting and ending points of the ramping curve. How the load, flexible generation and solar generation inside a generation pocket ramp on a spring afternoon is shown in Figure 6.4-2. The net export from the generation pocket peaks at HE17 and stresses the transmission system the most.

Figure 6.4-2: Illustration of Load and Resource Ramping and Impacts on Transmission



6.4.3 Flexible Capacity Deliverability Assessment Procedure

The ISO has proposed to revise the on-peak and off-peak deliverability assessment methodologies. The scenarios assessed in the revised on-peak methodology align with the starting and ending conditions for the system ramping need in the summer months. The scenario assessed in the revised off-peak methodology aligns with the starting conditions for the system ramping need in the non-summer months. The flexible deliverability test would rely on the deliverability assessment and add new tests to address the scenario not already covered in the deliverability assessment. A testing procedure was developed to monitor the generation pockets for flexible deliverability. However, no study and requirements will be proposed to be considered for enforcement on new generators in the generation interconnection study procedure until 1) it becomes clear how the flexible capacity will be counted, especially for the wind and solar capacity through the FRACMOO2 or follow-up initiative, 2) the revised on-peak and off-peak deliverability methodologies are approved and adopted, and 3) the TPP analysis identifies flexible deliverability constraints.

The proposed procedure to analyze flexible deliverability in the annual transmission planning process involves four major steps as described in the following sections.

6.4.3.1 Identify potential transmission constraints

Identify potential transmission constraints for flexible deliverability from planning studies and operational data. First, review the latest generation interconnection study reliability assessment. Select the overloads that were only identified under the off-peak condition. Then supplement the constraint list by examining congestions from the most recent transmission planning economic planning studies, and from real-time operation. If a congestion occurs during the high net load ramping hours, the binding constraint is selected for further analysis.

6.4.3.2 Define generation pockets (gen-pockets)

Group the potential constraints from Step 6.4.3.1 by the general electrical area. For each electrical area, select a proper off-peak power flow case in the current TPP cycle. Adjust the base case by the dispatch changes shown in Table 6.4-1 to represent the mid-day system condition on an off-peak season weekday.

Table 6.4-1: Base Case Dispatch Adjustment

Solar resources in the study area	Full output
Wind resources in the study area	Pgen = Historical minimum output; Pmax = historical maximum output
Other non-dispatchable resources in the study area	Full output
Flexible resources in the study area	Pgen = Minimum output (Pmin)
Load in the study area	Historical minimum
Imports that impact the study area	Historical minimum
Add a generator at tie-point for each import above	Status off; Pmax = historical maximum – historical minimum

Historical data from 3 pm to 8 pm on spring days are used to establish the dispatch condition because the highest system flexible need occurred in spring. If this changes in the future, the season and time period will be adjusted to ensure they align with the highest flexible need.

Use a power flow tool such as TARA to calculate distribution factors from each generator and load in the study area on each potential transmission constraint.

Define the gen-pocket as all generators that have 5% or greater distribution factor on the constraint and all loads that have -5% or less distribution factor.

6.4.3.3 Express transmission limits

For each potential transmission constraint and associated gen-pocket, express the constraint as

$$\sum_{\substack{w \in wind \\ resources}} d_w \Delta P_{gw} + \sum_{\substack{s \in solar \\ resources}} d_s \Delta P_{gs} + \sum_{\substack{f \in flexible \\ resources}} d_f \Delta P_{gf} + \sum_{\substack{i \in import \\ generators}} d_i \Delta P_{gi} + \sum_{l \in loads} d_l \Delta P_l$$

$$\leq Flow\ Limit - Flow\ in\ the\ Base\ Case \qquad (1)$$

$where$

d_w, d_s, d_f, d_i, d_l $are\ distribution\ factors\ of\ P_g\ and\ P_l$

$\Delta P_{gw} \leq Pmax_w - Pgen_w$

$-Pgen_s \leq \Delta P_{gs} \leq 0$

$\Delta P_{gf} \leq Pmax_f - Pgen_f$

$\Delta P_{gi} \leq Pmax_i - Pgen_i$

$\Delta P_l \leq Off\ peak\ season\ highest\ load - P_l$

$\sum \Delta P_{gf} \leq k\left(\sum \Delta P_l - \sum \Delta P_{gs}\right)$

In the expression, wind resource output is an independent variable bounded by the historical minimum and maximum outputs. Change of flexible resource output is bounded by the net change of load minus solar output multiplied by a factor of k.

