2018-2019

TRANSMISSION PLAN

California ISO

March 29, 2019
Version: Board Approved-Updated

Foreward to Board-Approved 2018-2019 Transmission Plan

At the March 27, 2019 ISO Board of Governors meeting, the ISO Board of Governors approved the 2018-2019 Transmission Plan.

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Executive Summary

The California Independent System Operator Corporation's 2018-2019 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. The latter has become even more critical than in the past, as the grid planning requirements are shifting from focusing on accessing renewable generation, to also include accessing the necessary integration resources to effectively operate the grid in a future of high volumes of renewable generation and a declining natural gas-fired generation fleet.

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. Key trends in this year's transmission plan include the following:

- The progress made through past transmission plans to address reliability issues overall and planning for the retirement of once-through-cooling generation – including the San Onofre Nuclear Generating Station – continue to result in relatively modest transmission reinforcement needs. Despite relatively flat load forecast growth currently projected over the planning period, new reliability challenges have emerged driving the need for system reinforcements on a case-by-case basis, however;
- Consistently declining load forecasts issued annually by the CEC – especially for the one-in-ten peak load forecasts affected by weather normalization processes – led to a three year comprehensive program of re-evaluation of previously-approved upgrades ending with the 2017-2018 transmission planning process. The downward pressure on peak demand load growth and energy consumption was compounded by higher than anticipated development of behind-the-meter solar photovoltaic generation. Behind-the-meter solar has reduced the summer peak loads traditionally occurring in mid-day in

many parts of the state and is steadily shifting them towards the unaffected load levels occurring later in the day when solar production has dropped off. The 2018-2019 effort focused on reviewing several projects that required additional study and consideration before final determinations could be made. As in the the 2017-2018 planning cycle, this year's efforts entailed both canceling and re-scoping projects to more effectively and efficiently meet needs. Project reviews will continue going forward in future planning cycles on a case-by-case basis as warranted;

- 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 2018-2019 transmission plan afforded few opportunities for these solutions;
- Transmission needed to access renewable generation development to achieve the state's 33 percent RPS goal by 2020 and 50 percent RPS goal by 2030 have largely been identified and are moving forward. This year's planning studies included reliability and economic studies performed meeting 50 percent RPS goals. Given past years' studies of transmission system capacity, and additional approvals of policy-driven transmission not being needed to achieve 50 percent RPS, policy analysis this year was performed on a sensitivity basis for portfolios achieving approximately 57 percent RPS levels. New transmission requirements to achieve 50 percent RPS standards were greatly reduced from expectations only a few years ago due to the much higher than anticipated development of behind-the-meter solar generation. While this generation does not count directly towards RPS measures, it reduces the amount of energy served by the grid. With 2030 RPS requirements now shifting to a 60 percent RPS goal, direction from the CPUC's integrated resource planning process for the 2019-2020 planning cycle is anticipated to be consistent with the higher RPS goal;
- In the course of the 2018-2019 planning cycle, the stakeholders submitted frequent feedback on renewable policy-related issues critical of the resource planning assumptions and outcomes provided by the CPUC to the ISO for transmission planning purposes. This feedback included comments critical of the consideration of energy-only renewable generaton to meet a portion of future RPS requirements. The ISO is accordingly continuing its coordination with the CPUC staff, and also referred these stakeholders to the appropriate CPUC proceedings;
- The 2018-2019 transmission planning cycle was heavily tasked with informational studies to help inform future transmission planning at the ISO and resource planning at the CPUC. These studies took the form of informational "special studies" such as the consideration of improving access to hydro generation in the Pacific Northwest, or by significantly increasing the scope of studies such as the 10 year Local Capacity Technical Study to not only establish local capacity requirements, but identify alternatives. Further, a subset of those alternatives were fed into the 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 taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements;
- Significant development interest in new transmission, including proposals for energy storage facilities seeking regulated cost of service revenue streams, was shown by potential project sponsors seeking to press ahead of the pace of resource planning. An impressive number of requests for consideration of proposed reliability-driven and economic-driven proposals were submitted, with the majority being examined in this planning cycle. The basis for many of the submissions were project sponsor assumptions regarding resource planning outcomes that went beyond the direction received from the CPUC given the current status of its integrated resource planning process, or views on planning standards that exceeded the ISO's approved planning standards. As well, as noted earlier, the ISO applied conservative (*i.e.* "modest") values to the benefits associated with reducing local gas-fired generation requirements due to the uncertainty regarding the need for those resources for system or flexible requirements; this also impacted the ISO's assessments of the economic viability of many of these projects;
- 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;
- The ISO and respective neighboring planning regions received six Interregional Transmission Project submissions for consideration in this transmission planning cycle, which is the first year of the biennial interregional coordination process the ISO has established with our neighboring planning regions. Three of these were carried forward and studied in the economic study phase of this year's transmission planning prcess to assess if they could provide more efficient or cost-effective solutions than regional projects for meeting identified needs. The economic assessments of these projects are affected by the same considerations discussed above for regional proposals, and accordingly none have been selected for approval in this planning cycle; and,
- Overall, the 2018-2019 Transmission Plan includes a modest increase in new reliability needs, continued refinement and downsizing of previously approved projects that required further analysis from the 2017-2018 transmission planning cycle, and a great deal of forward-looking studies and study methodology refinements to inform future

transmission planning processes, including CPUC integrated resource planning issues. The ISO's efforts to increase opportunity for non-transmission alternatives, particularly preferred resources and storage, continues to be a key focus of the transmission planning analysis – which in this planning cycle focused more on developing supportive tools and methodologies than the assessment of these resources due to the relatively modest needs for transmission system reinforcement.

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

- The ISO identified 11 transmission projects with an estimated cost of approximately $607.4 million as needed to maintain transmission system reliability. Several of these projects also entail a combination of preferred resource procurement and transmission upgrades working together to meet those needs;
- In reviewing previously approved projects in the PG&E service territory that were identified in the last planning cycle as needing more review, six projects are recommended to be canceled, paring between $440 million and $550 million from the ISO transmission capital program estimated costs. 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;
- Given 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 a 50% RPS – efforts focused on sensitivity studies for higher levels of RPS based on the CPUC's IRP reference plan 42 MMT portfolio, and those studies did not identify the need for additional policy-driven transmission to meet that portfolio;
- Two economic-driven transmission project with an estimated capital cost of $37 million is recommended for approval, providing energy cost savings by alleviating local congestion and eliminating the need for local capacity requirements;
- 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. Two transmission projects in this transmission plan include facilities eligible for competitive solicitation through the ISO's competitive solicitation process.

Progress also continued 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. The ISO's informational special studies undertaken in the planning process were primarily focused on supporting future resource planning processes.

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 2017-2018 planning cycle, for example, began in January 2017 and the 2017-2018 Transmission Plan was approved in March 2018.

Storage as a Transmission Asset accessing Market Revenues

The bulk of the grid-connected storage in California has been developed as maket-based resources. While the ISO has long recognized and studied the possibility of strorage also being acquired as a transmission asset, the ISO understanding was that such storage was precluded from participating in the electricity market and accessing market revenues. On January 19, 2017, FERC issued its policy statement “Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery” clarifying that such electric storage resources could receive cost-based rate recovery for certain services (such as transmission or grid support services or to address other needs identified by an RTO/ISO) while also receiving market-based revenues for providing separate market-based services, subject to a number of issues and concerns being addressed.

Accordingly, the ISO began a stakeholder initiative to address the implementation concerns set out in the policy statement. This initiative has been placed on hold, however, as a number of related and impactful issues are currently being explored for storage more generally through a separate and ongoing initiative – the ISO's Energy Storage and Distributed Energy Resources (ESDER 4) initiative. Nonetheless, the ISO has assessed the economic benefits the bulk of these submitted projects could provide, assuming that if appropriate, procurement could be investigated as market-based local capacity resources through CPUC procurement processes.

Planning Assumptions and State Agency Coordination

The 2018-2019 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 long term procurement plan (LTPP) proceedings, now replaced by the integrated resource planning (IRP) proceedings conducted by the CPUC, 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 a decision[1] on February 8, 2018 at the end of the first year of the 2017-2018 Integrated Resource Planning cycle, which adopted the integrated resource planning process and also provided resource planning assumptions to the ISO. A 50 percent RPS portfolio, based on the CPUC's "default" scenario and aligned with the SB 350 goal of 50 percent RPS by 2030 was communicated for purposes of reliability planning. This portfolio was also used for economic study purposes. Anticipating higher renewable generation requirements going forward, the CPUC communicated a portfolio based on its "42 MMT scenario" that results in approximately a 57 percent RPS as a sensitivity portfolio for policy-driven planning efforts. The CPUC declined to provide a "base" portfolio for actual project approval purposes, which was considered unnecessary, given past transmission planning studies and steadily declining estimates of the amount of grid-connected renewables necessary to achieve the 50 percent by 2030 goal. The 42 MMT scenario ultimately proved to be more

[1] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

aligned with the target of 60 percent RPS established by SB 100, which came into effect on September 10, 2018 and which will be taken into account in future planning cycles.

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 11 reliability-driven transmission projects representing an investment of approximately $607.4 million in infrastructure additions to the ISO controlled grid, all of which are located in the PG&E service territory. These are comprised of 9 smaller projects each less than $50 million totaling $168 million and two dynamic voltage support projects[3] totaling $440 million.

The two dynamic reactive support projects are eligible for the ISO's competitive solicitation process.

In addition to the identification of new reliability requirements, the ISO also reviewed a number of previously approved transmission projects in the PG&E service territory, which had been identified in previous planning cycles as needing further evaluation. These reviews looked not only at canceling projects where changing circumstances no longer supported the need for the project, but re-scoping of projects where needs still existed and changing circumstances could lead to more effective and economic solutions:

[2] The 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, March 30, 2018, is available at: http://www.caiso.com/Documents/Final2018-2019StudyPlan.pdf

[3] Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place.

- Six transmission projects with cost estimates totaling $440 to $550 million that were found to be no longer required and are recommended to be canceled.
- One project will continue to be on hold pending reassessment in future cycles.

Going forward, individual projects will continue to be considered for review on a case by case basis, as the need arises.

Renewables Portfolio Standard Policy-driven Transmission Assessment

As noted above, the CPUC's input was communicated via a decision[4] on February 8, 2018 at the end of the first year of the 2017-2018 Integrated Resource Planning cycle, which adopted the integrated resource planning process and also provided resource planning assumptions to the ISO. Anticipating higher renewable generation requirements going forward, the CPUC communicated a portfolio based on its "42 MMT scenario" that results in approximately a 57 percent RPS as a sensitivity portfolio for policy-driven planning efforts. The CPUC declined to provide a "base" portfolio for actual project approval purposes, which was considered unnecessary, given past transmission planning studies and steadily declining estimates of the amount of grid-connected renewables necessary to achieve the 50 percent by 2030 goal.

The ISO has accordingly performed policy-driven study assessments of the 42 MMT scenario as a sensitivity with the results being provided to the CPUC for future resource planning purposes, and the ISO is not recommending any new transmission solutions at this time for policy purposes.

A summary of the various transmission elements already underway for supporting California's renewables portfolio standard is shown in Table 1. These elements are composed of the following categories:

- Major transmission projects that have been previously-approved by the ISO and are fully permitted by the CPUC for construction;
- Additional 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.

[4] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

Table 1.1-1: Elements of 2018-2019 ISO Transmission Plan Supporting 50% Renewable Energy Goals

Transmission Facility	In-Service Date
Transmission Facilities Approved, Permitted and Under Construction	
West of Devers Reconductoring	2021
Sycamore – Penasquitos 230 kV Line	Completed
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	2020
Warnerville-Bellota 230 kV line reconductoring	2023
Wilson-Le Grand 115 kV line reconductoring	2020
Suncrest 300 Mvar SVC	2019
Lugo-Mohave series capacitors	2020
Additional Policy-Driven Transmission Elements Recommend for Approval	
None identified in 2018-2019 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.

Due to a convergence of circumstances, the ISO undertook far more economic planning analysis than typical, or set out in the ISO tariff. Beyond screening congestion results to select key focus areas for economic studies:

- The ISO received a number of economic study requests;
- A number of proposed reliability projects cited material economic benefits that could warrant moving forward;
- Several interregional transmission projects were submitted;
- In conjunction with the expanded 10-year local capacity technical study the ISO undertook in this planning cycle – examining not only the need and the characteristics of the need but alternatives to reduce local gas-fired generation capacity requirement - the ISO selected a subset of local capacity areas for detailed economic analysis where options appeared potentially viable.

As well, a number of the above proposals and submissions overlapped, necessitating a comprehensive approach. While the ISO tariff allows the ISO to limit the number of economic evaluations to five or less, the ISO studied proposals in 12 study areas, considering 25 alternatives overall, and with the largest area study addressing 8 separate stakeholder-submitted proposals.

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, 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 based their submissions on assumptions went beyond the policy direction received from the CPUC given the current status of its integrated

resource planning process, that were far less conservative in valuing local capacity requirement reductions, or that applied planning standards that exceeded the ISO's approved planning standards.

The project sponser and stakeholder views on these issues are being communicated to the CPUC, as appropriate, and being considered regarding the need to address some of the concerns in stakeholder initiatives. However, these issues are not reasonably addressed inside the planning process itself which is conducted on the basis of the tariff and standards currently in effect.

In summary, two projects were found to be needed as economic-driven projects in the 2018-2019 planning cycle:

- Giffen Line Reconductoring Project, estimated to cost less than $5 million, to reduce generator pocket congestion.
- Pease LCR Reduction Project, the looping in of the Pease-Marysville 60 kV line into the East Marysville 115 kV substation, estimated to cost $32 million and eliminating the need for local capacity requirements in the Pease sub-area.

Several paths and related projects will be monitored in future planning cycles to take into account improved hydro modeling, further consideration of suggested changes to ISO economic modeling, and further clarity on renewable resources supporting California's 50 percent renewable energy goals.

Interregional Transmission Coordination Process

The ISO's 2018-2019 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. This cycle reflects the complete transition from old process to new, taking into account the status of the policy drivers and the progress achieved in implementing the new interregional processes.

Six interregional transmission projects were submitted into the bieenial process. Of those, three were screened and fed into the ISO's economic study process for further analysis.

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. 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. None of the three projects studied in this cycle were found to be more economic and cost-effective solutions than regional proposals for meeting identified needs.

Non-Transmission Alternatives and Preferred Resources

The ISO has routinely emphasized exploring preferred resources[5] 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[6] and continued efforts to refine understanding of the necessary characteristics for resources such as slow response demand response to provide local capacity[7], the ISO's applications have expanded in this planning cycle beyond the ISO's original methodology[8] set in place some years ago. Further, in this 10-Year Local Capacity Technical Study developed in this year's transmission planning cycle, 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.

Reliance on Gas-fired Generation in Local Capacity Areas

The ISO undertook to conduct additional analysis of local capacity requirements in local capacity areas, to help inform resource planning issues. First, the 10-Year Local Capacity Study conducted as part of this 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

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5 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.

6 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.

7 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.

8 "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.

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.

Northwest Hydro

The ISO 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. The request was received by letter[9] on February 15, 2018, requesting that the ISO undertake specific transmission sensitivity studies considering the potential to increase the transfer of low-carbon supplies to and from the Northwest. This resulted in an extensive coordination effort among state agencies and a host of potentially affected owners and operators, as well as other stakeholders. The ISO acknowledges and appreciates the broad support and effort on behalf of many that went into that study. Please refer to chapter 7.

Longer term system and Flexible Capacity Requirements

The ISO has updated in the transmission plan the system-wide results from prior years' PLEXOS studies of the need for the existing gas-fired generation fleet for system capacity and flexibility requirements, as well as the production cost modeling benefits of large (hydro) storage. The system and flexibility requirements studies also help inform the ISO's participation in the CPUC's integerated resource planning processes. Note that the storage studies were limited to production cost modeling, and not a comprehensive review, as storage projects were also studied as economic study requests in the transmission planning process itself.

Note that in previous planning cycles, the ISO undertook frequency response studies and reported on associated modeling improvement efforts as a special study. Given the significance of that work, these efforts have now been moved to an ongoing study process inside the annual planning cycle despite not being a tariff-based obligation.

The additional informational "special" studies conducted in parallel with the transmission planning cycle provide additional clarity on issues that need to be considered in developing future policy direction or further analysis.

Conclusions and Recommendations

The 2018-2019 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 13 transmission projects, estimated to cost a total of approximately $644.4

[9] Letter of February 15, 2018 to Steve Berberich, ISO, http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf.

million, as needed to maintain the reliability of the ISO transmission system, meet the state's renewable energy mandate, and deliver material economic benefits.

The ISO has also identified 6 previously approved transmission projects that are recommended to be canceled, and one remains on hold requiring further evaluation in future planning cycles before applications proceed for construction permitting.

The additional informational studies conducted in parallel with the transmission planning cycle provide additional clarity on issues that need to be considered in developing future policy direction or further analysis.

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 2018-2019 planning cycle.

As in recent transmission planning cycles, the ISO has prepared this plan in the larger context of supporting important energy and environmental policies and assisting the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system. That future is not only being planned on the basis of transitioning to lower emission sources of electricity, but on 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 has also had to consider and adapt 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.

The transition to a generation fleet with significantly increased renewables penetration and “duck curve” issues, combined with increasing variability in net sales patterns due to behind-the-meter generation and other load-modifying behaviors, are both driving the ramping needs and flexible generation requirements within the electricity market, and are having a pronounced impact on the transmission grid as flow patterns change on a daily and seasonal basis from traditional patterns. As these other changes, including growth in behind-the-meter generation, have been occurring more rapidly than originally anticipated only a few short years ago, both the techniques relied upon to assess system needs and certain previously planned projects themselves continue to evolve.

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 2018-2019 Transmission Plan is heavily influenced by the success in past transmission planning cycles to address historical reliability issues as well as those triggered by more recent events, the progress made toward meeting 50 percent renewable portfolio standard (RPS) goals, and the ongoing development of various state agency processes and proceedings to address escalating renewable energy targets established by SB 350. Goals established in the more recent SB 100 will be taken into account through further coordination with state agencies, moving towards the 2019-2020 trasnmission planning cycle. 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. A transmission plan may also identify any transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects, or provide for merchant transmission projects. 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 summer on-peak and off-peak system 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.

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. For example, the ISO previously determined that a combination of transmission upgrades and preferred resources in concert would provide the most effective local capacity requirement replacement for the Oakland Generation Station, should that plant retire, and also meet the future needs in the Santa Clara sub-area as generation employing once-through-cooling in that sub-area retires. 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.

To increase awareness of the role of preferred resources, section 7.3 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.

This transmission plan documents ISO analyses, results, and mitigation plans.[10] 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 been largely established, and the focus in this plan shifted to the objectives of SB 350 – in particular, the 50 percent RPS by 2030 objective. Accordingly, the California Public Utilities Commission (CPUC) provided to the ISO renewable generation portfolios reflecting 50 percent RPS[11] for reliability and economic study purposes, and a higher portfolio representing approximately 57 percent[12] as a sensitivity case for policy-driven analysis. These portfolios pre-dated, but are aligned with the direction subsequently established with SB 100[13] becoming law in September, 2018. The ISO expects that the results of this sensitivity study will be helpful in future CPUC integrated resource planning efforts that will also take into account SB 100 direction.

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 undertook in this planning cycle a

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[10] 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.

[11] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

[12] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

[13] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

more in-depth analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs.

In addition to undertaking the aforementioned analyses required by the tariff, the ISO also conducted a “special study” at the request[14] of the chairman of the California Energy Commission (CEC), and the president of the CPUC, investigating the potential benefits of improved transfer capability between the ISO and hydro resources in the Pacific Northwest. Please refer to chapter 7.

1.2 Impacts of the Industry Transformation

As state efforts continue to reduce the carbon footprint and other environmental impacts of the electricity industry, 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 is therefore having to consider 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 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.

[14] Letter of February 15, 2018 to Steve Berberich, ISO, http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf.

The rest of this subsection discusses a number of the emerging issues and factors together with the inputs considered in this transmission planning cycle, as well as the 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.

1.2.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

Base Forecasts

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:

- Declining net peak loads have led to the review of several previously-approved load growth-driven transmission projects, particularly in the PG&E area[15].
- 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. This is an issue that has been progressing through subsequent IEPR processes, having first been noted in the CEC's 2015 effort.

The ISO's 2017-2018 Transmission Plan described in detail the progress made year-after-year in coming to terms with the refinements in forecasting techniques to address the issue, and the steps the ISO took to accommodate the evolution of the issue in each transmission plan.

These efforts have now resulted in the development of the California Energy Demand Forecast 2018-2028 (CED 2017) that the ISO is using in the 2018-2019 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

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

system needs and the effectiveness of use-limited preferred resources as part of meeting those needs.

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 energy efficiency programs driving demand in one direction, but decarbonizing other sectors such as transportation potentially causing increased demand in new and previously unseen consumption patterns.

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.

1.2.2 Resource Planning

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.

Regarding the former, 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 TPP. The portfolio development has transitioned from the CPUC's previous long term procurement plan proceedings to the current integrated resource planning (IRP) proceedings.

Integrated Resource Planning Process

The CPUC issued a decision[16] on February 8, 2018 at the end of the first year of the 2017-2018 Integrated Resource Planning cycle, which adopted the integrated resource planning 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.

The IRP process took into account the specific objectives established for the electricity industry through the Clean Energy and Pollution Reduction Act of 2015, and the broader state objectives

[16] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF

regarding reducing greenhouse gas emissions that are expected to reach beyond the requirements already set for the electricity industry.

Through the 2017 IRP effort, the CPUC established a 50 percent RPS “default” scenario that, as directed in the decision, was subsequently transmitted to the ISO to be used in the 2018-2019 TPP reliability assessment.

Further, a statewide electric sector GHG reduction target of 42 million metric tons (MMT) by 2030 was selected as the basis for a “42 MMT Scenario” reference plan for the load serving entities to consider in developing their individual plans as part of the 2018 process. This 42 MMT Scenario portfolio was transmitted to the ISO to be used as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission solutions based on the Reference System Plan. No base portfolio was transmitted to the ISO for use in the 2018-2019 TPP policy-driven assessment, *e.g.*, the CPUC direction enabled analysis for information purposes, but not as the basis for approval of policy-driven transmission in this 2018-2019 transmission planning cycle. The decision also noted the expectation that once the “preferred system plan” is adopted through the 2018 IRP effort, it will be utilized as a policy-preferred portfolio in the subsequent transmission planning process to identify Category 1 policy-driven transmission needs. The ISO expects that portfolio to also be more aligned with the 60% RPS goal set out in SB 100.

Clean Energy and Pollution Reduction Act of 2015

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

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

SB 350 creates a pathway to increased levels of renewable generation and lower greenhouse gas emissions.

The 100 Percent Clean Energy Act of 2018

On September 10, 2018 Governor Jerry Brown signed into law SB 100, the 100 Percent Clean Energy Act of 2018 also authored by Senator Kevin De León.

Among other provisions, SB 100 built on existing legislation including SB 350 and revised the above-described legislative findings and declarations to state that the goal of the program is 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 requires that retail sellers and local publicly owned electric utilities procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kilowatthours of those products sold to their retail end-use customers achieve 44 percent of retail sales by December 31, 2024, 52 percent by December 31, 2027, and 60 percent by December 31, 2030. This bill also states that it is the policy of the state 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. The bill requires that the achievement of this policy for California not increase carbon emissions elsewhere in the western grid and that the achievement not allow resource shuffling.

As this legislation came into effect well after the CPUC's 2017 integrated resource planning activities and the ISO's analysis of the renewable generation portfolios provided by the CPUC were underway, the specific measures set out in SB 100 were not incorporated directly into the 2018-2019 transmisson planning cycle. However, as noted earlier, the CPUC's 42 MMT scenario renewable generation portfolios achieved a higher GHG goal than the 50 percent RPS requirement by 2030, and is approximately equivalent to a 57 percent RPS.

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. Reliance on gas-fired generation in local capacity areas, and in particular in disadvantaged communities, continues to be of increasing concern.

The initial 2017-2018 two-year cycle of the CPUC's integrated resource planning process did not address potential gas-fired generation retirement beyond the known retirements and the retirement plans of generation currently relying on once-through-cooling. The ISO's planning assumptions in the 2018-2019 cycle took a somewhat more aggressive approach by maintaining the assumptions in previous plans – 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. However, it was recognized that a transmission plan recommendation for a project's approval based solely on the more aggressive retirement assumptions would be unlikely, and would need to be considered on a case-by-case basis.

Continuing with past efforts, 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 – from both a local and system perspective.

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. The studies did identify potential system-wide reserve margin issues emerging in the 2028 time frame with as little as 1000 to 2000 MW of retirements beyond the current planned retirements. The system-wide implications have been updated in this planning cycle and are discussed in chapter 7. These studies are also part of the ISO's analysis supporting the CPUC's integrated resource planning process, in which these issues are being considered and addressed.

The downward economic pressure on the gas-fired generation fleet not under long-term contract has also raised local capacity concerns and renewed focus on finding alternatives that would reduce local resource capacity requirements in specific local capacity areas. For example, on January 11, 2018, the CPUC adopted Resolution E-4909, authorizing PG&E to procure energy storage or preferred resources to address local deficiencies and ensure local reliability, which resulted in 567.5 MW of battery storage being approved by the CPUC on November 8, 2018. The ISO is working with utilities to incorporate energy storage, preferred resources, and transmission upgrades to achieve an overall comprehensive and economic solution to local needs. While targeting alternatives to achieve overall reductions in local capacity requirements may be an area of new policy direction from the state, the ISO is considering how to address these concerns as potential economic studies in this and future planning cycles. In particular, the ISO undertook a more comprehensive study of local capacity areas in 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. Please refer to chapter 5 and chapter 6.

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 the current and future economics of existing local capacity resources, the renewable integration benefits the generation may provide and the system need to retain that generation, and other criteria and characteristics that can make certain generators in the existing fleet more or less advantageous in prioritizing study efforts and in committing to alternatives to reduce local capacity needs. Proximity to disadvantaged communities must also be taken into account.

Coordination with CPUC Resource Adequacy Activities

Along with other drivers, the shifting of the net sales peak to later hours – largely due to the higher than once forecasted development 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. While expanding from focusing on system and local capacity to also incorporate flexibility, *e.g.*, ramping, needs helps address certain issues, resources need to be considered in the context of the load profiles being served, and the other resources being acquired – which has led to the incorporation of effective load carrying capability methodologies being pursued by the CPUC.

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."*[17]

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 the resource adequacy program, the ISO proposed the CPUC implement multi-year resource adequacy procurement requirements for system, local and flexible resources. The ISO also recommended that the CPUC (1) modify its adopted effective load carrying capacity values to ensure proper counting of resource adequacy resources and their contribution to reliability, (2) adjust system resource adequacy demand forecasts based on increased load variability, and (3) set local resource adequacy requirements to account for availability-limited resources. In all, these proposals are designed to ensure resources have the right capabilities and are available when and where needed to meet system needs across the year. In 2018, the CPUC decided to implement a multi-year procurement requirement for local resource adequacy capacity. As a result, the primary focus of the CPUC resource adequacy proceeding was on developing implementation details for the new multi-year resource adequacy framework. The ISO will continue to participate in the CPUC's resource adequacy proceeding to ensure that a workable multi-year procurement framework is adopted and to advance other program improvements.

In parallel, the ISO is conducting a review of existing ISO "backstop" procurement mechanisms. On January 12, 2018, the ISO filed a tariff amendment with the Federal Energy Regulatory Commission to improve its "risk of retirement" capacity procurement mechanisn (ROR CPM) designation process – which addresses an identified need a year hence, but where the

[17] *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.

generation is at risk of retiring during the intervening year – by making it more efficient and workable. Among other things, the proposed tariff amendments establish a revised framework that will allow the ISO, in specific circumstances, to signal its intent to designate a resource needed for reliability earlier in the year. On April 12, 2018, FERC rejected the ISO's January 12, 2018 filing to enhance the process for ROR CPM designations. One of the key features of the ROR CPM proposal was to create a new window each spring, in addition to the existing window each fall, for resources to request a ROR CPM designation. In its order FERC found that a spring window could result in front-running the RA process, price distortions and interference with bilateral RA procurement. In its order FERC noted that the ISO had initiated a stakeholder process to review RMR and CPM issues and strongly encouraged the ISO and stakeholders to adopt a holistic, rather than piecemeal, approach and encouraged the ISO to propose a package of comprehensive reforms.

Following the FERC order, the ISO included in its RMR and CPM Enhancements stakeholder initiative the substantive issues that were considered in the ROR CPM process enhancements initiative. The RMR and CPM Enhancements initiative will consider 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 under discussion are:

- Merge ROR CPM procurement and RMR procurement into one procurement mechanism under the RMR tariff.
- Consider modifications to CPM compensation above the CPM soft-offer cap.
- Make RMR units subject to a must offer obligation.
- Update the rate of return for RMR resources.
- Provide flexible and system RA credits from RMR resources.
- Lower banking costs for RMR invoicing.
- Streamline and automate RMR settlement process.

The ISO has held working group meetings on May 30, 2018, August 27, 2018, and November 1, 2018 to gather input from stakeholders. The working group meetings were well attended, including attendance by CPUC staff. Stakeholders discussed the various items that are within the scope of the initiative. The ISO issued a draft final proposal in January 2019 and has targeted taking a proposal to the ISO Board of Governors in March 2019.

As well, on October 29, 2018, the FERC approved a limited interim change to the pro forma RMR agreement that effective September 1, 2018, applies to new RMR designations and allow 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. The right to immediately re-designate would not apply to RMR resources under RMR agreements currently in effect.

Impact of Evolving Resource Fleet on Transmission Assessments supporting Resource Adequacy Programs

The same drivers leading to the development of effective load carrying capability (ELCC) methodologies in considering the usefulness of particular resources in meeting load requirements also affect ISO transmission assessment methodologies that underpinned resource planning efforts. In particular, 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. The shift 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. The ISO has addressed the impact by augmenting its existing deliverablity methodology – which from a technical tools perspective has not materially changed – by identifying the need for additional scenarios to be considered in the study process and revisiting certain study assumptions to ensure reasonable results meeting the original objectives of the deliverablity assessments. Please refer to chapter 3.

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, 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."[18] This effort is also expected to consider if and how the transmission service necessary to ensure access to flexible capacity needs to be assessed — the "flexible capacity" equivalent of deliverability assessed for local and system capacity.

Past special study efforts and other initiatives have, in addition to the above, have 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. 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.

Non-Transmission Alternatives and Preferred Resources

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

The ISO's approach, as noted in 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 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,[19] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[20] — 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

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[18] 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.

[19] "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.

[20] 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.

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.[21] In addition, the ISO has developed a methodology as discussed in section 6.6 of the 2017-2018 ISO 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.

Although the Board does not "approve" non-transmission (*e.g.*, preferred resource capacity) solutions, the ISO can identify these solutions as preferred solutions to transmission projects and then work with the appropriate local regulatory authorities to support their development. This is particularly viable when the transmission solution does not need to be initiated immediately and where time can be set aside to explore the viability of non-conventional alternatives first while relying on a more conventional transmission alternative as a backstop.

In examining the benefits preferred resources can provide, the ISO relies heavily on preferred resources identified through various resource procurement proceedings as well as proposals received in the request window and other stakeholder comment opportunities in the transmission planning processes.

High potential areas:

Each year's transmission plan identifies areas where reinforcement may be necessary in the future, but immediate action is not required. The ISO expects developers interested in developing and proposing preferred resources as mitigations in the transmission planning process to review those areas and highlight the potential benefits of preferred resource proposals in their submissions into utilities' procurement processes. To assist interested parties, each of the planning area discussions in chapter 2 contain 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.

[21] *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.

Energy storage:

In addition to considering energy storage as a potential transmisision solution, the ISO also considers storage solutions under the overall preferred resource umbrella in transmission planning. The ISO is also 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. An additional refinement is the ISO studies of the benefits of large scale energy storage can have on addressing flexible capacity needs. This analysis began in the 2015-2016 transmission planning cycle, and was updated and expanded, including consideration of locational benefits, in the 2016-2017 cycle. In 2017, the ISO conducted additional analysis as an extension of the 2016-2017 planning cycle. This work has helped inform the ISO's participation in CPUC integrated resource planning proceedings, and documenting these results in the ISO's transmission plans helps provide broader visibility to stakeholders of these results.

Storage also played a major role in the assessment of the viability of preferred resource alternatives in the Moorpark Sub-area Local Capacity Alternative Study, as well as the Oakland Clean Energy Initiative and the Dinuba storage project approved in the 2017-2018 Transmission Plan.

This has led to the evaluation of a number of specific storage project submissions in this 2018-2019 Transmission Plan looking at both local and system benefits, as discussed in section 4.9.

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 potential for electric storage to play a growing role in supporting the transmission system, as well as a growing role supporting renewable integration.

Existing 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 resource to participate more broadly in providing value to the market. In the case of electric storage resources, procurement also may result in distribution-connected resources and behind-the-meter resources that do not participate in the ISO's wholesale markets. In the system resource context, the storage resource would be functioning primarily as a market resource, with contractual obligations to the off-taker to provide certain services supporting local reliability.

The ISO has also studied in past planning cycles a number of potential applications of energy storage as transmission assets, and in that evaluation, assumed the energy storage would not be able to provide other market services and access other market-based revenue streams. This paradigm shifted on January 19, 2017, when FERC issued its policy statement "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery"[22] clarifying the ability of electric storage resources to receive cost-based rate recovery for

[22] *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.

transmission or grid support services while also receiving market-based revenues for providing separate market-based services.

The ISO's activities resulting from the policy statement are discussed in section 1.2.3 below.

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.[23]

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.

1.2.3 Storage as a Transmission Asset

The ISO has studied in past planning cycles a number of potential applications of energy storage as transmission assets, and in that evaluation, assumed the energy storage would not be able to provide other market services and access other market-based revenue streams.

The ISO had relied on the Federal Energy Regulatory Commission's (FERC's) guidance that transmission assets – and in particular electric storage as a transmission asset – could serve a transmission function such as addressing thermal loading and providing voltage support. In the context of the ISO's transmission planning process, the ISO previously studied a number of potential electric storage projects as reliability solutions in the form of transmission asset models. Consistent with past FERC direction, the ISO assumed that such projects, as transmission assets, were precluded from participating in energy or ancillary services markets.

On January 19, 2017, FERC issued its policy statement "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery" to:

> *"provide guidance and clarification regarding the ability of electric storage resources to receive cost-based rate recovery for certain services (such as transmission or grid support services or to address other needs identified by an RTO/ISO) while also receiving market-based revenues for providing separate market-based services.* [24]*"*

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[23] 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.

[24] *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.

The policy statement also sets out a number of concerns that would need to be addressed in order to enable this outcome.

Accordingly, the ISO began a stakeholder initiative to address the implementation concerns set out in the policy statement. This initiative considers using electric storage to provide certain grid services as a transmission facility, with all or a portion of costs recovered through the transmission access charge. This initiative is exploring issues around electric storage resources seeking to receive cost-based rate recovery for providing transmission services as a transmission asset and receiving market-based revenues for providing separate non-transmission, market-based rate services.

The ISO had initially targeted a first quarter of 2019 Board of Governor decision for the results of the initiative. However, despite the significant progress made over the last year, the ISO identified that this initiative needed to be held until broader market participation issues for storage and other non-generator resources (NGRs) can be developed within the ongoing fourth iteration of the ISO's Energy Storage and Distributed Energy Resources (ESDER 4) initiative. A central issue for SATA awards – to maintain reliability via maintaining a reliable state of charge in realtime when a SATA is called upon for market participation – also needs to be explored for storage functioning as a market-based local capacity resource. In addition, bidding and cost allocation rules would need adjustment to allow for optimizing costs between charging and discharging—necessitating assigning opportunity costs to storage, which are not currently available in the NGR framework.

Nonetheless, the ISO's evaluation of ratepayer benefits can consider market revenues in the context of storage participating as a market resource under a power purchase agreement, when considering storage also addressing a transmission need as a local capacity resource. Please refer to chapter 4.

1.2.4 System Modeling, Performance, and Assessments

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 the previous planning cycle and continued through this cycle in 2017 reaffirmed the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. (Refer to section 6.4.) 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 will be continuing with its efforts, in coordination with the Participating Transmission Owners, to collect this important information, as well as pursuing additional regulatory measures to ensure validated models are provided by generation owners.

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. The high expectations of preferred resources being part of a comprehensive solution, which also includes transmission reinforcement and conventional generation, has resulted in the ISO analyzing the role of preferred resources in that area.

Successfully mitigating reliability concerns remains dependent on materially higher levels of preferred resources in the future than have previously been achieved. Given the uncertainty regarding forecast resources materializing as planned, the ISO is continuing to monitor the progress of the forecast procurement of conventional and preferred resources and ISO-approved transmission upgrades underway. Chapter 2 touches on these issues.

1.3 Structure of the Transmission Planning Process

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. For example, the 2017-2018 planning cycle began in January 2017 and concluded in March 2018.

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

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

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

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

1.3.1 Phase 1

Phase 1 generally consists of developing and completing the annual unified planning assumptions and study plan. Continuing with the timelines and coordination achieved in past planning cycles, the generating resource portfolios used to analyze public policy-driven transmission needs were developed as part of the unified planning assumptions in phase 1 for the 2018-2019 planning cycle.

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

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

- Long-term 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 discussed in more detail below, which are a key assumption.

The results of that annual process fed into this 2018-2019 transmission planning process and was communicated via a ruling in the 2017 cycle of the 2017-2018 IRP process[25]. These process efforts continued in 2018 emphasizing the broad load forecast impacts of distributed generation and other material changes in customer needs and considering renewable integration challenges and the market impacts of increased renewable generation on the existing conventional generation fleet.

The ISO added public policy requirements and directives as an element of transmission planning process in 2010. Planning transmission to meet public policy directives is also a national requirement under Federal Energy Regulatory Commission (FERC) Order No. 1000. It enables the ISO to identify and approve transmission facilities that system users will need to comply with specified state and federal requirements or directives. The primary policy directive for the last number of years' planning cycles has been California's renewables portfolio standard. 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 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 the ISO first formulates alternative resource development portfolios or scenarios, then identifies the needed transmission to support each portfolio, and then selects for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

As we move closer to the 33 percent renewables portfolio standard compliance date of 2020, the focus is shifting to the higher requirements set by SB 350 and will now shift onward to SB 100 in future planning cycles. Accordingly, the ISO's focus in the 2018-2019 planning cycle was to confirm the effectiveness of current plans for achieving the 50 percent renewables portfolio standard established by SB 350 for 2030 and conducting sensitivities that will support higher

[25] CPUC Decision, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF referring to the Feb 20, 2018 Unified Resource Adequacy and IRP Inputs and Assumptions document: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K709/209709519.PDF.

levels of renewables to accommodate GHG reduction goals that go beyond the 2030 50 percent RPS established by SB 350. This latter effort was reflected in the policy-driven sensitivity study discussed in chapter 4.

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.

1.3.2 Phase 2

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

- Performs technical planning studies described in the phase 1 study plan and posts the study results;
- Provides a request window for stakeholders to submit reliability project proposals in response to the ISO's technical studies, demand response, storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- 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,[26] which is intended to minimize the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;
- Identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;
- Performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;
- Performs technical studies to assess the reliability impacts of new environmental policies such as new restrictions on the use of coastal and estuarine waters for power plant cooling, which is commonly referred to as once through cooling and AB 1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin;
- Conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and,
- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the ISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of phase 2 in March.

Board approval of the comprehensive transmission plan at the end of phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board's approval enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval.[27] 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

[26] 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.

[27] 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.

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.[28]

1.3.3 Phase 3

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

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 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.

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

1.4 Interregional Transmission Coordination per FERC Order No. 1000

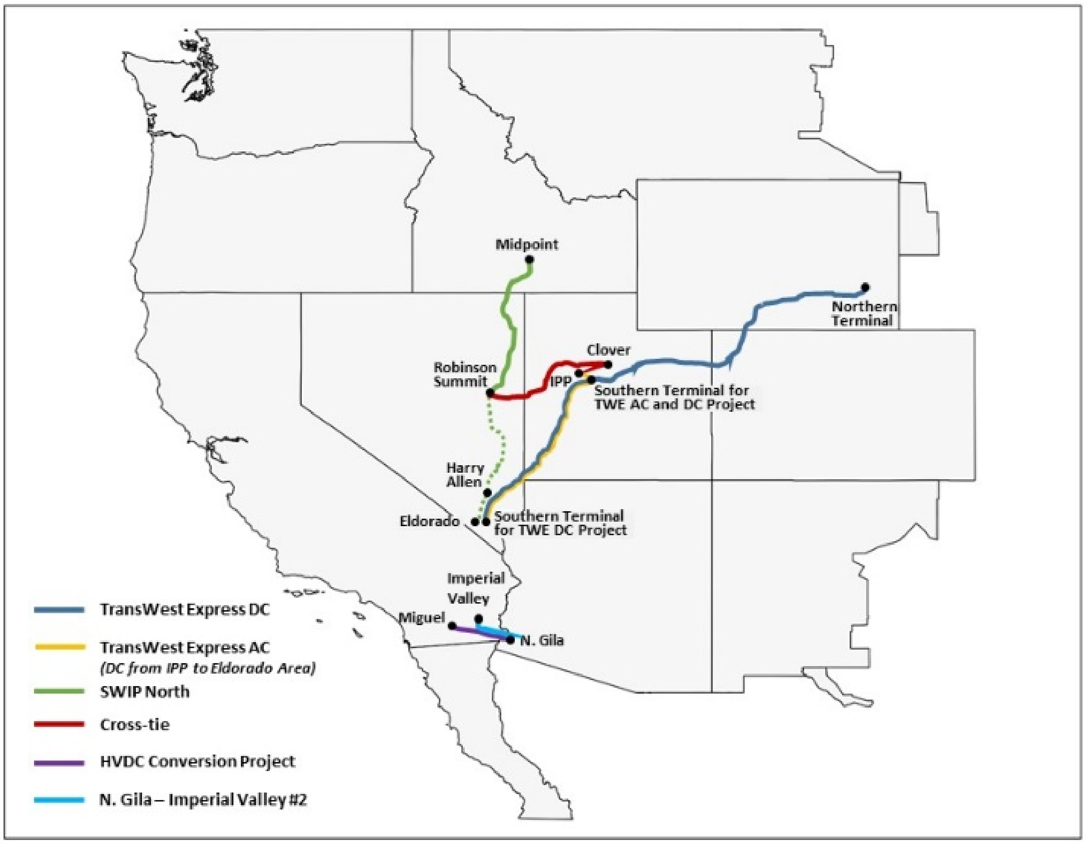
Beginning in January 2018 a new biennial Interregional Transmission coordination cycle was initiated. Following guiding principles largely developed during the 2016-2017 Interregional Transmission Coordination cycle, the ISO along with the other Western Planning Regions[29] continued to participate and 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 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.[30]

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. The submitted projects are shown in Figure 1.4-1. 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.

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

[30] 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 .

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



As discussed earlier in this chapter, state directives continue to focus on increasing California's renewable energy goals beyond 33 percent. In its 2016-2017 and 2017-2018 planning cycles the ISO performed a special study that considered the interregional transmission projects submitted to the ISO in the context of the 50% RPS that had been established at that time. The ISO concluded its consideration of these special studies in it 2017-2018 planning cycle and documented its results in it 2017-2018 transmission plan[31].

Moving forward into the 2018-2019 interregional coordination cycle, the ISO has considered the proposed projects in its 2018-2019 transmission plan but only as per the processes identified in the ISO tariff. More information regarding the ISO's consideration of the proposed projects can be found in Chapter 5.