6.4.3.4 Determine flexible deliverability margin

Use an optimization tool to find the maximum value of the left side expression of inequality equation (1). Factor k is the ratio of the total flexible generation change during the flexible capacity ramping period to the net load minus solar output change. The k factor is selected by observing production cost simulation or historical operation data for the generation pocket. The meaning of k factor in terms of defining the feasible region to solve the optimization problem is illustrated in Figure 6.4-3.

$$max \sum_{\substack{w \in wind \\ resources}} d_w \Delta P_{gw} + \sum_{\substack{s \in solar \\ resources}} d_s \Delta P_{gs} + \sum_{\substack{f \in flexible \\ resources}} d_f \Delta P_{gf} + \sum_{\substack{i \in import \\ generators}} d_i \Delta P_{gi} + \sum_{l \in loads} d_l \Delta P_l$$

$s.t.$

$\Delta P_{gw} \leq Pmax_w - Pgen_w$

$-Pgen_s \leq \Delta P_{gs} \leq 0$

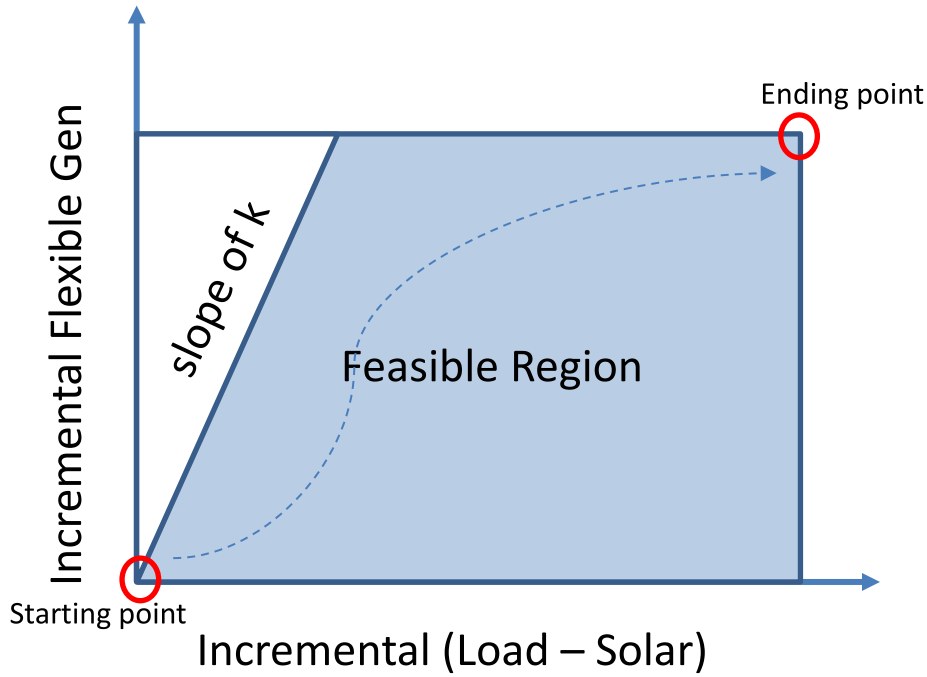
$\Delta P_{gf} \leq Pmax_f - Pgen_f$

$\Delta P_{gi} \leq Pmax_i - Pgen_i$

$\Delta P_l \leq Off\ peak\ season\ highest\ load - P_l$

$\sum \Delta P_{gf} \leq k\left(\sum \Delta P_l - \sum \Delta P_{gs}\right)$

Figure 6.4-3: Feasible Region for Optimization



The operating conditions, i.e. P_g and P_l, that achieve the maximum value in the optimization are considered the most stressed dispatch for the constraint and plugged into the base case. The rest of the system is adjusted to balance overall load and resources. The flexible deliverability margin is the difference between the applicable facility rating and the flow resulting from the most stressed dispatch. A positive margin means the constraint is not limiting the flexible deliverability while a negative margin means the transmission becomes the bottleneck.

6.4.4 Flexible Capacity Deliverability Assessment

The ISO performed the 2019-2020 flexible capacity deliverability assessment using the procedure described above. The 2029 spring off-peak base scenario is used to establish the starting point of the analysis. The system condition of the scenario are summarized in Table 6.4-2.