[31] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf; See Chapter 6 "Special Reliability Studies and Results"

1.5 ISO Processes coordinated with the Transmission Plan

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

Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

In July 2012, FERC approved the GIDAP, which significantly revised the generator interconnection procedures to better integrate those procedures with the transmission planning process. The ISO applied the GIDAP to queue cluster 5 in March 2012 and all subsequent queue clusters. Interconnection requests submitted into cluster 4 and earlier will continue to be subject to the provisions of the prior generation interconnection process (GIP).

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

The most significant implication for the transmission planning process at this time relates to the planning of policy-driven transmission to achieve the state's 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.[32] 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.

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

[32] 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.

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.

Distributed Generation (DG) Deliverability

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

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

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

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

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

Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[33] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

Planning Coordinator Footprint

The ISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area in 2014, [34] 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, under the planning coordinator services agreement the ISO is not responsible for planning and approving mitigations to identified reliability issues – but only verifying that mitigations have been identified and that they address the identified reliability concerns. 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

[33] 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.

[34] 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.

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 and the Metropolitan Water District, and the ISO has conducted the study efforts to meet the mandatory standards requirements for these entities within the framework of the annual transmission planning process. In Q4 2017 the ISO executed a planning coordinator services agreement with the City of Santa Clara, doing business as Silicon Valley Power (SVP) and began providing those services in 2018. Through a two-year implementation plan the ISO will collect all required information to fulfill its planning coordinator responsibility for SVP.

Finally, 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.

At this time, the ISO is not anticipating offering these services to other parties, as the ISO is not aware of other systems inside the boundaries of the ISO 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 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;

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

2.1.3 Peak Demand

The ISO-controlled grid peak demand in 2018 was 46,424 MW and occurred on July 25 at 5:27 p.m. The following were the peak demand for the four load-serving participating transmission owners' service areas:

PG&E peak demand occurred on July 25, 2018 at 6:34 p.m. with 19,245 MW;

SCE peak demand occurred on July 6, 2018 at 4:54 p.m. with 24,244 MW;

SDG&E peak demand occurred on August 8, 2018 at 5:02 p.m. with 4,399 MW; and

VEA peak demand occurred on July 23, 2018 at 3:26 p.m. with 146 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 2018-2019 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 2019-2028 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2018-2019 study.

2.2.1 NERC Reliability Standards

2.2.1.1 System Performance Reliability Standards

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

- TPL-001-4 Transmission System Planning Performance Requirements[35]; 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.[36]

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.[37] 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.

35 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.

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

37 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[38] (2019-2023) and longer-term[39] (2024-2028) per the requirements of the reliability standards. Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2020, 2023 and 2028.

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 8.1-1 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).[40]

38 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.

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

40 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 System

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

2.3.2.4 Control Devices

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

- All shunt capacitors in SCE and other areas;
- Static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, and Talega substations;
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects (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 February 21, 2018.

During 2017, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2017 IEPR final report, adopted on February 21, 2018, based on the IEPR record and in consultation with the CPUC and the ISO, 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.

In the 2018-2019 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 2017 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. Statewide, self-generation PV capacity is projected to reach 26,000 MW in the low demand case by 2030[41]. In 2018-2019 TPP base cases, the 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[42]

PTO	Forecast Climate Zone	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PG&E	Central Coast	305	337	368	397	425	451	477	501	525	549
	Central Valley	972	1083	1194	1300	1402	1501	1594	1684	1771	1857
	Greater Bay Area	1203	1353	1510	1665	1820	1969	2110	2241	2363	2476
	North Coast	319	350	382	412	441	467	490	511	528	543
	North Valley	210	231	251	271	289	306	321	336	349	361
	Southern Valley	1153	1279	1403	1520	1634	1744	1851	1957	2063	2169
	PG&E Total	4163	4632	5109	5565	6009	6437	6844	7230	7599	7955
SCE	Big Creek East	310	350	392	432	473	513	553	593	633	674
	Big Creek West	193	213	234	254	273	292	309	325	340	355
	Eastern	709	793	878	961	1044	1126	1208	1291	1376	1466
	LA Metro	1196	1362	1543	1728	1915	2100	2276	2439	2588	2724
	Northeast	485	541	601	660	720	779	835	889	939	987
	SCE Total	2892	3259	3647	4035	4426	4810	5182	5537	5877	6206
SDG&E	SDG&E	1010	1108	1198	1277	1349	1417	1482	1545	1608	1673

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

[41] http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-03/TN222287_20180120T141708_The_California_Energy_Demand_20182030_Revised_Forecast.pdf

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

2.3.3.3 Additional Achievable Photovoltaic (AAPV)

The California Energy Demand (CED) Forecast 2018-2030 also includes AAPV. AAPV is incremental to the PV in the baseline forecast and, used in developing the managed forecast. In 2018-2019 TPP base cases, the AAPV was modeled explicitly similar to the baseline PV self-generation. 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[43]

Year	PG&E		SCE		SDG&E	
	Mid-Low	Mid-Mid	Mid-Low	Mid-Mid	Mid-Low	Mid-Mid
2019	-	-	-	-	-	-
2020	66	75	63	72	11	13
2021	131	150	127	146	23	26
2022	197	226	193	221	34	39
2023	263	301	258	295	46	53
2024	329	376	324	370	58	66
2025	395	452	390	445	70	80
2026	462	528	456	521	82	93
2027	528	603	520	595	93	107
2028	592	677	585	669	105	120

Output of the AAPV was 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.

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

2.3.4.2 Renewable Generation

The CPUC issued a decision[44] on February 08, 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.

Based on the proposal voted on and adopted by the CPUC, a “Default Scenario” was transmitted to the ISO to be used in the 2018-2019 TPP reliability assessment. The Unified Inputs and Assumptions document[45] described the Default Scenario which corresponds to 50% RPS. Renewable resources under development with CPUC-approved contracts with the three investor-owned utilities were assumed to be part of the baseline assumptions while creating the Default Scenario portfolio. The ISO worked with the CPUC to identify such resources and model these in the reliability assessment base cases. The ISO supplemented this scenario with information regarding contracted RPS resources that are under construction as of May 2018.Generation included in this year’s baseline scenario as described in Section 24.4.6.6 of the ISO Tariff was also included in the 10-year Planning Cases. Given the data availability, generic dynamic data may be used for the future generation.

2.3.4.3 Thermal generation

For the latest updates on new generation projects, please refer to CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html). The ISO 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:

[44] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

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

- 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.

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.

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

Generating Facility	Owner	Existing Unit/ Technology[46] (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[47] (MW) and Technology[48] (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	
	PG&E	1 (ST)	12/31/2024	2025	1122		N/A	

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

[47] 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.

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

Generating Facility	Owner	Existing Unit/ Technology[46] (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[47] (MW) and Technology[48] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Diablo Canyon Power Plant		2 (ST)	12/31/2024	2025	1118	PG&E plans to replace with renewable energy, energy efficiency and energy storage.		On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2024 and 2025, respectively.
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	SCE plans to replace with renewable energy and storage	SCE's filing for replacement resources is at the CPUC, pending review and further actions.	Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215			
Ormond Beach	GenOn	1 (ST)	12/31/2020		741	To be retired (no repowering)	N/A	NRG California South LP has informed retirement of Ormond Beach generating facility effective October 1, 2018
		2 (ST)	12/31/2020	10/1/2018	775			
El Segundo	NRG	3 (ST)	12/31/2015	7/27/2013	335	560 MW El Segundo Power Redevelopment (CCGTs)	August 1, 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			

Generating Facility	Owner	Existing Unit/ Technology[46] (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[47] (MW) and Technology[48] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
		4 (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 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	9/30/2019	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) Carlsbad Energy Center, located on the same property as the Encina Power Plant.	Q4 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
		2 (ST)	12/31/2017	12/31/2018[49]	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)

[49] 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 LTPP Authorization Procurement

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Tracks 1 and 4 were considered along with the procurement activities to date from the utilities. Table 2.3-4 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 Authorized Procurement

LCR Area	LTTP Track-1		LTTP Track-4[50]	
	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

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

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 Basin51	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark Sub-area52	6.00	5.66	0.50	0	262	274.16
SDG&E's procurement	22.4*	0	25**-84*	33.6*	80053	881-940

Notes:

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

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

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

2.3.5 Preferred Resources

According to tariff Section 24.3.3(a), the ISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. In response, the ISO received demand response and energy storage information for consideration in planning studies from 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 Unified Planning Assumptions and 2018-2019 study plan.

Methodology

The ISO issued a paper[54] 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

[51] 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.

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

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

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

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 2017-2018 planning cycle, reliability assessments in the current planning cycle will consider a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies will also incorporate 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. 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 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[55]. 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 was utilized for considering fast-response DR and slow-response PDR resources[56].

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

[56] 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.

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. The following table describes the total supply-side DR capacity assumptions[57].

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[58]	6.74	917	RDRR	Yes
AP-I			50[59]	0.0	50	RDRR	Yes
AC Cycling Res[60]		61	56	7.18	124	PDR	Yes
AC Cycling Non-Res		0	20[61]	1.79	22	PDR	Yes
CBP		103[62]	143[63]	8.44	254	PDR	No
Other procurement program DR							
SCE LCR RFO,[64] post 2018			5.0		5	RDRR	Yes
DRAM[65]	2017	56.4	56.2	12	125	PDR[66]	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.

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57 http://www.cpuc.ca.gov/General.aspx?id=6442451972

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

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

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

62 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.

63 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.

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

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

66 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.

The following factors 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

Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the ISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs as shown in Table 2.3-8. Energy storage that will be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision is subsumed within the 2020 procurement target. The transmission-connected storage projects approved in the 2017-2018 Transmission Plan as regulated transmission asset were modeled.

Table 2.3-8: Total Energy Storage Procured to-Date[67]

Domain	Transmission- connected	Distribution- connected	Customer- connected
SDG&E	40	44	31
SCE	55	195	251
PG&E	30	17	0
Total	125	256	282

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.

2.3.6 Firm Transfers

Power flow on the major internal paths and paths that cross balancing authority boundaries represents the transfers modeled in the study. Firm Transmission Service and Interchange represents only a small fraction of these path flows, and is clearly included. In general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 2.3-9: Major paths and power transfer ranges in the Northern California assessment lists the capability and power flows modeled in each scenario on these paths in the northern area assessment[68].

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

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

Table 2.3-9: Major paths and power transfer ranges in the Northern California assessment[69]

Path	Transfer Capability/SOL (MW)	Scenario in which Path was stressed
Path 26 (N-S)	4000[70]	Summer Peak
PDCI (N-S)	3220[71]	
Path 66 (N-S)	4800[72]	
Path 15 (N-S)	-5400[73]	Summer Off Peak
Path 26 (N-S)	-3000	
Path 66 (N-S)	-3675	Winter Peak

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

Similarly, Table 2.3-10: Major Path flow ranges in southern area (SCE and SDG&E system) assessment 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.

69 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)

70 May not be achievable under certain system loading conditions.

71 PDCI Upgrade Project – to 3220 MW – was approved in 2017

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

73 May not be achievable under certain system loading conditions

Table 2.3-10: Major Path flow ranges in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path 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 9,600	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 are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 2.3.4.

Demand Level:

Since most of the ISO footprint is a summer peaking area, summer peak conditions were evaluated in all study areas. 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, summer off-peak or summer partial-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 2.3-11 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 2.3-11 summarizes these study areas and the corresponding base scenarios for the reliability assessment.

Table 2.3-11: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2020	2023	2028
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 Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Light Load	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Light Load	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer/Winter Peak Spring Light Load	Summer/Winter Peak Spring Off-Peak	Summer/Winter Peak

2.3.8.2 Sensitivity study cases

In addition to the base scenarios that the ISO assessed in the reliability analysis for the 2018-2019 transmission planning process, the ISO assessed the sensitivity scenarios identified in Table 2.3-12. 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 2.3-12: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2020	2023	2028
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-
Off peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-	-
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)[74]
- 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)[75]
- 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)

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

75 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[76] (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

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

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

2.3.10 Study Methodology

As noted earlier, the backbone and regional planning region assessments were performed using conventional analysis tools and widely accepted generation dispatch approaches. These methodology components are briefly described below.

2.3.10.1 Study Tools

The GE PSLF 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 Standards77 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)78. 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.

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

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

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 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 approved guide for voltage support and reactive power, by WECC TSS on March 30, 2006, was used for the analyses in the ISO controlled grid. According to the guideline, load is increased by 5% for Category P1 and 2.5% for other contingencies Category P2-P7 and studied to determine if the system has sufficient reactive margin. This study was conducted in the areas that have voltage and reactive concerns throughout the system.

Transient Stability Analyses

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

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

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

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

The 500 kV bulk transmission system in northern California consists of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue past Bakersfield in the south. This system transfers power between California and other states in the northwestern part of the United States and western Canada. The transmission system is also a gateway for accessing resources located in the sparsely populated portions of northern California, and the system typically delivers these resources to population centers in the Greater Bay Area and Central Valley. In addition, a large number of generation resources in the central California area are delivered over the 500 kV systems into southern California. The typical direction of power flow through Path 26 (three 500 kV lines between the Midway and Vincent substations) is from north-to-south during on-peak load periods and in the reverse direction during off-peak load periods. 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). Transient stability studies were performed for the selected five cases: three base cases – 2020 and 2028 Summer Peak and 2023 Spring off-Peak and two sensitivity cases with high renewable and low gas generation output - 2020 Summer Peak and 2023 Spring off-Peak.

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 2020, 2023 and 2028; and winter off-peak peak case for 2028. In addition, 3 sensitivity cases were studied: the 2020 Summer Peak case with high renewable and low gas generation output, 2023 Spring off-Peak case with high renewable and low gas generation output and 2023 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 the 2028 summer peak case 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-2020-SP	Base Line	2020 Summer peak load conditions. Peak load time -hour ending 19:00	4800 N-S	1600 N-S	3700 N-S	2700 N-S	80%
PGE-Bulk-2020-SpOp	Base Line	2020 Spring off-peak load conditions. Off-peak load time - hour ending 12:00	2800 S-N	120 N-S	3700 N-S	300 N-S	56%
PGE-Bulk-2023-SP	Base Line	2023 Summer peak load conditions. Peak load time - hour ending 19:00	4800 N-S	1260 N-S	3100 N-S	2800 N-S	80%
PGE-Bulk-2023-SpOP	Base Line	2023 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	2420 S-N	700 S-N	2900 N-S	300 N-S	42%
PGE-Bulk-2028-SP	Base Line	2028 Summer peak load conditions. Peak load time - hour ending 19:00	4800 N-S	470 N-S	400 N-S	2240 N-S	80%
PGE-Bulk-2028-SpOP	Base Line	2028 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	2500 S-N	220 S-N	1420 N-S	300 N-S	34%
PGE-Bulk-2028-WOP	Base Line	2028 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	120 N-S	2520 N-S	3000 N-S	300 N-S	70%
PGE-Bulk-2020-SP-HiRenew	Sensitivity	2020 Summer peak load conditions with high renewables and minimum gas	4800 N-S	1280 N-S	3700 N-S	2840 N-S	76%
PGE-Bulk-2023-SP-Hi CEC	Sensitivity	2023 Summer peak load conditions with high CEC forecasted load	4800 N-S	1330 N-S	3400 N-S	2800 N-S	89%
PGE-Bulk-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with high renewables and minimum gas	3670 S-N	50 N-S	3970 N-S	240 N-S	40%

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

Description	Battery Storage		Solar		Wind		Hydro		Thermal: incl. geo, nuclear, bio	
	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2020 Summer peak load conditions. Peak load time -hour ending 19:00	177	16	3,935	583	1,796	717	9,932	7,822	23,443	16,882
2020 Spring off-peak load conditions. Off-peak load time - hour ending 12:00	177	2	3,935	3,923	1,796	119	9,932	5,967	23,443	8,367
2023 Summer peak load conditions. Peak load time - hour ending 19:00	186	4	4,202	184	1,802	1,197	10,003	7,970	22,981	18,394
2023 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	186	4	4,202	3,741	1,802	73	10,003	4,568	22,981	6,919
2028 Summer peak load conditions. Peak load time - hour ending 19:00	186	8	4,202	183	1,802	1,179	10,003	8,069	20,570	15,901
2028 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	186	4	4,202	3,871	1,802	78	10,003	4,403	20,570	4,798
2028 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	186	4	4,202	115	1,802	316	10,003	6,592	20,570	11,427
2020 Summer peak load conditions with high renewables and minimum gas	177	157	3,935	3,450	1,796	1,409	9,932	7,791	23,443	9,475
2023 Summer peak load conditions with high CEC forecasted load	186	8	4,202	1,211	1,802	201	10,003	8,613	22,981	18,643
2023 spring off-peak load conditions with high renewables and minimum gas	186	4	4,202	3,802	1,802	1,128	10,003	4,440	22,981	7,410

Load Forecast

Per the ISO planning criteria for regional transmission planning studies, the demand within the ISO area reflects a coincident peak load for 1-in-5-year forecast conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50-60 percent of the 1-in-5 summer peak load level. The light load cases modeled the lowest load in the PG&E area that appears to be lower than the off-peak load. Table 2.4-3 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 (Irrigaiton and pump-storage)
					Installed	Output		Total	D2	
			MW	MW	MW	MW	MW	MW	MW	MW
PGE-Bulk-2020-SP	Base Line	2020 Summer peak load conditions. Peak load time -hour ending 19:00	26,992	474	4,698	846	**25,672**	505	298	597
PGE-Bulk-2020-SpOp	Base Line	2020 Spring off-peak load conditions. Off-peak load time - hour ending 12:00	13,902	325	4,698	3,711	**9,866**	505	298	1,527
PGE-Bulk-2023-SP	Base Line	2023 Summer peak load conditions. Peak load time - hour ending 19:00	29,229	1,145	6,272	191	**27,893**	509	298	609
PGE-Bulk-2023-SpOP	Base Line	2023 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	13,903	659	6,272	5,268	**7,976**	509	298	1,539
PGE-Bulk-2028-SP	Base Line	2028 Summer peak load conditions. Peak load time - hour ending 19:00	30,540	2,114	8,547	220	**28,206**	511	298	612
PGE-Bulk-2028-SpOP	Base Line	2028 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	15,696	1,198	8,547	7,215	**7,283**	511	298	1,542
PGE-Bulk-2028-WOP	Base Line	2028 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	15,589	1,273	8,547	0	**14,316**	511	298	612
PGE-Bulk-2020-SP-HiRenew	Sensitivity	2020 Summer peak load conditions with high renewables and minimum gas	27,052	463	4,698	4,651	**21,938**	505	298	597
PGE-Bulk-2023-SP-Hi CEC	Sensitivity	2023 Summer peak load conditions with high CEC forecasted load	29,296	0	6,272	849	**28,447**	509	298	609
PGE-Bulk-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with high renewables and minimum gas	13,938	655	6,272	6,197	**7,086**	509	298	1,539

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. However, there were three Category P0 overloads of the 115 kV lines; one in the 2028 Summer Peak case (Palermo-Wyandet) and two in the 2020 Spring off-Peak case (Wilson-Le Grand and Smyrna-Atwell Island). Heavy loading above 95% under normal system conditions was observed on one 230 kV line (Cayetano-Lone Tree), on one 230/70 kV transformer (Helm) and one 115 kV transmission line (Cheny-Panoche). There were also seven 70 kV line overloads under normal system conditions in the off-peak cases. Five overloads were identified on the 60 kV lines under summer peak normal conditions, and additional three 60 kV overloads were identified in the sensitivity peak cases. The overloads on the 230/70 kV transformer and the 115 kV and below systems and their mitigation measures are discussed in the local area sections of the report. The same transmission lines were also overloaded with single and double contingencies. Overloads of these facilities were either due to high generation, or for the lower voltages, some were radial lines overloaded due to high load at the end of the line. The 60 kV and 70 kV facilities are not considered to be Bulk Electric System (BES), therefore, considering that they were overloaded under normal system conditions, their overloads are not discussed here further. These overloads are considered in the local area studies.

- Two Category P1 overloads were identified under summer peak conditions in the base cases. 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. In addition, one transformer, Gates 500/230 kV, was identified as overloaded with a Category P1 contingency in the 2023 sensitivity off-Peak case with high renewable and minimum gas generation output. Also, Table Mountain 500/230 kV transformer may become heavily loaded in the same sensitivity case with a Category P1 contingency.
- 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. There were no additional Category P2 contingency overloads on the Bulk System.
- Under Category P3 contingencies with an outage of one of the Diablo Canyon generating units and another transmission facility, in addition to the facilities that were overloaded under Categories P0 and P1, Malin-Round Mountain # 1 500 kV line was identified as overloaded in the sensitivity peak cases, and as heavily loaded in the base peak cases. Other facilities that may overload under Category P3 contingencies studied include the Cottonwood –Round Mountain # 3 230 kV line, the Henrietta 230/115 kV transformer and the Henrietta-Leprino 115 kV transmission line. All these overloads were identified in the sensitivity cases. It was assumed that there were no system adjustments between the contingencies.
- Thirty-nine P6 overloaded facilities were identified in the studies in the base cases. Out of these, sixteen overloads were identified under summer peak conditions including three 500/230 transformers at the same substation (Metcalf). Twentythree facilities were overloaded under off-peak conditions, including two 500/230 kV transformers at the same substation (Gates). Out of these facilities, three were also overloaded under peak load conditions. Twelve Additional facilities were identified as overloaded only in the sensitivity cases: nine in the peak cases, three in the off-peak and one both in the peak and off-peak sensitivity cases. In the P6 studies, no generation re-dispatch was assumed after the first contingency.
- Twelve overloaded or heavily loaded facilities were identified with the 500 kV double contingencies in the same corridors, nine under peak, and three under off-peak conditions in the base and sensitivity cases.

- High voltages were observed on 500 kV system in Central California after Diablo Canyon 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.
- 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.

Dynamic stability studies used the new WECC composite load model to reflect more accurate load composition and load parameters. The composite load model included distributed solar PV generation modeled with the latest models that are more detailed than the distributed generation models used previously.

The studies showed that some renewable projects tripped due to under-voltage, under-frequency or other dynamic issues. This generation tripping could be due to modelling issues. In addition, some load and distributed generation was tripped off with three-phase faults by the composite load model due to low voltages. Some small generators located close to the simulated three-phase faults went out-of-step with double contingencies and were tripped. Also, several contingencies indicated some under-voltage load tripping. Dynamic stability studies used the new WECC TPL criteria that included transient voltage recovery. No criteria violations were identified in the studies.

The following table summarizes the overloaded facilities and the options for their mitigation.

Table 2.4-4: Overloaded facilities and contingencies causing thermal overload

Overloaded Facility	Loading % (Baseline Scenarios)							Loading % (Sensitivity Scenarios)			Project & Potential Mitigation Solutions
	2020 Summer Peak	2023 Summer Peak	2028 Summer Peak	2020 Spring Off-Peak	2023 Spring Off-Peak	2028 Spring Off-Peak	2028 Winter Off-Peak	2023 SP High CEC Forecast	2023 SpOP Hi Renew & Min Gas Gen	2020 SP Heavy Renewable & Min Gas Gen	
500 kV LINES											
MALIN-ROUND MTN # 2 500 kV	P3	P3						P3		P3	Reduce COI flow according to seasonal nomogram
ROUND MTN –TABLE MTN #1 500 kV	P1, P2, P3, P6	P1, P2, P3, P6	P1, P2, P6					P1, P2, P3, P6		P1, P2, P3, P6	Reduce COI flow according to seasonal nomogram or bypass ser caps on the remaining Round Mtn-Table Mtn 500 kV line if overload
ROUND MTN-TABLE MTN # 2 500 KV	P1, P3, P6	P1, P3, P6	P1, P3, P6					P1, P3, P6		P1, P3, P6	
CAPTAIN JACK-OLINDA 500 kV	P6, P7	P6, P7	P6, P7					P6, P7		P6, P7	Reduce COI flow according to seasonal nomogram
MIDWAY-VINCENT # 1 500 kV				P6					P6	P6	flow on Path 26 is N-S in off-peak cases, not enough generation at Midway to trip. Need to review RAS for Path 26 contingencies
MIDWAY-VINCENT # 2 500 kV				P6					P6	P6	
MIDWAY-WHIRLWIND # 3 500 kV				P7					P7	P7	
500/230 kV TRANSFORMERS											
OLINDA 500/230 kV x-former				P6, P7	P6, P7	P6, P7			P6, P7		Reverse flow on Olinda x-former in off-peak cases. Reduce Shasta generation aftet first contingency if overload. No overload with Table Mtn 500/230 kV RAS
TABLE MTN 500/230 kV x-former							P6		P7		Reverse flow on Table Mtn x-former in off-peak cases, don't bypass series capacitors on Table Mnt-Vac Dix to reduce flow
METCALF 500/230 kV x-former #11, 12 or 13			P6							P6	increase generation in San Jose after 1st contingency, trip load in San Jose if overload persists
GATES 500/230 kV # 1 or 2 x-former						P6			P1, P6		Reverse flow on Gates x-former in off-peak cases. Decrease generation at Mustang and/or Mc Call after first contingency. Develop Operational Procedure to reduce generation to avoid overload with single contingency

Overloaded Facility	Loading % (Baseline Scenarios)							Loading % (Sensitivity Scenarios)			Project & Potential Mitigation Solutions
	2020 Summer Peak	2023 Summer Peak	2028 Summer Peak	2020 Spring Off-Peak	2023 Spring Off-Peak	2028 Spring Off-Peak	2028 Winter Off-Peak	2023 SP High CEC Forecast	2023 SpOP Hi Renew & Min Gas Gen	2020 SP Heavy Renewable & Min Gas Gen	
230 kV LINES											
COTTONWD E-ROUND MTN 230kV #3	P7	P6, P7	P6, P7		P6			P3, P6, P7	P6	P6, P7	Reduce COI flow according to seasonal nomogram, or upgrade the line if economic
COTTONWD E-ROUND MTN 230kV #2		P7	P6, P7					P6, P7		P7	Reduce COI flow according to seasonal nomogram
COTTONWD E-ROUND MTN 230kV #1		P7	P6, P7					P6, P7		P7	
TABLE MTN-RIO OSO 230 kV	P6, P7										Terminal equipment upgrade will eliminate high loading
CAYETANO- LONETREE 230 kV			P6					P6			reduce generation in Contra Costa area, if overload
LAS POSITAS-NEWARK 230 KV		P6	P6					P6			
CAYETANO- N. DUBLIN 230 kV		P6	P6					P6			
NEWARK-LOS ESTEROS 230 kV								P6			adjust SVP phase shifter
GOLD HILL-LODI 230 kV					P6	P6			P6		Table Mtn 500/230 kV x-former RAS assumed for off-peak cases. Winter rating used for the winter case. Reduce generation at Ralston, MiddleFork and Collervl. Separate the system
GOLD HILL-EIGHT MILE 230 kV					P6	P6	P6		P6		
BELLOTA-WEBER 230 kV						P6	P6				Reduce Collerville or Electra generation if overload.
WEBER-TESLA 230 kV						P6	P6				
BELLOTA-TESLA 230 kV						P6	P6				
EIGHT MILE-TESLA 230 kV				P6	P6	P6	P6		P6		Reduce generation in Lodi and Feather River - Ralston if overload, or upgrade the facilities if economic or overload still remains.
STAGG-EIGHT MILE 230 kV				P6	P6	P6	P6		P6		
STAGG H - STAGG F BRK 230 kV						P6	P6				
STAGG D - STAGG F BRK 230 kV							P6				
STAGG-TESLA E 230 kV					P6	P6	P6		P6		
PANOCHE - DS AMIGO 230 kV									P6		Decrease generation at Tranquility if overload
LOS BANOS-PANOCHE #1 230 kV									P6		
LOS BANOS-PANOCHE #2 230 kV									P6		
MOSSLANDING-LAS AGUILAS 230 kV									P6	P6	Decrease generation at Las Aguilas if overload
MOSSLANDING-METCALF 230 kV # 1 or 2				P6							decrease generation at Moss Landing power plant if overload
230/115 kV TRANSFORMERS											
NEWARK 230/115 kV #11		P6	P6					P6			May be mitigated by adjusting SVP phase shifter
115 kV LINES											
DELTA - CASCADE 115 kV	P7	P7						P6, P7		P7	adjust Weed Phase Shifter or limit COI flow wihin seasonal nomogram
PEASE-E.MRSVLE-OLIVH 115 kV	P6, P7										South of Palermo Project. Prior to the project: limit COI import within nomogram
DRUM-BRUNSWICK -RIO OSO 115 kV		P6, P7								P6, P7	reduce Drum generation if overload
DRUM-BRUNSWICK -Dutch Flat 115 kV		P7								P6, P7	
NEWARK-NRS 115 kV		P6	P6				P6	P6		P6	also overloads for local contingencies. May be mitigated by adjusting NRS phase shifter

As can be seen from Table 2.4-4, no Category P0 overloads were observed on the PG&E Bulk system on the facilities at 230 kV and above. Heavy loading above 95% under normal system conditions was observed on one 230 kV line (Cayetano-Lone Tree). The same facility may also overload with multiple contingencies. In addition, there were three facilities that may overload with single contingencies. The same facilities may also overload with multiple contingencies. Two additional facility may overload with Category P3 contingencies. There were twelve facilities that may overload with Category P7 contingencies, one of them only in the sensitivity cases. Twenty four transmission facilities may overload only with Category P6 contingencies.

An approved transmission project (South of Palermo Transmission Reinforcement) will mitigate one Category P6 and P7 overload that may occur under peak conditions in 2020. Upgrading terminal equipment on one substation that will be performed as a part of the transmission system maintenance will address another Category P6 and P7 overload. Prior to the approved transmission solutions being completed, congestion management may be used.

No voltage deviation or reactive margin concerns were identified in the studies.

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

- Manage COI flow according to the seasonal nomograms.
- Implement RAS 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 economic-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 # 1, #2 and # 3 transmission lines
    - Moss Landing-Las Aguilas 230kV transmission line
- 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.
- Develop a project to install reactive support on the 500 kV network in the north and in the south of the PG&E system to mitigate high and low voltages.

The load in WECC, including the ISO, was modeled with the WECC composite load models in the dynamic stability studies. The load was modeled according to the current 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. Dynamic stability studies used the new WECC Transmission Planning criteria that included transient voltage recovery.

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.

- 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.
- Low transient voltages due to stalling of induction motor load around Gates were identified. Installing dynamic reactive support in the area (Gates 500 kV substation) may help also for these issues.
- 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.

The studies identified high voltages on the 500 kV Diablo, Gates and Midway buses starting from when Diablo Canyon Power Plant retires, currently scheduled for 2025. The Diablo Canyon Power Plant was modeled off-line in the 2028 cases. Voltage on the Diablo 500 kV bus may become as high as 550 kV under normal system conditions after the Diablo Canyon Power Plant retires, which is above the required limit. The studies did not identify any insufficient reactive margin issues.

Additional reactive support is required, preferably dynamic to both absorb reactive power under normal system conditions and supply reactive power with contingencies as needed. Dynamic reactive support in the northern part of the PG&E system also may be needed to avoid under-voltage load tripping in southern Oregon with three-phase faults in northern PG&E that was observed in dynamic stability studies. Dynamic reactive support in southern PG&E also may be needed to prevent momentary cessation of the inverters on the solar PV generators that was identified in the Gates area in the studies of momentary cessation of inverters.

High voltages were also identified on the sub-transmission system under off-peak conditions, mainly due to large amount of renewable generation connecting to this system. The requirement for the new renewable generation projects to maintain at least 0.95 lead/lag power factor at the Point of Interconnection may mitigate high voltages. Having the ability to absorb reactive power will reduce voltages in the sub-transmission system.

Also, the studies identified that voltage at the Maxwell 500 kV Substation in the Northern area may become too low with some contingencies. The most critical was double outage of the Round Mountain-Table Mountain 500 kV lines # 1 and # 2 when the voltage at Maxwell may become as low as 487 kV under peak load conditions. Maxwell Substation is owned by WAPA, and according to the WAPA Operational standards, 500 kV system voltages should be above

495 kV. Under the off-peak load conditions with all facilities in service, voltage at the Maxwell Substation may become as high as 547 kV.

Detailed assessment of the need and requirements of the voltage support was assess in both the northern (Round Mountain area) and southern (Gates area) of the PG&E area 500 kV system as follows.

Round Mountain 500 kV Dynamic Reactive Support

An assessment of reactive support in the Round Mountain area of the northern portion of the PG&E 500 kV system was conducted. The detailed assessment is included in Appendix B.

High voltage issues at Round Mountain 500 kV substation bus occur frequently in real-time operation under non-peak conditions when the COI flows are typically lower. High voltage issues have resulted in limited clearance opportunities to do maintenance work on system elements and in some cases the clearance had to be cancelled to bring the element back in service to address voltage issues. The worst condition occurs under the N-1 contingency of Round Mountain 500/230 kV transformer which is a 3-winding transformer with 4 x 47.7 Mvar reactor connected to its tertiary winding. The loss of the transformer disconnects the reactors and as a result high voltage condition worsens. Round Mountain bus voltage under N-0 and N-1 conditions in a 2019 minimum load case are 549 kV and 554 kV respectively.

To address the issue, a device with 500 Mvar reactive absorption rating is assumed at Round Mountain 500 kV bus. The reactive device is sized to bring the voltage close to 540 kV which is PG&E's maximum normal operating voltage. The studies showed that with reactive device in service, the voltage at the Round Mountain 500 kV bus drops to 538 kV and 541 KV under N-0 and N-1 conditions, respectively.

In addition to high voltage issues under light loading conditions, Round Mountain bus voltage varies significantly on a daily basis with the output of solar generation in California which results in COI flow changes on a daily basis. The hourly voltage fluctuations are expected to increase in future with more solar integration in California and the expansion of EIM in the northwest. To address the voltage variability at Round Mountain 500 kV bus, the recommended reactive device should be a dynamic device to be able to actively manage the voltage as the need for reactive support changes based upon the flows on COI.

The analysis of the study results demonstrates the need for a dynamic device at Round Mountain to absorb up to 500 Mvar reactive power. The benefits of the Round Mountain voltage support device having a dynamic range to inject reactive power is discussed in the following section.

The maximum voltage drop at Round Mountain 500 kV bus occurs following the trip of PDCI under a scenario in which both PDCI and COI are highly dispatched. This scenario is more severe under spring off-peak load conditions and is expected to happen typically in the evenings when imports from northwest are high to manage the evening ramp and the higher flows in the non-solar hours. The study results show that following the PDCI contingency and after all the automatic switching of the existing reactive devices (post transient condition), the voltage drop at Round Mountain 500 kV bus is around 35 kV. To prevent voltage from dropping below low end of emergency operating voltage of 495 kV, system operators keep the pre-contingency voltage quite high to ensure acceptable post contingency voltage. Having high voltage on 500 kV system will result in high voltages on 230 kV and to some degree the 115 kV and 60/70 kV lower voltage networks. High voltages across the PG&E system have been observed in real-time and planning studies under light load conditions that poses ongoing challenges for system operations. A dynamic device that has both reactive and capacitive range at Round Mountain, will enable system operations to be able to set the pre-contingency system voltages at lower values so that the post-contingency reactive power injection at Round Mountain 500 kV bus will support the voltage within acceptable ranges for normal operations and after the contingency. Study results show that with 500 Mvar injection from Round Mountain dynamic reactive device, the voltage drop after PDCI outage will be only 18 kV.

The results show that the voltage in the area ranged between 488 kV and 558 kV in the existing system which is outside the acceptable range, especially on the high voltage. After implementing the Round Mountain ±500 Mvar dynamic voltage support, the voltage in the area ranged between 503 kV and 548 kV which is within acceptable range. Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place. The reactive device is to be installed in a minimum of two equally-sized blocks independently connected to the 500 kV to accommodate maintenance and contingencies of the reactive device.. The reactive power support is required to provide continuous dynamic reactive power support over the complete range of the capability (unless the facility experienced a planned or forced outage). It can be one of the following types of devices: SVC (Static VAR Compensator) with Thyristor Switched Capacitors (TSC), STATCOM (Static Synchronous Compensator), or Synchronous Condenser. An appropriately sized and configured inverter associated with a battery storage project could also provide the reactive support. Voltage support requirements would take precedence over any other operation of the battery storage facility. The estimated cost of the project is $160 million to $190 million with and expected in-service date of June 2024.

Gates 500 kV Dynamic Reactive Support

An assessment of reactive support in the Gates area of the southern portion of the PG&E 500 kV system was conducted. The detailed assessment is included in Appendix B.

The studies showed that after the retirement of Diablo Canyon Power Plant, high voltages are expected in the south of the PG&E system, particularly on the Diablo and Gates 500 kV buses under all system conditions. The studies also showed voltages above 540 kV on the Gates 500 kV bus under off-peak system conditions with all facilities in service prior to the Diablo Canyon Power Plant retirement. The most critical cases appeared to be 2028 Spring off-peak or 2028 Winter off-peak. Even for the conditions when all transmission facilities are in service, 500 kV voltages are expected to rise up to 552 kV on the Diablo 500 kV bus and up to 548 kV on the Gates 500 kV bus. Analysis also showed that for a single outage (P1) of one of the Diablo – Midway 500 kV lines, voltage on the Diablo 500 kV bus may reach 554 kV. Voltages also exceeded 554 kV on the Diablo bus and 551 kV on the Gates bus for double outages of the Los Banos 500/230 kV transformer and one of 500 kV lines in the area for the 2028 off-peak conditions. Such normal and emergency voltage levels would clearly exceed the voltage criteria for the 500 kV system.

According to the ISO Planning Standards[79], voltage on the Diablo Canyon 500 kV bus should be between 512 and 545 kV both under normal and contingency conditions. Voltages on all the other 500 kV buses in the PG&E system should be between 518 and 550 kV under normal conditions and between 473 and 550 kV under contingency conditions. Along with these standards, PG&E Operations monitors and maintains the voltage based on the O-59 Operating Procedure. This procedure has voltage limits on 500 kV as from 525 kV to 540 kV under normal system conditions and from 495 kV to 551 kV for contingency conditions. For the purpose of proposing high voltage mitigations, to be more conservative, the high voltage operating limits identified in O-59 were considered.

In addition, dynamic stability studies showed large loss of load due to stalling and tripping of induction motors with three-phase faults in the Fresno area, especially with the faults close to the Gates and Midway 500 kV Substations. Studies of three-phase faults in an assumption of momentary cessation of inverters on the solar PV plants showed unstable system performance for some cases studied, if the faults are on the Gates 500 kV bus and the inverters have relatively high voltage when they go to momentary cessation (0.9 per unit) and relatively long recovery delay (5 seconds).

Adding voltage support in the area will mitigate both high voltages after the Diablo Canyon Power Plants retires as well as high voltages under off-peak conditions prior to its retirement, and will also mitigate dynamic stability issues with three-phase faults and induction motor stalling and tripping.

It is recommended to install an SVC with TSC or STATCOM capable of absorbing around 800 Mvar of reactive power. An 800 Mvar shunt reactor on Gates also appeared to be sufficient to reduce voltage both on the Diablo 500 kV bus and on all 500 kV buses in the area to the required limits for all the cases and contingencies studied. This reactive support should have either continuous regulation or steps to satisfy other system conditions when voltages in the 500 kV system in the Southern PG&E area are not as high and when the full range of the reactive power absorption is not needed.

Power flow studies did not show low voltages in the south of the PG&E system that would require reactive support that would produce reactive power; however similar to the hourly flows of COI in the Round Mountain Reactive Support assessment, flows in the southern portion of the PG&E bulk system will vary through out the day with the continued addition of solar generation. In addition, the dynamic stability studies showed large loss of load due to stalling and tripping of induction motors with three-phase faults in the area and also possibility of momentary cessation of inverters that might cause system instability.

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[79] California ISO Planning Standards http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf#search=iso%20planning%20standard

The studies showed that dynamic reactive support installed at the Gates 500 kV Substation may reduce amount of the load lost due to stalling or tripping of induction motor load with faults. For an outage of the Gates-Midway 500 kV line with a three-phase fault under 2028 Summer peak load conditions, amount of load lost in PG&E reduced from 445 MW to 295 MW with installation of an SVC with TSC capable of producing reactive power. The same result was with a STATCOM instead of SVC.

Dynamic stability studies were also performed to investigate if installation of dynamic reactive support on the Gates 500 kV Substation may help to improve momentary cessation of the inverters on the solar PV plants and prevent instability caused by momentary cessation. For these studies, a 2020 Summer Peak case with high renewable generation output was selected since it had high amount of solar PV in the Fresno area and high air-conditioning load. An outage of the Gates-Midway 500 kV line with a three-phase fault was studied. Momentary cessation of the inverters was assumed to occur at the 0.9 per unit voltage with a 5 second delay. The ramp at which inverters recover was assumed to be 0.2 per unit per second. The performance of a STATCOM in the dynamic stability studies was better than an SVC.

The study results indicated that a +/- 800 Mvar dynamic reactive device at Gates is required to address the high voltage and to improve dynamic performance. The recommendation is to approve installation of a total of +/-800 Mvar of dynamic reactive support on the Gates 500 kV bus. The reactive device is to be installed in a minimum of two equally-sized blocks independently connected to the 500 kV to accommodate maintenance and contingencies of the reactive device. The reactive power support is required to provide continuous dynamic reactive power support over the complete range of the capability (unless the facility experienced a planned or forced outage). It can be one of the following types of devices: SVC (Static VAR Compensator) with Thyristor Switched Capacitors (TSC), STATCOM (Static Synchronous Compensator), or Synchronous Condenser. An appropriately sized and configured inverter associated with a battery storage project could also provide the reactive support. Voltage support requirements would take precedence over any other operation of the battery storage facility.The ISO recommends the Gates 500 kV Dynamic Reactive support project with an estimated cost of $210 million to $250 million with an in-service date of no later than June 2024 so as to be in-service prior to the retirement of the Diablo Canyon Power Plant in 2025.

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 2.4-2

.Table 2.4-2 Request Window Submissions

Project Name	Proponent	Size/capacity	Cost Estimate	Operational Date
Round Mountain 500 kV Substation Voltage Support	PG&E	+/-500 Mvar STATCOM	$160M-$190M	December 31, 2024
Gates 500 kV Substation Voltage Support	PG&E			
Option l-Gates500kV	PG&E	+/-lOOOMvar STATCOM	$241M-$291M	December 31, 2024
Option II Gates500kV	PG&E	+/-500 Mvar STATCOM and -500 Mvar shunt reactors	Slightly lower than Option 1	December 31, 2024
Option Ill Gates500kV	PG&E	+0/1000 Mvar STATCOM and +350 Mvar shunt capacitors	Slightly lower or equal to Option 1	December 31, 2024
Round Mountain Dynamic Reactive 500 kV Transmission System	NEET West	+/-300 Mvar SVC or STATCOM	$75M	December 1, 2024
Gates or Diablo Dynamic Reactive 500 kV Transmission System	NEET West			
Option l-Diablo 500kV	NEET West	+100 /-275 Mvar SVC or STATCOM	$65M	December 1, 2024
Option II Gates 500 kV	NEET West	+100 /-250 Mvar SVC or STATCOM	$65M	December 1, 2024
Option Ill Gates500kV	NEET West	+150 /-450 Mvar SVC or STATCOM	$75M	December 1, 2019
500/230 lkV Chorro Junction Sustation on Diablo-Gates 500 kV line	California Transmission Development, LLC	+/-500 Mvar SVC		June 1, 2023
500kV Wells Place Substation on Round Mountain – Table Mountain #1 Line	California Transmission Development, LLC	+/-500 Mvar SVC		June 1, 2023
Southwest lntertie Project – North	Great Basin Transmission, LLC	+/-2000MW Transmission Line	$525M	December 31, 2022

<u>Round Mountain 500 kV Substation Voltage Support Project</u>

This project was submitted in the 2018 Request Window as a transmission solution to resolve the issue of high voltage in the 500 kV in Northern California under off-peak conditions and low voltage under peak load conditions and contingencies. The project was proposed by a PTO.

The proposed project consists of:

- A single +/- 500 Mvar STATCOM providing reactive support with continuous and controlled capability. The STATCOM can provide dynamic support to the grid.
- As part of this project, Round Mountain 500 kV bus will be converted to three bays of BAAH, which will also allow for the connection of the STATCOM.
- Install four 500 kV breaker and associated switches
- Connect lines and bank to the new BAAH
- Build a bus to connect the reactive support equipment
- Install new control building for the new equipment, if the space in the existing 500 kV control building is not adequate
- Upgrade protection to BAAH configuration
- Obtain permit and relocate the security fence
- Grade the new area

The estimated cost of the proposed Round Mountain Reactive Support 500 kV system is approximately $104 million for the voltage support equipment procurement and installation and approximately $54 million for upgrades to Round Mountain Substation to accommodate the installation. Total cost is estimated between $160 million and $190 million. The estimated in-service date of December 31, 2024.

The ISO reviewed this proposal and recommended the Round Mountain 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

Gates 500 kV Voltage Support Project

The following project was submitted in the 2018 Request Window as a transmission solution to resolve the issue of high voltage in the 500 kV in Central California under off-peak conditions when Diablo Canyon Power Plant retires. The project was proposed by a PTO. Various options were considered in the submittal.

Option 1 includes the following:

- Install two +/- 500 Mvar STATCOM segments providing a total of 1000 Mvars capacitive and 1000 Mvars inductive reactive support with continuous and controlled capability. Both STATCOMS could operate independently, providing redundancy and provide dynamic support to the grid even when one is out of service.
- Install one 500 kV breaker and associated switches in Bay 2
- Build new partial bay (two breakers) with breakers and switches on the West side of the bus
- Build a bus to connect the reactive support equipment
- Install breakers and reactive support equipment protection scheme in the existing 500 kV control building

- Relocate the security fence
- Grade the new area

The expected costs for the project are: $190M for the voltage support device procurement and installation and $50M for the upgrades to the Gates substation to accommodate the installation. Total estimated cost of the project is between $240M and $290M.

Option 2 includes the following:

- Install one +/-500 Mvar STATCOM and -500 Mvar shunt reactors at Gates 500 kV Substation. the proponent indicated that the hybrid system will provide a good balance of inductive and capacitive dynamic reactive support in addition to discrete inductive capability that could be controlled by the STATCOM. This hybrid system also provides redundancy in addressing the most critical condition which is high system voltages.
- Install one 500 kV breaker and associated switches in Bay 2
- Build new partial bay (two breakers) with breakers and switches on the West side of the bus
- Build a bus to connect the reactive support equipment
- Install breakers and reactive support equipment protection scheme in the existing 500 kV control building
- Relocate the security fence
- Grade the new area

The expected costs for the project might be slightly lower than Option 1 as the cost of the devices could be slightly lower. However, actual cost would still need to be determined based upon the desired shunt reactor number of steps (i.e. 2 X 250 Mvar).

Option 3 includes the following:

- Install one +0/-1000 Mvar SVC and +350 Mvar shunt capacitors at Gates 500 kV Substation. the proponent indicated that the hybrid system will provide a good balance of continuous and controlled inductive dynamic reactive support in addition to discrete capacitive reactive capability, controlled by the SVC. One initial drawback of this option is that the entire inductive reactive support is provided by the SVC, and in the event of a total SVC system failure the entire grid support would be lost. As part of the evaluation it could be investigated if installing two SVCs with separate controllers would be a better option or other methods of redundancy.
- Install one 500 kV breaker and associated switches in Bay 2
- Build new partial bay (two breakers) with breakers and switches on the West side of the bus
- Build a bus to connect the reactive support equipment

- Install breakers and reactive support equipment protection scheme in the existing 500 kV control building
- Relocate the security fence
- Grade the new area

The expected costs of this option might be slightly lower or equal to the cost of Option 1 as the cost of the SVC and shunt capacitor devices could be slightly lower. However, the desired level of redundancy required for the SVC would also impact the final cost for this option.

The estimated in-service date of the project is December 31, 2024.

The ISO reviewed this proposal and recommended the Gates 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

Round Mountain Dynamic Reactive 500 kV Transmission System

This was submitted in the 2018 Request Window as a transmission solution to resolve voltage stability concerns at or close proximity to the Round Mountain 500 kV Substation under anticipated 2020, 2023, and 2028 summer peak and off-peak conditions. The project was proposed by a non-PTO, NextEra Energy Transmission West, LLC. (NEET West) as a Reliability Transmission Project.

The proposed project consists of:

- A new ± 300 Mvar SVC (or STATCOM) connected to a new 500 kV bus through a single 500/23.2 kV step-up transformer, with a rating of approximately 340 MVA.
- A new 500 kV tie line connecting the high-side bus of the SVC (or STATCOM) step up transformer to PG&E's existing Round Mountain 500 kV substation, with a line rating of approximately 380 Amps Normal/Emergency.
- A new bay position at the Round Mountain 500 kV bus consisting of two new 500 kV breakers.

The estimated cost of the proposed Round Mountain Dynamic Reactive 500 kV Transmission System is approximately $75 Million in 2018 dollars. This cost excludes any incumbent costs for interconnection of proposed facilities. The estimated in-service date is December 1, 2024.

The ISO reviewed this proposal and recommended the Round Mountain 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

Gates or Diablo Dynamic Reactive 500 kV Transmission System

This project was submitted in the 2018 Request Window as a transmission solution to resolve the issue of high voltage in the 500 kV in Central California under various system conditions when Diablo Canyon Power Plant retires. The project was proposed by a non-PTO, NextEra Energy Transmission West, LLC. (NEET West) as a Reliability Transmission Project.

The project includes several following alternatives.

Diablo Dynamic Reactive 500 kV Transmission System Alternative

This alternative of the project includes:

- +100 /-275 Mvar SVC or STATCOM connected to the existing PG&E's Diablo Substation, which has breaker-and-a-half configuration
- 320 MVA 500/23.2 kV transformer,
- Tie-line: 350 A at 500 kV
- Circuit breaker at Diablo: 3000 A/63 kA (Interruptible)

Installation of a SVC or STATCOM at Diablo resolves the high voltage concerns at both Diablo and Gates Substations.

Gates Dynamic Reactive 500 kV Transmission System Alternative I

This alternative of the project includes:

- +100 /-250 Mvar SVC or STATCOM connected to the existing PG&E's Gates Substation, which has breaker-and-a-half configuration
- 290 MVA 500/23.2 kV transformer,
- Tie-line: 320 A at 500 kV
- Circuit breaker at Gates: 3000 A/63 kA (Interruptible)

This alternative mitigates only high voltage issues at the Gates Substation after the Diablo Canyon Power Plant retires.

Gates Dynamic Reactive 500 kV Transmission System Alternative II

This alternative of the project includes:

- +150 /-450 Mvar SVC or STATCOM connected to the existing PG&E's Gates Substation, which has breaker-and-a-half configuration
- 550 MVA 500/23.2 kV transformer,
- Tie-line: 610 A at 500 kV
- Circuit breaker at Gates: 3000 A/63 kA (Interruptible)

This alternative resolves the high voltage concerns at both Diablo and Gates Substations.

The estimated cost of the proposed Diablo Dynamic Reactive Transmission System is $65 million, Gates Alternative I is $65 million, and Gates Alternative II is $75 million in 2018 dollars. These costs exclude any incumbent costs for interconnection of proposed facilities.

The estimated in-service date is of the project is December 1, 2024.

The ISO reviewed this proposal and recommended the Gates 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

500 kV/230 kV Chorro Junction Substation

The following project was submitted in the 2018 Request Window as a transmission solution to address high voltage violations on the Gates and Diablo 500 kV buses. Additionally, the proponent indicated that the 500 kV/230 kV Chorro Junction Project would provide dynamic reactive support capable of absorbing or injecting VARS to provide transient stability for faults at the Midway, Tracy, and Tesla 500kV substations. The project was proposed by a non-PTO, California Transmission Development, LLC, an affiliate of LS Power as a Reliability Transmission Project.

The 500 kV/230 kV Chorro Junction Project would break the Diablo Canyon - Gates 500 kV transmission line at the Diablo Canyon - Mesa 230 kV & Morro Bay – Mesa 230 kV line crossing and interconnect both 500 kV lines in a new four-position ring bus substation located on property adjacent to and just west of the 230 kV line crossings. A +/- 500 Mvar Static Var Compensator would connect to a third position in the 500 kV ring bus. A 500/230 kV transformer will connect the fourth position of the 500 kV ring bus to the new five-position 230 kV ring bus at Chorro Junction Substation. The Project would break the Morro Bay - Diablo Canyon 230 kV and Morro Bay – Mesa 230 kV transmission lines and loop them into the new 230kV ring bus. The Diablo Canyon – Mesa 230 kV line will be left as is.

The Project aims to address the high voltage and possible dynamic instability issues on the 500 kV system in Southern PG&E bulk system by:

- Connecting the 500 kV system to loads on 230kV system and;
- Installing a +/- 500 Mvar Static Var Compensator on the 500 kV bus to provide reactive support by absorbing reactive power.

A commercial operation date of June 1, 2023 was proposed.

The ISO reviewed this proposal and recommended the Gates 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

500 kV Wells Place Substation

This project was submitted in the 2018 Request Window as a transmission solution to address high voltage violations on the 500 kV transmission system in Northern California. Additionally, the proponent indicated that the 500 kV Wells Place Substation Project would provide dynamic reactive support capable of absorbing or injecting reactive power to provide transient stability for contingencies otherwise resulting in tripped load and also would also protect against possible low voltage conditions under contingency conditions for Heavy Summer peak conditions with high COI flows in North to South direction.

The project was proposed by a non-PTO, California Transmission Development, LLC, an affiliate of LS Power, as a Reliability Transmission Project.

The 500 kV Wells Place Substation Project would break the Round Mountain – Table Mountain #1 500 kV transmission line at approximately the midpoint of the transmission line (45 miles south of Round Mountain) and interconnect both 500 kV lines in a new three-position ring bus substation located on property adjacent to and just east of the 500 kV corridor. A +/- 500 Mvar Static Var Compensator would connect to a third position in the 500 kV ring bus. The Round Mountain – Table Mountain #2 500 kV line would be left as is.

The Project aims to address the high voltage issues and possible transient stability and low voltage issues on the 500 kV system in Northern California by installing a +/- 500 Mvar Static Var Compensator on the new 500 kV bus created by looping in Round Mountain – Table Mountain #1 line.

A commercial operation date June 1, 2023 was proposed.

The ISO reviewed this proposal and recommended the Round Mountain 500 kV Dynamic Voltage Support project identified in section 2.4.3 above.

Southwest Intertie Project - North (SWIP - North)

The project was submitted in the 2018 Request Window as a transmission solution to address thermal overloads on the 500 kV and 230 kV systems in northern California and to improve low voltage issues in northern California during summer peak conditions with high COI N-S flows. The project was proposed by a non-PTO, Great Basin Transmission (GBT), LLC, an affiliate of LS Power, as a Reliability Transmission Project. The project was also submitted as part of an economic study request as set out in chapter 4 and an interregional transmission project as set out in chapter 5.

The SWIP transmission project is an approximately 500-mile, 500 kV single circuit AC transmission line that connects the Midpoint 500 kV substation in southern Idaho, the Robinson Summit 500 kV substation, and the Harry Allen 500 kV substation.

The proponent indicated that SWIP is expected to have a bi-directional WECC-approved path rating of approximately 2,000 MW, and that in addition to addressing the reliability needs identified in ISO Transmission Plan, the SWIP is an important regional project, and a critical component to spur additional development of renewable power generation resources throughout the western United States.

SWIP-North is the proposed 275-mile northern portion of the SWIP that would connect Robinson Summit with Midpoint (near Twin Falls, Idaho), and includes a 500 kV 35% fixed series capacitor bank near each terminus.

Figure 2.4-2 SWIP - North Preliminary Route

Upon completion of SWIP - North, a capacity sharing arrangement would be triggered between GBT and NV Energy across the existing ON Line (Midpoint to Harry Allen) and SWIP - North. GBT will retain control of approximately 1000 MW of the planned 2000 MW capacity in both directions on SWIP - North, and will have a contract path to the ISO at Harry Allen. Therefore, this submittal contemplates the availability of 1000 MW of capacity from Midpoint to Harry Allen available to the ISO.

The proposed operation date of the project is December 31, 2022.

The planning level cost of the project is $525 Million in 2018 dollars. This cost includes 500 kV series capacitors, interconnection costs and some additional planning level contingency. It does not include any network upgrades that may or may not be identified by interconnection studies.

The ISO reliability assessment did not identify any reliability needs that the the SWIP – North Project was required to mitigate.

The ISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Tier Transmission Group (NTTG) planning regions, respectively. The SWIP - North line is not physically connected to ISO-controlled facilities. Please refer to chapter 5. The scheduling capacity from the Harry Allen end of the ISO's approved Harry Allen-Eldorado transmission line to Robinson Summit also creates opportunity for the submitted project to provide benefits to the ISO, in which case the ISO can select to participate in the project – if that is found to be the preferred solution to meeting the ISO's regional need.

2.4.5 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-drive. 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 # 1, #2 and # 3 transmission lines
- Moss Landing-Las Aguilas 230kV transmission line

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 the 500 kV system in Central California after Diablo Canyon Power Plant retires. In the northern part of the 500 kV system high voltages were observed under normal system conditions, and low voltages observed with contingencies. To address voltage issues identified in central and northern PG&E bulk system two projects are recommended for approval.

- Gates 500 kV Dynamic Voltage Support
- Round Mountain 500 kV Dynamic Voltage Support.
    - Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round

Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place.

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 below.

Table 2.5-1: Humboldt load and generation assumptions

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)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
HMB-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	116	2	19	1	112	4	3	0	0	0	0	0	5	0	259	176
HMB-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	122	5	32	0	117	4	3	0	0	0	0	0	5	0	259	174
HMB-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	130	9	48	0	121	4	3	0	0	0	0	0	5	0	259	175
HMB-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – weekend morning.	76	2	19	15	59	4	3	0	0	0	0	0	5	0	259	65
HMB-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – weekend morning.	77	3	32	26	47	4	3	0	0	0	0	0	5	0	259	25
HMB-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	145	2	19	0	143	4	3	0	0	0	0	0	5	0	259	172
HMB-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	139	4	32	0	134	4	3	0	0	0	0	0	5	0	259	173
HMB-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	163	9	48	0	155	4	3	0	0	0	0	0	5	0	259	172
HMB-2023HS-SP-P7	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	121	0	32	0	120	4	3	0	0	0	0	0	5	0	259	90
HMB-2020-HR-P7	Sensitivity	2020 summer peak load conditions with hi renewable dispatch sensitivity	81	2	19	19	59	4	3	0	0	0	0	0	5	0	259	164
HMB-2023-HR-P7	Sensitivity	2023 summer peak load conditions with hi renewable dispatch sensitivity	77	3	32	31	42	4	3	0	0	0	0	0	5	0	259	29

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 2.5-2 that were not modeled in the study scenario base cases.

Table 2.5-2: Humboldt Approved Project not Modeled in Base Case

Project Name	TPP Approved In	Current ISD
Bridgeville – Garberville No. 2 115 kV Line	2011-2012 TPP	Jan 2024

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 2018-2019 reliability assessment of the PG&E Humboldt Area has identified several reliability concerns consisting of thermal overloads under Category P6 contingencies. The areas where additional mitigation requirements were identified are discussed below.

Within the Humboldt Area there were a number of P6 contingencies that resulted in overloads were observed in the base and sensitivity scenarios. The overloaded facilities and contingencies were related to Non-BES facilities per the ISO Planning Standards so no mitigation has been recommended for approval.

Summary of review of previously approved projects

There is one previously approved active project 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. Table 2.5-3 shows the final recommendation for this one project not modeled in the study cases:

Table 2.5-3: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
Bridgeville – Garberville No. 2 115 kV Line	P6

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 4 MW of AAEE and more than 32 MW of installed behind-the-meter PV reduced the Humboldt Area load in winter 2023. This year's reliability assessment for Humboldt Area included "2023 Sumer peak with high CEC forecast" and "2020 Summer peak with high renewable" sensitivity cases for which modeled no AAEE. Comparison between the reliability issues identified in the 2023 winter peak baseline case and the sensitivity cases shows that following facility overloads are potentially avoided due to reduction in net load.

Table 2.5-4: Reliability Issues in Sensitivity Studies

Facility	Category
Humboldt – Bridgeville 115 kv Line	P6
Humboldt – Trinity 115 kv Line	P6
Humboldt – Humboldt JT 60 kv Line	P1
Eureka – Humboldt Bay 60 kv Line	P1
Carlotta – Rio Dell TP 60 kv Line	P1
Carlotta – Swains Flat 60 kv Line	P1
Swains Flat – Bridgeville 60 kv Line	P1
Bridgeville – Fruitland JT 60 kv Line	P0
Fruitland – Fort Seward 60 kv Line	P1
Fort Seward – Garberville 60 kv Line	P0

Furthermore, 4 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 2018-2019 Transmission Plan, several reliability concerns were identified for the PG&E Humboldt. These concerns consisted of thermal overloads and voltage concerns under Categories P6 contingency conditions. There are no new projects recommended for approval.

In regards to the previously-approved on-hold project, one project was on hold in the Humboldt Area that is recommended to be canceled in this cycle.

- Bridgeville – Garberville No. 2 115 kV Line project

There are no new projects recommended for approval in the Humboldt area.

2.5.2 North Coast and North Bay Areas

2.5.2.1 Area Description

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

The North Coast area covers approximately 10,000 square miles north of the Bay Area and south of the Humboldt area along the northwest coast of California. It has a population of approximately 850,000 in Sonoma, Mendocino, Lake and a portion of Marin counties, and extends from Laytonville in the north to Petaluma in the south. The North Coast area has both coastal and interior climate regions. Some substations in the North Coast area are summer peaking and some are winter peaking. 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 provided below.

Table 2.5-5: North Coast and North Bay 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)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	NCNB-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,571	23	388	56	1,492	16	10	0	0	0	0	0	25	12	1,534	709
2	NCNB-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,621	46	552	6	1,569	16	10	0	0	0	0	0	25	12	1,534	709
3	NCNB-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,695	88	811	0	1,607	16	10	0	0	0	0	0	25	12	1,534	705
4	NCNB-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – weekend morning.	734	17	388	306	411	16	10	0	0	0	0	0	25	3	1,534	704
5	NCNB-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – weekend morning.	751	34	552	464	253	16	10	0	0	0	0	0	25	2	1,534	702
6	NCNB-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,600	22	388	0	1,578	16	10	0	0	0	0	0	25	12	1,534	707
7	NCNB-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,182	23	388	0	1,159	16	10	0	0	0	0	0	25	3	1,534	709
8	NCNB-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours between 16:00 and 18:00.	1,731	86	811	0	1,645	16	10	0	0	0	0	0	25	12	1,534	707
9	NCNB-2023HS-SP	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	1,621	0	552	6	1,615	16	10	0	0	0	0	0	25	12	1,534	709
10	NCNB-2020-HR	Sensitivity	2020 summer peak load conditions with hi renewable dispatch sensitivity	1,182	23	388	384	775	16	10	0	0	0	0	0	25	3	1,534	709
11	NCNB-2023-HR	Sensitivity	2023 summer peak load conditions with hi renewable dispatch sensitivity	751	34	552	547	170	16	10	0	0	0	0	0	25	2	1,534	707
12	NCNB-2028-QF	Sensitivity	2027 summer peak load conditions with QF retirement sensitivity	1,695	88	0	0	1,607	16	10	0	0	0	0	0	25	12	1,534	701

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 2018-2019 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. 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 were observed in the North Coast and North Bay area.

Bus Upgrade – Fulton 115kV

Category P2 of a bus-tie breaker failure results in an overload on the Bellvue=Pennigrove 115kV line. The overload is due to both the Fulton-Santa Rosa #1 and Fulton-SantaRosa #2 getting tripped as a result of the P2 contingency. The ISO is working with PG&E to rearrange the termination of the lines on the bus sections. If this is not feasible the alternative will be to install a sectionalizing breaker in the Fulton 115 kV bus. The estimated cost of the sectionalizing breaker is $10 to 20 million. The ISO will continue to work with PG&E with further assessment in the next planning cycle.

Bus Upgrade – Lakeville 115kV

Category P2 of a bus-tie breaker failure results in an overload on the STHELNJ1 - PUEBLO 115kV Line.

To mitigate the contingency will require the installation of a sectionalizing breaker to be installed on 115 kV bus section “D”at Lakeville. The estimated cost of the bus upgrade is $10 to 15 million. The ISO will continue to monitor the load forecast in this area with further assessment in the next planning cycle..

Protection Upgrade – Fulton 115kV

Category P5 contingency of a failure of non-redundant relay causes an overload on multiple 60kV and 115kV for a fault on the Fulton 230 KV BUS #1. The ISO recommends PG&E to install redundant protection at Fulton substation.

Details of the reliability assessment are presented in Appendix B.

2.5.2.4 Request Window Submissions

There were no project submissions in the North Valley area in the 2018 request window.

2.5.2.5 Consideration of Preferred Resources and Energy Storage

As presented in section 2.5.2, about 54 MW of AAEE and more than 113 MW of installed behind-the-meter PV reduced the North Coast North Bay Area load in 2022. This year's reliability assessment for North Coast North Bay Area included a "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 69 MW less behind-the-meter PV output. A comparison between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case shows that facility overloads shown in Table 2.5-6 are potentially avoided due to the reduction in net load:

Table 2.5-6: Reliabillity Issues in Sensitivity Studies

Facility	Category
Cache J2-Redbud J2 115 kV Line	P6
Indian Valley-Lucern J1 115kV Line	P6

Furthermore, about 13 MW of demand response and 10 MW of 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.

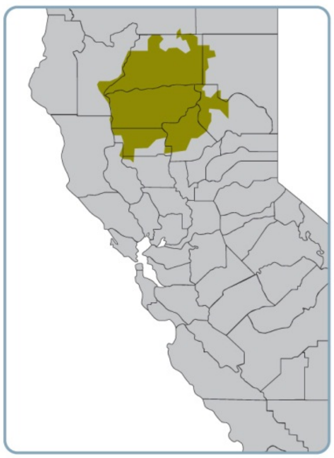
2.5.2.6 Recommendation

Based on the studies performed for the 2018-2019 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.

2.5.3 North Valley Area

2.5.3.1 Area Description

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



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

Historically, North Valley experiences its highest demand during the summer season; however, a few small areas in the mountains experience highest demand during the winter season. 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 marker 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 provided below.

Table 2.5-7: North Valley load and generation assumptions

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)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
NVLY-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 18:00.	970	15	254	48	907	36	28	0	0	0	103	39	1,774	1,472	1,064	821
NVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	1,012	29	353	51	932	37	28	0	0	0	103	69	1,774	1,470	1,064	821
NVLY-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 18:00.	1,012	29	353	51	932	37	28	0	0	0	103	69	1,774	1,450	1,064	785
NVLY-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – hours ending 12:00.	319	11	254	201	108	36	28	0	0	0	103	7	1,774	778	1,064	250
NVLY-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	320	21	353	297	2	37	28	0	0	0	103	0	1,774	486	1,064	748
NVLY-2023-SP-HiCEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	1,012	0	353	51	961	37	28	0	0	0	103	93	1,774	1,451	1,064	815
NVLY-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	320	21	353	350	51	37	28	0	0	0	103	0	1,774	423	1,064	886
NVLY-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	941	15	254	252	675	36	28	0	0	0	103	69	1,774	1,472	1,064	351
NVLY-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	1,012	29	353	51	932	37	28	0	0	0	103	0	1,774	1,339	1,064	651

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

2.5.3.3 Assessment Summary

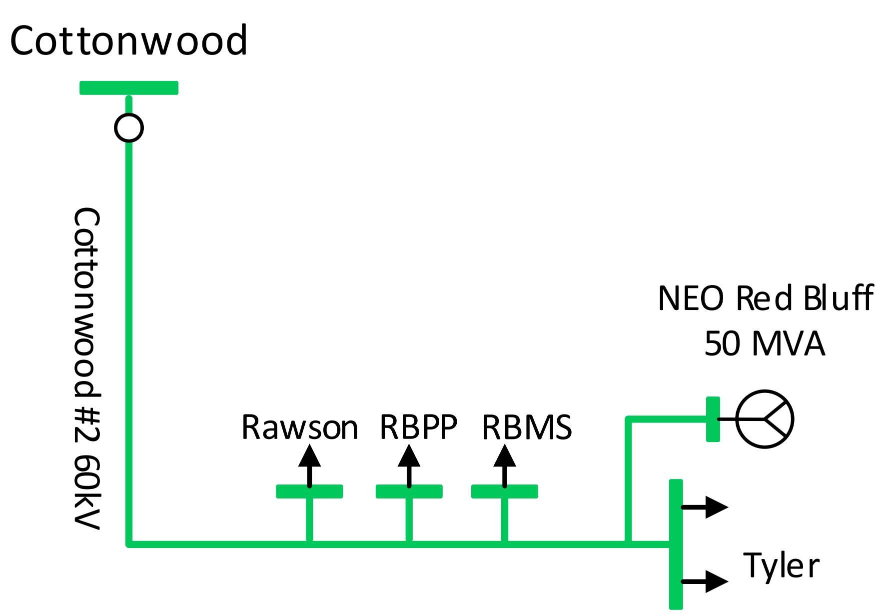
The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2018-2019 reliability assessment of the PG&E North 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 and will mitigate them if the issues are identified in future assessments.

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

Tyler 60 kV Shunt Capacitor Project

Figure 2.5-1 shows the schematic diagram of the area served radially by Cottonwood #2 60 kV line. Voltage deviation issues were identified in the area in last year's reliability assessment in the medium to long term under P1 contingency of losing NEO Red Bluff 50 MW generator. In this year's assessment, in addition to voltage deviation that occurs in all 3 study years, there are voltage range issues as well as overload on Cottonwood #2 60 kV line in the long. The reason for overload is due to low voltage following the contingency. The ISO is recommending the approval of the "Tyler 60 kV Shunt Capacitor Project" with the scope of installing 2x10 Mvar capacitor bank at Tyler 60 kV bus to address both voltage criteria violations and thermal overload issues. The estimated cost of this project is between $5.8M to $7.0M and in-service date is May 2022.

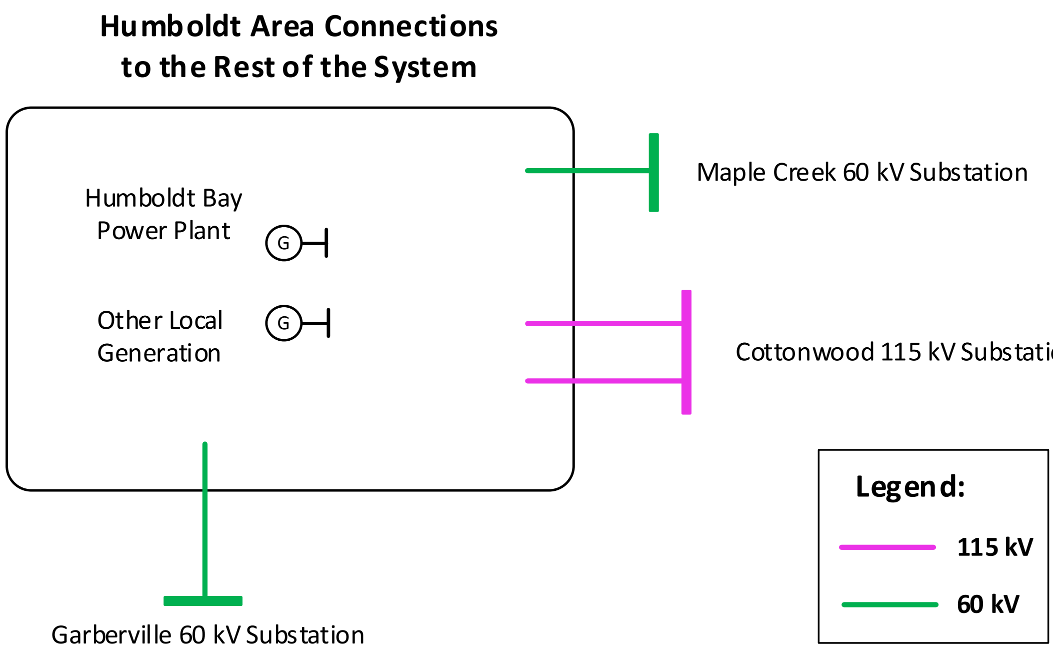
Figure 2.5-1: Area with voltage deviation issue following generator outage



Cottonwood 115kV Bus Sectionalizing Breakers Project

Figure B2.3-3 shows the schematic diagram of the area impacted by the bus tie-breaker (P2-4) contingency on Cottonwood 115 kV bus. The main issue is in the Humboldt area in which such contingency trips two of the 115 kV lines supplying Humboldt area. With two 115 kV lines tripped, the 60 kV connection between Cascade and Humboldt area experiences significant overload. To address the issue, The ISO is recommending approval of the "Cottonwood 115 kV bus Sectionalizing Breakers" project so that both 115 kV connections to Humboldt area are not tripped due to the bus tie-breaker fault. The estimated cost of this project is $8.5M to $10.5M and in-service date is May 2022.

Figure 2.5-2 Area impacted by Bus tie-breaker (P2-4) contingency on Cottonwood 115 kV bus



Details of the reliability assessment are presented in Appendix B.

2.5.3.4 Request Window Submissions

There were two project submissions in the North Valley area in the 2018 request window by PG&E.

- Tyler Shunt Capacity Project
- Cottonwood 115 kV Bus Sectionalizing Breakers

The Tyler Shunt Capitor Project and the Cottonwood 115 kV Bus Sectionaling Breaker projects were reviewed above and are recommended for approval.

2.5.3.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1, about 23 MW of AAEE and around 190 MW of installed behind-the-meter PV reduced the North Valley Area load in 2022 by about 9%. This year's reliability assessment for North Valley Area included "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 40 MW less behind-the-meter PV output. A comparison of the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case shows that following facility overloads are potentially avoided due to reductions in net load:

Table 2.5-8: Reliability Issues in Sensitivity Studies

Facility	Category
Cascade - Cottonwood 115 kV Line	P6
Palermo - Wyandotte 115 kV Line	P6
Keswick - Cascade 60 kV	P2
Sycamore Creek - Notre Dame - Table Mountain 115 kV Line	P2
Table Mountain - Butte #1 115 kV	P2
Paradise - Table Mountain 115 kV	P2

Furthermore, more than 36 MW of demand response is modeled in 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 2018-2019 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 Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Valley area.

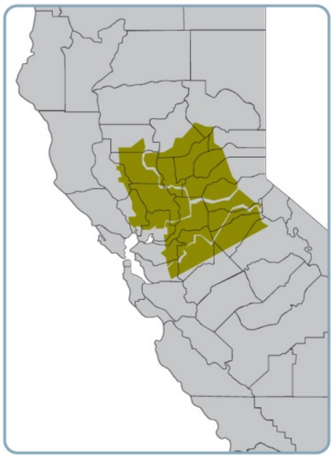
To address reliability concerns not associated and addressed by previously approved projects, the ISO recommends approval for the following two projects in the North Valley area.

- Tyler 60 kV Shunt Capacitor
- Cottonwood 115 kV Bus Sectionalizing Breaker

2.5.4 Central Valley Area

2.5.4.1 Area Description

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



Sacramento Division

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

Sierra Division

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

Stockton Division

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

Stanislaus Division

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

Historically, the Central Valley area experiences its highest demand during the summer season. 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 provided below.

Table 2.5-9 Central Valley 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)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
CVLY-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 19:00.	4,067	71	1,037	0	3,996	102	59	0	841	0	0	0	0	0	3,939	1,221
CVLY-2020-SpOP	Baseline	2020 spring off-peak load conditions. Off-peak load time - hours ending 12:00.	1,460	52	1,037	820	588	102	59	0	841	832	0	0	0	0	3,939	1,177
CVLY-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	3,876	71	1,037	1027	2,778	102	59	0	841	832	0	0	0	0	3,939	653
CVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	4,251	141	1,354	0	4,110	103	59	0	841	0	0	0	0	0	3,939	1,221
CVLY-2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,460	105	1,354	1137	218	103	59	0	841	742	0	0	0	0	3,939	130
CVLY-2023-SP-Hi-CEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	4,251	0	1,354	0	4,251	103	59	0	841	0	0	0	0	0	3,939	1,252
CVLY-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	1,460	105	1,354	1340	15	103	59	0	841	800	0	0	0	0	3,939	145
CVLY-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 19:00.	4,519	268	1,741	0	4,251	104	59	0	841	0	0	0	0	0	3,939	1,252
CVLY-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	4,519	268	1,741	0	4,251	104	59	0	841	0	0	0	0	0	3,939	1,252

The transmission modeling assumptions were consistent with the general assumptions described in section 2.3 with an exception of the approved project shown in Table 2.5-10 which was not modeled in the base cases.

Table 2.5-10: Central Velley Approved Project not Modeled in Base Case

Project Name	TPP Approved In	Current ISD
Atlantic – Placer 115 kV Line	2012-2013 TPP	Dec 2021

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 2018-2019 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 Valley area.

Vaca – Plainfield 60 kV Line Overload

The load at Plainfield and Winters substation is forecast to increase and reach around 32 MW by year 2023 and 34 MW by year 2028. The ISO is recommending PG&E to reconfigure Plainfield substation and connect load bank #1 to the E. Nicolaus substation. The ISO will continue to monitor the load forecast in this area in future planning cycles.

Details of the reliability assessment are presented in Appendix B.

Summary of review of previously approved projects

There was one previously approved project in the Central Valley Area that was not modeled in the study cases **Error! Reference source not found.** below shows the recommendation for the project not modeled in the study cases.

Table 2.5-11: Recommendations for previously approved projects not modeled in the study cases

Project Name	Recommendation
Atlantic – Placer 115 kV Line	Cancel

Details of the review of previously approved project not modeled in study cases are presented in Appendix B. High level discussion of the project review and recommendation is provided below:

Atlantic-Placer 115 kV Line

Figure 2.5-3 shows the 115 kV system from Drum to Gold Hill to El Dorado PH substations. The entire load in the area is currently served from two 230/115 kV transformers at Gold Hill, the Drum – Higgins 115 kV line, and 6 generating units connected to the system in the area. This project was put on hold in the 2016-2017 transmission planning process and was recommended to remain on-hold in last year's planning cycle to perform further assessment. In summary similar issues as identified in previous planning cycles were identified in this area in the 2018-2019 transmission planning process reliability assessment.

- P6 and P2 contingencies that trips both Gold Hill 230/115 kV transformers under peak load will causes voltage collapse in the area.
- P2-4 contingency on Gold Hill 115 kV bus causes severe overload on Drum – Higgins 115 kV line. The reason is that the contingency opens both the Gold Hill – Placer lines from Gold Hill end while the load on the double tap connections to these lines such as Horseshoe will remain connected, which is significantly beyond the capacity of the Drum – Higgins 115 kV line.

Figure 2.5-3 The 115 kV Transmission System from Drum to Gold Hill

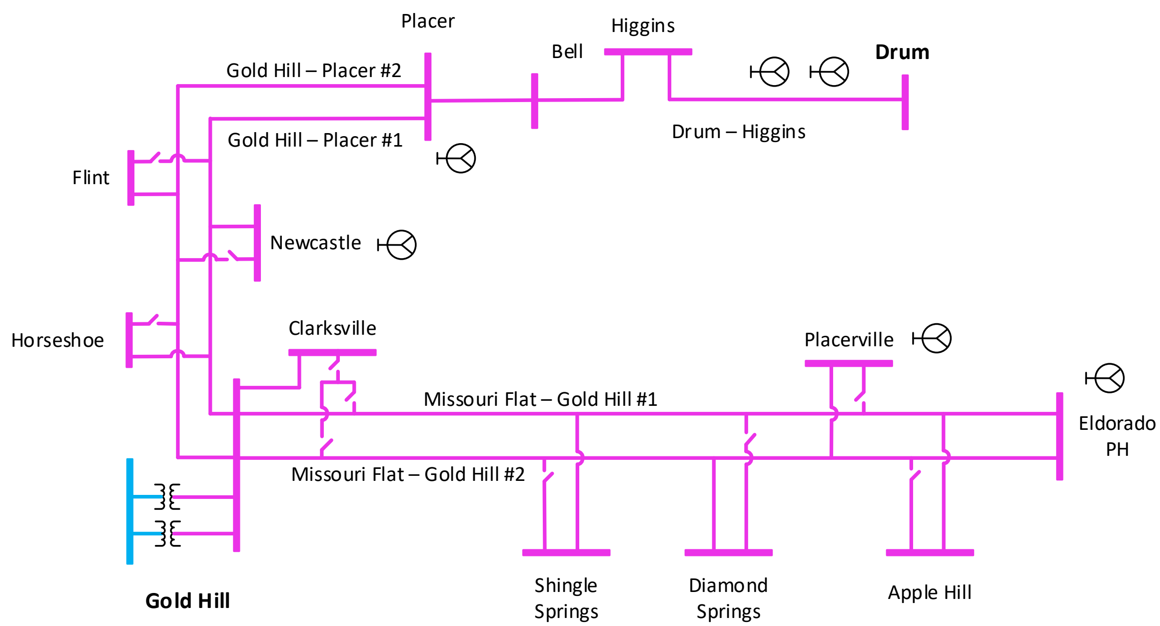
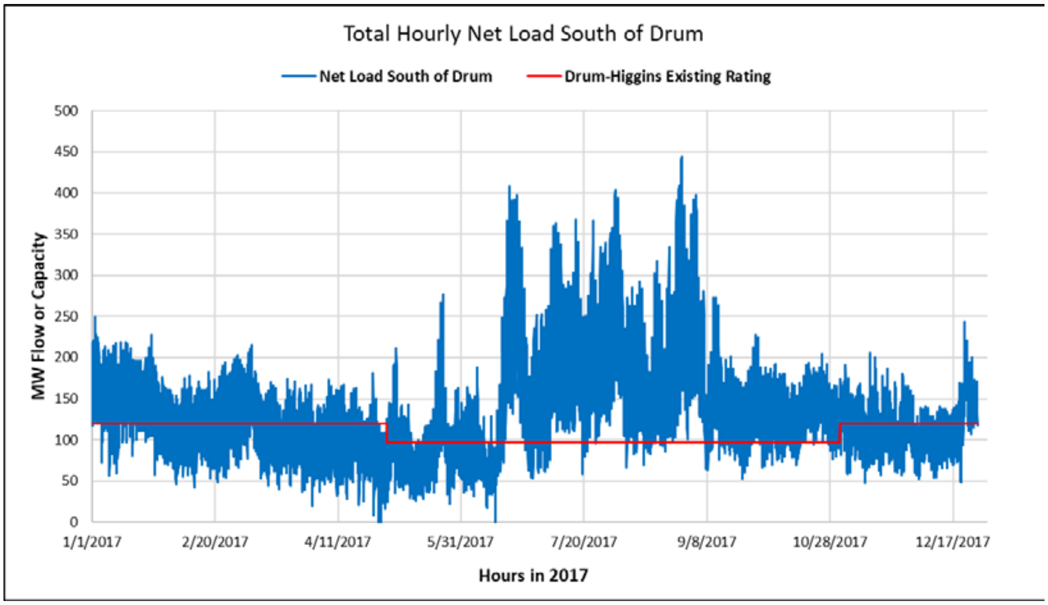


Figure 2.5-4 shows the hourly total flow on two Gold Hill transformers and Drum–Higgins 115 kV line in 2017along with the existing summer and winter emergency ratings of Drum Higgins line. The graph shows that almost at any time, if one Gold Hill transformer is taken out for maintenance, the contingency of the next transformer causes overload on the Drum–Higgins 115 kV line.

Figure 2.5-4 Hourly total flow on Gold Hill Transformers and Drum-Higgins 115 kV Line in 2017



Another aspect of existing transmission system in the area is that the P7 contingency of both Missouri Flat – Gold Hill 115 kV lines will result in consequential tripping of the entire load connected to the 115 kV network from Gold Hill to El Dorado PH that could reach 160 MW under peak conditions. While this is not a criteria violation, it should be taken into account in developing transmission plan for the area.

A P2-1 overload on Missouri Flats – Gold Hill lines 115 kV were identified in last year's analysis and was addressed by switching load in the area. This year's results show that given the load growth in the area, the P2-1 overload shows up in the long term.

Alternatives to Atlantic – Placer 115 kV Project:

Considering the above results, 3 alternatives were considered to address the identified constraints:

Alternative 1: Upgrade Drum-Higgins 115 kV line

This Alternative is feasible with a cost estimate of around $81M. The estimates assume that the parallel conductor sections will only be replaced with a single conductor.

Alternative 2: Add a third 230/115 kV transformer at Gold Hill

This Alternative is feasible with a cost estimate of around $22M.

Alternative 3: Bring another source to the Placerville/Shingle Spring area utilizing the existing 230 kV network in the area. This alternative is under review by PG&E for feasibility assessment and cost estimate.

The ISO is recommending to cancel the Altlantic Placer 115 kV project and to approve the installation of a third 230/115 kV transformer at Gold Hill substation with an estimated cost of $22 million and an in-service date of 2024.

The ISO will continue to monitor the load in the Placerville and Eldorado area to address the forecast P2-1 overloads in the 2028 timeframe and continue to assess the feasibility of alternative 3 to address the P2-1 and P7 if required in future planning cycles.

2.5.4.4 Request Window Submissions

There were two projects submitted into the 2018 Request Window.

Tesla 230 kV Bus Series Reactor

PG&E submitted the Tesla 230 kV Bus Series Reactor project in the 2018 Request Window. The Tesla substation is connected to the bulk transmission system via five 500 kV lines and fourteen 230 kV Lines. In addition, Tesla Substation has three 500/230 kV and two 230/115 transformer banks. Due to the number of bulk system connections and its relative proximity to generation facilities, Tesla has had issues with high fault current levels. PG&E's System Protection Department has identified a need to reduce the fault current on the Tesla 230 kV Bus due to overstressed Circuit Breakers. This concern is significant since the level will exceeded the maximum PG&E system design limit of 63 kA. The short circuit duty study identified 11 breakers at Tesla 230kV bus overstressed during certain fault condition, and this project is to mitigate the overstressed breaker issues without replacing these breakers. It will also maintain electrical worker safety from arc flash or inadequate personal grounding and will reduce the risk of equipment failure from a fault.

There are existing bus reactors between Tesla 230 kV bus sections C-D and D-E, which are 8 ohms and 4 ohms equivalent, respectively. The project proposes to:

- Replace existing reactors with 18 ohm equivalent bus reactors between bus sections C-D and D-E
- Re-arrange various 230 kV line connections on the Tesla 230kV Bus
- Make protection system upgrades as required

This project is expected to cost between $24 million to $29 million. The in-service date for this prject is May 2023. The ISO recommends the approval of the Tesla 230 kV Bus Series Reactor project.

Weber – Manteca 230 kV Project

NextEra Energy Transmission West, LLC (NEET 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. This project is expected to cost $35 million (excluding any incumbent cost) with an estimated in-service date of December 2024.