Table 6.4-2: 2029 Spring Off-Peak Base Scenario

Scenario	Day/Time (PST)	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
	2029	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
Spring Off Peak	4/7 HE 13	80%	81%	79%	100%	98%	98%	55%	54%	22%	21%	26%	17%

Potential generation pockets were selected by reviewing the real time congestion data from market operation, production cost simulation results and generation interconnection studies. Then separate base cases were created for each generation pocket according to Table 6.4-1. The sections below provide the details of the generation pocket analyses.

6.4.4.1 SCE area results

Three generation pockets were identified and analyzed in SCE area. See Table 6.3 below.

Table 6.4-3: SCE Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
North of Lugo	Lugo AA bank	base case	Cluster 11 Phase I RTM
North of Magunden	Vestal - Magunden No. 1	Vestal - Magunden No. 2	Cluster 11 Phase I RTM
Blythe	Julian Hinds - Mirage 230kV	base case	RTM

North of Lugo Constraint

The Lugo 500/230 kV transformer banks limit energy delivery from North of Lugo area to the rest of the ISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 1153 MW of flexible capacity and 1427 MW of solar resources North of Lugo. During spring afternoons, the load seen at the transmission level is projected to be between 227 MW to 604 MW. The analysis results for this generation pocket are shown in Table 6.4-4. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 2, corresponding to 25% margin. If more energy storage is added in North of Lugo, k would increase and the margin will reduce. It was estimated that about 280 MW energy storage could be added without hitting the transmission limitation.

Table 6.4-4: Analysis of North of Lugo Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	52.82	0	1153	1153	1153	1153
Solar Gen	1427	0	1427	981	1130	1337
Load	227	227	604	332	297	248
Monitored Flow	583			840	918	1026
Flow Margin				25%	18%	8%

North of Magunden Constraint

The Vestal – Maguden 230kV line flows limit energy delivery from Big Creek, Rector, Springville and Vestal to the rest of the ISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 1069 MW of flexible capacity and 157 MW of solar resources in the generation pocket. During spring afternoons, the load seen at the transmission level is projected to be between 244 MW to 678 MW. The analysis results for this generation pocket are shown in Table 6.4-5. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 3, corresponding to 51% margin. If more energy storage is added in the pocket, k would increase and the margin will reduce. It was estimated that about 500 MW energy storage could be added without hitting the transmission limitation.

Table 6.4-5: Analysis of North of Magunden Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	0	0	1069	1069	1069	1069
Solar Gen	157	0	157	15	62	129
Load	244	244	678	637	506	323
Monitored Flow	-21			210	299	424
Flow Margin				65%	51%	30%

Blythe Constraint

The Julian Hinds – Mirage 230kV line flow limits the energy delivery of Blythe generation to the rest of the ISO system. This is a small generation pocket with 493 MW flexible capacity and negligible solar resources. The Blythe import is contained in the generation pocket. Blythe import ranges from 0 to 17 MW on a spring day. There is significant pumping load in the pocket. The pumping load ranges from 0 to 317 MW on a spring day. The Julian Hinds – Mirage line flow is stressed the most under low pumping load and high import condition. A deliverability margin of 12% under the most stressed condition is shown in Table 6.4-6. It was estimated that about 70 MW energy storage could be added without hitting the transmission limitation.

Table 6.4-6: Analysis of Blythe Constraint

Variable	Min	Max	Max Flow Point
Flexible Gen	0	493	493
Pump	0	317	0
Import	0	17	17
Monitored Flow			315
Flow Margin			12%

6.4.4.2 SDG&E area results

Three generation pockets were identified and analyzed in SDG&E area. The results are summarized in Table 6.4-7.

Table 6.4-7: SDG&E Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
Doublet Tap-Friars	Doublet Tap-Friars 138 kV	San Luis Rey-Encina 230 kV and San Luis Rey-Encina-Palomar 230 kV	RTM
San Luis Rey-San Onofre	San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	PCM
Silvergate-Bay Boulevard	Silvergate-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1 and #2	PCM

Doublet Tap-Friars Constraint

The Doublet Tap-Friars 138 kV line loading limits energy in the Imperial Valley area as well as various locations inside the SDGE load pocket from being delivered to the rest of the ISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 1914 MW of flexible capacity and 1479 MW of solar resources behind this constraint. During spring afternoons, the load seen at the transmission level is projected to be between 438 MW to 1322 MW. The analysis results for this generation pocket are shown in Table 6.4-8. The historical value of k is 0.8, corresponding to 84% margin. If more energy storage is added in this area, k would increase and the margin will reduce. It was estimated that more than 500 MW of energy storage could be added without hitting the transmission limitation.