The ISO is currently working with PG&E to evaluate substation upgrade options to address P2-4 issues at Bellota and Tesla substations. In the short term, the ISO recommends SPS to address the issue. A Benefit to Cost Ratio (BCR) analysis will be required to justify the economic benefits of preventing load loss under P6 contingency that is not a reliability criteria violation.

2.5.4.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1, about 160 MW of AAEE and more than 800 MW of installed behind-the-meter PV reduced the Central Valley Area load in 2022 by about 11%. This year's reliability assessment for the Central Valley Area included the "high CEC forecast" sensitivity case for year 2022 which modeled no AAEE and about 170 MW less behind-the-meter PV output. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case show that the facility overloads shown in Table 2.5-12 are potentially avoided due to reduction in net load:

Table 2.5-12: Reliability Issues in Sensitivity Studies

Facility	Category
Drum - Higgins 115 kV line	P7
Stanislaus-Melones-Manteca 115 kV Line No. 1	P2
Tesla - Tracy 115 kV Line	P2, P6
Eldorado - Missouri Flat 115 kV No. 1 Line	P2-1
Stanislaus-Melones-Manteca 115 kV Line	P2
Bellota - Riverbank - Melones 115KV Line	P2
Stanislaus-Melones-Riverbank 115 kV Line	P2
Drum - Grass Valley - Weimar 60 kV Line	P3

Furthermore, more than 100 MW of demand response and 34 MW of battery energy storage 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 2018-2019 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.

In regards to the previously-approved on-hold projects, one project was on hold in the Central Valley Area that is recommended to be canceled in this cycle.

- Atlantic-Placer 115 kV Line project

The following two new project are recommended for approval in the Central Valley area.

- Gold Hill 230/115 kV Transformer Addition project
- Tesla 230 kV Bus Series Reactor project

2.5.5 Greater Bay Area

2.5.5.1 Area Description

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

The East Bay sub-area includes cities in Alameda and Contra Costa counties. Some major cities are Concord, Berkeley, Oakland, Hayward, Fremont and Pittsburg. This area primarily relies on its internal generation to serve electricity customers. The South Bay sub-area covers approximately 1,500 square miles and includes Santa Clara County. Some major cities are San Jose, Mountain View, Morgan Hill and Gilroy. Los Esteros, Metcalf, Monta Vista and Newark are the key substations that deliver power to this sub-area. The South Bay sub-area encompasses the De Anza and San Jose divisions and the City of Santa Clara. Generation units within this sub-area include Calpine's Metcalf Energy Center, Los Esteros Energy Center, Calpine Gilroy Power Units, and SVP's Donald Von Raesfeld Power Plant. In addition, this sub-area has key 500 kV and 230 kV interconnections to the Moss Landing and Tesla substations. 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 2.5-143.

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3 with the exception of the following previously approved project which is not modeled in the base cases:

Table 2.5-13: Greater Bay Area previously approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
Jefferson – Stanford #2 60 kV Line	2010-2011 TPP	On-Hold

Table 2.5-14 Greater Bay Area load and generation assumptions

Base Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV Installed (MW)	BTM-PV Output (MW)	Net Load (MW)	Demand Total (MW)	Demand D2 (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)
GBA-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 18:00.	8,741	127	1,323	192	8,422	183	95	5	21	4	263	97	0	0	7,848	5,118
GBA-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours ending 19:00.	7,901	122	1,323	0	7,779	183	95	5	21	0	263	11	0	0	7,848	3,174
GBA-2020-SpOP	Baseline	2020 spring off-peak load conditions. Off-peak load time - hours ending 12:00.	5,072	92	1,323	1045	3,935	183	95	5	21	21	263	13	0	0	7,848	1,684
GBA-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	7,320	127	1,323	1310	5,883	183	95	5	21	21	263	176	0	0	7,848	1,896
GBA-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	9,121	253	1,900	275	8,593	184	95	5	21	3	263	136	0	0	7,848	4,742
GBA-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 18:00.	8,192	199	1,900	19	7,974	184	95	5	21	0	263	8	0	0	7,848	4,226
GBA-2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	5,109	187	1,900	1596	3,326	184	95	5	21	20	263	5	0	0	7,848	527
GBA-2023-SP-Hi-CEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	9,121	0	1,900	275	8,846	184	95	5	21	3	263	122	0	0	7,848	5,477
GBA-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	5,109	187	1,900	1881	3,041	184	95	5	21	21	263	140	0	0	7,848	281
GBA-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 18:00.	9,514	480	2,795	281	8,753	184	95	5	21	2	263	55	0	0	7,848	4,091
GBA-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours ending 19:00.	8,618	473	2,795	0	8,145	184	95	5	21	0	263	28	0	0	7,848	3,269
GBA-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	9,514	480	2,795	281	8,753	184	95	5	21	2	263	55	0	0	7,848	4,142

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 2018-2019 reliability assessment of the PG&E Greater Bay Area 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.

Christie-Sobrante 115 kV Line Reconductor

Categories P2 and P7 contingency overloads were identified in the Oleum-Martinez 115 kV system. The P2 overloads are due to loss of supply from Sobrante. The P7 overloads are due to loss of Sobrante-G 115 kV DCTL. The ISO is recommending approval of the "Christie-Sobrante 115 kV Line Reconductor" project which includes reconductoring of the limited sections of the line. The estimated cost of this project is $10.5M and the forecast in-service date is 2022. In the interim, the area will rely on the operating action plan. There may be an opportunity to perform this work in conjunction with the previously approved North Tower Looping Project.

Regarding the overloads resulting from P2 contingencies at the Sobrante substation, PG&E has notified the ISO that the Sobrante 115 kV bus is currently undergoing an upgrade as part of another PG&E project. This other project is expected to rearrange and swap lines between Sobrante 115 kV bus sections D and E. The ISO will continue to monitor issues resulting from P2 contingencies at Sobrante 115 kV in future cycles.

Moraga-Sobrante 115 kV Line Reconductor

Categories P2 overloads were identified on the Moraga-Sobrante 115 kV line starting in 2020. The ISO is recommending approval of the "Moraga-Sobrante 115 kV Line Reconductor" project. The estimated cost of this project is between $12M to $18M and an in-service date of 2023 is forecast. In the interim, the area will rely on the operating action plan.

Ravenswood 230/115 kV Transformer #1 Limiting Facility Upgrade

Categories P2 and P6 contingency overloads in baseline and P1 and P3 overloads in sensitivity scenarios were identified on the Ravenswood 230/115 kV transformer #1. The transformer rating is limited by rating of substation equipment. The ISO is recommending approval of the "Ravenswood 230/115 kV LineTransformer #1 Limiting Facility Upgrade " project which includes upgrading of the limiting substation equipment on the Ravenswood 230/115 kV LineTransformer #1. The estimated cost of this project is between $1.5M to $2.0M and in-service date is forecast of December 2018.

Summary of review of on-hold projects

The previously approved project shown in Table 2.5-15 was put on hold in the last cycle but is recommended for cancellation in this planning cycle.

Table 2.5-15: Recommendation for Previously Approved on-hold Projects

Project Name	Recommendation
Jefferson – Stanford #2 60 kV Line	Cancel

Details of the review of previously approved on-hold projects are presented in Appendix B.

Below is the high level discussion of the review of the on-hold project:

Jefferson - Stanford #2 60 kV Line

The *Jefferson - Stanford #2 60 kV Line* project was put on hold due load uncertainty in the area. Some 60 kV lines and 115/60 kV transformers in Peninsula area were found to be overloaded in all peak and sensitivity cases for P6 and P7 contingencies due to the interim configuration implemented for not modeling this project. The interim configuration avoids potential P1 contingency overload in the area. The load in the Stanford 60 kV system continues to remain uncertain. As such, the ISO recommends to cancel Jefferson - Stanford #2 60 kV Line project.

To address the P6 contingency the ISO is recommending an operating solution to to open Bair-Cooley Landing 60 kV lines following the first contingency for P6 overloads.

To address the P7 contingency the ISO is recommending Jefferson 230 kV Bus Upgrade project to keep Jefferson-Martin 230 kV cable in-service following the P7 contingency of the Monta Vista-Jefferson 230 kV lines. The estimated cost of the alternaive is $6 to 11 million with an in-service date of 2022.

2.5.5.4 Request Window Submissions

The ISO received two submissions in the 2018 Request Window in the Greater Bay Area.

Request Window Submission - Cayetano 230 kV Energy Storage

NextEra Energy Transmission West, LLC (NEET West) proposed the Cayetano 230 kV Energy Storage targeting thermal overloads in the Contra Costa-Newark 230 kV corridor as a reliability need. NEET West proposed four projects which included combinations of 100 to 300 MW of energy storage in the Tri-valley area and Las Positas-Newark 230 kV line rerating. A summary of the four proposals is shown in Table 2.5-16.

Table 2.5-16: Cayetano 230 kV Energy Storage Proposed Options

Proposal	Energy Storage	Transmission Upgrade
1A	50 MW Battery Storage @ North Dublin 50 MW Battery Storage @ Vineyard 150 MW Battery Storage @ Newark	None
2A	150 MW Battery Storage @ Vineyard 150 MW Battery Storage @ Newark	None
1B	50 MW Battery Storage @ North Dublin 50 MW Battery Storage @ Vineyard	Increase Las Positas-Newark Emergency Rating
2B	150 MW Battery Storage @ Vineyard	Increase Las Positas-Newark Emergency Rating

The overloads observed in the Conta Costa-Newark 230 kV corridor were starting around 2023 and were mainly driven by higher load in the overall Mission division and high generation in the Contra Costa area. The ISO will continue to monitor Mission division load increases in the future load forecast. Hence, the ISO will not evaluate the proposed Cayetano 230 kV Energy Storage in this TPP cycle.

Request Window Submission - Delta Reliability Energy Storage

Tenaska, Inc. proposed the Delta Reliability Energy Storage targeting thermal overload on the Tesla-Delta Switch Yard 230 kV Line identified as a constraint for Contra Costa LCR Sub-area. In the 2018-2019 transmission planning process the Contra Costa LCR Sub-area was not selected to assess alternatives to reduce or eliminate the requirement for gas-fired generation to address the LCR requirement. As such, the ISO will not evaluate the proposed Delta Reliability Energy Storage in this TPP cycle.

2.5.5.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.5.2, about 250 MW of AAEE and more than 1900 MW of installed behind-the-meter PV reduced the Greater Bay Area load in 2023 by about 6%. This year's reliability assessment for Greater Bay Area included the "high CEC forecast" sensitivity case for year 2023 which modeled no AAEE. Comparisons between the reliability issues identified in the 2022 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-17: Reliability Issues in Sensitivity Studies

Facility	Category
Cayetano-Lone Tree (Lone Tree-USWP) 230kV Line	P2
Cayetano-Lone Tree (Lone Tree-USWP) 230kV Line	P7
FMC-San Jose 'B' 115 kV Line	P2
Las Positas-Newark 230kV Line	P2
Los Esteros-Nortech 115 kV Line	P2
Newark-Kifer 115kV Line	P2
Newark-Kifer 115kV Line	P7
Newark-Northern Receiving Station #1 115kV Line	P1
Newark-Northern Receiving Station #1 115kV Line	P2
North Dublin-Cayetano 230kV Cable	P2
NRS-Scott No. 1 115 kV Line	P2
Oleum - North Tower-Christie 115 kV (North tower sub to North Tower Jt2)	P2
Oleum - North Tower-Christie 115 kV (North tower sub to North Tower Jt2)	P7
Ravenswood 230/115kV Transformer #1	P1
San Mateo-Belmont 115kV Line	P5
San Mateo-Belmont 115kV Line	P7
Scott-Duane 115 kV Line	P2

Furthermore, about 184 MW of demand response and 5 MW of battery energy storage are modeled in the Greater Bay 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.

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 2.5-18.

Table 2.5-18: 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 2018-2019 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.

Two projects were submitted through Request Window in the Greater Bay Area in this cycle. The ISO did not evaluate both submissions in this cycle due to the reliability issues being seen to start around the fifth year only and the modeling of significantly higher load in the area compared to previous cycles and the LCR sub-area not selected to assess alternatives to reduce or eliminate the requirement in this cycle.

The previously approved project, “Oakland Clean Energy Initiative (OCEI)”, is recommended to have a scope change in regards to classification of the energy storage portion of the project and identify a minimum need at Oakland L substation. The CAISO’s original approval of the OCEI project included 10MW / 4 hour energy storage part to be a transmission asset and additional 10 MW-24 MW of preferred resources sited within the Oakland C and Oakland L 115 kV substation pocket. The CAISO recommends to no longer explicitly require this energy storage to be a transmission asset to allow for the most cost-effective combination of resources. Also, the CAISO clarifies that of the total resource mix (20 MW/120 MWh) to be sited within the Oakland C and Oakland L 115 kV substation pocket, no less than 7 MW/28 MWh should be either located at the Oakland L substation or interconnected via the PG&E distribution system to the CAISO-controlled grid at Oakland L.

In regards to the previously-approved on-hold projects, one project was on hold in the Greater Bay Area that is recommended to be canceled in this cycle.

- Jefferson - Stanford #2 60 kV Line project

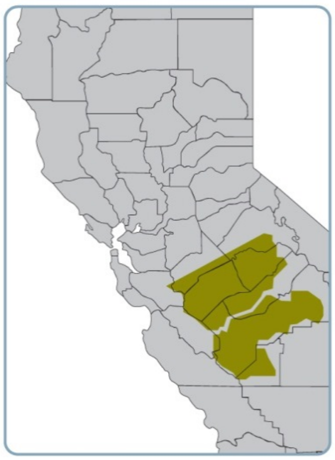
The following four new project are recommended for approval in the Greater Bay Area.

- Christie-Sobrante 115 kV Line Reconductor
- Moraga-Sobrante 115 kV Line Reconductor
- Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade
- Jefferson 230 kV Bus Upgrade project

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 provided below.

Table 2.5-19 Greater Fresno 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)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	GFA-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 18:00.	3,248	62	920	0	3,186	59	29	156	2402	0	13	5	1892	1766	1,453	1,185
2	GFA-2020-SpOP	Baseline	2020 spring off-peak load conditions. Off-peak load time - hours ending 12:00.	1,035	45	920	727	263	59	29	156	2402	2238	13	1	1892	-560	1,453	453
3	GFA-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	3,212	62	920	911	2,239	59	29	156	2402	2378	13	9	1892	1775	1,453	609
4	GFA-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	3,430	123	1,165	0	3,307	60	29	156	2402	0	13	9	1892	1744	1,453	1,199
5	GFA-2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,051	91	1,165	978	(18)	60	29	156	2402	1987	13	0	1892	-561	1,453	226
6	GFA-2023-SP-Hi-CEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	3,430	0	1,165	0	3,430	60	29	156	2402	0	13	5	1892	1685	1,453	1,232
7	GFA-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	1,051	91	1,165	1153	(193)	60	29	156	2402	2045	13	9	1892	-550	1,453	717
8	GFA-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 18:00.	3,676	233	1,568	0	3,443	60	29	156	2402	0	13	9	1892	1799	1,453	1,227
9	GFA-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	3,676	233	1,568	0	3,443	60	29	156	2402	0	13	0	1892	1799	1,453	1,239

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 2018-2019 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-Madera 70 kV Area overloads

There were several P6 overloads found in this area. The contingency causing the overloads are not BES and limiting elements are also not BES, therefore no mitigations were developed for these overloads.

Wilson-Atwater 115 kV Area overloads

There were several P6 and P7 overloads found in this area in all Baseline scenarios. The mitigation identified for the P6 contingencies is to do Operational Switching following the first contingency. The P7 overloads are mitigated by the Atwater SPS.

Kerckhoff 115 kV Area overloads

There were several P6 overloads identified in this area in all Baseline scenarios. The overloads are mitigated by the Kerckhoff SPS.

Coalinga 70 kV Area overloads

There were Category P2 and P7 overloads identified on Gates230/70kV TB #5 and on sections of the Schindler-Huron-Gates 70 kV line (Huron Junction to Cal flax substation & Schindler to Five point switching station) in the spring off-peak scenarios. This is due the dispatch of generation in the area and can be mitigated by redispatching generation in the area.

Panoche 115 kV Area overloads

There were P1, P2 and P6 overloads identified in this area for all 2020 and 2023 Spring off-peak scenarios. Generation re-dispatch is the preferred mitigation.

McCall 115 kV Area overloads

There were P2, P6 and P7 overloads identified in this area for the 2028 Baseline scenario as well as the High CEC sensitivity scenario. We will continue to monitor future load forecasts in the area in future planning cycles.

Reedley 70 kV Area overloads

There was a Category P1, P2, P3, and P6 overloads seen in all the Baseline scenarios in the area. The use the previously approved 7 MW Energy storage at Dinuba 70 kV substation in the Reedley 70 kV Reinforcement project addresses the reliability needs for this area. Current in Service date is May 2021.

P5 overloads

There were P5 Contingency of the Gregg 230 KV BAAH Bus #2 that overloaded several 115 kV and 230 kV lines in the base and sensitivity scenarios. The ISO is recommending PG&E to add redundant relay protection as the preferred mitigation.

Mendota 115kV Area and Coalinga 70kV Voltage concerns

In the 2028 Summer Peak baseline scenario, some low voltages were identified for Category P2, P3 and P6 contingencies. The ISO will continue to monitor future load forecasts for this issue.

Summary of review of on-hold projects

The previously approved project shown in Table 2.5-20 was put on hold in the last cycle but is recommended for cancellation in this planning cycle.

Table 2.5-20: Recommendation for Previously Approved on-hold Projects

Project Name	Recommendation
Gates-Gregg 230 kV Line Project	Cancel

Details of the review of previously approved on-hold projects are presented in Appendix B.

Below is the high level discussion of the review of the on-hold project:

Gates-Gregg 230 kV Line

The Gates-Gregg 230 kV Line project was approved in the 2012-2013 transmission planning process as a Reliability Driven Project with renewable integration benefits. The reliability-driven need for the line was to increase the pumping opportunities at the Helms pumped storage/generation facility to ensure there would be adequate water available when the generation was called upon to support local area loads. The 2012-2013 transmission planning process identified that the availability of pumping would begin to decrease in the 2023 timeframe with inadequate pumping opportunities to provide sufficient water for generation to meet reliability needs in Fresno local area by the 2029 timeframe. The original cost estimate for the project was $115 to $145 million.

In the 2016-2017 transmission planning process the ISO reviewed the need for the Gates-Gregg 230 kV Line project. The assessment determined the reliability need had been deferred by at least 10 years due to the change in load characteristics in the area allowing increased pumping from the HELMS facility to allow for generation during peak loading conditions in the area. There were renewable integration benefits due to increased pumping conditions; however these were not found to provide adequate economic benefits. There was uncertainty of the renewable integration benefits that may need further assessment for the determination of the need for the Gates-Gregg 230 kV Line project, in particular the CPUC Integrated Resource Plan (IRP) and the CEC IEPR Energy Demand Forecast. The project was put on hold in the 2016-2017 transmission planning process.

The project was also reviewed in the 2017-2018 transmission planning process. The load forecast, profile and load modifier assumptions (DER) in the 2017-2018 TPP were consistent with those of the 2016-2017 TPP assessment when the ISO put the project on hold. PG&E has confirmed that while the project is on hold it is continuing to accrue carrying costs since March 2017 when the 2016-2017 Transmission Plan was approved by the ISO Board of Governors. With this, if the project remains on hold and is cancelled in future cycles no additional costs associated with leaving it on hold. With this the project remained on hold.

The reliability need for the project has been reassessed in the 2018-2019 transmission planning process indicating similar to the reviews in the previous cycles that the reliability need has been deferred by more than 10 years. To assess the renewable integration benefits, the ISO confirmed the Fresno area system capability to supply the area load that was determined in the 2016-2017 transmission planning process.

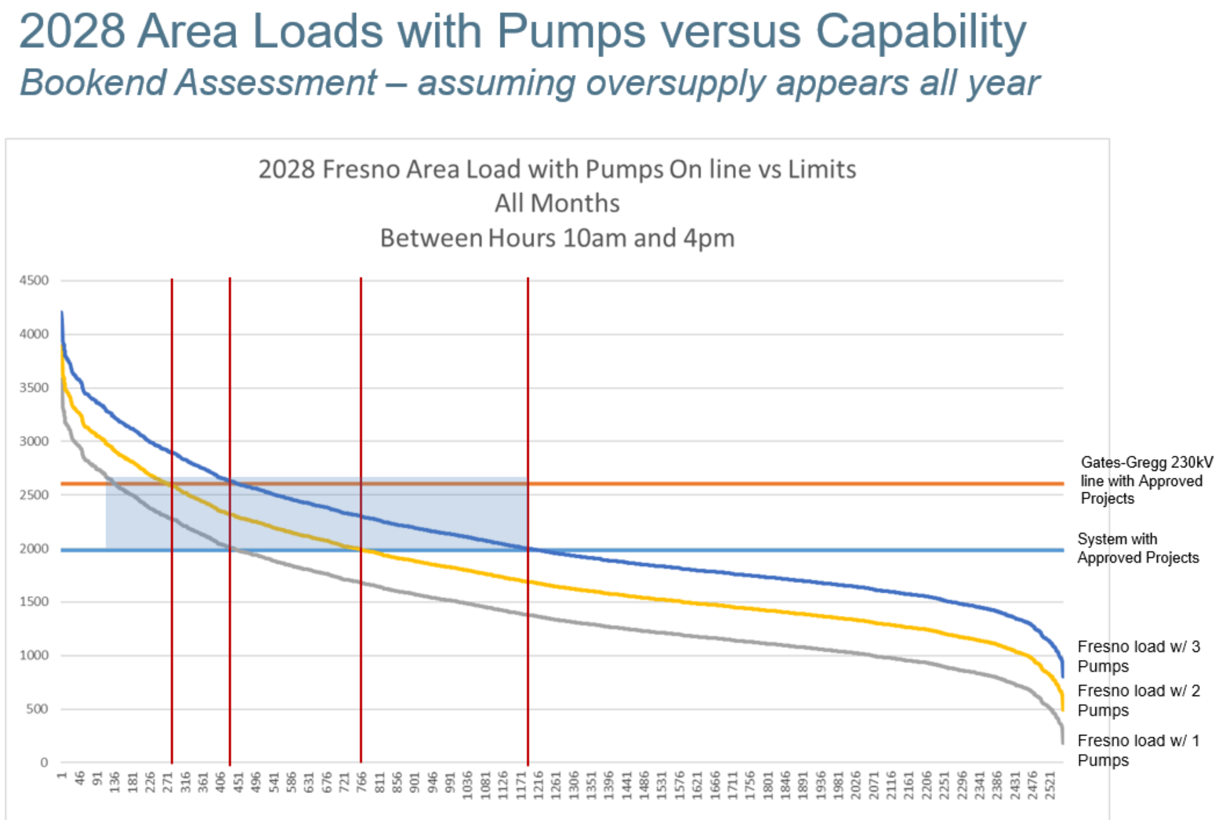
- 1980 MW - Existing system with approved upgrades; and
- 2605 MW - With the Gates-Gregg 230 kV Line project

In addition to the power flow analysis that determined the system capabilities above, in this year's planning cycle, the ISO performed Transient Stability analysis. The assessment did not identify any transient issues that the line mitigated.

Based upon the 2028 forecasted load profile for the Fresno area, using the system capabilities of the transmission system to supply the load in the Fresno area the periods of time when the HELMS pumping would be limited were determined.

illustrates the load duration curve for the Fresno area with the HELMS pumping load for one pump, two pump and three pumps operating between the hours of 10 am and 4 pm when system curtailment is forecast to occur. The output of the HELMS pumps are not variable in the pumping mode and as such are either 0 MW or 305 MW per pump when operated in the pumping mode. The area in blue represents the period of time that the HELMS pumps would not be able to operate due to the Fresno area load profile and the transmission system capability.

Figure B 2.5-2 2028 Fresno Area Loads with Pumps vs Capability for a full year between the hours of 10am and 4pm



Based on the hours identified in Figure B 2.5-2 that the pumps would not be able to operate, assuming system over supply conditions occur for all hours that the pumping is not available the MWh of curtailment that could have been avoided and the estimated value of the avoided pumping per year is as follows:

- MWh where pumping not available without Gates-Gregg 230 kV Line
  - (775 hours * 300 MW) + (470 hours*300MW)+ (275 hours * 300 MW)
  - 456,000 MWh of curtailment
- Value of Pumping for Avoided Curtailment
  - At $40/MWh estimated cost of curtailment
    - 456,000 MWh * $40/MWh
    - $18.24 million/year estimated value of curtailed energy
  - At $66/MWh estimated cost of curtailment
    - 456,000 MWh * $66/MWh
    - $30.1 million/year estimated value of curtailed energy

  - At $100/MWh estimated cost of curtailment
    - 456,000 MWh * $100/MWh
    - $45.6 million/year estimated value of curtailed energy

The values above assumes that system oversupply conditions resulting in renewable curtailment to occur for all hours that the pumping is unavailable due to the transmission system capability for the forecast area load profile with the pumping load. System over supply conditions are not forecast to occur for all hours between 10 am and 4 pm, particularly in the summer. Further assessment using the forecast of curtailment identified in the production simulation analysis in Chapter 4 was done using the hourly profile and MW of curtailment. The MWh of when pumping would not be available and system oversupply occurs resulted in the following:

- MWh where pumping not available without Gates-Gregg 230 kV Line 3
  - 228,510 MWh of curtailment
- Value of Pumping for Avoided Curtailment
  - At $40/MWh estimated cost of curtailment
    - 120,960 MWh * $40/MWh
    - $9.14 million/year estimated value of curtailed energy
  - At $66/MWh estimated cost of curtailment
    - 120,960 MWh * $66/MWh
    - $15.1 million/year estimated value of curtailed energy
  - At $100/MWh estimated cost of curtailment
    - 20,960 MWh * $100/MWh
    - $22.9 million/year estimated value of curtailed energy

The current estimate cost of the Gates-Gregg 230 kV Line project is from $200 to 250 Million. Table B2.5-21 shows the benefit to cost ratio of the avoided curtailment of the Gates-Gregg 230 kV line based upon the above economic analysis for oversupply for all hours and the expected hours of oversupply from production cost simulation when the HELMS pumps would be curtailed due to the transmission system capability.

Table B2.5-22 Benefit to Cost Ratio (Ratepayer Benefit per TEAM) of Gates to Gregg 230 kV Line

Gates-Gregg Project						
Avoided Curtailment Benefit						
Avoided Curtailment Benefits	Pumping Not Available Assuming Overssuppy for All Hours			Pumping Not Available with Expected Overssuppy Hours		
	At $40/MWh estimated cost of curtailment	At $66/MWh estimated cost of curtailment	At $100/MWh estimated cost of curtailment	At $40/MWh estimated cost of curtailment	At $66/MWh estimated cost of curtailment	At $100/MWh estimated cost of curtailment
Net Curtailment Saving ($million/year)	$18.24	$30.10	$45.60	$9.14	$15.10	$22.90
PV of Curtailment Savings ($million)	$251.73	$415.40	$629.31	$126.14	$208.39	$316.04
Capital Cost						
Capital Cost Estimate ($ million)	$250			$250		
Estimated "Total" Cost (screening) ($million)	$325			$325		
Benefit to Cost						
PV of Savings ($million)	$251.73	$415.40	$629.31	$126.14	$208.39	$316.04
Estimated "Total" Cost (screening) ($million)	$325.00			$325.00		
Benefit to Cost	0.77	1.28	1.94	0.39	0.64	0.97

The assumption that system oversupply conditions would occur during all hours that HELMS pumping would be limited due to the transmission system capability overstates the amount of curtailment that could be avoided with the Gates-Gregg line in-service. Using the expected oversupply from the production simulation analysis to determine the avoided curtailment when the HELMS pumping would be limited due to the transmission system capability is more appropriate. With a value of curtailment of $40/MWh the Benefit to Cost Ratio (BCR) would be 0.39 and a value of curtailment of $100/MWh the BCR would be 0.97. The average value of curtailment currently is estimated closer to $40/MWh. With this the economic benefit of the Gates-Gregg 230 kV Line project is below a BCR of 1.0. With this the economic benefit of the avoided curtailment is not enough to justify the Gates-Gregg 230 kV Line project and accordingly the recommendation is to cancel the project.

2.5.6.4 Request Window Submissions

Kingsburg-Leemore Reconductoring

PG&E submitted Kingsburg-Leemore Reconductoring project into the 2018 Request Window. The project consistes of reconductoring approximately 8.3 miles of the Kingsburg – Lemoore 70 kV Line between Hanford Switching Station and Lemoore Substation, with 715 AAC conductor or an equivalent conductor. This reconductoring project is proposed to increase load serving capability and provide additional reliability for electric customers in Fresno and Kings Counties. There is no reliability criteria issue identified in the reliability assessment and this project was submbitted as BCR project.

This project would reduce the number and duration of sustained outages for the customers served by the Lemoore Substation, due to an outage of Henrietta – Lemoore 70 kV Line.

This project is expected to cost between $12.2M - $14.6M. PG&E indicated that the BCR for this project would be greater than 1.0; however based upon the current information provided by PG&E and considering the load profiles in the area, the Benefit to Cost Ratio is 0.54 which is not sufficient to justy the project. PG&E Operations also provided information regarding potential voltage violations following P1 contingencies which the ISO did not observe the voltage issues in the reliability assessment.

The ISO has requested additional information from PG&E regarding the voltage violations of this proposed reconductoring project. The ISO will continue to work with PG&E and conduct further assessment of the need for this upgrade in the next planning cycle.

2.5.6.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.6.2, about 123 MW of AAEE reduced the Greater Fresno Area load in 2023 by about 3.4%. This year’s reliability assessment for the Greater Fresno Area included the “high CEC forecast” sensitivity case for the year 2023 which modeled no AAEE. Comparisons between the reliability issues identified in the 2023 summer peak baseline case and the “high CEC forecast” sensitivity case show that following facility overloads are potentially avoided due to reductions in net load:

Table 2.5-23: Reliability Issues in Sensitivity Studies

Facility	Category
Reedley 115/70kV TB #1	P1
Reedley 115/70kV TB #1	P2
Herndon-Ashan 230kV line	P5
GWFHEP to Contadina 115 kV line	P5
McCall 230/115 kV TB #3	P5
Borden 230/70kV TB #1	P6

Furthermore, about 60 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 2018-2019 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.

In regards to the previously-approved on-hold project, one project was on hold in the Greater Fresno Area that is recommended to be canceled in this cycle.

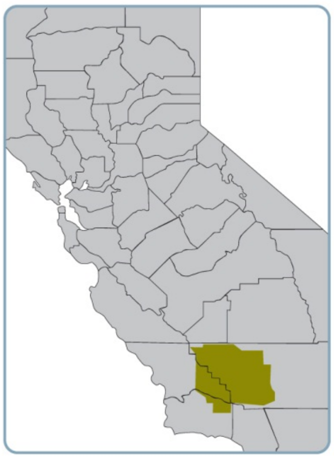
- Gates-Gregg 230kV Line project.

One project was submitted through Request Window in the Greater Fresno Area in this cycle; the ISO has requested additional information to further assess the project. The ISO will continue to work with PG&E and conduct further assessment of the need for this upgrade in the next planning cycle.

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 provided below:

Table 2.5-24 Kern Area load and generation assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV Installed (MW)	BTM-PV Output (MW)	Net Load (MW)	Demand Response Total (MW)	Demand Response D2 (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)
1	KERN-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 19:00.	1,935	34	431	0	1,901	76	57	2	673	0	0	0	18	7	2,222	1,899
2	KERN-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	2,039	67	512	0	1,973	77	57	0	520	0	0	0	18	6	2,212	1,905
3	KERN-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 19:00.	2,183	127	587	0	2,056	77	57	0	520	0	0	0	18	6	2,212	1,906
4	KERN-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – hours ending 12:00.	857	24	431	340	492	76	57	2	673	532	0	0	29	14	3,298	529
5	KERN-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	866	50	512	430	386	77	57	0	520	407	0	0	29	9	3,288	567
6	KERN-2023-SP-HiCEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	2,039	0	512	0	2,039	77	57	0	520	0	0	0	18	13	2,212	2,126
7	KERN-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	866	50	512	507	309	77	57	0	520	421	0	0	29	21	3,288	717
8	KERN-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	1,935	34	431	426	1,475	76	57	2	673	628	0	0	29	9	3,298	567
9	KERN-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	2,183	127	587	0	2,056	77	57	0	520	0	0	0	18	6	2,212	1,906

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 2018-2019 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.

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 67 and 127 MW of AAEE reduced the Kern Area net load by 3 and 6% in 2023 and 2028 respectively . This year's reliability assessment for Kern Area included the "high CEC forecast" sensitivity case for year 2023 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2023 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-25: Reliability Issues in Sensitivity Studies

Facility	Category
Kern-WestPark # 1 115 kV	P3
Kern-WestPark # 2 115 kV	P3
Kern Oil Jn to Kern Water 115 kV	P3
Kern PP 230/115 kV # 3, 4 and 5	P6
Kern PP 230/115 kV # 5	P6
Kern PP- Tevis J1 115 kV line section	P2
Kern PP- Tevis J2 115 kV line section	P2
Taft 115/70 kV bank # 2	P3
Midway-Wheelerridge 230 kV lines	P2/P6

Furthermore, about 76 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.

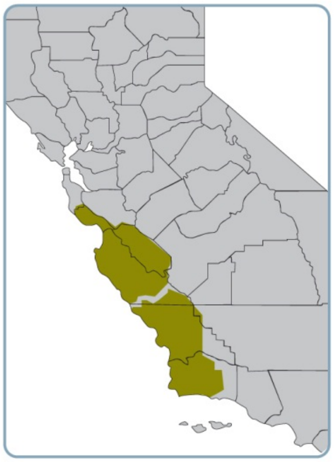
2.5.7.6 Recommendation

Based on the studies performed for the 2018-2019 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. A number 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.

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 provided below.

Table 2.5-26 Central Cost and Los Padres Area 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)		Total (MW)	D2 (MW)		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	CCLP-2020-SP	Baseline	2020 summer peak load conditions. Peak load time - hours ending 20:00.	1,253	23	324	0	1,231	29	16	0	841	0	0	0	0	0	3,939	1,237
2	CCLP-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 20:00.	1,298	46	403	0	1,252	29	16	0	841	0	0	0	0	0	3,773	1,221
3	CCLP-2028-SP	Baseline	2028 summer peak load conditions. Peak load time - hours ending 20:00.	1,356	86	487	0	1,270	29	16	0	816	0	0	0	0	0	3,773	1,252
4	CCLP-2020-SOP	Baseline	2020 spring off-peak load conditions. Off-peak load time – hours ending 12:00.	655	17	324	256	382	29	16	0	841	832	0	0	0	0	3,939	1,177
5	CCLP-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	653	34	403	339	281	29	16	0	841	742	0	0	0	0	3,773	130
6	CCLP-2020-WP	Baseline	2020 winter peak load conditions. Peak load time - hours ending 19:00.	1,188	22	324	0	1,166	29	16	0	841	0	0	0	0	0	3,939	1,228
7	CCLP-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 18:00.	1,225	25	403	4	1,197	29	16	0	841	0	0	0	0	0	3,939	1,176
8	CCLP-2028-WP	Baseline	2028 winter peak load conditions. Peak load time - hours ending 19:00.	1,292	85	487	0	1,207	29	16	0	816	0	0	0	0	0	3,773	1,252
9	CCLP-2023-SP-HiCEC	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	1,298	0	403	0	1,298	29	16	0	841	0	0	0	0	0	3,773	1,252
10	CCLP-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	653	34	403	399	220	29	16	0	841	800	0	0	0	0	3,773	145
11	CCLP-2020-SP-HiRenew	Sensitivity	2020 summer peak load conditions with hi-renewable dispatch sensitivity	1,105	23	324	321	761	29	16	0	841	832	0	0	0	0	3,939	653
12	CCLP-2028-SP-QF	Sensitivity	2028 summer peak load conditions with QF retirement sensitivity	1,226	86	487	0	1,134	29	16	0	816	0	0	0	0	0	3,773	1,122

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with the exception of approved projects shown in Table 2.5-27 which were not modeled in the base cases:

Table 2.5-27: Central Coast / Los Padres approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
Midway-Andrew Project	2012-2013 TPP	Jun-2025
Morro Bay 230/115 kV Transformer Project	2010 TPP	Apr-2019
Diablo Canyon Voltage Support Project	2012-2013 TPP	Dec-2019

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 2018-2019 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.

Crazy Horse-Salanis 115 kV Lines

Category P6 contingency overloads were identified in the Salinas 115 kV system. PG&E has identified that the overloaded lines have been identified in their maintenance plans to be rebuilt. The ISO is recommending PG&E to review the maintenance schedule for these lines, and when the lines are rebuilt as a part of the maintenance plan, the ISO recommends that the rating be increased to address the overloads. Until the maintenance upgrades for these facilities are in place, the ISO recommends PG&E install a SPS to mitigate the reliability constraints.

Summary of review of previously approved projects

There are three previously approved active projects in the Central Coast/Los Padres area, out of which all three projects were 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. Table 2.5-28 shows final recommendation for the three projects not modeled in the study cases:

Table 2.5-28: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
Midway-Andrew Project	Hold
Morro Bay 230/115 kV Transformer Project	Cancel
Diablo Canyon Voltage Support Project	Cancel

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

Below is the high level discussion of projects recommended to proceed with the revised scope:

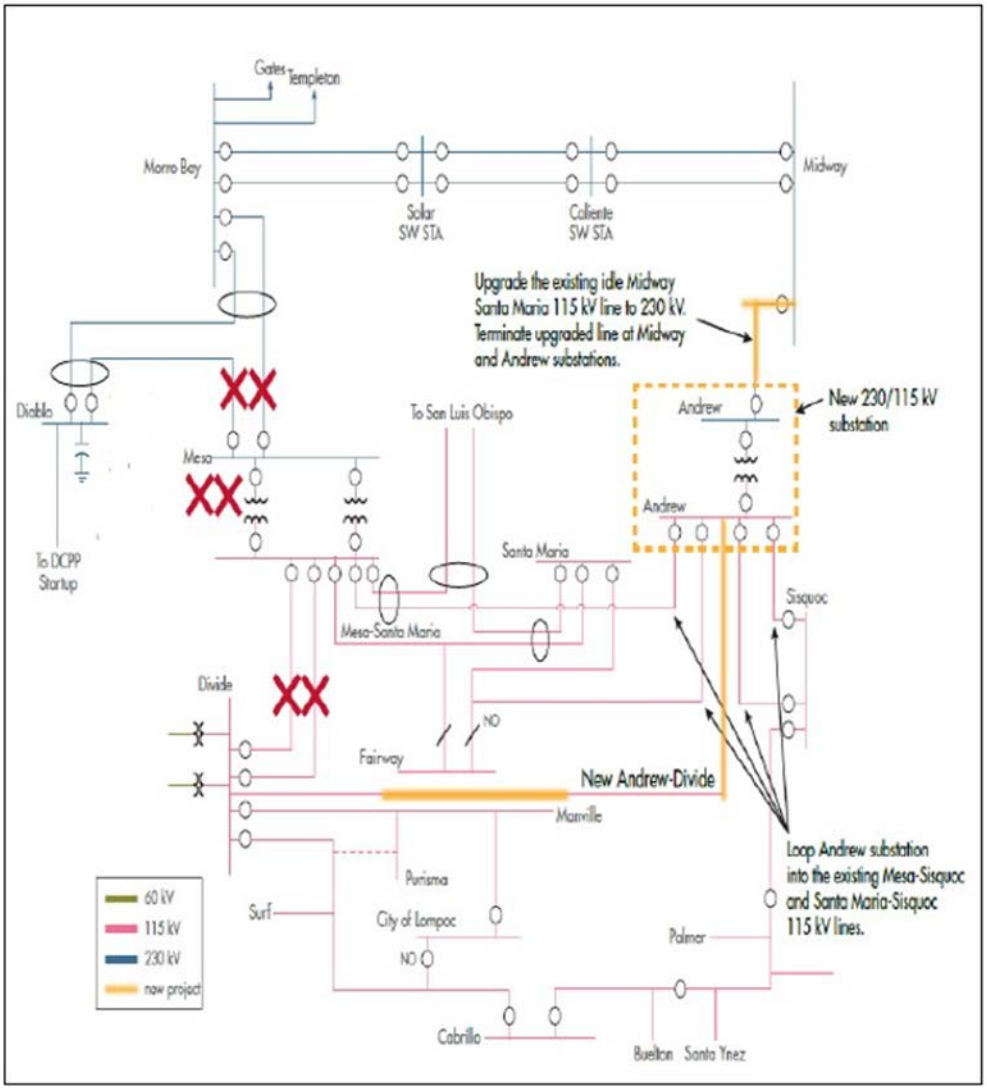
Midway-Andrew Project

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 in order to assess additional alternatives due to increases in the estimated cost and potential feasibility issues identified for the implementation of the project. The reliability assessment identified severe P2 and P6 thermal overloads in the 115 kV system supplied from the Mesa substation. 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.

Original Scope:

- Build new 230/115 kV Andrew substation
- Upgrade existing Midway-Santa Maria 115 kV line to 230 kV and build new Andrew-Divide 115 kV line.
- 2012-2013 TPP estimated cost: $120 to $150 million
- Current estimated cost: $215 to $215 million
- Current in-service date: June 2025

Figure 2.5.8-1: Midway-Andrew 230 kV Project Original Scope.



The need for mitigation in the area is still required. The ISO assessed potential alternatives for the project. This project can be split into two sections, North of Mesa, where the ISO is considering repurposing one of the 500 kV lines from Midway to Diablo after the retirement of the Diablo Canyon Power Plant in 2025. The second section is South of Mesa where the ISO is considering reinforcing the 115 kV system and adding a capacitor for voltage support. These section alternatives can be combined to address several P2 and P6 reliability needs in the area as a whole.

- North of Mesa Upgrade Alternatives
    - <u>Alternative 1</u>: 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.

- o <u>Alternative 2</u>: 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.

- South of Mesa Upgrade Alternatives
  - o <u>Alternative 1</u>: Increase the Winter emergency rating of Sisquoc - Santa Ynez 115 kV line to 120 MVA, install 20 Mvar capacitor bank at Cabrillo, and install SPS to shed load if P6 occurs under peak load
  - o <u>Alternative 2</u>: Increase the Summer emergency rating of Sisquoc - Santa Ynez 115 kV line to around 160 MVA and install SVC at Cabrillo
  - o <u>Alternative 3</u>: Build a new greenfield 115 kV line from Divide to Mesa or other substations.
  - o Alternative 4: Reconductor the Sisquoc - Santa Ynez 115 kV line, install 20 Mvar capacitor bank at Cabrillo, and install SPS to shed load if P6 occurs under peak load

Due to uncertainty of potential generation development and transmission alternatives in the area, further assessment of the conversion of one of the 500 kV lines from Midway-Diablo will be required in 2019-2020 transmission planning process. As identified above, the Midway-Andrew 230 kV project can be separated into two projects. The North of Mesa Upgrade is the portion of the project that is dependant on the potential conversion of one of the 500 kV lines from Midway-Diablo. The need and alternatives of the South of Mesa Upgrade is independent from North of Mesa Upgrade. With this the ISO is recommending to rescope the Midway-Andrew project to Alternative 2 of the North of Mesa Upgrade, and rename the project to North of Mesa Upgrade. The estimated cost of the North of Mesa Upgrade is $114 to $144 million with an in-service date of 2026, after Diablo generation has retired and one of the 500 kV lines can be convered to 230 kV. The rescoping of the Midway-Andrew 230 kV project to the North of Mesa Upgrade project is recommended to remain on hold.

It has been determined that rerating of the Sisquoc - Santa Ynez 115 kV line is not feasible as identified in Alternatives 1 and 2.The ISO is recommending the approval of Alternative 4 of the South of Mesa Upgrade. The estimated cost of the $29.6 to $59.2 million with an in-service date of 2023.

<u>Morro Bay 230/115 kV Transformer Project</u>

The reliability assessment did not identify any P0, P1, or P3 overloads in the area following the loss of the Morro Bay 230/115 kV transformer. A maintenance outage review based on historical data indicated that reasonable opportunities are available to take the transformer out for maintenance. Therefore, it is recommended that the previously approved Morro Bay 230/1115 kV Transformer Project approved in the 2010 TPP be canceled.

<u>Diablo Canyon Voltage Support Project</u>

In the ISO 2012-2013 Transmission Plan, the Diablo Canyon Voltage Support Project was approved to install a +150 Mvar/-75 Mvar dynamic voltage support (SVC) at the Diablo Canyon 230 kV bus. Following a study of credible double circuit transmission line contingencies it was found that local area RAS would be sufficient to mitigate all thermal and voltage concerns in the DCPP area. The local RAS is an interim mitigation until such time that Midway – Andrew goes into service at which point DCPP will have retired. It is recommended that the local RAS be used as a mitigation until DCPP retires in 2025 and thus this project is recommended to be canceled.

2.5.8.4 Request Window Submissions

Crazy Horse-Salinas 115 kV Lines

Pacific Gas and Electric (PG&E) proposed this project within the Crazy Horse-Salinas system.

The scope of this project is to reconductor CHCSS-Natividad and Natividad-Salinas sections of the CHCSS-Salinas-Soledad #1 and #2 115 kV lines to achieve at least 800 Amps under summer emergency conditions.

This project protect would mitigate the Category P6 and P7. The estimated cost of the project is expected to cost between $35 million to $42 million.

As indicated above, PG&E has identified that the overloaded lines have been identified in their maintenance plans to be rebuilt. The ISO is recommending PG&E to review the maintenance schedule for these lines, and when the lines are rebuilt as a part of the maintenance plan, the ISO recommends that the rating be increased to address the overloads. Until the maintenance upgrades for these facilities are in place, the ISO recommends PG&E install a SPS to mitigate the reliability constraints.

Lopez to Divide 500/230 kV Transmission System Project

NextEra Energy Resources, LLC proposed the Lopez to Divide 500/230 kV Transmission System project

The Lopez to Divide 500/230 kV Transmission System project is intended to mitigate Category P6, P7, P5 and P2 contingencies. The project scope is to:

- Build a new Lopez 500 kV ring bus to loop into Diablo-Midway #3 500 kV line.
- Install a new 230 kV substation Lopez and a new 230 kV Divide bus.
- Construct a new 24 mile line from Lopez substation to Divide substation.
- Install Lopez 500/230 kV and Divide 230/115 kV Transformers.

The project is intended to address the post contingency thermal and voltage collapse issues for P5, P6 and P7 contingencies. 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 to the previously approved Midway-Andrew 230 kV project, particularly the North of Mesa Upgrade, that is recommended to remain on hold.

Los Padres ACAES Project

Hydrostor proposed a 175 MW – 200 MW Advanced Compressed Air Energy Storage (“A-CAES”) project to be connected to the PG&E Mesa 230 kV switchyard for the purpose of meeting reliability needs in the Los Padres area in the vicinity of Mesa/Santa Maria (see the

Needs Identification section below). This project also offers options to provide long duration storage to address transmission line contingencies. Hydrostor proposed a 200 MW to 300 MW, 4-hour duration A-CAES system, which at this scale Hydrostor indicated would be ideally positioned to cost-effectively eliminate local voltage collapse and significantly mitigate concerns with thermal overload in this part of the grid. Hydrostor also indicated that the expected net cost to the ISO of such a solution would be $190M to $320M depending on the scale of the project and the associated ability to provide additional market services to the ISO-administered market and/or receive contracted offtake as a storage/resource adequacy asset. In addition as configured in the submission, the project would not address all of the reliability needs in the area such as the P6 contingency of the 230/115 kV transformers at Mesa substation.

2.5.8.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.8.2, about 46 and 86 MW of AAEE reduced the Central Coast and Los Padres Area net load by 3 and 6% in 2023 and 2028 respectively . This year's reliability assessment for Central Coast and Los Padres Area included the "high CEC forecast" sensitivity case for year 2023 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2023 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads are potentially avoided due to reduction in net load:

Table 2.5-29: Reliability Issues in Sensitivity Studies

Facility	Category
30915 MORROBAY 230 30916 SOLARSS 230 1 1	P6
36027 SALINAS1 60.0 36054 SNBRN JT 60.0 1 1	P2
36260 SISQUOC 115 36286 PALMR 115 1 1	P2
36264 S.YNZ JT 115 36288 ZACA 115 1 1	P2
36266 SNTA MRA 115 36269 FRWAYTP 115 1 1	P6
36286 PALMR 115 36288 ZACA 115 1 1	P2
36353 ESTRELLA 70.0 36356 PSA RBLS 70.0 1 1	P2
36358 ATASCDRO 70.0 36362 CACOS J2 70.0 1 1	P2
36362 CACOS J2 70.0 36364 CAYUCOS 70.0 1 1	P2

Furthermore, about 29 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 2018-2019 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 P2, P6, P5 and P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Central Coast and Los Padres Area.

In regards to the previously-approved on-hold projects, two projects hold in the Central Coast and Los Padres Area are recommended to be canceled in this cycle.

- Morro bay 230/115 kV Transformer Project
- Diablo Canyon Voltage Support Project

In regards the previously approved Midway-Andrew 230 kV project the ISO is recommending rescoping the project to the following scope and renaming it to the North Mesa Upgrade project.

- 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.

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

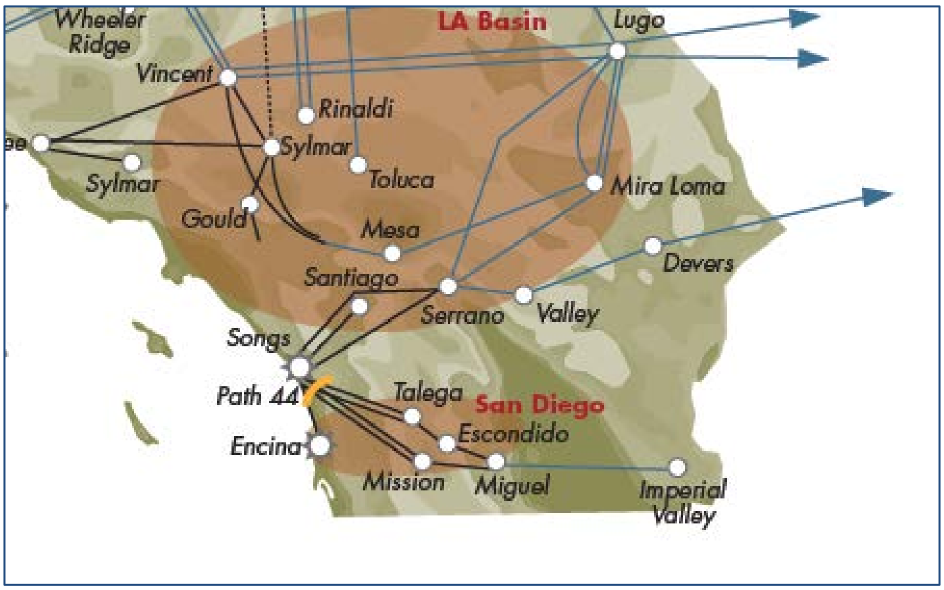
- South Mesa Upgrade

2.6 Southern California Bulk Transmission System Assessment

2.6.1 Area Description

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

Figure 2.6-1: 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[80] and certain other cities81. 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 159 MW82 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 130 MW per year[83]. 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 2028

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

[81] 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.

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

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

summer peak 1-in-5 forecast sales load, including system losses, is 22,814 MW[84]. 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[85] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2028 summer peak 1-in-5 forecast load for the SDG&E area including Mid-AAEE and system losses is 4,405 MW. Most of the SDG&E area load is served by generation that includes a diverse mix of renewables, qualifying facilities, small pumped storage, and gas-fired power plants. The remaining demand is served by power transfers into San Diego via points of imports discussed above.

Electric grid reliability in southern California has been challenged by the retirement of the San Onofre Nuclear Generating Station and the expected retirement of power plants using ocean or estuarine water for cooling due to OTC regulations. In total, approximately 10,760 MW of generation (8,514 MW gas-fired generation and 2,246 MW San Onofre nuclear generation) in the region has been affected. A total of 4,662 MW of OTC-related electric generation has been retired since 2010. In the next three years, the remaining existing 6,138 MW of gas-fired generation is scheduled to retire to comply with the State Water Resources Control Board's Policy on OTC Plants. Some are scheduled to be replaced, such as Alamitos, Huntington Beach and Encina generation, albeit with lower capacity, through the CPUC long-term procurement plan for the local capacity requirement areas in the LA Basin and San Diego. Additionally, consistent with 2018-2019 transmission plan, the ISO has also taken into account the potential retirement of 2,194 MW of aging non-OTC and mothballed generation in the area.[86]

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.[87] In May 2015, the CPUC issued Decision D.15-05-051 that conditionally approved SDG&E's application for entering into a purchase power and tolling agreement (PPTA) with Carlsbad Energy Center, LLC, for 500 MW. The Decision also

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

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

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

[87] 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).

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 below.

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	2020 Summer Peak	Baseline	Summer peak load time (9/3 HE 16 PST)	26,112	511	2,400	1,561	24,040	436	502	70	6,899	3,588	4,204	1,515	1,216	414	19,660	7,370
B2	2023 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	27,365	1,184	3,195	2,248	23,933	436	502	385	6,900	3,657	4,223	887	1,216	784	13,336	8,209
B3	2028 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	28,445	2,462	5,296	3,260	22,722	436	502	409	9,687	5,134	4,372	918	1,257	364	13,942	6,908
B4	2020 Spring Light Loa	Baseline	Spring minimum net load time (4/9 HE 13 PST)	13,088	511	2,400	2,491	10,086	436	502	70	6,899	6,373	4,088	-	1,216	144	19,645	390
B5	2023 Spring Off-Peak	Baseline	Spring shoulder load time (4/17 HE 20 PST)	16,982	1,184	3,195	-	15,799	436	502	385	6,900	-	4,103	2,828	1,216	219	13,336	10,565
S1	2023 SP High CEC Loa	Sensitivit	2023 Summer Peak case with high CEC load forecast scenario	29,171	1,184	3,195	2,248	25,740	436	502	385	6,900	3,657	4,103	862	1,216	784	13,336	9,004
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen.	Sensitivit	2023 Spring Off-Peak case with heavy renewable output and minimum gas generation commitment	21,478	1,184	3,195	2,248	15,799	436	502	385	6,900	6,772	4,103	2,828	1,216	12	13,336	8,111
S3	2020 SP Heavy Renewable Output & Min. Gas Gen.	Sensitivit	2020 Summer Peak case with heavy renewable output and minimum gas generation commitment	26,112	511	2,400	1,561	24,040	436	502	70	6,899	6,811	4,084	2,736	1,216	414	19,660	5,381

Notes:
DR and storage are modeled offline in starting base cases.

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.

Path Flow Assumptions

Table 2.6-2 lists the transfers modeled on major paths in the southern California assessment.

Table 2.6-2: Path Flow Assumptions

Path	SOL/Transfer Capability (MW)	2020SP (MW)	2023SP (MW)	2028SP (MW)	2020 LL (MW)	2023 OP (MW)	2023SP w/High CEC Load (MW)	2023 OP Heavy Ren. (MW)	2023 SP Heavy Ren. (MW)
Path 26 (N-S)	4,000	3,887	3,779	3,629	278	290	4073	-1,262	2,557
PDCI (N-S)	3,220	3,220	3,220	3,220	-400	1,474	3,220	-1,000	3,220
SCIT	17,870	16,484	16,140	15,415	2,950	9,728	16,810	7,069	13,819
Path 46 (WOR)(E-W)	11,200	6,780	7,095	6,518	1,402	6,068	7,553	7,003	6,026
Path 49 (EOR)(E-W)	10,100	5,588	4,262	3,463	-262	3,506	4,287	3,301	4,978

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.

Lugo-Victorville 500 kV thermal overload

The Lugo-Victorville 500 kV line was overloaded under several Category P6 conditions in the 2020 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 bypassing LADWP series capacitors after the initial contingency in accordance with existing operating procedures. The overload did not occur in the 2022 and 2027 cases due to the previously approved Lugo-Victorville 500 kV Transmission Line Upgrade Project.

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 2,462 MW of additional energy efficiency (AAEE), and up to 5,296 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 436 MW and energy storage amounting 409 MW were used to mitigate Category P6 related thermal overloads on Lugo-Victorville 500 kV line until the approved rating increase project is in service.
- 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 Lugo-Victorville 500 kV line will be addressed in the short term using existing operating procedures. In the longer term, the previously approved Lugo-Victorville 500 kV Transmission Line Upgrade Project will address the loading concern.

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 2194 MW in 2028 including the impact of 841 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 229 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 described below.

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	2020 Summer Peak	Baseline	2020 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	2,574.2	47.3	527.0	267.8	2,259.1	0	0	0	2,874	1,494	3,491	1,257	1,093	339	2,028	1,232
B2	2023 Summer Peak	Baseline	2023 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	2,709.9	109.2	527.0	344.2	2,256.5	0	0	0	2,873	1,523	3,494	734	1,093	331	2,029	1,232
B3	2028 Summer Peak	Baseline	2028 summer peak load conditions. Peak load time - hours between 16:00 and 18:00.	2,883.8	229.5	841.0	460.2	2,194.1	0	0	0	4,686	2,484	3,642	765	1,093	332	2,029	732
B4	2020 Spring Light Load	Baseline	2020 spring light load conditions. Off-peak load time – weekend morning.	1,428.5	47.3	527.0	453.5	927.7	0	0	0	2,874	2,514	3,491	0	1,093	1,002	2,028	-144
B5	2021 Spring Off-Peak	Baseline	2023 spring off-peak load conditions. Off-peak load time – weekend morning.	1,465.8	109.2	527.0	0.0	1,356.6	0	0	0	2,873	0	3,494	2,408	1,093	939	2,029	749
S1	2023 SP High CEC Load	Sensitivity	2023 summer peak load conditions with hi-CEC load forecast sensitivity	2,842.7	109.2	527.0	344.2	2,389.3	0	0	0	2,873	1,523	3,494	734	1,093	889	2,029	1,477
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	1,656.8	109.2	527.0	191.0	1,356.6	0	0	0	2,873	2,836	3,494	2,408	1,093	586	2,029	375
S3	2020 SP Heavy Renewable Output & Min. Gas Gen	Sensitivity	2020 summer peak load conditions with hi renewable dispatch sensitivity	2,663.9	47.3	527.0	357.5	2,259.1	0	0	0	2,874	2,846	3,491	2,339	1,093	519	2,028	953

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.

For the summer peak base cases, the ISO relied on previous analysis of real time Big Creek generation data from summer 2015 to represent the period of lowest hydro generation. Based on that, the ISO modeled total hydro generation of approximately 330 MW in the Big Creek area. For the light load and off peak base cases a high hydro generation level was modeled.

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 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 several Category P5 transient issues. There are several protection projects coming into service to mitigate these issues as discussed in Appendix B.

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 229 MW additional energy efficiency (AAEE), and up to 841 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 below.

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

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV MW)		Net Load (MW)	Demand Response (MW)		Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed	Output		Fast	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	1078	17	543	255	805	35	59	0	898	467	0	0	74	57	1381	1138
B2	2023 Summer Peak	1194	38	727	349	807	35	59	0	898	476	0	0	74	0	1381	1232
B3	2028 Summer Peak	1350	80	1006	483	787	35	59	0	1876	994	0	0	74	52	1381	1173
B4	2020 Spring Light Load	684	10.95	543	407	266	35	59	0	898	870	0	0	74	0	1381	512
B5	2023 Spring Off-peak	576	18.42	727	0	557	35	59	0	898	0	0	0	74	53	1381	986
S1	2023 SP High CEC Load	1259	38	727	349	872	35	59	0	898	476	0	0	74	0	1381	1235
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen	576	18.42	727	0	557	35	59	0	898	882	0	0	74	53	1381	951
S3	2020 SP Heavy Renewable Output & Min. Gas Gen.	1078	17	543	255	805	35	59	0	898	886	0	0	74	57	1381	226

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 2020, 2023 and 2028 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 2018-2019 reliability assessment of the North of Lugo area has identified several thermal overloads and low voltages issues under Category 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 contingency with the existing RAS activated. The ISO recommends redispatching generation after the first contingency and reviewing the HDPP and Mohave Desert RAS schemes and modification if needed.

2.7.2.4 Request Window Project Submissions

The ISO received three request window submissions for the North of Lugo area in this planning cycle. Below is a description of the submissions followed by ISO comments and findings:

Control-Silver Peak 55 kV Line Rebuild

The project was submitted by Southern California Edison. The project consists of a tear down and rebuild of the existing Control-Silver Peak "A" and "C" 55 kV circuits as part of the SCE's Transmission Line Remediation Rating (TLRR) Program. The rebuild would take place from the SCE Control Substation to point of change of ownership with NVE. The estimated cost of the project is $60 to $75 million. The proposed in-service date is December 31, 2025.

The objectives of the proposed project include reduction in customer outages with the new shield wire, hardening of the circuits in a Cal Fire threat severity zone and reduction of weather related outages. The project would also reduce environmental impact due to the elimination of one circuit on a separate tower line. The ISO has reviewed the submittal and has not identified any concerns with the project. ISO approval is not required for SCE to proceed with this project.

Ivanpah to Control Segment 3 Rebuild & Derate

The project was submitted by Southern California Edison. The project consists of a tear down and rebuild of the existing Coolwater-Kramer 115 kV line with new double-circuit lines while derating the Kramer-Tortilla and Coolwater-SEGS-Tortilla 115kV lines as part of the SCE's Transmission Line Remediation Rating (TLRR) Program. The rebuild would take place from the SCE Kramer Substation to SCE Coolwater Substation. The estimated cost of the project is $35 to $50 million. The proposed in-service date is January 1, 2025.

The objectives of the proposed project include reduction in customer outages with the new shield wire, reduction of weather related outages and increased aesthetic impact for towers upgraded to a double circuit configuration. The ISO has reviewed the submittal and has not identified any concerns with the project. ISO approval is not required for SCE to proceed with this project.

Ivanpah to Control Segment 4 Baker Ring Bus & Derate

The project was submitted by Southern California Edison. The project consists of installing a ring bus at Baker Substation while derating the Coolwater-Dunn Siding, Dunn Siding-Baker, Baker-Mountain Pass, Mountain Pass-Ivanpah 115kV lines as part of the SCE's Transmission Line Remediation Rating (TLRR) Program for the purpose of mitigating electrical clearance issues on the SCE system in support of NERC reliability and in compliance with CPUC's General Order 95. The ring bus installation would take place at SCE's Baker Substation.

The proposed project on the Coolwater-Dunn Siding-Baker-Mountain Pass-Ivanpah 115 kV line consists of converting the tap bus configuration at Baker Substation into a ring bus that is normally closed. Under heavy loading condition where the line sagging poses potential clearance issues, the ring bus will open which will split the original line into Coolwater-Dunn Siding-Baker 115kV line and Ivanpah-Mountain Pass-Baker 115kV line, resulting in a reduced flow which effectively eliminates the overhead clearance issues.

Figure 2.7-1 Existing Configuration

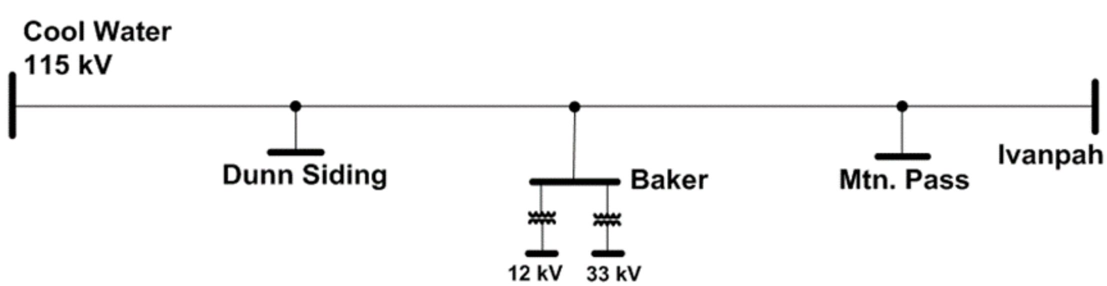
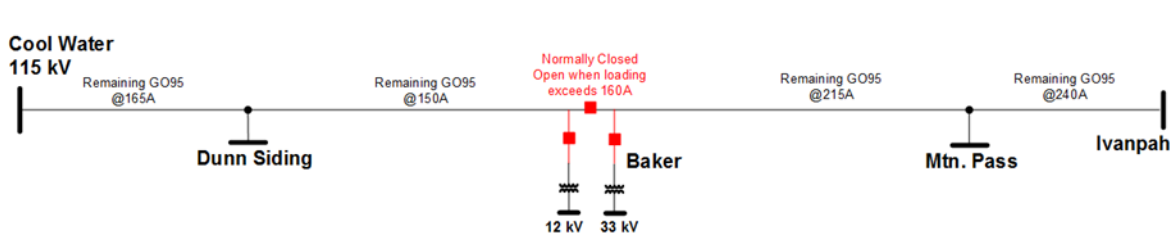


Figure 2.7-2 Proposed Configuration



The estimated cost of the project is $8 to $15 million. The proposed in-service date is December 31, 2025.

The objectives of the proposed project include reduction of environmental impacts due to a reduction in line construction, and reduction of outages that impact all loads served out of the Baker, Dunn Siding and Mountain Pass substations. The ISO has reviewed the submittal and has not identified any concerns with the project. ISO approval is not required for SCE to proceed with this project.

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 80 MW additional achievable energy efficiency (AAEE), and up to 483 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 42 percent.
- The existing and planned fast-response demand response amounting to 94 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

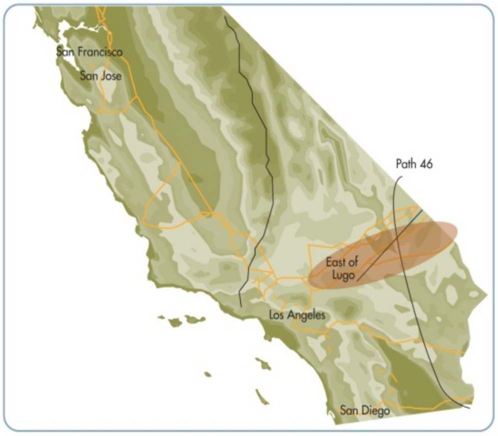
The North of Lugo area assessment identified several category P6 related thermal overloads and low voltage issues. Operating solutions, including relying upon existing operating procedures and congestion management are recommended to address the issues.

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 rely on generation redispatch after the first contingency and reviewing the existing RAS schemes and modification if needed.

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 below.

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

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Demand Response (MW)		Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed	Output		Fast	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	3.46	0	0	0	3.46	0	0	0	1254	652	0	0	0	0	525	330
B2	2023 Summer Peak	3.75	0	0	0	3.75	0	0	0	1254	665	0	0	0	0	525	330
B3	2028 Summer Peak	4.11	0	0	0	4.11	0	0	0	1889	1001	0	0	0	0	525	0
B4	2020 Spring Light Load	1.14	0	0	0	1.14	0	0	0	1254	1196	0	0	0	0	525	0
B5	2023 Spring Off-peak	2.56	0	0	0	2.56	0	0	0	1254	0	0	0	0	0	525	525
S1	2023 SP High CEC Load	3.96	0	0	0	0	0	0	0	1254	665	0	0	0	0	525	525
S2	2023 SOP Heavy Renewable Output & Min. Gas Gen	2.56	0	0	0	0	0	0	0	1254	1234	0	0	0	0	525	520
S3	2020 SP Heavy Renewable Output & Min. Gas Gen.	3.46	0	0	0	0	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 2020 study cases are:

- Harry Allen-Eldorado 500 kV transmission line

The transmission upgrades modeled in the 2023 and 2028 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 two Category P1 thermal overloads in the off-peak and /or sensitivity cases and one Category P6 system divergence issue in all cases. The thermal overloading issues could be mitigated by the previously approved transmission project, existing RAS and generation redispatch. 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 two Category P1 thermal overloads. The issues can be mitigated by the previously approved transmission projects, existing RAS and generation redispatch. The assessment also 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:

- Path 42 Upgrade Project (2016);
- 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 31 percent and 69 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 provided below.

Table 2.7-4 Eastern 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	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	20 Peak	Baseline	2020 summer peak load conditions on 9/3/2020 at hour 16	5,074	109	716	336	4,628	70	19	0	1409	733	586	212	0	0	4,350	2,233
2	23 Peak	Baseline	2023 summer peak load conditions on 8/31/2023 at hour 16	5,423	240	1,001	481	4,702	70	19	0	1659	879	602	126	0	0	4,350	2,661
3	28 Peak	Baseline	2028 summer peak load conditions on 8/31/2028 at hour 16	5,770	484	1,474	707	4,579	70	19	0	1657	878	602	126	0	0	4,350	2,612
4	20 Light Load	Baseline	2020 spring off peak load conditions on 4/9/2020 at hour 13	2,097	109	716	537	1,451	70	19	0	1409	1367	589	0	0	0	4,350	11
5	23 Off Peak	Baseline	2023 spring off peak load conditions on 4/17/2023 at hour 20	3,483	240	1,001	0	3,244	70	19	0	1659	0	602	415	0	0	4,350	3,222
6	20 Peak High CEC Load	Sensitivity	2020 summer peak load conditions with high CEC Load	5,714	240	1,001	481	4,993	70	19	0	1659	879	602	126	0	0	4,350	2,968
7	23 Off Peak HR	Sensitivity	2023 spring off peak load conditions with high renewable dispatch	3,964	240	1,001	481	3,244	70	19	0	1659	1606	602	415	0	0	4,350	2,098
8	20 Peak HR	Sensitivity	2020 summer peak load conditions with high renewable dispatch	5,074	109	716	336	4,628	70	19	0	1409	1378	586	392	0	0	4,350	425

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 P6 and P7 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.

Etiwanda-Vista 230 kV Transmission Line Upgrade Project

The project was submitted by SCE and involves upgrading the existing Etiwanda-Vista 230 kV transmission line. SCE's Transmission Line Rating Remediation (TLRR) Program is scheduled to upgrade 5 out of the 18 conductor spans. SCE proposes to upgrade the remaining 13 spans to increase the line rating to a 4-hour emergency capacity of 3350 Amps. The project has an estimated cost of $3 to $6 million and expected operating date of December 31, 2021.

The project has not been found to be needed in this planning cycle. There was no overloading found on the line under N-1 or N-2 contingencies.

Mountainview RAS Modification

The project was submitted by SCE as an alternative lower cost option to the Etiwanda-Vista 230 kV Transmission Line Upgrade Project. The modified RAS has completely redundant and diversely routed communication facilities that will monitor the loading on the Etiwanda-Vista 230 kV line. It also includes supervisory logic to address RAS misoperation concerns. If a thermal overload is detected in a westbound direction on the line, the RAS will trip Mountainview and Sentinel generation accordingly until the thermal overload is relieved. The project has an estimated cost of $2 to $5 million, and the expected operating date is aligned with the West of Devers Project's operating date of December 31, 2021. The project has not been found to be needed in this planning cycle. There was no overloading found on the line under N-1 or N-2 contingencies.

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 and 2017-18 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.

Red Bluff-Lugo-Victorville 500 kV Transmission Project

The project was submitted by NextEra Energy Transmission West LLC and involves construction of a new 154-mile 500 kV transmission line between Red Bluff 500 kV substation and Victorville-Lugo 500 kV transmission line tap with 50% compensation. The project has an estimated cost of $1.011 billion and expected in-service date of December 1, 2024.

The project has not been found to be needed 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.

Colorado River 230 kV Bus-Julian Hinds 230 kV

The project involves converting the existing privately owned Buck Blvd - Julian Hinds 230 kV generation tie-line into a network facility by way of segmenting the gen-tie line and connecting one terminal of both segments into the Colorado River Substation 230 kV bus. It creates a networked facility identified as Colorado River - Julian Hinds 230 kV line, and a revised 230 kV gen-tie line identified as Buck Blvd - Colorado River 230 kV line. The Colorado River - Julian Hinds 230 kV line would have 117 Smart Wires Power Guardian 700-1150 devices (~19.58 Ω/phase) in series with the line. These Power Guardians will be set to switch into injection mode to limit the power flow on the Julian Hinds - Mirage 230 kV line to avoid potential overloads. The project has an estimated cost of $67 million and expected in-service date of June 1, 2020.

The need for a similar project was assessed as part of the 2014-15 and 2016-17 ISO transmission planning cycle and was not found to be needed. The project with the inclusion of the Smart Wires devices was carried over and reviewed in this planning cycle, and again has not been found to be needed for reliability purposes. However, power flow analysis was performed on the project to determine if it should be further considered as an economic-driven project. It was found that with the project modeled in the 2017-2018 TPP S4 Heavy Renewables sensitivity case, with the Smart Wires devices on the Colorado River - Julian Hinds 230 kV line fully activated, the Julian Hinds - Mirage 230 kV line was heavily overloaded under contingency conditions. However, AltaGas has proposed a RAS that would open the overloaded line created by this proposed project during this contingency condition. While working with AltaGas in previous transmission cycles, the ISO has raised concerns about the use of a RAS to open this proposed transmission line. This new RAS would be in addition to the existing RAS that also drops over 1000 MW of generation. The ISO has also raised concerns that the new RAS proposed by AltaGas would leave the Blythe gas fired generation connected to the Colorado River 230 kV bus and would cause deliverability impacts on the existing generation in the area. AltaGas has requested that the ISO assess this deliverability impact with the proposed revisions to the ISO Generation Deliverability Methodology, once they are finalized. In the interim, AltaGas has also asked the ISO to reevaluate the economic benefits of their proposed project. Please see Chapter 4 for this analysis.

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 P6 and P7 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 18,192 MW in 2028 including the impact of 4,229 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 1,473 MW of additional achievable energy efficiency (AAEE).

The area had approximately 10,913 MW of grid-connected generation at the beginning of the current planning cycle of which a total of 6410 MW of generation has since been or is scheduled to be retired by the end of 2020 to comply with the state’s policy regarding once-through-cooled (OTC) generation or for economic reasons. The California Public Utilities Commission (CPUC) has approved a total of 2,086 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 ISO has approved the following major transmission projects in this area in prior planning cycles:

- Mesa 500 kV Substation (3/1/2022);
- Laguna Bell Corridor Upgrade (3/1/2022);
- Method of Service for Alberhill 500/115 kV Substation (6/1/2021);
- Method of Service for Wildlife 230/66 kV Substation (7/1/2023); and
- Moorpark-Pardee No. 4 230 kV Circuit Project (12/31/2020).

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 below.

Table 2.7-5: Metro Area 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	2020 Summer Peak	Baseline	Summer peak load time (9/3 HE 16 PST)	19,887	317	2,000	940	18,630	287	384	70	12	6	0	0	10	0	9,712	4,543
B2	2023 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	19,938	707	2,738	1314	17,917	287	384	385	12	6	0	0	10	0	6,022	4,653
B3	2028 Summer Peak	Baseline	Summer peak load time (8/31 HE 16 PST)	21,695	1473	4,229	2030	18,192	287	384	409	12	5	0	0	10	0	6,022	4,388
B4	2020 Spring Light Loa	Baseline	Spring minimum net load time (4/9 HE 13 PST)	7,392	105	1,882	1412	5,875	287	384	70	12	11	0	0	10	0	9,712	35
B5	2023 Spring Off-Peak	Baseline	Spring shoulder load time (4/17 HE 20 PST)	13,396	488	2,883	-	12,908	287	384	385	12	0	0	0	10	0	6,022	3,285
S1	2023 SP High CEC Loa	Sensitivit	2023 Summer Peak case with high CEC load forecast scenario	21,189	879	2,738	1314	18,996	287	384	385	12	6	0	0	10	0	6,022	4,853
S2	2023 SOP Heavy Renewable Output & Min Gas Gen	Sensitivit	2023 Spring Off-Peak case with heavy renewable output and minimum gas generation commitment	14,710	488	1,883	1314	12,908	287	384	385	12	11	0	0	10	0	6,022	1,888
S3	2020 SP Heavy Renewable Output & Min Gas Gen	Sensitivity	2020 Summer Peak case with heavy renewable output and minimum gas generation commitment	19,887	317	2,000	940	18,630	287	384	70	12	11	0	0	10	0	9,712	4,504

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 category P6 and one category P7 related thermal overloads under various contingency conditions. 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 steady state assessment identified low voltages at Goleta substation in all summer peak cases under category P0, P1, P3 and P6 conditions. The 2020 summer peak assessment was performed assuming Ellwood and Ormond Beach generating facilities will be unavailable based on the notice NRG gave earlier this year announcing both facilities will be retired by the end of the current year. In response to local capacity needs identified by the ISO, the facilities are now under contract for their capacity, and NRG has recently withdrawn its notice and announced that it no longer intends to retire these generating facilities on the schedule set out in the notice. With these generating facilities available until the end of 2020, voltages at Goleta can be maintained within acceptable limits under normal and contingency conditions.

Beyond 2020, Ormond Beach is expected to retire in accordance with the OTC compliance schedule and Ellwood is expected to be replaced with preferred rescources and energy storage SCE is currently in the process of procuring to meet the local capacity need in the Santa Clara area. The ISO is working with SCE to ensure the selected portfolio of resources will address the low voltage issue in the longer term.

The stability analysis performed in the Metro Area assessment did not identify transient stability issues that require mitigation.

As a result, no new corrective action plans were found to be needed for the Metro area to meet TPL 001-4 requirements.

2.7.5.4 Request Window Project Submissions

The ISO did not receive request window submittals for the SCE Metro Area in this planning cycle.

2.7.5.5 Consideration of Preferred Resources and Energy Storage

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

- As indicated earlier, projected amounts of up to 1,473 MW of additional energy efficiency (AAEE), and up to 4,229 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 16 percent.
- The existing and planned fast-response demand response amounting 287 MW and energy storage amounting 409 MW were used in the base or sensitivity cases to mitigate category P6 related thermal overloads on Serrano 500/230 kV transformers and the Mesa-Laguna Bell No.1 230 kV line.
- Incremental preferred resources and energy storage are being considered in the Santa Clara area to address local capacity need.

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 the thermal loading issues.

The assessment also identified low voltages at Goleta substation in all summer peak cases under category P0, P1, P3 and P6 conditions. Continued operation of Ellwood and Ormond Beach until 2021 will address the problem in the short-term. The ISO is working with SCE to ensure the selected portfolio of local capacity resources being procured to replace these facilities will continue to address the low voltage concern in the longer term.

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 Transco, LLC is now 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 Innovation and Pahrump 230 kV substations are connected to the NV Energy's Northwest and WAPA's Mead 230 kV substations through two 230 kV lines.

The VEA system is electrically connected to neighboring 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 – Pahrump 230 kV tie line with WAPA; and
- Northwest – Desert View 230 kV tie line with NV Energy.

2.8.2 Area-Specific Assumptions and System Conditions

The Valley Electric Association 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 below.

Table 2.8-1: VEA Area load and generation assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Demand Response (MW)		Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed	Output		Fast	Slow		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2020 Summer Peak	152	0	0	0	152	0	0	0	15	7	0	0	0	0	0	0
B2	2023 Summer Peak	153	0	0	0	153	0	0	0	102	54	0	0	0	0	0	0
B3	2028 Summer Peak	164	0	0	0	164	0	0	0	1113	589	0	0	0	0	0	0
B4	2020 Spring Light Load	124	0	0	0	124	0	0	0	15	11	0	0	0	0	0	0
B5	2023 Spring Off-peak	108	0	0	0	108	0	0	0	102	0	0	0	0	0	0	0
S1	2020SP Load Addition & NNSS Reconfiguration	163	0	0	0	163	0	0	0	15	7	0	0	0	0	0	0
S2	2023SP Load Addition & NNSS Reconfiguration	181	0	0	0	181	0	0	0	102	54	0	0	0	0	0	0
S3	2023OP High Renewable	108	0	0	0	108	0	0	0	728	594	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 2020, 2023, and 2028 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 Transformer Overload and Low Voltage Issues Mitigation

The Valley Electric Association area steady state assessment identified thermal overloads on the Amargosa 230/138 kV transformer and low voltage at 138 kV buses following multiple Category P1, P4 and P7 contingencies under various base and sensitivity scenarios. Several alternatives were proposed by the ISO or submitted through the Request Window Submission process to address the issue. The issue was mainly caused by the load growth and the power factor[88] . It was discovered that the power factors at 138kV side of most 138/24.95 kV distribution transformers were much less than 0.97 lagging. Correcting the power factors to 0.97 and installing a 10 Mvar shunt capacitor on the 138 kV system would mitigate the Amargosa transformer overloads and low voltage issues under the base scenarios.

Another alternative would be to add a new 230 kV bus to the existing Gamebird 138 kV substation, loop the Pahrump-Bob SS 230 kV line into Gamebird substation, and install a new 230/138 kV transformer at Gamebird. This alternative would mitigate the Amargosa transformer overload in all base and sensitivity scenarios. The voltages at 138 kV buses would still be below 0.9 p.u. under the 2023 high load sensitivity scenario. However, correcting the power factors to 0.97 would address these low voltages.

The ISO will work with VEA and GWT to further investigate these alternatives.

Pahrump Transformer Overloads

The assessment identified thermal overloads on the remaining Pahrump 230/138kV transformer following a Category P6 contingency of the other Pahrump transformer and a few 138 kV lines under the 2028 base and 2023 sensitivity scenarios. The Gamebird 230/138 kV transformer

[88] CAISO Tariff Section 8.2.3.3 states that "All Loads directly connected to the CAISO Controlled Grid shall maintain reactive flow at grid interface points within a specified power factor band of 0.97 lag to 0.99 lead."

addition discussed above would address these overloads. Alternatively, a RAS could be installed to curtail a portion of the Pahrump distribution load following the second contingency to mitigate the overloads.

In addition to the Amargosa transformer and Pahrump transformer overloads, the assessment identified several Category P1 and P6 related thermal overloads under the 2028 summer peak and 2023 off-peak high renewable sensitivity scenarios which could be mitigated by a previously identified generation-tripping RAS scheme or congestion management. The assessment also identified two Category P1 overloads under the 2020 summer peak high load and NNSS reconfiguration sensitivity scenario which could be mitigated by a new operating procedure, if necessary. Two system divergence issues under P6 contingency conditions were observed under various base and sensitivity scenarios and could be mitigated by the existing UVLS scheme.

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.

Amargosa Valley Reliability Improvement Project

The project was submitted by GridLiance West Transco, LLC (GWT). The scope of the project includes installing a new 230 kV bus and a 230/138 kV transformer at Valley Substation and building a new 40-mile 230 kV line between the new Valley 230 kV Substation and Innovation 230 kV Substation. The cost estimate provided is $41.5 million for a 40-mile 230kV rebuild and associated equipment. The expected in-service date is June 30, 2022.

The proposed project would increase the transmission capacity and reliability, and potentially facilitate the delivery of renewable generation out of Nevada into California. However, the issues could be mitigated by the existing UVLS, future Remedial Action Scheme (RAS) and congestion management which would have a lower cost and an earlier in-service date. It was also confirmed that the future RAS schemes would be consistent with the ISO RAS guidelines as stated in the ISO Planning Standards. It was also noticed that the proposed project would not eliminate any of the UVLS or future RAS schemes, rather it would only reduce the number of contingencies that required those schemes. In addition, the project could not mitigate the Amargosa bank overloads. For these reasons, the project was not found to be needed.

Pahrump Valley Loop-in Project

The project was submitted by GridLiance West Transco, LLC (GWT). The scope of the project includes building a new 230 kV switching station near Vista and looping into the Pahrump-Innovation 230 kV line; expanding the Charleston Park Substation to install a 230 kV bus and a 230/138 kV transformer; and building a new 11.2-mile Vista-Charleston Park 230 kV line. The cost estimate provided is $23.6 million for an 11.2-mile 230 kV line and associated equipment. The expected in-service date is September 30, 2022.

The proposed project would mitigate the identified Amargosa bank and Pahrump transformer overloads and the low voltage issues. It would also potentially facilitate the delivery of renewable generation out of Nevada into California. However, compared to other alternatives which could also address the identified issues, this project scope included substantial greenfield construction and the cost was much higher. For these reasons, the project was not found to be needed.

Southwest Nevada Reliability Improvement Project

The project was submitted by GridLiance West Transco, LLC (GWT). The scope of the project includes rebuilding the Amargosa-Gamebird 138 kV line to 230 kV and extending the line to terminate at Arden 230 kV and Pahrump 230 kV instead. The new Arden-Pahrump 230 kV line would be approximately 63.5 miles. Sandy 138 kV Substation which tapped to the Amargosa-Gamebird 138kV line would be converted to 230 kV and tapped to the new Arden-Pahrump 230 kV line. The cost estimate provided is $65.4 million for the 63.5-mile 230 kV line rebuild and associated equipment. The expected in-service date is May 31, 2023.

The proposed project would result in Gamebird, Thousandaire and Charleston substations being served radially from Pahrump Substation. A single outage of Pahrump-Gamebird 138 kV line would result in 1/3 of VEA's distribution load being out of service. Thus, the project would have an adverse impact to the system reliability. For these reasons, the project was not found to be needed.

Gamebird-Charleston 230kV Transmission System Project

The project was submitted by NextEra Energy Transmission West, LLC (NEET West). The scope of the project includes expanding the Charleston Park Substation to install a 230 kV bus and a 230/138 kV transformer and building a 17-mile Gamebird-Charleston Park 230kV line. The estimated cost provided is $35 million. The expected in-service date is December, 2024.

The proposed project would mitigate the identified Amargosa bank and Pahrump transformer overloads and the low voltage issues. It would also potentially facilitate the delivery of renewable generation out of Nevada into California. However, compared to other alternatives which could also address the identified issues, this project scope included substantial greenfield construction and the cost was much higher. In addition, the project depended on the implementation of a future switching station which would not be in-service before the issue emerged. For these reasons, the project was not found to be needed.

2.8.5 Consideration of Preferred Resources and Energy Storage

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

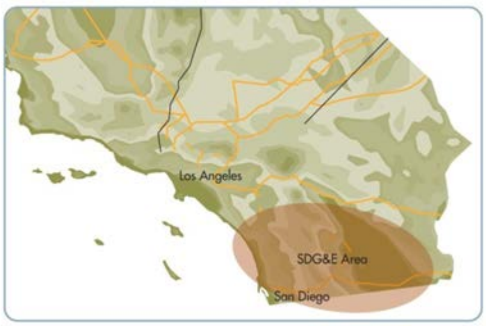
2.8.6 Recommendation

The Valley Electric Association area assessment identified Amargosa 230/138 kV transformer thermal overloads and low voltage issues for Category P1, P4 and P7 outages under various base and sensitivity scenarios. The Pahrump 230/138 kV transformer was also found to be overloaded for Category P6 contingencies under both base and sensitivity scenarios. Adding a new 230kV bus to the existing Gamebird 138kV substation, looping the Pahrump-Bob SS 230 kV line into Gamebird substation, and installing a new 230/138 kV transformer at Gamebird appears to be the best solution for addressing the identified reliability concerns. The ISO will work with VEA and GWT to further investigate this alternative. The ISO will also coordinate with VEA on the power factor at the transmission and distribution interfaces.