Table 6.4-8: Doublet Tap-Friars Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=0.8)
Flexible Gen	100	0	1914	129
Solar Gen	1450	0	1479	1312
Load	438	438	1322	522
Monitored Flow	18			126
Flow Margin				84%

San Luis Rey-San Onofre Constraint

The San Luis Rey-San Onofre 230 kV line loading limits energy in the Imperial Valley area as well as various locations inside the SDG&E load pocket from being delivered to the rest of the ISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 3698 MW of flexible capacity and 1479 MW of solar resources behind this constraint. During spring afternoons, the load seen at the transmission level is projected to be between 941 MW to 2577 MW. The analysis results for this generation pocket is shown in Table 6.4-9. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1.2, corresponding to 40% margin. If more energy storage is added in this area, k would increase and the margin will reduce. There is not much margin to add energy storage before this constraint will be binding.

Table 6.4-9: San Luis Rey-San Onofre Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=1.2)	Max Flow Point (k=2)	Max Flow Point (k=3)
Flexible Gen	0	0	3698	1353	2300	2300
Solar Gen	1450	0	1479	894	894	1079
Load	941	941	2577	1568	1568	1359
Monitored Flow (with RAS)	541			694	941	1077
Flow Margin (with RAS)				40%	18%	6%

Silvergate-Bay Boulevard Constraint

The Silvergate-Bay Boulevard 230 kV line loading limits energy in the Imperial Valley area as well as various locations inside the SDG&E load pocket from being delivered to the rest of the ISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 2068 MW of flexible capacity and 1423 MW of solar resources behind this constraint. During spring afternoons, the load seen at the transmission level is projected to be between 152 MW to 494 MW. The analysis results for this generation pocket is shown in Table 6.4-10. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1.2, corresponding to 44% margin. If more energy storage is added in the pocket, k would increase and the margin will reduce. It was estimated that more than 500 MW of energy storage could be added without hitting the transmission limitation.

Table 6.4-10: Silvergate-Bay Boulevard Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=1.2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	0	0	2068	2068	2068	2068
Solar Gen	1395	0	1423	11	842	1229
Load	152	152	494	491	287	193
Monitored Flow	460			663	767	816
Flow Margin				44%	35%	31%

6.4.4.3 PG&E area results

Three generation pockets were identified and analyzed in the PG&E area. These generation pockets are shown in Table 6.4-11.

Table 6.4-11: PG&E Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
North of Fresno # 1	Mosslanding-LosAguilas 230 kV	Mosslanding-LosBanos 500 kV	Cluster 11 Phase I/ RTM
North of Fresno # 2	Los Banos-Quinto 230 kV Line	Tesla-LosBanos 500 kV line	RTM

North of Fresno Constraint # 1

The Moss Landing-Las Aguilas 230 kV line limits energy delivery from Fresno area to the rest of the ISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 760 MW of flexible capacity and 1349 MW of solar resources in the Fresno area. During spring afternoons, the load seen at the transmission level is projected to be between 174 MW to 566 MW. The analysis results for this generation pocket are shown in Table 6.4-12. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1, corresponding to 32% margin. If more energy storage is added in Fresno area, k would increase and the margin will reduce. It was estimated that about 700 MW energy storage could be added without hitting the transmission limitation. This estimates are location sensitive and the estimates are highly variable depending on the location of these energy storage resources.

Table 6.4-12: North of Fresno # 1 constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	35	204	760	600	760	760
Solar Gen	1192	0	1349	842	1108	1186
Load	174	148	566	255	174	150
Monitored Flow	266			272	314	323
Flow Margin				32%	21%	19%

North of Fresno Constraint # 2

The Los Banos-Quinto 230 kV line limits energy delivery from Fresno area to the rest of the ISO system. The net export from the pocket is higher during off-peak period than the peak period. There is about 1921 MW of flexible capacity and 2530 of MW solar resources in the Fresno area. During spring afternoons, the load seen at the transmission level is projected to be between 128 MW to 1921 MW. The analysis results for this generation pocket are shown in Table 6.4-13. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1, corresponding to 74% margin. No energy storage estimates are provided due to very high flow margin in this case. The margin is primarily due to a new upgrade not present in historical congestion data.