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 two counties and 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 exclusively 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 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) project.

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 4,681 MW in 2028 after incorporating a load reduction of 332 MW of additional achievable energy efficiency (AAEE) and 0 MW of forecast behind-the-meter photovoltaic (BTM PV) generation as the San Diego peak hour is shifted to HE19:00.

The area is forecast to have approximately 5,795 MW of grid-connected generation by the year 2020, including a total of 2069 MW renewable generation and 161 MW battery storage resources. The California Public Utilities Commission (CPUC) approved a total of 750 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 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 shown in a table below.

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 35 percent and 65 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.

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		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	B1-20SP	Baseline	2019 Summer Peak Load	4524	71	1119	0	4,453	16	24	1,399	0	670	208	201	40	3,525	3,600
B2	B2-23SP	Baseline	2022 Summer Peak Load	4713	159	1395	0	4,554	16	24	1,399	0	670	7	201	40	3,525	3,616
B3	B3-28SP	Baseline	2027 Summer Peak Load	5013	332	1778	0	4,681	16	24	1,399	0	670	7	201	40	3,525	3,611
B4	B4-20LL	Baseline	2019 Spring Light Load (35% of the peak)	2341	23	1,119	862	1,456	16	24	1,399	1,357	670	7	201	-161	3,525	1,805
B5	B5-23OP	Baseline	2022 Spring Off-Peak (65% of the peak)	3959	134	1,395	0	3,825	16	24	1,399	0	670	34	201	-161	3,525	2,084
S1	S1-23SP HLOAD	Sensitivity	2023 High CEC Load Forecast & Peak-Shift	5005	159	1395	0	4,846	16	24	1,399	0	670	208	201	40	3,525	3,215
S2	S2-23OP HRPS	Sensitivity	2023 Spring off-peak with Heavy Reneable Output	5033	133	1395	1,074	3,825	16	24	1,399	1,343	670	342	201	-161	3,525	1,918
S3	S3-20SP HRPS	Sensitivity	2020 Summer peak with heavy reneable output	4524	71	1119	0	4,453	16	24	1,399	1,343	670	342	201	0	3,525	2,580

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

2.9.3 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 2018-2019 reliability assessments of the SDG&E main and its sub-transmission systems identified various reliability concerns consisting of thermal overload and voltage concerns. The assessment confirmed that these concerns could be mitigated in the operations horizon without relying on non-consequential load loss to meet applicable reliability standards in the planning horizon.

The steady state assessment of the baseline scenarios identified a total of eight thermal overload and voltage concerns under Category P1/P2/P3/P4/P6 contingencies in the SDG&E main systems and two thermal overload concerns under P1 and P3 contingencies in the SDG&E sub-transmission system. The sensitivity scenarios assessment identified similar or more severe concerns compared to the baseline scenarios. All of these concerns can be mitigated by previously approved projects and operational mitigations including remedial action scheme (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 in allowing operation actions including re-configuring the system, redispatching resources, reducing battery storage charing, and adjusting the phase shifting transformers at Imperial Valley substation. The stability analysis performed did not identify transient issues that require mitigation. Please refer to Appendix B for details on these concerns and associated mitigations. As a result, no new corrective action plan except operational mitigation has been found to be needed for the San Diego main and subtransmision systems to meet TPL 001-4 requirements.

2.9.4 Request Window Project Submissions

The ISO received a total of thirteen project submittals through the 2018 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.

Pala Sub-area LCR Reduction

SDG&E proposed this project as a reliability and an economic-driven transmission need to eliminate the LCR need for the Pala sub-area. The proposed scope is to upgrade Monserate–Morro Hill Tap 69 kV line (TL694A) and Morro Hill Tap-Melrose 69 kV line (TL694B). The project has an estimated cost of $25~37 million and an expected in-service date of June 2021.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on Monserate–Morro Hill Tap 69 kV (TL694A), Morro Hill Tap-Melrose 69 kV (TL694B), San Luis Rey-Ocean Ranch, and Ocean Ranch-Melrose 69kV lines can be eliminated by dispatching the 80 MW/200 MWh battery energy storage resources at Melrose and Avocado. The battery storage resources could potentially provide sufficient capacity and energy to eliminate the P6 overloads in the area without running the gas generation at Pala. Please refer to chapter 4 for the discussion of the areas and sub-areas selected for detailed analysis.

El Cajon Sub-area LCR Reduction

This project was proposed by SDG&E as a reliability and economic-driven transmission need to eliminate the LCR need for the El Cajon sub-area. The proposed scope is to upgrade Los Coches – El Cajon 69 kV line (TL631). The project has an estimated cost of $28~43 million and an expected in-service date of June 2023.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on the Los Coches–El Cajon 69 kV line can be eliminated by dispatching the resources in the local area including 7.5 MW/30 MWh battery energy storage facility and the gas generation at El Cajon. The economic analysis on the project's LCR reduction benefits can be found in Chapter 4.

Esco Sub-area LCR Reduction

SDG&E proposed this project as a reliability and an economic-driven transmission need to eliminate the LCR need for the Esco sub-area. The proposed scope is to add second 230/69 kV transformer at Artesian. The project has an estimated cost of $14~20 million and an expected in-service date of June 2023.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on Sycamore Canyon–Pomerado (TL6915 and TL6924) 69 kV lines can be eliminated by dispatching generation resource in the local area. Please refer to chapter 4 for the discussion of the areas and sub-areas selected for detailed analysis.

Border Sub-area LCR Reduction

SDG&E proposed this project as a reliability and economic-driven transmission need to eliminate the LCR need for the Border sub-area. The proposed scope is reconductor Bay Boulevard–Imperial Beach 69 kV line (TL647). The project has an estimated cost of $6~10 million and an expected in-service date of June 2021.

The ISO has not identified a reliability need for this project. The P6 thermal overloads identified on Bay Boulevard–Imperial Beach (TL647) 69 kV line can be eliminated by dispatching generation resources in the local area. The economic analysis on the project's LCR reduction benefits can be found in Chapter 4.

Southern California Regional LCR Reduction

SDG&E proposed this project as a reliability and economic-driven transmission need that is intended to reduce LCR need in the southern California region. The proposed scope is to construct a new Mission-San Luis Rey-San Onofre 230 kV line, install a 230 kV phase shifter station at Mission Substation, and upgrade various existing 230 kV lines (TL23004, TL23006, TL23022 and TL23023) in the San Diego area. The project has an estimated cost of $100~200 million and an expected in-service date of June 2023.

The ISO has not identified a reliability need for this project. The potential congestion in the Encina-San Luis Rey 230 kV system (TL23003 and TL23011) were identified during system off-peak conditions with heavy renewable generation output. The ISO's analysis confirmed that the congestions can be mitigated in the ISO market by redispatching generation in the San Diego area and LA Basin without resulting in significant congestion cost. More detail of economic analysis on the project can be found in Chapter 4.

Suncrest-Sycamore 230 kV_Transmission project

NextEra Energy Transmission West, LLC (NEET West) proposed the Suncrest – Sycamore 230 kV Transmission project targeting thermal overloads in the Suncrest–Sycamore 230 kV corridor as a reliability need. The proposed scope is to construct a new 27-mile 230 kV line from the Suncrest substation to the Sycamore 230 kV substation. The project has an estimated cost of $100 million and an expected 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 230 kV corridor can be eliminated by the existing RASs including newly implemented TL23054/TL23055 RAS and along with operation actions, such as adjustment of the IV phase shifting transformers, system reconfiguration, and generation redispatch in the baseline scenarios. Further assessment concluded that the preferred resources and the operation actions are adequate to mitigate the overload concerns identified in the sensitivity scenarios. For these reasons, the project was not found to be needed.

Sycamore 230 kV Energy Storage Project

NextEra Energy Transmission West, LLC (NEET West) proposed Sycamore 230 kV Energy Storage Project as a reliability transmission need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers, and Miguel 500/230 kV transformers. The proposed scope is to build a 210 MW energy storage and connect it to the SDG&E Sycamore substation. The project has an estimated cost of $200 million and an expected in-service year of 2024.

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 the operational measures including the RASs. For this reason, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

Westside Canal Reliability Center

Sempra Renewables proposed this energy storage project as a reliability transmission need to eliminate the P6 thermal overload concerns on the San Diego main system specifically targeting the Suncrest –Sycamore 230 kV lines. The proposed scope is to build a 268 MW energy storage with a faster response time provide reactive power support capability and interconnect it to the SDG&E Imperial Valley 230 substation. The project has an estimated cost of $304 million and an expected in-service year of 2021.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified in the area can be eliminated by the operational measures including the RASs discussed above. On the other hand, when the battery is operating in load mode, the battery project could worsen the thermal overload concerns in the neighboring systems even after the Imperially Valley- El Centro 230 kV line (S-Line) upgrade project is completed. For these reasons, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

Sycamore Reliability Energy Storage Proposed By NEET West

NextEra Energy Transmission West, LLC (NEET West) proposed this project as a reliability need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers, and Miguel 500/230 kV transformers. The proposed scope is to build a 210 MW battery energy storage system (BESS) and interconnect it to the SDG&E Sycamore substation. The project has an estimated cost of $200 million and an expected in-service year of 2024.

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 the operational measures including the RASs. For this reason, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

Sycamore Reliability Energy Storage proposed By Tenaska, Inc.

Tenaska, Inc. proposed this project as a reliability need to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers. The Project is also proposed as an 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 substation. The project has an estimated cost of $108~178 million and an expected in-service date of December 2021.

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 the operational measures. For this reasons, the project was not found to be needed for reliability. The economic analysis on the project can be found in Chapter 4.

Lake Elsinore Advanced Pump Storage Project

ZGlobal, on behalf of the Nevada Hydro Company, proposed the Lake Elsinore Advanced Pump Storage (LEAPS) project as a reliability need to resolve the overloads concerns identified in the San Diego main system. The Project was also proposed as an economic-driven project to reduce the LCR requirement for the San Diego sub-area. The LEAPS project consists of a 500/600 MW advanced pumped storage facility, two new 500 kV interconnecting transmission lines, two new 500 kV substations, three new 500/230 kV transformers, and three new phase shifting transformers. The project has an estimated cost of $1.76~2.04 billion and an expected in-service year of 2025.

The ISO has not identified a reliability need for this project. As discussed above, 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 economic analysis on the project can be found in Chapter 4.

San Vicente Energy Storage Facility

City of San Diego proposed the San Vicente Energy Storage Facility (SVES) project as a policy-driven and economic-driven transmission need to reduce renewable generation curtailment and to increase market revenues. The project can provide significant reliability benefit to eliminate the P6 thermal overload concerns on the Suncrest-Sycamore 230 kV lines, Suncrest 500/230 kV transformers, and Miguel 500/230 kV transformers. The proposed energy storage plant is configured with four individual generating units (4x125MW) interconnected to the SDG&E's Suncrest-Sycamore 230 kV lines in two 230 kV generation interconnection line circuits. The project has an estimated cost of $1.5~2 billion and an expected in-service year of 2028.

The ISO has not identified a reliability need for this project. As discussed above, the P6 thermal overloads identified can be eliminated by the operational measures. For this reason, the project was not found to be needed as reliability project. The economic analysis on the project can be found in Chapter 4.

Otay-Otay Lake Tap 69 kV Reconductor Project

This project was proposed as a reliability transmission need to reconductor TL649A Otay-Otay Lake Tap 69 kV line and achieve a minimum continuous rating of 64 MVA. The estimated cost of the project is between $4 million and $6 million, and the expected in-service date is June, 2021.

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.

2.9.5 Operational Modification and RAS Mitigations

Bypassing 500 kV Series Capacitors in SWPL and SRPL

A need for bypassing the existing 500 kV series capacitor banks in SWPL and SRPL under summer peak load conditions were identified in the 2014-2015 ISO transmission plan. Since then, this operational modification has been confirmed and utilized in the transmission reliability, generation interconnection, and local capacity requirement planning processes. With the development of renewable generation and the implementation of once-through-cooling generation retirement in the southern California region, the ISO continues to recommend bypassing the series capacitor banks in the ECO-Miguel TL50001 and Ocotillo-Suncrest TL50003 500 kV lines under normal system operating conditions after the planned Suncrest SVC project is in service by December 2019. The bypassing configuration would deliver maximum system benefits without causing parallel flow concerns on the CENACE system with the Imperial Valley phase shifting transformers. This operational modification would provide considerable incremental benefits including but not limited to increasing generation deliverability in the greater IV area, reducing local capacity requirement in the San Diego area and LA Basin, and boosting the transmission import capability into San Diego (SDIT).

Modification on Existing Miguel Banks #80 and #81 RAS

This RAS scheme was recently modified to accommodate the system changes by tripping up to all of the renewable and conventional generation in the greater Imperial Valley area. The ISO suggests to further enhance the RAS performance and operational flexibility by adding a feature to bypass the 500 kV series capacitor banks in TL50001 ECO-Miguel 500 kV line prior to dropping the generation, in case the series capacitor banks are not bypassed under all normal system operating conditions. The 30-minute emergency ratings of the Miguel banks should also be relied upon under the P6 contingencies in allowing operating actions including re-configuring the system, redispatching resources, and adjusting the phase shifting transformers at Imperial Valley substation.

2.9.6 Consideration of Preferred Resources and Energy Storage

As indicated earlier, projected amounts of up to 332 MW energy efficiency (AAEE) and 1,778 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 853 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
- Miguel-Mission 230 kV path overloads for Category P6 contingencies
- SCE’s Ellis 220 kV south corridor for Category P6 contingency
- Cross-tripping the 230 kV tie lines with CENACE for Category P3/P6 contingencies
- Imperial Valley – El Centro 230 kV tie line for Category P3/P6 contingencies

The operational and planned battery energy storage and demand response amounting to 161 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 and energy storage in appropriate locations could be helpful to mitigate or reduce exposure to some of the reliability concerns.

2.9.7 Recommendation

The assessments identified a total of eight thermal overload and voltage concerns under Category P1/P2/P3/P4/P6 contingencies in the SDG&E main system and two thermal overload concerns under P1 and P3 contingencies in the SDG&E sub-transmission system. The sensitivity scenarios assessment identified similar or more severe concerns compared to the base scenarios. In response to the ISO study results and proposed alternative mitigations, a total of thirteen project submissions were received through the 2018 request window. The ISO evaluated the alternatives and did not find a reliability need for these projects, and is recommending two operational mitigations as cost-effective mitigations to address the identified reliability concerns, along with preferred resources and energy storage. Below is a summary of the recommendations for the SDG&E area:

1. Bypassing 500 kV Series Capacitors in SWPL and SRPL
2. Modifications on existing Miguel Banks #80 and #81 RAS

Chapter 3

3 Policy-Driven Need Assessment

3.1 Background

The CPUC issued a decision[89] 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. The decision also established a 50 percent RPS "default" scenario to be transmitted to the ISO to be used in the 2018-2019 TPP reliability (and economic) assessment, and a 42 MMT Scenario portfolio to be used as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission based on the Reference System Plan. The decision also stipulated that no base portfolio would be transmitted to the ISO as part of the 2018-2019 TPP policy-driven assessment, but that once the "preferred system plan" is adopted through the 2018 IRP effort, it will be utilized as a policy-preferred portfolio in the subsequent transmission planning process to identify Category 1 policy-driven transmission needs.

The CPUC used the RESOLVE model for creating the 42 MMT Scenario portfolio. 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. The ISO worked with the CPUC to identify such resources and model[90] these in the policy-driven assessment base cases. The ISO supplemented this scenario with information regarding contracted RPS resources that are under construction as of May 2018. Because the CPUC adopted the 42 MMT Scenario portfolio to be assessed as a sensitivity in the 2018-2019 TPP policy-driven assessment, and specifically excluded a base portfolio for policy-driven analysis, the ISO is not recommending approval of any policy-driven transmission elements as part of the 2018-2019 TPP.

3.2 Objectives of policy-driven assessment

The four key objectives of the policy-driven assessment were:

3. Study the transmission impacts of the sensitivity portfolio transmitted to the ISO.
    a. Capture reliability impacts.
    b. Test the deliverability of resources selected to be full capacity deliverability status (FCDS).
    c. Analyze renewable curtailment data.

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

90 http://docketpublic.energy.ca.gov/PublicDocuments/17-MISC-03/TN222569_20180215T155902_Energy_Commission_Staff_Proof_of_Concept_Report_to_CPUC_Staff.pdf

4. Evaluate transmission solutions (only Category 2 in this planning cycle) needed to meet state, municipal, county or federal policy requirements or directives as specified in the Study Plan.
5. Test the transmission capability estimates used in CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation.
6. Test deliverability of FCDS resources in the portfolio using new renewable output assumptions that take into account the new qualifying capacity calculations for solar and wind.

3.3 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.

3.3.1 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 described in chapter 2 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.

3.3.2 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.

3.3.3 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

3.3.4 Renewable Portfolio

As set out above, a 42 MMT Scenario portfolio was transmitted to the ISO to be used as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission based on the Reference System Plan. No base portfolio was transmitted to the ISO as part of the 2018-2019 TPP policy-driven assessment.

Compared to the renewable portfolios transmitted to the ISO by the CPUC during the 2017-2018 transmission planning process, the portfolios transmitted to the ISO as part of 2018-2019 TPP contain several changes in terms of resource classification and the nature of modeling/mapping data. The key changes are as follows:

- “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 portfolio now includes only the new generic (not contracted) resources. In the past, portfolios were comprised of contracted and generic resources. Contracted resources (on-line and planned) are now considered as baseline resources in RESOLVE model, so these resources are not part of the optimization.
- A mix of resources with Full Capacity Deliverability Status (FCDS) and Energy Only Deliverability Status (EODS) are selected as part of portfolios.
- The 2,000 MW of energy storage included in the portfolio is primarily for system-wide renewable integration purpose, so it does not have a material impact on deliverability and reliability studies being performed as part of the policy-driven assessment.

Figure 3.3-1 shows a comparison of the 42 MMT portfolio with the default portfolio modeled in the TPP reliability assessment. For the most part, the default portfolio appears like a subset of the 42 MMT portfolio. Table 3.3-1 lists the renewable resources selected as part of the 42 MMT portfolio.

Figure 3.3-1: 42 MMT portfolio and default portfolio

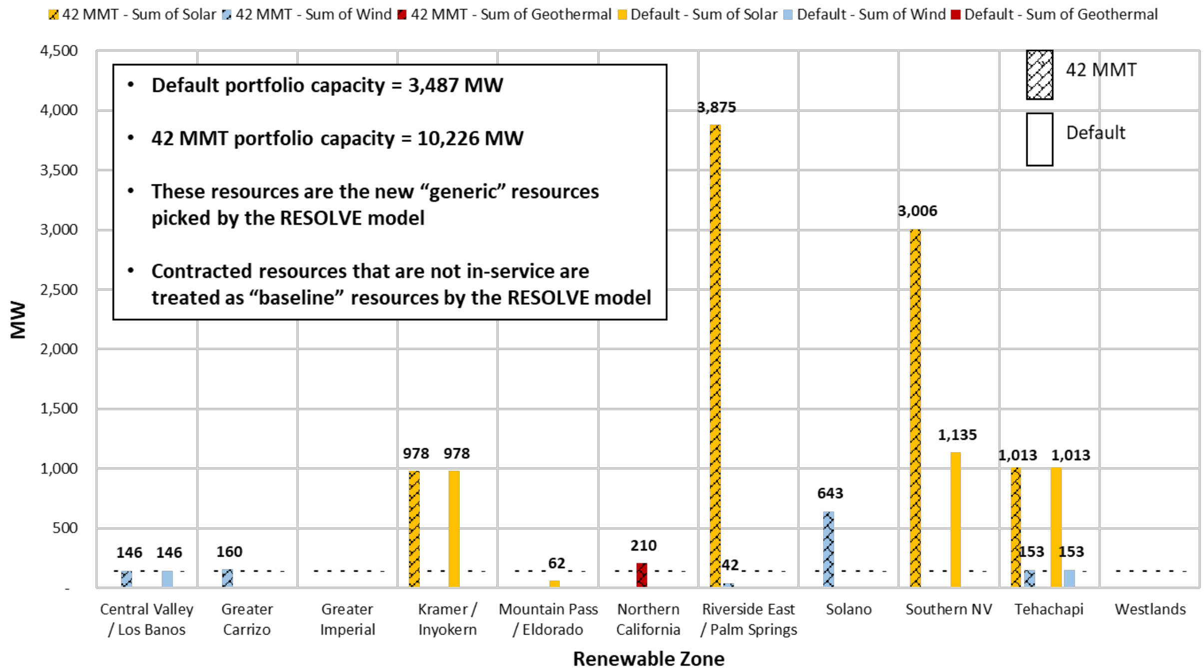


Table 3.3-1: 42 MMT portfolio resource summary

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)	TOTAL
Northern CA	-	-	210	210
Solano	-	643	-	643
Central Valley / Los Banos	-	146	-	146
Greater Carrizo	-	160	-	160
Tehachapi	1,013	153	-	1,166
Kramer & Inyokern	978	-	-	978
El Dorado, Mountain Pass, Southern NV	3,006	-	-	3,006
Riverside East & Palm Springs	3,875	42	-	3,917
TOTAL	8,872	1,144	210	10,226

The portfolio comprises of a mix of FCDS and EODS resources. Figure 3.3-2 and Table 3.3-2 show a breakdown of the portfolio by technology and by deliverability status of the resources. FCDS resources are predominantly selected in Central Valley-Los Banos, Kramer-Inyokern, Riverside East & Palm Springs, Southern Nevada and Tehachapi zones. EODS resources are selected in Greater Carrizo, Riverside East & Palm Springs, Solano and Southern Nevada.

Figure 3.3-2: 42 MMT portfolio by technology and by deliverability status

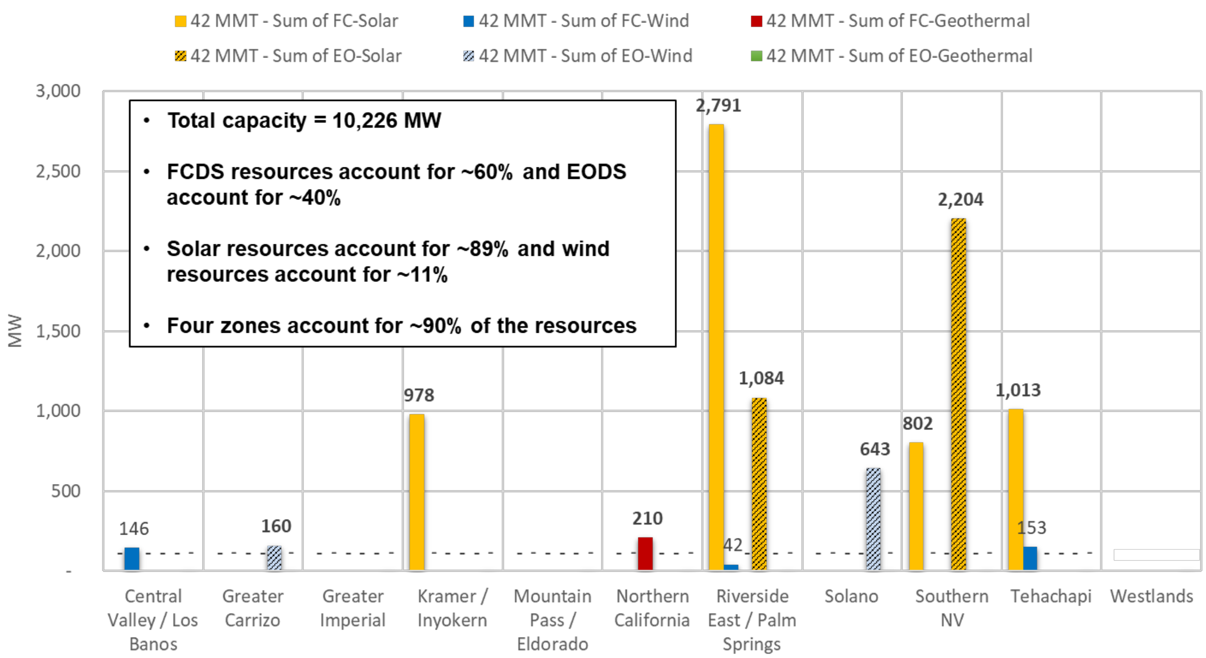


Table 3.3-2: 42 MMT portfolio resource summary by technology and by deliverability status

Renewable Zones	**Solar (MW)**		**Wind (MW)**		**Geothermal (MW)**	
	FCDS	**EODS**	**FCDS**	**EODS**	**FCDS**	**EODS**
Northern CA	-	-	-	-	-	210
Solano	-	-	-	643	-	-
Central Valley / Los Banos	-	-	146	-	-	-
Greater Carrizo	-	-	-	160	-	-
Tehachapi	1,013	-	153	-	-	-
Kramer & Inyokern	978	-	-	-	-	-
El Dorado, Mountain Pass, Southern NV	802	2,204	-	-	-	-
Riverside East & Palm Springs	2,791	1,084	42	-	-	-
TOTAL	**5,584**	**3,288**	**341**	**803**	**-**	**210**

3.3.5 Mapping of portfolio resources to transmission substations

The ISO used the proposed resource mapping[91] provided by the CEC staff and made minor modifications to the suggested transmission locations.

The portfolios provided by the CPUC contained resource amounts at a geographic scale that was too broad for transmission planning analysis, which requires specific interconnection locations. CEC staff developed a proposed substation allocation by relying on information from the CPUC, the ISO, RETI 2.0 results, California Department of Fish and Wildlife, and U.S. Bureau of Land Management (Nevada). The ISO then relied on more specific information about interconnection challenges in some locations that resulted in changing the resource allocation to substations in Southern NV zone.

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 observed for a specific generation build-out within a renewable zone should be independent of the specific projects that get built.

3.3.6 Transmission capability estimates and corresponding utilization in 42 MMT portfolio

The estimated available transmission capability to support future renewable generation is monitored annually through the ISO transmission planning process. The ISO relies on past transmission analysis from policy-driven assessments, special studies, generation interconnection studies and the work ISO performed in supporting the RETI 2.0 initiative. Figure 3.3-3 shows an approximate geographical representation of the information transmitted to the CPUC to assist in the RESOLVE modeling efforts in support of the IRP process and the 2018-2019 TPP. The EODS estimates shown in this diagram are inclusive of the FCDS estimates. For example, in Tehachapi zone FCDS estimate is 5,000 MW and EODS estimate is 5,800 MW. This should be interpreted as 5,800 MW is the estimated limit for selecting any mix of FCDS and EODS resources combined as long as FCDS resource selection does not exceed 5,000 MW.

[91] https://efiling.energy.ca.gov/GetDocument.aspx?tn=222569

Figure 3.3-3: Transmission capability estimates provided as an input into IRP

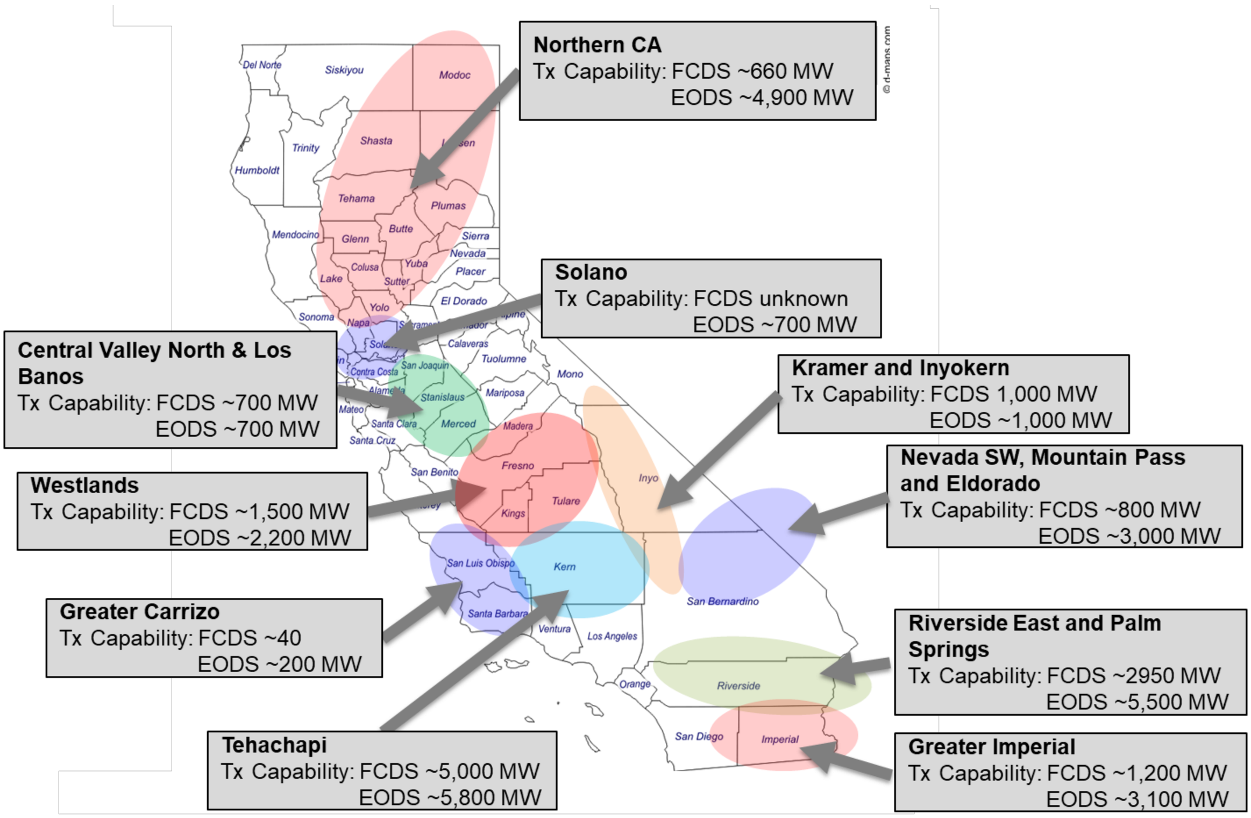


Figure 3.3-4 and Figure 3.3-5 show how the 42 MMT portfolio utilized the transmission capability estimates provided by the ISO. The estimated FCDS capability is fully utilized in some zones and considerable surplus remains elsewhere – the same applied for the EODS capability estimates and corresponding utilization. It is important to note that these transmission capability estimates are only one of the several deciding factors utilized for resources selection in the RESOLVE model.

Figure 3.3-4: Utilization of FCDS transmission capability estimates

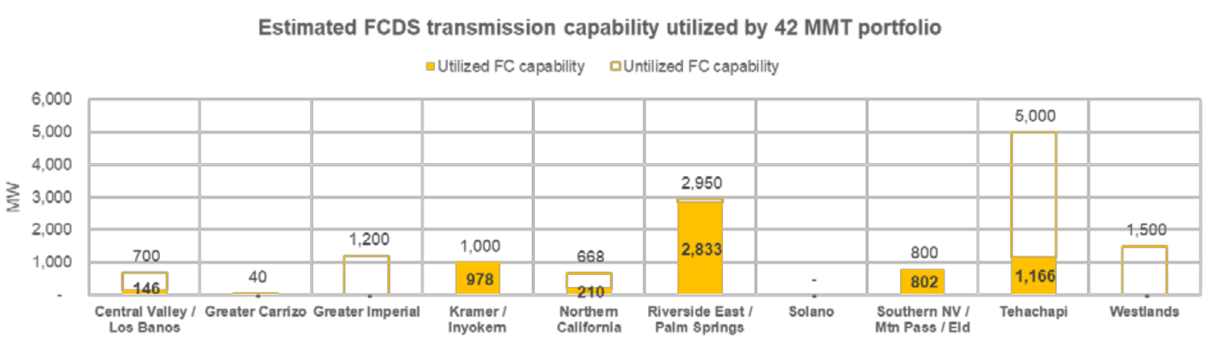
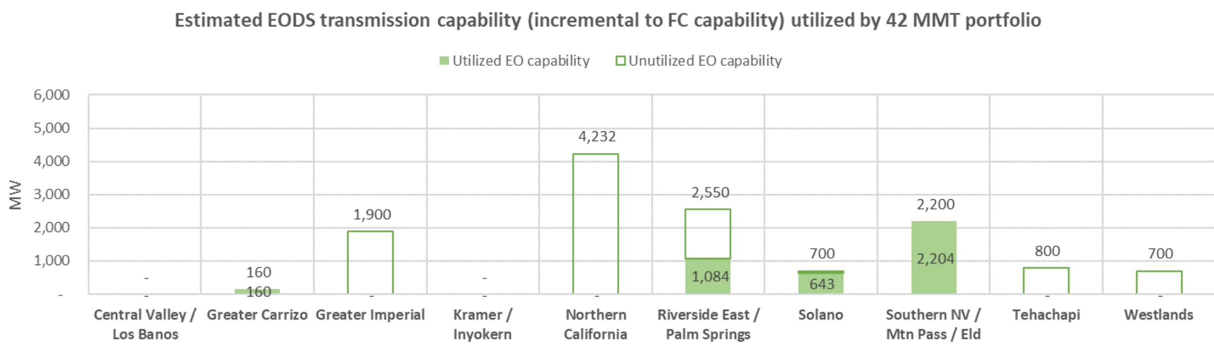


Figure 3.3-5: Utilization of EODS transmission capability estimates

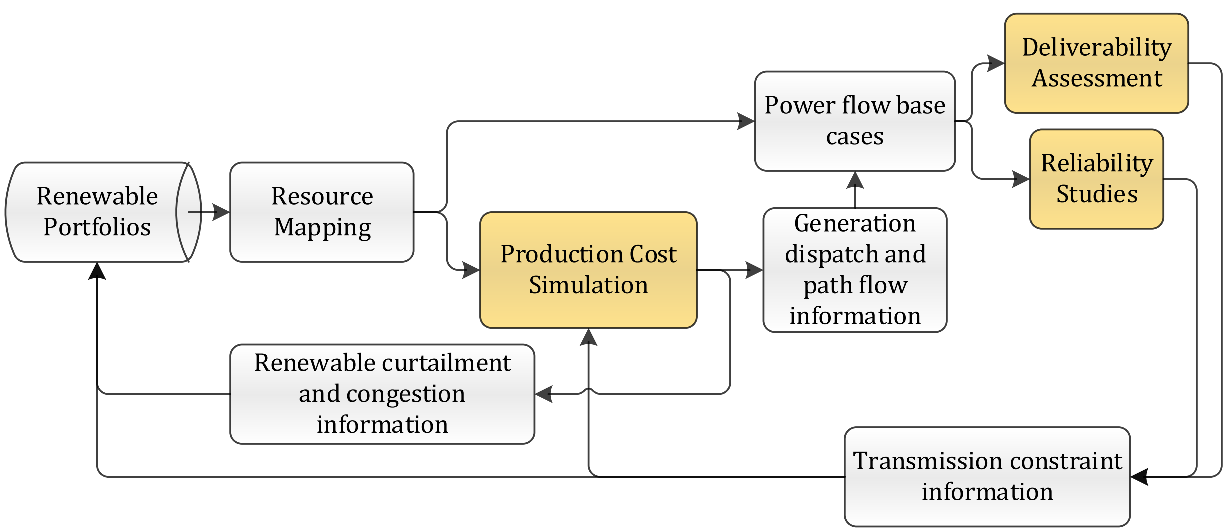


As part of the 2018-2019 TPP policy-driven assessment the ISO plans to refine the existing transmission capability estimates and provide these updated estimates as an input in support of the ongoing IRP process.

3.4 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies. 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 3.4-1: 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 difference of renewable curtailment between the first and the second scenarios can be a good approximation of renewable curtailment related to transmission constraints within California. It should be noted, however, that the “no export limit” scenario may still have some renewable curtailment due to system constraints, but this should be relatively small. Production cost simulations were used to create hourly snapshots of the system to be used for reliability studies which involve power flow simulations.

Reliability studies (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 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. An essential step in deliverability assessment of this year’s policy-driven portfolio was to review the study methodology in order to adapt to the changing generation fleet characteristics and load profiles that are also leading to changes to resource counting methodology for resource adequacy purposes. The ISO relied on the capacity margin data and corresponding renewable resource output from the 2018 summer assessment data to adjust the dispatch assumptions in order to reflect the new resource counting methodology. This approach also included an enhancement of the methodology used to identify upgrades in the deliverability assessment. A detailed discussion of this proposed deliverability methodology is presented in section 3.5.

3.5 Deliverability assessment

The ISO initially developed a deliverability study methodology for resource adequacy purposes in 2004. The methodology was generally adopted in the CPUC’s Resource Adequacy (RA) proceeding in 2004. A generating resource must pass the ISO deliverability test under system summer peak load condition for its Qualifying Capacity (QC) to become Net Qualifying Capacity (NQC) that can be counted to meet the RA requirement. At that time, the generating resources were predominantly non-intermittent, such as thermal plants and hydro plants. The QC values used in the deliverability assessment were the respective maximum output for the resource. The adoption of 20 percent and 33 percent RPS targets led to a high volume of renewable generation interconnection requests to the grid; hence the methodology was expanded to account for intermittent resources. The QC values for wind and solar resources were calculated based on resource production exceedance values. Aligned with the QC calculation, the ISO developed the capacity assumptions for intermittent resources in the deliverability assessment based on the exceedance values during the same QC counting window in the summer months. The methodology has been applied in the ISO generation interconnection studies and transmission planning studies. Several policy driven transmission upgrades were identified and approved to support deliverability of 33 percent RPS portfolio.

Starting in 2018, the CPUC has replace the exceedance based QC calculation with an effective load carrying capability (ELCC) approach. As the resource portfolio keeps evolving toward a higher RPS target, energy efficiency, demand response and behind-the-meter distributed generation, both the characteristics of the load profile and the resource portfolio are going through a transformation which raise concerns about the overall utility of the current methodologies included in the QC approach and corresponding deliverability methodology. In response to this change, the ISO performed an informational study in the 2016-2017 TPP 50 percent RPS deliverability assessment that evaluated the deliverability methodology and experimented with modifications to the study assumptions in the deliverability assessment. The ISO has since summarized the previous work and reviewed the deliverability assessment from a broader perspective that involves the study methodology, upgrades identification and study process. The ISO team proposed modifications to the deliverability assessment methodology to stakeholders and tested the proposal on the 42 MMT portfolio.

3.5.1 Proposed deliverability approach

The proposed deliverability assessment is a test under multiple system conditions – the highest system need scenario and the secondary system need scenarios, and to better align generation output assumptions with the time of day and time of year of those system needs. To select the scenarios, the ISO needs to obtain the forecasted hourly profiles for the gross consumption, behind-the-meter generation, and in-front-of-the-meter generation of the study year. The ISO relied on data from ISO 2018 summer loads and resources assessment, as this data was not available at the time from the CPUC's ELCC studies.

The ISO 2018 summer loads and resources assessment indicated that the ISO faced significant risk of encountering operating conditions that could result in operating reserve shortfalls. The hours with risk of operating reserve shortfalls in the 2018 summer assessment were used to establish the study assumptions for the highest and secondary system need scenarios. The 2018 summer assessment used a stochastic process to randomly generate 2000 unique scenarios – each representing a combination of forecasted 8,760 hourly load profiles and renewable generation levels based on historic annual weather patterns. By simulating the 2000 scenarios, the unloaded capacity margin was calculated for each simulated hour. The hours with unloaded capacity margin less than 6 percent were used to establish the deliverability assessment assumptions. The combination of the load, solar, wind and other transmission and generation conditions during these hours are most likely to result in a capacity shortage.

3.5.1.1 Highest System Need Scenario (HSN)

The 2018 summer assessment indicated that most of the MCUM hours are around hour ending 20:00, which aligns with the expected hours of highest load seen from the transmission grid. HE18 to 22 with UCM less than 6 percent in the 2018 summer assessment results were selected to be the highest system need window to examine intermittent generation output levels. Wind and solar outputs were examined during those hours and Table 3.5-1 shows the percentile output levels.

Table 3.5-1: Wind and Solar Output Percentile for HE18~22 & UCM<6 Percent Hours

		min	max	50%	60%	70%	80%	90%
wind	SDG&E	0%	86%	11.1%	16.3%	23.0%	33.7%	45.5%
	SCE	0%	88%	27.6%	36.9%	46.3%	55.7%	65.6%
	PG&E	0%	98%	29.8%	38.2%	52.5%	66.5%	78.2%
solar	SDG&E	0%	57%	0.0%	0.1%	1.7%	3.0%	7.6%
	SCE	0%	75%	1.9%	3.9%	7.0%	10.6%	14.8%
	PG&E	0%	70%	0.9%	4.1%	6.8%	10.0%	13.7%

The ISO proposed to use the 80th percentile, i.e. 20 percent exceedance, output level from hours of UCM<6 percent, or hours of loss of load events if ELCC data is available, between HE 18 and HE 22 in the summer months for the highest system need scenario. This is when the capacity is needed the most and it is critical to have higher certainty of wind and solar being deliverable during the time period. The value of 20 percent exceedance levels would be examined periodically and updated for use in the deliverability assessment.

Table 3.5-2: Modeling Assumptions for Highest System Need Scenario

Selected Hours	HE18 ~ 22 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in ISO summer assessment)
Load	1-in-5 peak sale forecast by CEC
Non-Intermittent Generators	Pmax set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Pmax set to 20% exceedance level during the selected hours
Import	MIC data with expansion approved in TPP

The deliverability assessment then followed the steps in the current methodology. Deliverability constraints were identified and delivery network upgrades were identified for each constraint.

3.5.1.2 Secondary System Need Scenario (SSN)

The solar output level is very low in the highest system need hours. The highest system need scenario alone does not provide sufficient confidence that the solar resources are deliverable in all the hours when they are needed. A second scenario supplements the highest system need by testing deliverability when both the system load and the solar production are high. HE15 to 17 with UCM less than 6 percent in the 2018 summer assessment results were identified as relatively high solar output with a mild risk of capacity shortage. Wind and solar outputs were examined during these hours and Table 3.5-3 shows the percentile output levels.

Table 3.5-3: Wind and Solar Output Percentile for HE15~17 & UCM<6% Hours

		min	max	50%	60%	70%	80%	90%
wind	SDG&E	0%	69%	11.2%	16.6%	26.5%	40.8%	47.9%
	SCE	1%	70%	20.8%	24.8%	34.9%	57.4%	64.8%
	PG&E	1%	83%	16.3%	21.4%	44.7%	69.7%	76.8%
solar	SDG&E	2%	88%	35.9%	44.7%	58.0%	72.1%	75.4%
	SCE	17%	96%	42.7%	49.6%	51.8%	61.9%	86.3%
	PG&E	16%	91%	55.6%	61.6%	63.2%	74.6%	75.9%

It was proposed to use the median, i.e. 50 percent exceedance, output level from hours of UCM<6 percent, or if ELCC data available, hours of LOLE events, between HE 15 and HE 17 in the summer months. During these hours, there is a mild risk of capacity shortage. It is reasonable to lower the requirement for being simultaneously deliverable. The value of 50 percent exceedance levels would be examined periodically and updated in the deliverability assessment.

The load is scaled from the 1-in-5 peak sale forecast by examining the hourly load and behind the meter generation data from CEC.

The highest imports that were selected for MIC calculation align with the highest system need hours. During the secondary system need hours, historical data show that total import is about 2000 MW lower than the highest need hours. For 2016 and 2017 summer, the highest import HE18-22 is 11,780 MW and the highest import HE15-17 is 9,142 MW.

Table 3.5-4: Modeling Assumptions for Secondary System Need Scenario

Select Hours	HE15 ~ 17 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in ISO summer assessment)
Load	1-in-5 peak sale forecast by CEC adjusted to peak consumption hour
Non-Intermittent Generators	Pmax set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Pmax set to 50% exceedance level during the selected hours
Import	Highest import schedules for the selected hours

3.5.1.3 Application of Highest System Need Scenario and the Secondary System Need Scenario study results

The highest system need scenario represents the time when a capacity shortage is most likely to occur. As a result, if the addition of a resource will cause a deliverability deficiency determined based on a deliverability test under the HSN scenario, then the constraint would be classified as either a Local Deliverability Constraint or an Area Deliverability Constraint. The upgrade needs identified in the transmission planning policy deliverability assessment would qualify as policy upgrades.

The secondary system need scenario represents the time when the capacity shortage risk will increase if the intermittent generation - while capable of producing at a significant output level - is not deliverable. If the addition of a resource will cause a deliverability deficiency determined based on a deliverability test under the SSN scenario, and is not identified in the HSN scenario, then the constraint could be classified as an Area Deliverability Constraint following the classification guidelines in the BPM for the Generator Interconnection and Deliverability Allocation Procedures. The upgrade needs identified for SSN only in the transmission planning policy deliverability assessment would be recommended for approval only if the upgrades are identified in the policy powerflow and stability study or production cost simulation. Otherwise, the upgrades would be determined as not needed yet.

3.5.2 Deliverability assessment results

The proposed study approach was tested on the 42 MMT portfolio. The renewable generation designated as full capacity deliverability status was modeled with the assumptions in Table 3.5-2 and

Table 3.5-4. The energy only renewable generation in the portfolio was not dispatched in the assessment.

No deliverability constraints were identified in the highest system need scenario.

Deliverability constraints observed under the secondary system need scenario are shown in Table 3.5-5.

Table 3.5-5: Deliverability Constraints in 42 MMT Secondary System Need Scenario

Contingency	Overloaded Facilities	Flow
Kramer – Victor 230 kV No. 1 & 2	Kramer – Roadway 115 kV	123.62%
Kramer – Victor 230 kV No. 1 & 2	Kramer - Victor 115 kV	119.01%
Kramer – Victor 230 kV No. 1 & 2	Kramer 230/115 kV No. 1 & 2	114.43%

These overloads can be mitigated by adding generators to the existing RAS.

Based on the results, no transmission upgrades beyond what have already been approved previously are needed to support the deliverability of the 42 MMT portfolio.

3.6 Production cost simulation (PCM) study

3.6.1 PCM assumptions

The 42 MMT portfolio described in Section 3.3.4 was utilized for the PCM study during this 2018-2019 TPP policy-driven assessment. Details of PCM assumptions and development can be found in Chapter 4. Similar to the changes made in the default portfolio study as described in Section 4.6.4, renewable resources in Kramer-Inyokern and Southern Nevada areas identified as generic in CPUC’s portfolios were modeled at Lugo 500 kV and Eldorado 500 kV buses respectively because of the lack of a clear interconnection plan and the obvious local transmission constraints that were observed in the initial PCM simulations.

Two scenarios with different ISO net export limit were studied, 2000 MW limit and no export limit, in order to estimate transmission related curtailment.

3.6.2 PCM results

3.6.2.1 Congestion

Table 3.6-1 lists the congestion summary results of the scenario with 2000 MW ISO net export limit. The constraints in this list are ranked in the descending order of total number of hours of congestion. It should note that the results in Table 3.6-1 already reflect the modeling change of moving generic resources in Kramer-Inyokern and Southern Nevada areas to Lugo 500 kV and Eldoradao 500 kV buses respectively. Without this modeling change, congestion in SCE NOL-Kramer-Inyokern-Control zone, and in VEA zone would increase, compared to the congestion results for the default portfolio study discussed in chapter 4. This increase can be attributed to the incremental renewable generators identified in SCE's Kramer-Inyokern area and the VEA area in the 42 MMT portfolio.

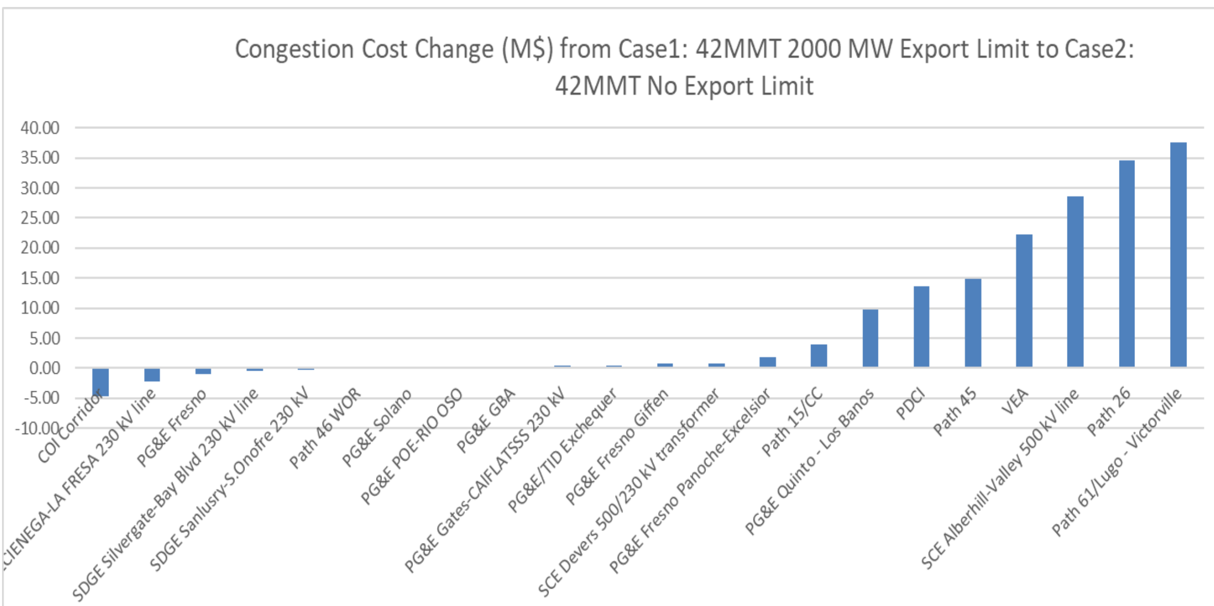
Table 3.6-1: Congestion summary – 2000 MW ISO net export limit

Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
Path 26	61.46	1,609
PG&E Fresno Giffen	0.49	1,597
Path 45	5.68	1,567
SCE NOL-Kramer-Inyokern-Control	1.44	1,130
PG&E/TID Exchequer	2.93	1,102
VEA	5.93	813
PG&E Fresno Panoche-Excelsior	1.27	650
PDCI	3.06	317
SCE Alberhill-Valley 500 kV line	26.89	279
SCE J.HINDS-MIRAGE 230 kV line	1.02	170
COI Corridor	9.51	154
SDGE Sanlusry-S.Onofre 230 kV	1.03	146
Path 61/Lugo - Victorville	0.26	133
SCE LCIENEGA-LA FRESA 230 kV line	4.89	101
PG&E Quinto - Los Banos	2.59	99
PG&E POE-RIO OSO	1.83	85
PG&E Fresno	1.11	73
Path 15/CC	3.47	55
SCE Devers 500/230 kV transformer	1.45	52
SDGE Silvergate-Bay Blvd 230 kV line	1.19	50
SCE Sylmar - Pardee 230 kV	0.19	26
SDGE IV-SD Import	0.32	18
Path 46 WOR	0.44	17
PG&E Solano	0.63	12
PG&E Delevn-Cortina 230 kV	0.15	11
PG&E GBA	0.16	10
SDGE-CFE OTAYMESA-TJI 230 kV line	0.04	8
PG&E Gates-CAlFLATSSS 230 kV	0.02	7
PG&E Humboldt	0.00	4
SCE Delaney-ColoradoRiver 500 kV	0.02	2
PG&E Table Mt.-Palermo 230 kV line	0.02	1
SDGE-CFE IV-ROA 230 kV line and IV PFC	0.00	1
SDGE N.Gila-Imperial Valley 500 kV line	0.00	1

Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
SDGE Hoodoo Wash - N.Gila 500 kV line	0.00	1
Path 25	0.09	1
PG&E Summit-Drum 115 kV	0.08	1
Path 24	0.05	1

Figure 3.6-1 shows the changes in congestion 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 VEA's Bob SS – Mead 230 kV line increased. Path 26 (south to north direction) and SCE Alberhill-Valley 500 kV line (Valley to Alberhill direction) congestion increased mainly due to more renewable generators being able to remain online when no export limit was modeled. This resulted in higher flows along these two corridors.

Figure 3.6-1: Congestion changes between 2000 MW export limit and no export limit scenarios



3.6.2.2 Curtailment

Table 3.6-2 shows the total wind and solar generation output and the total curtailment in the two scenarios. Without enforcing an ISO net export limit, renewable curtailment reduced since the surplus generation can be exported to other regions. There were still 4.24 TWh of curtailment in the ISO's system, which were caused mainly by transmission constraints.

Table 3.6-2: Wind and Solar generation and curtailment

Scenario	42 MMT 2000 MW ISO Net Export Limit	42 MMT No Export Limit
Total Wind and Solar Generation (TWh)	82.92	96.50
Total Curtailment (TWh)	17.82	4.24

Figure 3.6-2 and Figure 3.6-3 show the wind and solar generation 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 Eastern and East of Lugo areas and the VEA area had the most curtailment in the 2000 MW Net Export Limit scenario. In terms of percentage, the VEA area and the SCE East of Lugo area had the highest percentages of curtailment, which was defined as curtailment divided by the summation of curtailment and generation.

Figure 3.6-3 compared the curtailment by area between these two export limit scenarios. The SCE Eastern area, the East of Lugo area and the VEA area 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 3.6-2: Wind and Solar generation and curtailment – 2000 MW Net Export Scenario

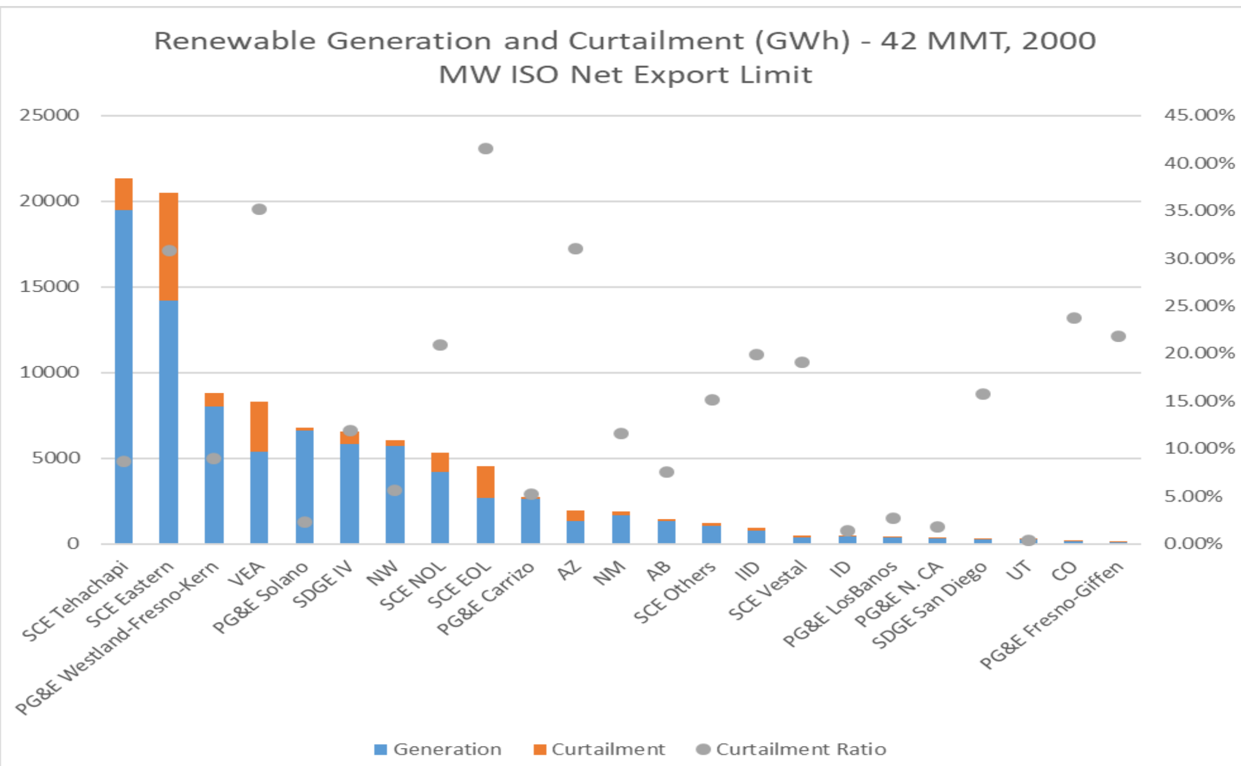


Figure 3.6-3: Wind and Solar generation and curtailment – No Export Limit

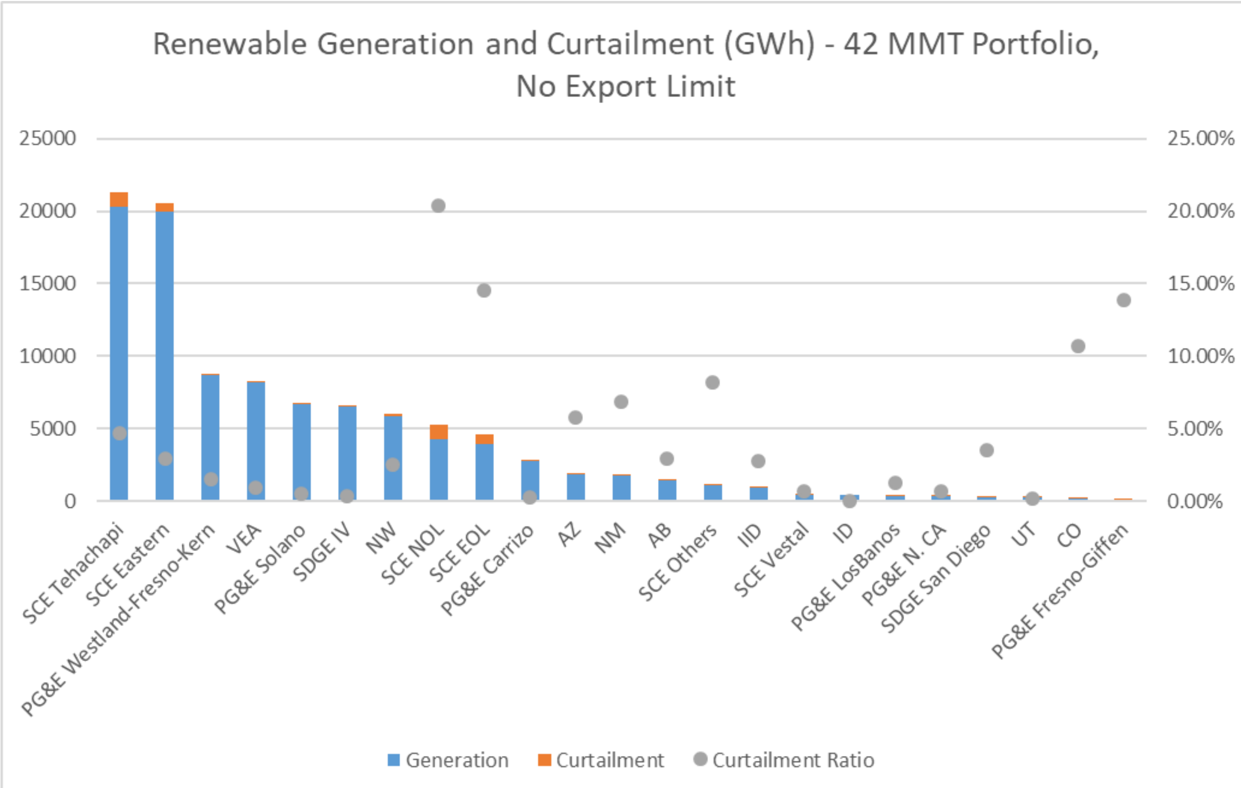
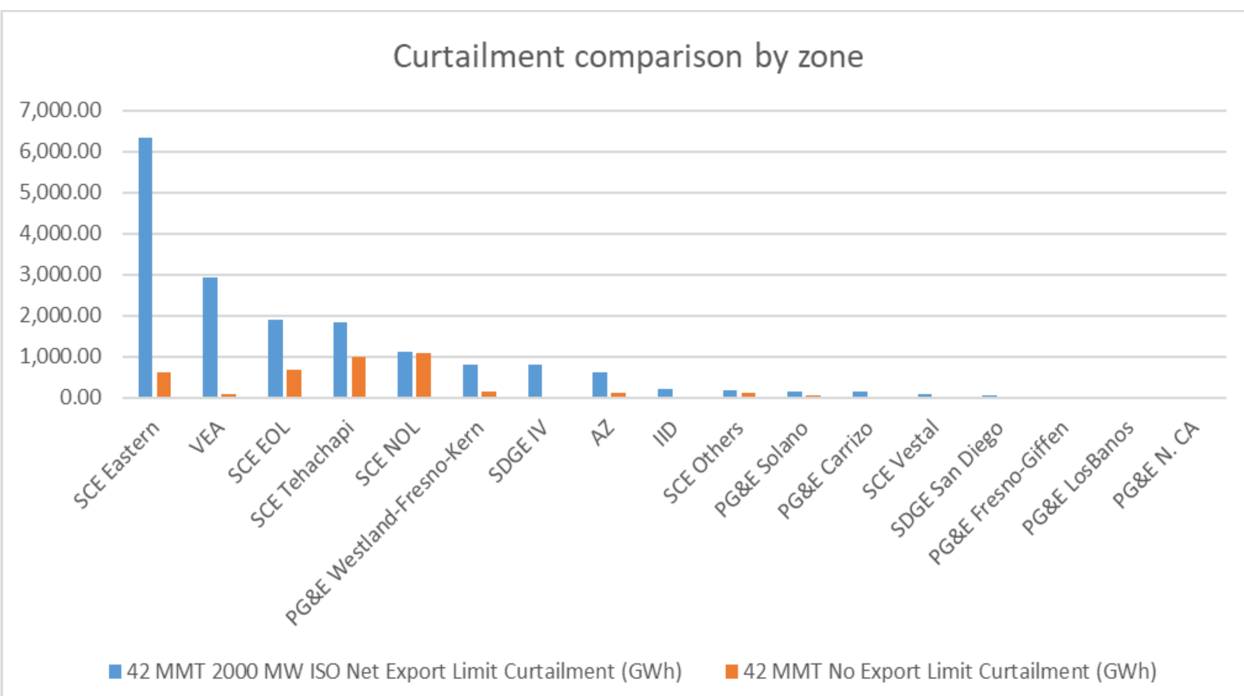


Figure 3.6-4: Curtailment changes between 2000 MW Net Export Limit and No Export Limit



3.7 Powerflow study

3.7.1 Starting base cases

The ISO utilized the 2028 summer peak base cases developed for Northern California bulk system and Southern California Bulk system assessment described in Chapter 2. These two base cases were merged to create a consolidated ISO base case. The ISO team added the resources selected as part of the 42 MMT portfolio in the form of generic equivalent models. The team relied on the resource mapping provided by the CEC staff as explained in Section 0.

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.

Certain hours that represent transmission system stress patterns due to high renewable dispatch in year 2028 were selected from the production cost simulation results with the objective of studying a reasonable upper bound on stressed system conditions.

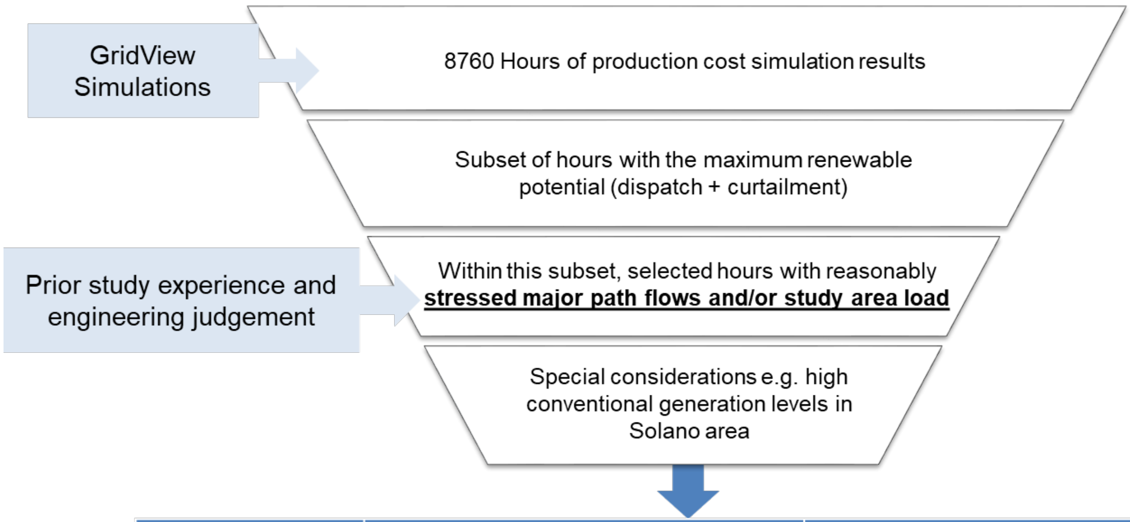
The following critical factors were considered in selecting the stressed patterns:

- renewable generation potential system-wide and within renewable study areas
- power flow on the major transfer paths in California

For example, hours that were selected for reference purposes in Southern CA were during times of near maximum renewable generation potential within key study areas (Southern Nevada, Eldorado, Mountain Pass, GridLiance and Greater Kramer) and reasonably high South-to-North flow on Path 26 during these hours with high renewable potential.

A reliability assessment was performed based on a dispatch that modeled the renewable potential (the PCM output level plus the curtailment level) instead of only renewable output. The renewable curtailment in the production cost simulation could be due to ISO system-wide over-supply or transmission congestion, and the objective of the reliability assessment was to identify and examine the transmission system constraints. 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 snapshot selection based on renewable potential allows for identification of new transmission constraints that were not modeled in production cost simulations. Figure 3.7-1 shows 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.

Figure 3.7-1: Snapshot selection for reliability assessment of portfolios



Scenario	Northern CA	Southern CA
42 MMT portfolio	August 17, 2028 Hr 21	April 25, 2028 Hr 13

3.7.3 Powerflow results

3.7.3.1 Summary of Northern CA portfolio reliability assessment

For the Northern CA reliability assessment of the 42 MMT portfolio, the primary focus was on Solano area since this portfolio contains significant amount of EO wind resources (643 MW) in this area. Due to this focus on wind resource output, the stressed snapshot for Northern CA case was an hour 21 snapshot as indicated in Table 3.7-1. No solar resources were selected in Northern CA region as part of the 42 MMT portfolio.

Table 3.7-1 presents a summary of resource nameplate amounts selected in Northern CA zones. These values were modeled in the respective base cases for the purpose of this reliability assessment.

Table 3.7-1: Summary of portfolio resources in Northern CA

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
Northern CA	-	-	210
Greater Carrizo	-	160	-
Central Valley / Los Banos	-	146	-
Solano	-	643	-

Table 3.7-2 shows major overloads that were observed when portfolio resources in Solano were dispatched to ~90 percent of the nameplate capacity and conventional generation dispatch was at ~100 percent of the nameplate capacity in accordance with the corresponding snapshot hour (August 17, 2028 Hour 21) selected for the power flow study.

Table 3.7-2: Reliability issues observed in Solano zone

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
North Dublin – Cayetano 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	103.7%	Solano	Curtailment of conventional generation is adequate. Mitigation could be in the form of pre-contingency curtailment or a RAS action triggered by contingencies listed in this table.
Newark – Las Positas 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	111.5%		
Cayetano – Lone Tree 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	109.5%		
Newark – Las Positas 230 kV Line	Contra Costa – Moraga No. 1 and 2 230 kV lines	P7-1	103.5%		

Key findings from the Northern CA reliability assessment 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 Contra Costa substation or the Contra Costa – Moraga No. 1 and No. 2 230 kV lines.
- Potential mitigations for these issues include (i) pre-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 3.7-2.

3.7.3.2 Summary of Southern CA portfolio reliability assessment

As shown in Figure 3.7-1, April 25, 2028 Hour 13 was studied for evaluating the impact on the Southern CA system as a result of a large amount of solar resources in the portfolio in renewable zones in Southern CA.

Table 3.7-3 presents a summary of resource nameplate amounts selected in Southern CA zones. These values were modeled in the respective base cases for the purpose of this reliability assessment.

Table 3.7-3: Summary of portfolio resources in Southern CA

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
El Dorado, Mountain Pass, Southern NV	3,006	-	-
Kramer & Inyokern	978	-	-
Riverside East & Palm Springs	3,875	42	-
Tehachapi	1,013	153	-

3.7.3.2.1 Reliability issues observed in Eldorado, Mountain Pass and Southern NV

Table 3.7-4 shows 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 to 98 percent of their nameplate capacity in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for Southern CA region.

Table 3.7-4: Reliability issues observed in Eldorado, Mountain Pass and Southern NV zones

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Indian Springs Tap – Mercury Switch (VEA to NV Energy's Northwest 138 kV path)	Base case (N-0)	P0	305.00%	Southern NV	A phase shifting transformer limiting the flow towards NV Energy's Indian Springs substation or renewable curtailment (~1,300 MW)
Amargosa 230/138 kV Transformer	Base case (N-0)	P0	248.33%	Southern NV	Upgrade the existing transformer or add a new 230/138 kV transformer at Amargosa or renewable curtailment (~1,200 MW)
Innovation – Desert View 230 kV	Base case (N-0)	P0	347.48%	Southern NV	A combination of 230 kV upgrades on the GridLiance system (described in Table 3.7-5) combined with RAS and/or pre-contingency curtailment or renewable curtailment (~1,200 to ~1,500 MW)
Trout Canyon (Crazy Eyes) – Sloan Canyon (Bob) 230 kV	Base case (N-0)	P0	279.32%	Southern NV	
Northwest – Desert View 230 kV	Base case (N-0)	P0	232.39%	Southern NV	
Pahrump 230/138 kV Transformer No. 1	Base case (N-0)	P0	113.86%	Southern NV	
Pahrump 230/138 kV Transformer No. 2	Base case (N-0)	P0	108.13%	Southern NV	
Innovation 230/138 kV Transformer	Base case (N-0)	P0	108.07%	Southern NV	
Divergence	Desert View – Northwest 230 kV	P1	N/A	Southern NV	
Divergence	Innovation – Desert View 230 kV	P1	N/A	Southern NV	
Divergence	Pahrump – Innovation 230kV & Vista – Johnnie 138kV	P7-1	N/A	Southern NV	
Amargosa 230/138 kV Transformer	Pahrump – Innovation 230 kV	P1	283.43%	Southern NV	Upgrade the existing transformer or add a new 230/138 kV transformer at Amargosa or renewable curtailment
Northwest – Westside 230 kV	Northwest – Beltway 230 kV No. 2	P1	112.85%	Southern NV	

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Ivanpah 230/115 kV Transformer Bank No. 1 or No. 2	Ivanpah 230/115 kV Transformer Bank No. 2 or No. 1	P1	116.06%	Southern NV, Eldorado and Mountain Pass	Pre-contingency curtailment and/or RAS to trip generation
Eldorado 500/230 5AA Transformer	Base case (N-0)	P0	107.14%	Southern NV, Eldorado and Mountain Pass	
Eldorado – Bob 230 kV	Eldorado 500/230 5AA Transformer	P1	123.02%	Southern NV, Eldorado and Mountain Pass	

The key observations for the Eldorado, Mountain Pass and Southern NV zones are:

- Most of the 3,006 MW modeled in Southern NV region was modeled at 230 kV substations in the GridLiance system.
- Several base case (N-0) and contingency (N-1 and N-2) transmission constraints observed in this area provide an explanation for a portion of the renewable curtailment observed in the initial PCM studies which modeled all the resources at the same locations as those assumed for power flow modeling in the same area.
- If some of the resources modeled at GridLiance substations are modeled at Eldorado substation, then the transmission constraints may not be as severe. But the ISO recognizes that the mapping effort carried out by the CEC staff indicated an environmental preference for GridLiance and VEA substations over Eldorado substation for connecting portfolio resources.

To account for the environmentally preferred locations in the Southern NV zone, the ISO tested a variety of upgrade options that can partially mitigate the transmission constraints observed in Table 3.7-4. Table 3.7-5 presents the upgrade options considered by the ISO and shows how each of these options would mitigate reliability issues in the Southern NV zone. The mitigation effectiveness was tested only in power flow studies in order to get directional insights about the scope and costs of upgrades that may be required if the objective is to eliminate most of the transmission constraints in this zone that could result in renewable curtailment. It is important to note that the elimination of all the constraints was not the objective, so upgrades with incremental additions to the scope were tested. PCM studies were not performed on the upgrade options listed in Table 3.7-5.

Table 3.7-5: Southern NV conceptual upgrades tested for reliability performance

Option	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
I	• Phase shifting transformer at Mercury Switching Station to prevent overloads on NV Energy's 138 kV lines connected to Northwest 230/138 kV substation • Rebuild existing Pahrump – Sloan Canyon (Bob) 230 kV line to 926/1195 MVA normal/emergency rating and connect to Carpenter Canyon (Gamebird) and Trout Canyon (Crazy Eyes). • Rebuild existing Innovation – Desert View 230 kV line to 926/1195 MVA normal/emergency rating and add a 2nd circuit with the same rating. • Add 2nd 230 kV circuit Desert View – Northwest at 926/1195 MVA normal/emergency rating.	~$150 M	- Not all base case overloads can be eliminated - Some contingency overloads cannot be managed using RAS and pre-contingency curtailment - If Southern NV renewable capacity was reduced to ~2,000 MW from 3,000 MW, then very little transmission-driven curtailment is expected - With Southern NV dispatch reduced to 2,000 MW, Amargosa 230/138 kV bank overload still observed for a large number of contingency scenarios
II	In addition to Option I • Upgrade existing Desert View - Northwest 230 to 926/1195 MVA normal/emergency rating • Upgrade existing Pahrump - Innovation 230 kV to 926/1195 MVA normal/emergency rating	~$180 M	- Marginal improvement over Option I - With Southern NV capacity reduced to 2,000 MW, the number of contingencies causing Amargosa 230/138 kV bank to overload is almost cut into half
III	In addition to Option I • A new 230 kV substation at Vista • A new Vista - Charleston 230 kV line (926/1195 MVA normal/emergency rating) • Rebuild Vista - Pahrump 230 kV line to 926/1195 MVA normal/emergency rating	~$190 M	- Marginal improvement over option I - With Southern NV capacity reduced to 2,000 MW, Amargosa 230/138 kV bank overloads increased under this option with a large number of contingency scenarios resulting in an overload
IV	In addition to Option II, • A 2nd Pahrump - Sloan Canyon 230 kV line (926/1195 MVA normal/emergency) • 500 kV loop-in station at Sloan Canyon connecting to Harry Allen – Eldorado 500 kV line	~$300 M	- All base case overloads except Amargosa 230/138 kV bank overload can be eliminated. - Most contingency overloads are eliminated and the rest can be managed with a RAS - If Southern NV renewable capacity was reduced to ~2,000 MW from 3,000 MW, then very little transmission-driven curtailment is expected.

Please note that the cost estimates listed above are highly conceptual in nature. Among these conceptual upgrades tested as part of this study,

- Option IV seemed to eliminate most of the reliability issues observed under ~3,000 MW renewables dispatch in Southern NV.
- Option I seemed to eliminate several base case overloads and reduced the severity of the remaining overloads under 3,000 MW Southern NV renewable dispatch.
- Options II and III showed marginal improvements over Option I
- When tested with a reduced capacity of ~2,000 MW in Southern NV, all the options seemed to address most of the reliability issues except for the Amargosa 230/138 kV bank overloads. This issue can be mitigated by upgrading the existing bank or by adding another bank at Amargosa depending on the feasibility of upgrading this WAPA facility.

The ISO performed this analysis in order to understand the extent of upgrades that may be required if we were to eliminate most of the transmission constraints resulting in renewable curtailment. The study also allowed us to understand the amount of resources that could be accommodated in this zone with some upgrades that would considerably reduce the possibility of renewable curtailment due to transmission constraints for Southern NV resources connecting to GridLiance system.

3.7.3.2.2 Reliability issues observed in Kramer and Inyokern (Greater Kramer)

Table 3.7-6 shows major overloads observed when portfolio resources along with existing and contracted resources in Kramer and Inyokern zone were dispatched to 98 percent of their nameplate in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for the Southern CA region.

Table 3.7-6: Reliability issues observed in Kramer and Inyokern zones

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Kramer – Victor 220 kV No. 1 and No. 2	Base case (N-0)	P0	142.02%	Kramer and Inyokern	Coolwater – Calcite – Lugo 230 kV line or renewable curtailment (~400 MW)
Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	Base case (N-0)	P0	103.53%	Kramer and Inyokern	Coolwater – Calcite – Lugo 230 kV line or renewable curtailment (~200 MW)
Kramer – Victor 220 kV No. 1 or No. 2	Kramer – Victor 230 kV No. 2 or No. 1	P1	184.64%	Kramer and Inyokern	RAS to trip generation after the contingency
Any three of the Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	Any of the Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	P1	102.87%	Kramer and Inyokern	RAS to trip generation after the contingency
Lugo 500/220 kV Transformer No. 1 or No. 2	Lugo 500/220 kV Transformer No. 2 or No. 1	P1	151.82%	Kramer and Inyokern	Existing RAS or bus reconfiguration
Divergence	Kramer – Victor 220 kV No. 1 and No. 2	P7	N/A	Kramer and Inyokern	Coolwater – Calcite – Lugo 230 kV line
Kramer – Victor 220 kV No. 1 and No. 2	Kramer – Victor 220 kV No. 1 and Kramer – Roadway 115 kV No. 1	P7	128.95%	Kramer and Inyokern	RAS to trip generation after the contingency
Lugo – Victor 220 kV line No. 1 and No. 2	Lugo – Victor 220 kV line No. 3 and No. 4	P7	154.35%	Kramer and Inyokern	RAS to trip generation after the contingency

Key observations for Kramer and Inyokern zone:

- 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 combined with more than 950 MW of behind-the-meter (BTM) solar generation modeled in this zone and dispatched for an Hour 13 snapshot resulted in transmission constraints. Kramer and Inyokern zone being a radial pocket can experience severe congestion due to high levels of BTM solar especially during off-peak hours.

The ISO tested a Coolwater – Calcite – Lugo 230 kV upgrade option to mitigate the reliability issues observed along Kramer to Victor and Victor to Lugo 230 kV corridor. Table 3.7-7 summarizes the upgrade option tested by the ISO.

Table 3.7-7: Kramer and Inyokern conceptual upgrade tested for reliability performance

Upgrade	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
Coolwater – Calcite – Lugo 220 kV upgrade	Build a new 220 kV Calcite-Coolwater Transmission line Rebuild transmission structures and transmission conductor along the existing Calcite - Lugo 220 kV Transmission Line	~$480 M	Victor – Lugo 220 kV base case overloads are mitigated Kramer – Victor 220 kV base case overloads are reduced to 105%, so can be managed with modest amounts of curtailment All the contingency overloads can be mitigated by relying on RAS to drop generation

The Coolwater – Calcite – Lugo 220 kV upgrade would completely mitigate the Victor – Lugo 220 kV line overloads under base case scenario but cannot entirely mitigate the Kramer – Lugo 220 kV line overloads under base case scenario. With this upgrade, Lugo 500/230 kV transformer banks are expected to continue to overload under contingency conditions as shown in Table 3.7-6. An existing RAS and future modifications to this RAS could address this issue and reduce pre-contingency curtailment of renewables.

The Kramer – Victor 220 kV lines were overloaded to 105% of their normal rating in spite of the Coolwater – Calcite – Lugo 220 kV upgrade. These base case overloads indicate that the upgrade could reduce the curtailment of ~400 MW generation in some hours, but would not be able to support a larger increase in resources in this zone.

3.7.3.2.3 Reliability issues observed in Riverside East and Palm Springs

Table 3.7-8 shows major overloads observed when portfolio resources along with existing and contracted resources in Riverside East and Palm Springs zones were dispatched to 98% (for Solar) and 82% (for Wind) of their nameplate in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for the Southern CA region.

Table 3.7-8: Reliability issues observed in Riverside East and Palm Springs zones

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Devers – Red Bluff 500 kV No. 1 or No. 2	Devers – Red Bluff 500 kV No. 2 or No. 1	P1	119.88%	Riverside East	RAS to drop generation or pre-contingency curtailment
Devers 500/230 kV Transformer	Devers – Valley 500 kV No. 1 and No. 2	P1	101.91%	Riverside East	
Divergence	Devers – Red Bluff 500 kV No. 1 and No. 2	P7	N/A	Riverside East	Add portfolio generation to the existing RAS to drop generation

Key observations for Riverside East and Palm Springs zones:

- Majority of resources in this zone were mapped to Red Bluff and Colorado River 500 kV substations based on the mapping work performed by the CEC staff. A small fraction of resources were mapped to Devers 230 kV.
- Reliability issues observed in this area can be mitigated by either a RAS action or pre-contingency curtailment. The generation tripping required to mitigate these reliability issues is ~1,150 MW for the N-1 (P1) contingency and ~1,400 MW for the N-2 (P7) contingency listed in Table 3.7-8.

The need to trip large amounts of generation to mitigate reliability issues indicates that any additional resources in this zone could trigger significant renewable curtailment in certain hours or could trigger major upgrades if renewable curtailment is to be avoided.

3.7.3.2.4 Reliability issues observed in Tehachapi

Table 3.7-9 shows major overloads observed when portfolio resources along with existing and contracted resources in Tehachapi zone were dispatched to 98 percent (for Solar) and 82 percent (for Wind) of their nameplate in accordance with the snapshot hour (April 25, 2028 Hour 13) selected for Southern CA region.

Table 3.7-9: Reliability issues observed in Tehachapi zone

Limiting Element	Contingency	Type	Overload (%)	Renewable Zones Impacted	Potential Mitigation
Midway – Whirlwind 500 kV No. 3	Base case (N-0)	P0	120.42%	Tehachapi	Generation curtailment (~1,000 MW). Some of this curtailment can come from conventional resources.
Windhub 500/230 kV Transformer Bank No. 1 or 2	Windhub 500/230 kV Transformer Bank No. 2 or 1	P1	155.11%	Tehachapi	RAS to trip generation or bus reconfiguration at Windhub 500 kV
Windhub 500/230 kV Transformer Bank No. 3 or 4	Windhub 500/230 kV Transformer Bank No. 4 or 3	P1	109.74%	Tehachapi	
Midway – Whirlwind 500 kV No. 3	Midway – Vincent 500 kV No. 1 or 2	P1	105.07%	Tehachapi	RAS to trip generation

Key observations for Tehachapi zone:

- Majority of resources in this zone were mapped to Windhub and Highwind 230 kV substations based on the mapping work performed by the CEC staff.
- Reliability issues observed in this area can be mitigated by either a RAS action or pre-contingency curtailment.

- Base case overload on Midway – Whirlwind 500 kV line no. 3 is caused by heavy South to North flow on Path 26 which is one of the most frequently congested paths as observed in PCM results presented in Section 3.6.2.2. Although renewable resource in Tehachapi greatly impact this constraint, resources in most of the Southern CA region could be curtailed to relieve this congestion.

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 11. An estimate of the generation deliverability supported by the existing system and approved upgrades is listed in Table 3.8-1 through Table 3.8-3[92]. 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 11.

Table 3.8-1: Deliverability for Area Deliverability Constraints in SDG&E area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
East of Miguel constraint	Arizona	~3,566
	Baja	
	Imperial	
Imperial Valley transformer constraint	Imperial	~2,558

[92] The transmission plan deliverability is estimated relative to the last official renewable portfolio provided for TPP policy driven transmission need analysis. This portfolio was provided during the 2015-2016 TPP, so some amount of deliverability may have been utilized by renewable generation that has become operational.

Table 3.8-2: Deliverability for Area Deliverability Constraints in SCE area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
Desert Area Constraint	Mountain Pass	~7,800
	Riverside East	
	Imperial	
	Nevada C	
Lugo AA Bank capacity limit	Kramer	~990
	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	~6,996
	Distributed Solar – SCE (Big Creek)	
Laguna Bell – Mesa flow limit	Non-CREZ	~1,488
Pardee – Santa Clara flow limit	Non-CREZ	~1,167

Table 3.8-3: Deliverability for Area Deliverability Constraints in PG&E area

Area Deliverability Constraint	Renewable Zones	Deliverability (MW)
Manning 500/230 kV Substation Deliverability Constraint	Westlands, Carizzo, non-CREZ	~2,101 to ~4,598
Gates 500/230 kV Bank #13 Deliverability Constraint	Westlands, Carizzo, non-CREZ	~2,871 to ~6,495
Gates-11C1504-Midway #3 230kV Line Deliverability Constraint	Westlands and Carizzo	~2,826 to ~3,956
California Flats-Gates 230kV Line Deliverability Constraint	Westlands and Carizzo	~1,539 to ~1,568
New Humboldt-Trinity-Cottonwood 115 kV Line	Non-CREZ	0
East Shore-San Mateo 230kV Re-conductor Deliverability Constraint	Non-CREZ	0
Delevan 500/230 kV Substation Deliverability Constraint	Solano, Carrizo, non-CREZ	~2202
New Bay Area Lines Deliverability Constraint (Contra Costa to Tesla and Newark 230 kV lines and Birds Landing Series reactors)	Solano, non-CREZ	~631 to ~709

3.9 Conclusion

This assessment provided an opportunity to study the transmission impacts of the 42 MMT portfolio. The ISO evaluated conceptual transmission solutions in renewable zones where a significant amount of transmission constraints were observed in the powerflow snapshot assessment and renewable curtailment was observed in PCM studies. This study was also used to test the transmission capability estimates used in the CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation. The ISO used this as an opportunity to test deliverability of FCDS resources in the portfolio using proposed new renewable output assumptions that take into account the new qualifying capacity calculations for solar and wind.

Key takeaways from the deliverability, PCM and powerflow analyses:

- The proposed deliverability assessment approach found that no transmission upgrades beyond what have already been approved previously would be needed to support the 42 MMT portfolio resources that were identified as FCDS resources. The proposed approach relies on multiple system conditions – the highest system need scenario and the secondary system need scenarios to better align generation output assumptions with the time of day and time of year of those system needs.

- Compared to the congestion results for the default portfolio study discussed in chapter 4, congestion on Path 26, in SCE NOL-Kramer-Inyokern-Control zone, and in VEA zone increased with the 42 MMT portfolio. This increase can be primarily attributed to the incremental renewable resources identified in Southern CA, specifically in the Kramer-Inyokern zone and the Southern NV zone in the 42 MMT portfolio.
- The ISO net export limit exhibited an inverse relationship with the energy being delivered out of Southern CA renewable zones. The Riverside East, Palm Springs, Eldorado, Mountain Pass and Southern NV zones experienced large reductions in renewable curtailment when the ISO net export limit was relaxed. The reason for reduction in curtailment was that the solar generation in these areas could export to other regions through adjacent tie lines.
- Powerflow snapshot assessment showed that portfolio resources in Northern CA (primarily in Solano) are unlikely to be curtailed due to transmission limitations. No area-wide transmission issue that would limit portfolio generation from interconnecting to the ISO controlled grid or from being dispatched was identified in the reliability assessment.
- Powerflow snapshot assessment in Southern CA indicated that portfolio resources in Southern NV, Eldorado, Kramer and Inyokern zones contribute to severe transmission overloading resulting in significant renewable curtailment. Conceptual upgrades primarily consisting of 230 kV system enhancements to the GridLiance system were tested using the resource mapping recommended by the CEC staff. These upgrades could effectively reduce the expected curtailment and could accommodate ~2,000 MW resources without triggering a large amount of renewable curtailment. The conceptual upgrade tested in Kramer-Inyokern zone is likely to avoid ~400 MW of renewable curtailment during hours when severe curtailment is expected.