Table 6.4-13: North of Fresno # 2 constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	128	211	1921	1100	1545	1921
Solar Gen	3051	0	3051	3051	3004	3030
Load	995	844	2530	844	870	857
Monitored Flow	265			307	329	353
Flow Margin				74%	72%	70%

6.4.5 Future Work

This assessment did not identify any flexible deliverability concerns. However, future work is needed to improve the assessment methodology.

The assessment focused on the candidate generation pocket. All load and resource variables inside the generation pocket are examined and solved through an optimization tool to find the condition that stressed the transmission. Generation outside the generation pocket was scaled evenly to balance the load and resource changes from the generation pocket. How the conditions change outside the generation pocket impacts flows on the transmission facilities and needs to be refined.

Inside the generation pocket, the transmission constraint is linearized and the correlation among flexible generation, solar output and load is also linearized. This is partly due to the dimensional limit of the tool being used. Capturing the non-linearity of the transmission constraint requires the actual power flow equations in the optimization and a more accurate correlation involves time-sequence data of the load and resources.

Other uncertainties, such as planned outages of transmission facilities, were not considered in the assessment.

Work is being planned to address the above issues. In addition, the future work will also consider assessing energy storage charging capability to allow ramping of energy storage facilities to meet flexible capacity needs.

Chapter 7

7 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 in past transmission planning studies 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 the 2019-2020 Transmission Plan the ISO did not undertake any additional "special studies".

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Chapter 8

8 Transmission Project List

8.1 Transmission Project Updates

Table 8.1-1 and Table 8.1-2 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 8.1-1: Status of Previously Approved Projects Costing Less than $50 M

No	Project	PTO	Expected In-Service Date
1	Estrella Substation Project	NEET West/PG&E[138]	Nov-2023
2	Bellota 230 kV Substation Shunt Reactor	PG&E	Completed
3	Borden 230 kV Voltage Support	PG&E	Completed
4	Cascade 115/60 kV No.2 Transformer Project	PG&E	Jan-2022
5	Clear Lake 60 kV System Reinforcement	PG&E	Feb-2022
6	Coburn-Oil Fields 60 kV system project	PG&E	Sept-2022
7	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	Completed
8	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	Nov-2020
9	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	Nov-2021
10	Delevan 230 kV Substation Shunt Reactor	PG&E	Sept-2020
11	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	Apr-2021
12	Fulton-Hopland 60 kV Line Project	PG&E	Mar-2020
13	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	Dec-2020
14	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	Jan-2021

[138] NEET West was awarded the 230 kV substation component of the project through competitive solicitation. PG&E will construct and own the 70 kV substation and associated upgrades.

No	Project	PTO	Expected In-Service Date
15	Herndon-Bullard 115 kV Reconductoring Project	PG&E	Jan-2021
16	Ignacio 230 kV Reactor	PG&E	Completed
17	Ignacio Area Upgrade	PG&E	Dec-2023
18	Kearney – Hearndon 230 kV Line Reconductoring	PG&E	Completed
19	Kearney-Caruthers 70 kV Line Reconductor	PG&E	Completed
20	Kern PP 230 kV Area Reinforcement	PG&E	Mar-2021
21	Lakeville 60 kV Area Reinforcement	PG&E	Dec-2021
22	Los Esteros 230 kV Substation Shunt Reactor	PG&E	May-2020
23	Maple Creek Reactive Support	PG&E	Jul-2022
24	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	Completed
25	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	Apr-2022
26	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	May-2023
27	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	Dec-2022
28	Monta Vista 230 kV Bus Upgrade	PG&E	Mar-2021
29	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Mar-2021
30	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	Jul-2021
31	Mosher Transmission Project	PG&E	Mar-2021
32	Moss Landing–Panoche 230 kV Path Upgrade	PG&E	Completed
33	Newark-Lawrence 115 kV Line Limiting Facility Upgrade	PG&E	Canceled
34	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	Nov-2020
35	North Tower 115 kV Looping Project	PG&E	Dec-2021
36	NRS-Scott No. 1 115 kV Line Reconductor[139]	PG&E	Completed
37	Oakland Clean Energy Initiative	PG&E	Aug-2022
38	Oro Loma 70 kV Area Reinforcement	PG&E	Apr-2024

[139] The scope of this project has been modified to include reconductoring of both NRS-Scott #1 & #2 115 kV lines. Cost responsibility between PG&E and SVP has not been resolved – ISO approval does not pre-suppose the outcome of the dispute process underway at FERC.

No	Project	PTO	Expected In-Service Date
39	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	Apr-2021
40	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	Mar-2020
41	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	Jan-2021
42	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	Feb-2021
43	Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects)	PG&E	May-2021
44	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Jun-2022
45	Rio Oso Area 230 kV Voltage Support	PG&E	Sept-2022
46	Ripon 115 kV Line	PG&E	Completed
47	San Bernard – Tejon 70 kV Line Reconductor	PG&E	Dec-2019
48	San Jose-Trimble 115 kV Series Reactors	PG&E	Completed
49	Semitropic – Midway 115 kV Line Reconductor	PG&E	Mar-2021
50	South of San Mateo Capacity Increase	PG&E	Mar-2026
51	Stockton ‘A’ –Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	Completed
52	Trimble-San Jose B 115 kV Line Limiting Facility Upgrade	PG&E	Completed
53	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	Apr-2021
54	Vierra 115 kV Looping Project	PG&E	Jan-2023
55	Warnerville-Bellota 230 kV line reconductoring	PG&E	Mar-2024
56	West Point – Valley Springs 60 kV Line	PG&E	Jul-2020
57	Wheeler Ridge Voltage Support	PG&E	Apr-2021
58	Wheeler Ridge-Weedpatch 70 kV Line Reconductor	PG&E	Completed
59	Wilson 115 kV Area Reinforcement	PG&E	May-2023
60	Wilson 115 kV SVC	PG&E	Apr-2021
61	Wilson-Le Grand 115 kV line reconductoring	PG&E	Apr-2021
62	Tyler 60 kV Shunt Capacitor	PG&E	Dec-2022
63	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	Dec-2022
64	Gold Hill 230/115 kV Transformer Addition Project	PG&E	Dec-2024

No	Project	PTO	Expected In-Service Date
65	Jefferson 230 kV Bus Upgrade	PG&E	May-2022
66	Christie-Sobrante 115 kV Line Reconductor	PG&E	Dec-2022
67	Moraga-Sobrante 115 kV Line Reconductor	PG&E	On hold
68	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	Jun-2021
69	Tesla 230 kV Bus Series Reactor project	PG&E	Dec-2023
70	South of Mesa Upgrade	PG&E	Dec-2023
71	Giffen Line Reconductoring Project	PG&E	Apr-2024
72	East Marysville 115/60 kV Project	PG&E	Dec-2022
73	2nd Escondido-San Marcos 69 kV T/L	SDG&E	May-2021
74	2nd Pomerado - Poway 69kV Circuit	SDG&E	Apr-2026
75	Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously-approved New Sycamore - Bernardo 69 kV line)	SDG&E	Jan-2020
76	IID S-Line Upgrade	SDG&E	Dec-20
77	Miramar-Mesa Rim 69 kV System Reconfiguration	SDG&E	May-2020
78	Mission Bank #51 and #52 replacement	SDG&E	Complete
79	Reconductor TL 605 Silvergate – Urban	SDG&E	Jun-2027
80	Reconductor TL663, Mission-Kearny	SDG&E	Completed
81	Reconductor TL676, Mission-Mesa Heights	SDG&E	Completed
82	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	Sep-2021
83	Rose Canyon-La Jolla 69 kV T/L	SDG&E	Jan-2019
84	San Ysidro 69 kV Reconductoring	SDG&E	Feb-2020
85	Second Miguel – Bay Boulevard 230 kV Transmission Circuit	SDG&E	Completed
86	Sweetwater Reliability Enhancement	SDG&E	Dec-2027
87	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	Dec-2021
88	TL600: "Mesa Heights Loop-in + Reconductor	SDG&E	Jan-2025
89	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Dec-2024
90	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Jun-2021

No	Project	PTO	Expected In-Service Date
91	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	Sep-2021
92	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	Jun-2026
93	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Jun-2022
94	Laguna Bell Corridor Upgrade	SCE	Mar-2022
95	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-2020
96	Method of Service for Wildlife 230/66 kV Substation	SCE	Sep-2024
97	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	Jun-2021
98	Big Creek Rating Increase Project	SCE	Completed
99	Moorpark-Pardee No. 4 230 kV Circuit	SCE	Dec-2020
100	Tie line Phasor Measurement Units	PG&E, SCE, VEA	Dec-2020
101	Bob-Mead 230 kV Reconductoring	VEA	Dec-2020

Table 8.1-2: Status of Previously-Approved Projects Costing $50 M or More

No	Project	PTO	Expected In-Service Date
1	Delaney-Colorado River 500 kV line	DCR Transmission	Dec-2021
2	Suncrest 300 Mvar dynamic reactive device	NEET West	Dec-2019
3	Cottonwood-Red Bluff No. 2 60 kV Line Project	PG&E	May-2021
4	Gates #2 500/230 kV Transformer Addition	PG&E	Mar-2020
5	Kern PP 115 kV Area Reinforcement	PG&E	Dec-2023
6	Lockeford-Lodi Area 230 kV Development	PG&E	Jul-2025
7	Martin 230 kV Bus Extension	PG&E	Jan-2023
8	Midway – Kern PP #2 230 kV Line	PG&E	May-2023
9	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)[140]	PG&E	Dec-2026
10	Northern Fresno 115 kV Area Reinforcement	PG&E	Mar-2021
11	South of Palermo 115 kV Reinforcement Project	PG&E	Nov-2022
12	Vaca Dixon Area Reinforcement	PG&E	Feb-2022
13	Wheeler Ridge Junction Substation	PG&E	May-2024
14	Round Mountain 500 kV Dynamic Voltage Support	PG&E	Dec-2024
15	Gates 500 kV Dynamic Voltage Support	PG&E	Dec-2024
16	Artesian 230 kV Sub & loop-in TL23051	SDG&E	Mar-2020
17	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	Mar-2021
18	Alberhill 500 kV Method of Service	SCE	TBD
19	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	Dec-2021
20	Lugo-Mohave series capacitor upgrade	SCE	Dec-2021
21	Mesa 500 kV Substation Loop-In	SCE	Mar-2022
22	Harry Allen-Eldorado 500 kV transmission project	DesertLink LLC	May-2020

[140] The Midway-Andrew 230 kV Project has been renamed the North of Mesa Upgrade, and remains on hold. The south of Mesa component has been separated into a standalone project named the South of Mesa Upgrade, and approval of that project was recommended in the 2018-2019 Transmission Plan.

8.2 Transmission Projects found to be needed in the 2019-2020 Planning Cycle

In the 2019-2020 transmission planning process, the ISO determined that 10 transmission projects were needed to mitigate identified reliability concerns; no policy-driven projects were needed to meet the 60 percent RPS and no economic-driven projects were found to be needed. The summary of these transmission projects are in Table 8.2-1, Table 8.2-2, and Table 8.2-3.

A list of projects that came through the 2019 Request Window can be found in Appendix E.

Table 8.2-1: New Reliability Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Tulucay-Napa #2 60 kV Line Capacity Increase	PG&E	2023	$5-$10M
2	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	2024	$2-$4M
3	Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition	PG&E	2024	$3-$6M
4	Moraga 230 kV Bus Upgrade	PG&E	2024	$17M
5	Wilson-Oro Loma 115kV Line Reconductoring	PG&E	2026	$11.3-$22.7M
6	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	2025	$11.5-$23M
7	Salinas-Firestone #1 and #2 60 kV Lines	PG&E	2024	$19M-$38M
8	Gamebird 230/138 kV Transformer Upgrade	VEA/GLW	2021	$5M
9	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	2023[141]	$16M

[141] For reliability purposes the project is needed in 2025. However, the ISO understands that it could potentially be in-service as early as 2023 and the economic benefits of advancing the project in-service date to 2023 have been provided in Chapter 4.

Table 8.2-2: 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 2019-2020 Transmission Plan			

Table 8.2-3: 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 2019-2020 Transmission Plan			

8.3 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2019-2020Transmission 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 through reliance on demand side resources such as additional achievable energy efficiency and other existing or forecast preferred resources.

As set out in the 2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan, the ISO assesses the potential for existing and planned demand side resources to meet identified needs as a first step in considering mitigations to address reliability concerns.

The bulk of the ISO's additional and more focused efforts consisted of the development of local capacity requirement need profiles for all areas and sub-areas, as part of the biennial 10 year local capacity technical study completed as part of this transmission planning cycle. This provides the necessary information to consider the potential to replace local capacity requirements for gas-fired generation, depending on the policy or long term resource planning direction set by the CPUC's integrated resource planning process.

As well, the ISO studied numerous storage projects proposed as providing reliability and economic benefits, as set out in chapter 2 and 4. Given the circumstances of this year's limited planning needs, there were few opportunities for development.

In addition to relying on the preferred resources incorporated into the managed forecasts prepared by the CEC, the ISO is also relying on preferred resources as part of integrated, multi-faceted solutions to address reliability needs in a number of study areas.

LA Basin-San Diego

Considerable amounts of grid connected and behind-the-meter preferred resources in the LA Basin and San Diego local capacity area, as described in Sections 2.6.1 and 2.9.1, were relied upon to meet the reliability needs of this large metropolitan area. Various initiatives including the LTPP local capacity long-term procurement that was approved by the CPUC have contributed to the expected development of these resources. Existing demand response was also assumed to be available within the SCE and SDG&E areas with the necessary operational characteristics (i.e., 20-minute response) for use during overlapping contingency conditions.

Oakland Sub-area

The reliability planning for the Oakland 115 kV system anticipating the retirement of local generation is advancing mitigations that include in-station transmission upgrades, an in-front-of-the-meter energy storage project and load-modifying preferred resources. These resources are being pursued through the PG&E "Oakland Clean Energy Initiative" approved in the 2017-2018 Transmission Plan. Due to the increase in the area's load forecast and based on the latest Northern Oakland area load profile, the portfolio need has increased to about 36 MW and 173 MWh for 2024 from storage to sufficiently meet the current forecasted reliability need. This includes 7 MW and 28 MWh storage at Oakland L and 29 MW and 145 MWh storage at Oakland C. The approved project is expected to be in-service in 2022.

Moorpark and Santa Clara Sub-areas

As set out in section 2.7.5, the ISO is supporting the SCE's preferred resource procurement effort for the Santa Clara sub-area submitted to the CPUC Energy Division on December 21, 2017, by providing input into SCE's procurement activities and validating the effectiveness of potential portfolios identified by SCE. This procurement, together with the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double circuit towers which was approved in the ISO's 2017-2018 Transmission Plan, will enable the retirement of the Mandalay Generating Station and the Ormond Beach Generating Station in compliance with state policy regarding the use of coastal and estuary water for once-through cooling.

8.4 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 2017-2018 transmission are eligible for competitive solicitation.

8.5 Capital Program Impacts on Transmission High Voltage Access Charge

8.5.1 Background

The purpose of the ISO's internal High Voltage Transmission Access Charge (HV TAC) estimating tool is to provide an estimation of the impact of the capital projects identified in the ISO's annual transmission planning processes on the access charge. The ISO is continuing to update and enhance its model since the 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 November 2018. 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 estimates 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.

8.5.2 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. PTO input is sought each year regarding these values, recognizing that the ISO does not have a role regarding those costs.

To account for the impact of ISO-approved transmission capital projects, the tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

Draft Transmission Plan Editorial Note:

An estimate of future HV TAC rates is not available at this time. The ISO is currently in the process of updating the “starting point” for the HV TAC estimating tool to January 1, 2020. As well, the cost and timing of previously approved transmission is being reviewed. This is especially important as certain large projects can be capitalized in stages and also expenditures on projects that are receiving “CWIP-in-rate base” incentive treatment can impact rates before capitalization. Correct treatment of these issues is necessary to avoid double counting forecast impacts on rates.

Also, the ISO will review the assumptions used for escalation of O&M costs and capital maintenance as a percentage of gross plant, in addition to other capital costs which do not require ISO approval. As the ISO has indicated previously, however, the focus in this analysis is the impact of the planning decisions in the transmission plan itself.

The ISO is targeting updating these results for inclusion in the revised draft transmission plan to be presented to the ISO Board of Governors in March.