The 42 MMT portfolio was transmitted to the ISO as a sensitivity portfolio. A large number of alternative transmission solutions were identified that would mitigate some or all of the transmission constraints identified. With the preliminary nature of the sensitivity portfolio provided and the wide range of potential solutions, none of the solutions are recommended to be designated as either Category 1 or Category 2 policy-driven transmission solutions. The key takeaways described above will be used to inform the development of future actionable renewable portfolios as described in the next section.

3.10 Next steps

- The ISO has already used preliminary results from this study and the latest generation interconnection studies to provide input into current IRP proceeding. The ISO will update the transmission capability estimates and assist the CPUC with incorporating those into the RESOLVE model.
- The insights generated about renewable curtailment and conceptual upgrades in the Kramer-Inyokern, Eldorado, Mountain Pass and Southern NV zones will be provided to the CPUC as the renewable portfolios for 2019-2020 TPP cycle get finalized.
- The ISO will rely on the key findings from this study in coordinating with the CEC staff on mapping of portfolio resources in zones in which severe transmission constraints were observed in the PCM as well as the powerflow snapshot assessment.

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.

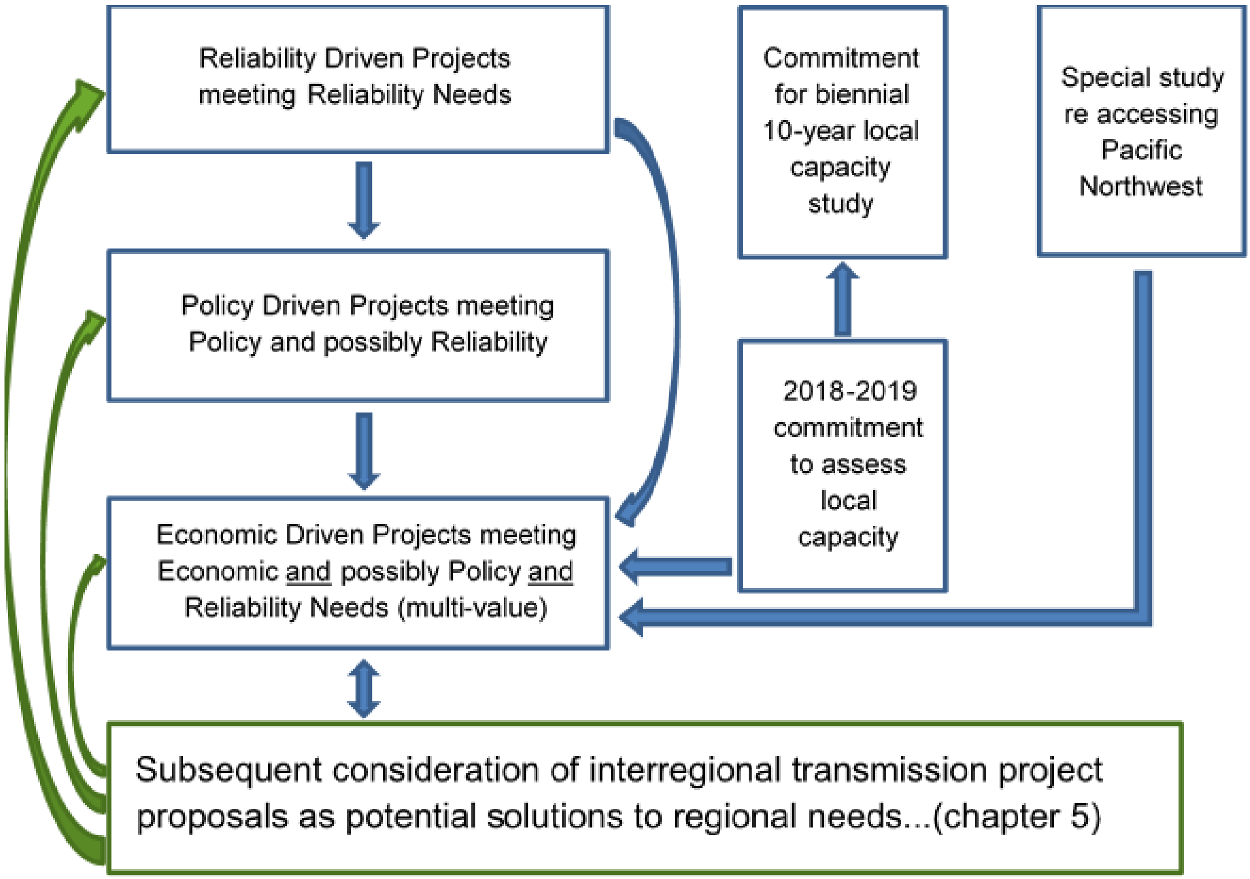
These more diverse drivers require a broader view of economic study methodologies and coordination between study efforts than in the past. This year's study requirements are further complicated by the "special" study the ISO conducted regarding the benefits of increased access to Pacific Northwest hydro resources, which, while conducted as an exploratory study and using assumptions outside of those for actual project approval, provide additional insights into the Pacific AC Intertie congestion that was the subject of an economic study request and an interregional transmission project submission. As well, the ISO conducted an exploratory economic study of potential reductions or elimination of local area and sub-area needs, which overlapped with the ISO's previous commitments to conduct a biennial 10-year local capacity requirements study; which also fell on this year.

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 economic planning study was then performed 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).[93]

The above issues resulted in stronger interrelationships between studies conducted under different aspects of the transmission planning process, and which are normally documented more discretely in specific chapters in the transmission plan. As a result, there are stronger linkages and cross-references between different chapters than in the past, 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.

[93] 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 on a case by case basis, 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.

The more localized benefits discussed above were largely conceptualized around conventional transmission upgrades, with preferred resource procurement explored as an option where there was potential for those resources to be successful. 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. Consideration of these new or increasing value chains creates additional complexity to economic analysis, and leads to supplementing transmission congestion analysis conducted on the GridView platform with additional platforms such as PLEXOS which provides better results for assessing system and flexible capacity benefits.

4.2 Technical Study Approach and Process

Different components of benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the “pre-project” and “post-project” study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit includes three components of ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles. The calculation of these benefits is discussed in more detail in section 0.

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.

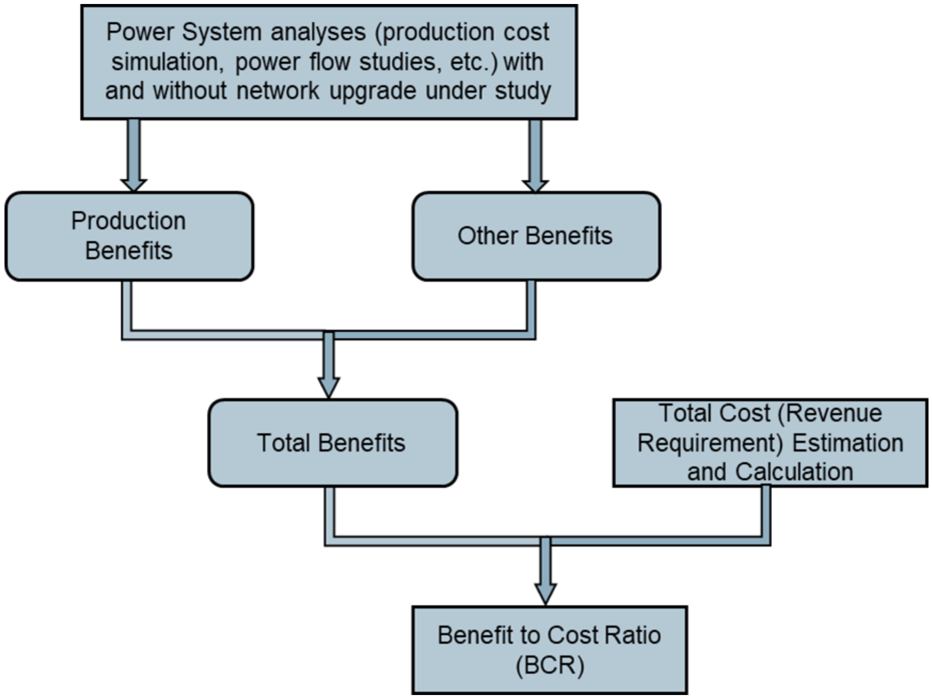
The production cost simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis is also used in quantifying other economic benefits such as system and local capacity savings. Further, as noted above, platforms such as PLEXOS are proving useful in assessing impacts on system production costs.

In addition to the production and capacity benefits, any other benefits — where applicable and quantifiable — can also be included. However, it is not always viable to quantify social benefits into dollars.

Once the total economic benefit is calculated, the benefit is weighed against the cost, 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 needs to be greater than 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 4.2-1. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis, which is a financial calculation that is generally conducted in spreadsheets.

Figure 4.2-1: 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 2016 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net present values. By default, the proposed operation year is 2021 unless specially indicated.

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 used in previous transmission plans and set out in the ISO's TEAM documentation[94] 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.

In this planning cycle, the ISO recognized the need to adapt this approach in considering battery storage devices. 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 were developed for battery storage capital costs and those levelized annual revenue requirements were 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 0.

[94] 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.[95]

When detailed analysis of a high priority study area is required, production cost simulation and subsequent benefits calculations are conducted 10th planning year - in this case, for 2027. For years beyond 2026 the benefits are estimated by extending the 2027 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 2028 = 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 were 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

[95] 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 4.9.

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[96], 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

[96] 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 and $3.48/kW-month for the LA Basin area. This results in a $38,160/MW-Year and $41,760/MW-year price, respectively, for this capacity. Recognizing that local capacity in the San Diego-Imperial Valley area or the LA Basin area 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 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 LA Basin and San Diego 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
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:

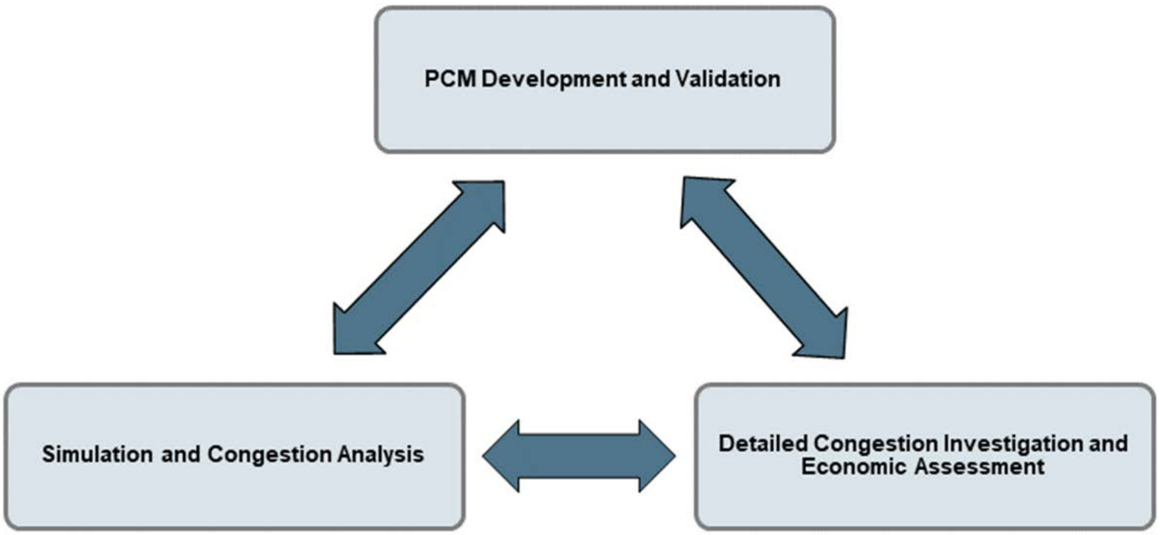
1. Network model (transmission topology, generator location, and load distribution)
2. Transmission operation model, such as transmission constraints, nomograms, phase shifters, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, renewable profiles.
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™	10.2.46	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 a 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.

As discussed in chapter 7, the ISO also relies on PLEXOS analysis is considering system-wide resource issues outside of the ISO's tariff-based transmission planning process, in particular in support of the CPUC's integrated resource planning proceedings. While that analysis is often based on different forecast parameters and does not address intra-ISO transmission limits to the extent that the GridView analysis does, it can provide helpful comparisons of overall GridView results in some cases. Accordingly, the ISO has drawn occasional comparisons in this chapter between the results of the “special study” work documented in chapter 7 with the economic study results developed through GridView in this chapter.

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 TEPPC 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 ISO’s economic planning production cost model (PCM) used the Anchor Data Set (ADS) PCM v1.0 as a starting database and incorporated the validated changes in the consequent versions of ADS PCM case. Using this database the ISO developed the base cases for the ISO 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 demand

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions load in the system to represent typical or average load condition across the ISO transmission network. The California load data was drawn from the California Energy Demand Forecast 2018-2030, Revised Electricity Forecast adopted by California Energy Commission (CEC) on February 21, 2018.

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 2018-2019 reliability assessment power flow cases, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

Renewable resources in Kramer-Inyokern and Southern Nevada areas identified as generic in CPUC's portfolios were modeled at Lugo 500 kV and Eldorado 500 kV buses respectively because of the lack of clear interconnection plan and the obvious local transmission constraints.

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 TEPPC database only enforced transmission limits under normal condition for transmission lines at 230 kV and above, and for transformers at 345 kV and above.

The ISO made an important enhancement in expanding the modeling of transmission contingency constraints, which the original TEPPC database did not model. In the updated database, the ISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the California ISO transmission grid to make sure that in the event of losing one transmission facility (and sometimes multiple transmission facilities), the remaining transmission facilities would stay within their emergency limits. The contingencies that were modeled in the ISO's database mainly are the ones that identified as critical in the ISO's reliability assessments, local capacity requirement (LCR) studies, and generation interconnection (GIP) studies. While all N-1 and N-2 (common mode) contingencies were modeled to be enforced in both unit commitment and economic dispatch stages in production cost simulation, N-1-1 contingencies that included multiple transmission facilities that were not in common mode, were normally modeled to be enforced in the unit commitment stage only. This modeling approach reflected the system reliability need identified in the other planning studies in production cost simulation, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits for some transmission lines in the California ISO transmission grid at lower voltage than 230 kV are enforced.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the ISO were modeled, including COI, Path 26, and Path 15. These nomograms were developed in ISO's reliability assessments or identified in the operating procedures.

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 Renewable curtailment price

Multi-tiered renewable curtailment prices were used in 2018-2019 planning cycle PCM. The ISO's historical market data of LMP were used to develop the curtailment price profile, as shown in Table 4.6-1. This multi-tiered renewable curtailment price profile applies to all hours. Both GridView and PLEXOS production cost models use the same profile.

Table 4.6-1: Multi-tier Prices of Renewable Curtailment

Aggregated Curve	Segment 1	Segment 2	Segment 3	Segment 4	Floor price
Curtailment Price ($/MWh)	-15	-25	-50	-150	-300
Segment Capacity to be curtailed (MW)	0~2000	2000~7000	7000~12,000	12,000~18,000	>18,000

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 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 2028

Area or Branch Group	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
VEA	MEAD S-BOB SS 230 kV line #1	0	0	28,506	1,580	28,506	1,580
Path 26	P26 Northern-Southern California	0	0	15,971	718	15,971	718
Path 26	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	8,525	287	8,525	287
Path 45	P45 SDG&E-CFE	294	199	5,716	1,295	6,009	1,494
COI Corridor	P66 COI	4,050	152	0	0	4,050	152
PG&E Quinto - Los Banos	QUINTO_SS-LOSBANOS 230 kV line #1	0	0	3,710	118	3,710	118
PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-Merced M 115/70 kV xfmr	3,613	1,350	0	0	3,613	1,350
PG&E Fresno Panoche-Excelsior	PANOCHE1-KAMM 115 kV line #1	0	0	2,748	641	2,748	641
PG&E POE-RIO OSO	POE-RIO OSO 230 kV line #1	2,148	87	0	0	2,148	87
Path 15/CC	GATES-GT_MW_11 500 kV line #1	0	0	1,730	37	1,730	37
SCE NOL-Kramer-Inyokern-Control	INYO 115/115 kV transformer #1	1,636	1,442	0	0	1,636	1,442
SDG&E Sanlusry-S.Onofre 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDG&E N-2 SLR-SO 230 kV #2 and #3 with RAS	1,327	161	0	0	1,327	161
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	1,236	48	1,236	48
SDG&E Silvergate-Bay Blvd 230 kV line	SILVERGT-BAY BLVD 230 kV line, subject to SDG&E N-2 Miguel-Mission 230 kV #1 and #2 with RAS	0	0	1,171	61	1,171	61

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 J.HINDS-MIRAGE 230 kV line	J.HINDS-MIRAGE 230 kV line #1	1,103	178	0	0	1,103	178
COI Corridor	TBL MT D-RIO OSO 230 kV line, subject to PG&E N-2 TableMtn-Tesla and TableMtn-VacaDixon 500 kV	1,007	13	0	0	1,007	13
PG&E Fresno Giffen	GFFNJCT-GIFFEN 70.0 kV line #1	0	0	866	1,483	866	1,483
Path 46 WOR	P46 West of Colorado River (WOR)	802	26	0	0	802	26
PDCI	P65 Pacific DC Intertie (PDCI)	0	0	503	76	503	76
PG&E Solano	RPN JNCN-MANTECA 115 kV line #1	0	0	486	9	486	9
Path 26	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500 kV	0	0	449	21	449	21
Path 61/Lugo - Victorville	P61 Lugo-Victorville 500 kV Line	0	0	371	119	371	119
SDG&E IV-SD Import	SUNCREST-SUNCREST TP1 230 kV line, subject to SDG&E N-1 Eco-Miguel 500 kV with RAS	280	12	0	0	280	12
PG&E Delevn-Cortina 230 kV	DELEVN-CORTINA 230 kV line, subject to PG&E N-2 TableMtn-Tesla and TableMtn-VacaDixon 500 kV	225	12	0	0	225	12
SCE Sylmar - Pardee 230 kV	PARDEE-SYLMAR S 230 kV line, subject to SCE N-1 Sylmar-Pardee 230 kV	0	0	197	25	197	25
PG&E GBA	NRS 230/115 kV transformer #1	145	9	0	0	145	9
SDG&E IV-SD Import	SUNCREST-SUNCREST TP2 230 kV line, subject to SDG&E N-1 Sycamore-Suncrest 230 kV #1 with RAS	141	5	0	0	141	5

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 15/CC	GT_MW_11-MIDWAY 500 kV line #1	0	0	118	5	118	5
SDG&E-CFE OTAYMESA-TJI 230 kV line	OTAYMESA-TJI-230 230 kV line #1	0	0	100	23	100	23
PG&E Fresno	SANGER-MC CALL 115 kV line #3	0	0	89	9	89	9
PG&E Table Mt.-Palermo 230 kV line	TBL MT D-PALERMO 230 kV line, subject to PG&E N-2 TableMtn-Tesla and TableMtn-VacaDixon 500 kV	84	1	0	0	84	1
PG&E Fresno	BORDEN-GREGG 230 kV line #1	0	0	81	12	81	12
Path 26	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #1 500 kV	0	0	58	3	58	3
SDG&E IV-SD Import	SUNCREST-SUNCREST TP2 230 kV line, subject to SDG&E N-1 Eco-Miguel 500 kV with RAS	52	2	0	0	52	2
PG&E/TID Exchequer	EXCHEQUR-LE GRAND 115 kV line, subject to PG&E N-1 Merced-MrcdFLLs 70 kV	49	18	0	0	49	18
PG&E Fresno	SANGER-AIRWAYJ2 115 kV line #1	32	3	0	0	32	3
SCE Delaney-ColoradoRiver 500 kV	DELANY-COLRIVER 500 kV line, subject to SDG&E N-1 N.Gila-Imperial Valley 500 kV	25	2	0	0	25	2
SDG&E-CFE IV-ROA 230 kV line and IV PFC	IV PFC1 230/230 kV transformer #1	9	1	0	0	9	1
PG&E GBA	SN JSE A-SJB EF 115 kV line #1	7	1	0	0	7	1
PG&E GBA	MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	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)
SDG&E N.Gila-Imperial Valley 500 kV line	N.GILA-IMPRLVLY 500 kV line, subject to SCE N-1 PaloVerde-ColoradoRiver 500 kV	2	1	0	0	2	1
PG&E Fresno	ATWELL_JCT-SMYRNA 115 kV line #1	1	8	0	0	1	8
SCE Devers 230/115 kV transformer	DEVERS 115/230 kV transformer #1	1	1	0	0	1	1
PG&E Fresno	BORDEN-GREGG 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	1	1	1	1
PG&E Humboldt	HUMBOLDT-TRINITY 115 kV line #1	0	1	0	0	0	1

Table 4.7-2 summarizes the potential congestion across specific branch groups and local capacity areas. 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 2028 congestion cost.

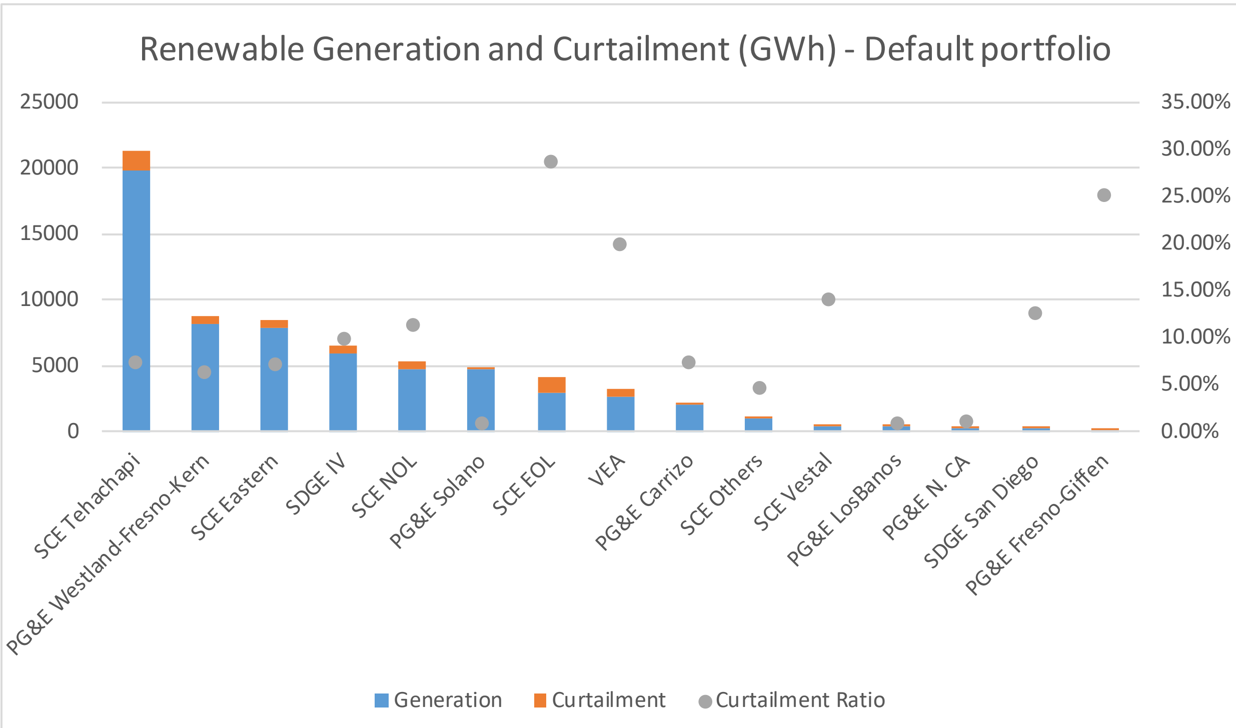
Table 4.7-2: Aggregated potential congestion in the ISO-controlled grid in 2028

No	Aggregated congestion	2028	
		Costs (M$)	Duration (Hr)
1	VEA	28.51	1,580
2	Path 26	25.00	1,029
3	Path 45	6.01	1,494
4	COI Corridor	5.06	165
5	PG&E Quinto - Los Banos	3.71	118
6	PG&E/TID Exchequer	3.66	1,368
7	PG&E Fresno Panoche-Excelsior	2.75	641
8	PG&E POE-RIO OSO	2.15	87
9	Path 15/CC	1.85	42
10	SCE NOL-Kramer-Inyokern-Control	1.64	1,442
11	SDG&E Sanlusry-S.Onofre 230 kV	1.33	161
12	SCE LCIENEGA-LA FRESA 230 kV line	1.24	48
13	SDG&E Silvergate-Bay Blvd 230 kV line	1.17	61
14	SCE J.HINDS-MIRAGE 230 kV line	1.10	178
15	PG&E Fresno Giffen	0.87	1,483
16	Path 46 WOR	0.80	26
17	PDCI	0.50	76
18	PG&E Solano	0.49	9
19	SDG&E IV-SD Import	0.47	19
20	Path 61/Lugo - Victorville	0.37	119
21	PG&E Delevn-Cortina 230 kV	0.22	12
22	PG&E Fresno	0.20	33
23	SCE Sylmar - Pardee 230 kV	0.20	25
24	PG&E GBA	0.16	11
25	SDG&E-CFE OTAYMESA-TJI 230 kV line	0.10	23
26	PG&E Table Mt.-Palermo 230 kV line	0.08	1
27	SCE Delaney-ColoradoRiver 500 kV	0.03	2
28	SDG&E-CFE IV-ROA 230 kV line and IV PFC	0.01	1
29	SDG&E N.Gila-Imperial Valley 500 kV line	0.00	1
30	SCE Devers 230/115 kV transformer	0.00	1
31	PG&E Humboldt	0.00	1

4.7.2 Renewable curtailment

Figure 4.7-1 sets out the renewable curtailment found in the default portfolio, by renewable energy zone within the ISO footprint. The total wind and solar curtailment in ISO's system in the study year (2028) in the default portfolio was about 7.47 TWh, which is about 9.2% of the total potential wind and solar energy.

Figure 4.7-1: Renewable Generation and Curtailment (GWh) - Default portfolio



4.7.3 Congestion analysis

In this planning cycle, detailed investigations were conducted on the constraints that may have a large impact on the bulk system and showed recurring congestion. Specifically, these constraints selected for further analysis are shown in Table 4.7-3. The detailed analysis results are in Section 0.

Table 4.7-3: Constraints selected for Detailed Investigation

Aggregated congestion	Cost (M$)	Duration (Hours)	Reason for selection
Path 26	25.00	1,029	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.
COI corridor	5.06	165	A continuation of work on COI congestion investigation. COI congestion increased from previous planning cycles.
PG&E Fresno Giffen	0.87	1483	Giffen congestion is an existing issue.
San Diego congestions	2.97	241	Includes Sanlusry-S.Onofre 230 kV, Silvergate-Bay Blvd 230 kV, and IV-SD import corridor congestions. These congestions were studied in detail as an effort to investigate potential LCR reduction in local areas.
SCE J.Hinds-Mirage	1.10	178	A continuation of work on this recurring congestion.

Congestions in Table 4.7-3 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, in VEA and SCE EOL area, SCE NOL area, PG&E Fresno area, and PG&E Los Banos area. PG&E Fresno Giffen congestion was selected because the congestion in Giffen area is an existing issue.

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

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.

A detailed analysis was performed on the congestion on the Exchequer-La Grant 115 kV line in the 2015-2016 transmission planning cycle and no economic justification was identified. There is no change in circumstance for this constraint, therefore the ISO did not conduct further detailed studies.

Because Exchequer hydro generator is owned by non-ISO utilities, the majority of the benefits from mitigating the Exchequer-La Grant congestion would go to the generator owners rather than the ISO ratepayers. Therefore, the ISO did not conduct detailed economic analysis on Exchequer-La Grant congestion in this planning cycle. It will be monitored in the 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. This congestion was further investigated in Path 26 study, but 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 reviewed each regional study or project being considered for detailed analysis, and the basis for carrying the project forward for detailed analysis – or not – is set out in section 4.8. 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.

4.8.1 California-Oregon Intertie Congestion and Southwest Intertie Project

The economic study request regarding California-Oregon Intertie Congestion and the Southwest Intertie Project – North project was submitted by LS Power Development, LLC. The Southwest Intertie Project - North (SWIP - North) project was also submitted as a reliability transmission project into the 2018 Request Window as set out in chapter 2 and an interregional transmission project as set out in chapter 5.

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 examine the causes of the historical actual day-ahead market congestion, 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.

Evaluation

Table 4.8-1 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-1: 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 and PACI; 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. However, the day-ahead congestion being experienced over the past number of years is a concern, and the ISO is investigating potential to access Northwest hydro resources.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Request states that project offers policy benefits by allowing out of state renewables to help meet the new California RPS targets: 40% in 2024, 45% in 2027 and 50% in 2030. Project will allow geographical diversity to incremental RPS build out which will help reduce locational aspects of congestion caused by over generation. This will benefit ISO ratepayers with or without expansion of ISO's borders as this new line will provide a transmission path for out of state renewables to be either directly connected to or Pseudo Tied to the ISO Balancing Authority Area.	Project was studied in the informational 50% RPS and interregional transmission planning process and results are publicly available for consideration in resource planning processes.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	Refer to earlier comment regarding "Identified Congestion".
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection Generators" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	Study request recommends that ISO improve the study model to quantify the actual "scheduling" congestion on ISO's PACI interface, a component that has not been included in prior cycles Adding SWIP - North relieves certain reliability and economic constraints related to imports across COI. This translates into incremental import capability into ISO. This increase in incremental import capability should be accounted for estimate of the Capacity Benefits of SWIP - North	The associated market interface issues need to be explored more fully before such benefits can be unilaterally incorporated into transmission capital decisions.

Conclusion

While LS Power requested an economic study of its proposed project as well as of COI congestion, the issue the proposed project is seeking to address as a source of economic benefit is primarily congestion on the California-Oregon Intertie (COI). The ISO therefore considered the request to be an economic study request for increasing transfer capability over COI to eliminate or reduce potential congestion costs, for which the SWIP - North proposal may be means to mitigate.

The ISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Tier Transmission Group (NTTG) planning regions, respectively. The SWIP - North line is not physically connected to ISO-controlled facilities. Please refer to chapter 5. The scheduling capacity from the Harry Allen end of the ISO's approved Harry Allen-Eldorado transmission line to Robinson Summit also creates opportunity for the submitted project to provide benefits to the ISO, in which case the ISO can select to participate in the project – if that is found to be the preferred solution to meeting the ISO's regional need.

Given the expressed concerns regarding the day-ahead market congestion, the study request focusing on COI congestion was selected for additional study. Please refer to section 4.9.1 below.

4.8.2 Lake Elsinore Advanced Pumped Storage

The Nevada Hydro Company submitted the Lake Elsinore Advanced Pumped Storage project into the 2018-2019 transmission planning cycle through several venues:

- The project was first submitted to the ISO on February 14, 2018 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". Although section 24.3.2(a) refers to "The planning data and assumptions to be used in the Transmission Planning Process cycle, including, but not limited to, those related to Demand Forecasts and distribution, potential generation capacity additions and retirements, and transmission system modifications", *e.g.* study assumptions rather than potential solutions to needs identified through the study process, nonetheless the ISO indicated in the draft and final Unified Planning Assumptions and Study Plan[97] that it would consider the submission as an economic study request, and also suggested the proponent consider submitting the project in the 2018 Request Window specifying the ISO-identified reliability constraints the project could mitigate.
- The project was then submitted into the 2018 Request Window on October 1, 2018 purporting to address reliability needs in addition to providing other benefits. As set out

[97] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Draft, February 22, 2018, and Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Final, March 30, 2018

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 have been are proposed:

Option 1: SCE/SDG&E Connection

- This option interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill[98] 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

Table 4.8-2 summarizes the benefits described in the submission and ISO's evaluation of the economic study request.

[98] 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)

Table 4.8-2: 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	LEAPS requested the ISO to evaluate congestion that was observed in the 2017-2018 transmission planning process for the following: P45 SDG&E-CFE OTAYMESA-TJI-230 230 kV line, subject to SDG&E N-1 Eco-Miguel 500 kV with RAS SUNCREST-SUNCREST TP2 230 kV line, subject to SDG&E N-1 Sycamore-Suncrest 230 kV #1 with RAS ENCINATP-SANLUSRY 230 kV line, subject to SDG&E N-1 EN-SLR 230 kV OTAYMESA-TJI-230 230 kV, subject to SDG&E N-1 Ocotillo-Suncrest 500 kV with RAS SYCAMORE TP2-SYCAMORE 230 kV line, subject to SDG&E N-1 Sycamore-Suncrest 230 kV#1 with RAS OTAYMESA-TJI-230 230 kV line, subject to SDG&E N-2 Sycamore-Suncrest 230 kV #1 and #2 with RAS MIGUEL-MIGUELMP 230 kV line, subject to SDG&E T-1 Miguel 500-230 kV #2 with RAS Nevada Hydro Company requested that TEAM analysis be performed by the ISO to assess the economic benefits provided by LEAPS to eliminate observed congestion and associated costs.	Economic studies performed by the ISO have identified congestion in San Diego area and on the corridor from IV area to San Diego area, and Path 45 as well. Detailed analysis for these congestions were conducted in this planning cycle, and the LEAPS project was studied as an alternative for congestion mitigation.
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 50% (now 60%) by 2030. Nevada Hydro also stated that TEAM analysis prepared by ZGlobal, Nevada Hydro's consultant, demonstrated that LEAPS provided economic benefits of between $34 and $51 million annually by providing storage of renewable energy that would otherwise be curtailed during oversupply conditions caused by 50% RPS portfolios. The stored energy can then be shifted to other peak-demand hours when renewable energy output is unavailable.	Detailed production cost simulation was conducted modeling LEAPS as set out in section 4.9.11.5.
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.	Please see further detailed analysis for local capacity benefits in section 4.9.11.5.

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. Nevada Hydro stated that LEAPS could provide between $51 and $81 million in annual benefits by reducing overbuild and related interconnection costs to meet 50% RPS. Nevada Hydro also stated that LEAPS has the capability to reduce overall production costs for the ISO for an estimated energy cost savings to consumers of between $40 and $89 million annually.	Detailed production cost simulation was conducted modeling LEAPS as set out in section 4.9.11.5.
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 and Initial TEAM analysis estimates this benefit to consumers to be between $38 and $60 million annually. • As described in Section 3.2 of Attachment A, LEAPS will provide reliability benefits by improving grid resiliency such as providing frequency response and voltage support to the grid. • As demonstrated in Section 3.1 of Attachment A, 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. No reliability requirements were identified in chapter 2 driving the need for the project.

Conclusion

The LEAPS project is an alternative to reduce local capacity requirements for gas-fired generation in the San Diego sub-area and combined Imperial Valley/San Diego/LA Basin area, and those areas were selected for detailed analysis as discussed in section 4.8.7. Based on this and the economic study request as stated in the draft and final Unified Planning Assumptions and Study Plan, the project has therefore been included in the detailed analysis of those local capacity areas. Consideration as to, in reducing gas-fired generation local capacity requirements, whether LEAPS is providing transmission services such that the project could be considered a transmission asset or is providing local resource capacity services like a market resource is discussed in section 4.9.11.5 below. As the Federal Energy Regulatory Commission has recognized, an electric storage resource seeking cost recovery through transmission rates must demonstrate that it is operating as a transmission facility to address particular transmission needs.[99] That consideration does not drive or preclude, in itself, whether the ISO will perform the detailed analysis, as the ISO can and does consider non-transmission alternatives.

4.8.3 Red Bluff – Mira Loma 500 kV Transmission Project

Study request overview

The project was submitted by NextEra Energy Transmission West LLC as an economic study request and was also submitted into the 2018 Request Window as a potential reliability project. It involves the 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 assessment of the reliability need for this project is addressed in chapter 2.

Evaluation

Table 4.8-3 summarizes the benefits described in the submission and ISO's evaluation of the study request.

[99] *Nevada Hydro Company, Inc.* 164 FERC ¶61,197 at PP 24-25 (2018).

Table 4.8-3: Evaluating study request – Red Bluff – Mira Loma 500 kV Transmission Project

Study Request: Mira Loma – Red Bluff 500 kV Project		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Not addressed in submission	No benefits identified by ISO
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	The project can support integration of renewable generation for the ISO. The Cluster 8 Phase 1&2 and Cluster 9 Phase 1 Interconnection Study Report identified several thermal overloads with all facilities in-service. This constraint is commonly referenced as the "West of Devers Area Deliverability Constraint". The project can integrate higher levels of renewable generation that were curtailed in ISO's 50% RPS "informational only" study, which indicated high potential for generation curtailment in Riverside County	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 project supports Eastern LA Basin LCR Sub-Area process. The LCR need for the Eastern LA Basin sub-area is based on the need to mitigate post-transient voltage instability that is caused by the loss of the Alberhill – Serrano 500 kV line, followed by an N-2 of Red Bluff-Devers #1 and #2 500 kV lines. The LCR need to mitigate this post-transient voltage instability concern is determined to be approximately 2,230 MW (source: ISO TPP 2015-2016), which is to be met by available resources in the Eastern LA Basin sub-area.	The ISO's preliminary analysis 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	See "Delivery of Location Constrained Resource Interconnection Generators" above	See "Delivery of Location Constrained Resource Interconnection Generators" above

Study Request: Mira Loma – Red Bluff 500 kV Project		
Benefits category	Benefits stated in submission	ISO evaluation
Other	Study request states that the proposed project improve the reliability and thermal overloads of the existing 230 kV transmission network in the area of Devers, San Bernardino, El Casco, and Vista. The project can eliminate and/or minimize the congestion management cost. Presently, congestion management is used to mitigate thermal issues on the existing West of Devers 230 kV and 500 kV transmission network. Project would reduce the amount of congestion management necessary (including generation curtailments) to alleviate the thermal issue and consequently economic savings could be realized. The project will minimize continued reliance on the existing Special Protection Systems (SPS), specifically Inland SPS and West of Devers SPS, and continued reliance on operating procedures for voltage and thermal control. The project complements the integration of ISO approved participating transmission owner's projects and the approved competitive transmission solicitation projects. The project combats Reactive Power Deficiencies. With the continued load growth and addition of renewable generation in the Eastern area, voltage degradation to the system was observed. The inclusion of the project improved base case voltage issues. Part of the project's scope is to identify the need for additional voltage support at Red Bluff, Colorado River, and Serrano substations. This analysis will need to be conducted separately to determine an accurate amount of reactive support needed at these existing substations.	The West of Devers Project will upgrade the existing 230 kV transmission network in the area of Devers, San Bernardino, El Casco, and Vista and will address most if not all of these issues.

Conclusion

The proposed project is an alternative that could reduce local capacity requirements in the Eastern LA Basin sub-area, and was selected for detailed analysis. Please refer to section 4.9.9.2 below.

4.8.4 Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)

Study request overview

The proposed California Transmission Project (CTP) is a 320 kV HVDC submarine cable that would utilize Voltage Source Converters (VSC) to interconnect with existing HVAC transmission facilities in both the Pacific Gas & Electric and Southern California Edison service areas. The cable would be routed offshore of California in the Pacific Ocean and will have three segments, two between Diablo Canyon and Ormond Beach with approximate lengths of 139 miles and 159 miles. One cable would be positioned farther out into the ocean than the other for potential future interconnection with offshore wind development. The third segment, running between Ormond Beach and Redondo Beach would be approximately 50 miles in length. See Figure 4.9-7 below.

The northern terminus of the CTP is proposed to be the Diablo Canyon 500 kV switching station and would utilize the two BAAH bay positions that will be vacated with the decommissioning of the Diablo Canyon Power Plant. There would be two 1,000 MW VSCs located on shore at Diablo Canyon with switching to enable flexible operations and maintenance while one VSC remains in operation. There would be two separate southern terminals for the CTP, one at Ormond Beach and one at Redondo Beach. At the southern terminals, there will be one 1,000 MW VSC to enable connection to the 220 kV bus at the SCE Ormond Beach 220 kV substation and one 1,000 MW VSC to enable connection to the SCE Redondo Beach 220 kV substation. Both 320 kV HVDC cables, rated at 1,000 MW each, originating at Diablo Canyon will connect to an on-shore HVDC station at Ormond Beach to allow for flexible operations and maintenance. There would be a single 320 HVDC cable running between Ormond Beach and Redondo Beach, also rated at 1,000 MW.

Evaluation

Table 4.8-4 summarizes the benefits described in the submission and ISO's evaluation of the study request.

Table 4.8-4: Evaluating study request – 1.8.4 Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)

Study Request: 1.8.4	Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)	
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	CTP will address specific PG&E area reliability issues found by the ISO in its preliminary reliability studies published on August 15, 20183. The ISO found 3 overloads on Path 26 which can be addressed by the CTP, see Table 1. 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. CTP as proposed, is in parallel with Path 26, adding 2,000 MW of transfer capacity under steady state conditions.	The project could address identified congestion on Path 26.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	One of the two undersea cables proposed by the project proponent is positioned farther out into the ocean than the other for potential future with offshore wind development.	Although there is no offshore wind in the CPUC provided renewable portfolio for the 2018-2019 TPP, future portfolios could include such resources.
Local Capacity Area Resource requirements	The project proponent states that the Project can provide a local capacity benefit to the LA Basin of 2,656 MW.	The proposed project connects to the ISO system at Diablo Canyon, Ormond Beach, and Redondo switchyards. 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, so Ormond Beach will no longer be located in an LCR area or sub-area. However, Redondo is located in the Western LA Basin LCR sub-area. The project could potentially provide approximately 1000 MW of LCR reduction benefits in the Western LA Basin.
Increase in Identified Congestion	See above	See above
Integrate New Generation Resources or Loads	See above	See above.
Other		

Conclusion

The proposed project is an alternative to reducing Western LA Basin sub-area local capacity requirements. That sub-area was not selected for detailed analysis in this transmission planning cycle as discussed in section 4.8.7 and section 4.9.10. The proposed project is also an alternative that could reduce congestion on Path 26, which has been selected for detailed analysis. The project has been included in that analysis. Please refer to section 4.9.3.2 below.

4.8.5 Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project

Study request overview

This proposed project was submitted as a reliability, economic, and policy-driven transmission project in the 2017-2018 transmission planning cycle, named San Diego/LA Basin Transmission Interconnection, and was intended to enhance reliability in the region, meet regulatory requirements, and mitigate needs caused by the possible closure of Aliso Canyon Natural Gas Storage facility. It was re-submitted into the 2018-2019 transmission planning cycle as an economic study request. The project could provide additional import capacity into the region through a new 500/230 kV transmission path between the LA Basin and San Diego/Imperial Valley areas, and reduce local capacity requirements in a highly populated region. The project includes:

- Building a new 500 kV transmission line from the planned Alberhill 500 kV substation in SCE to a new 500 kV Sycamore Canyon substation with a 500/230 kV transformer installed.
- Installing a 3rd 500/230 kV transformer at Suncrest Substation and building two 230 kV transmission circuits by looping existing Miguel–Sycamore Canyon 230 kV transmission line to the Suncrest 230 kV substation.

The preliminary cost estimate provided by the proponent is $500 million with a proposed in-service date of June, 2025.

Evaluation

Table 4.8-5 summarizes the benefits described in the submission and ISO’s evaluation of the study request.

Table 4.8-5: Evaluating study request – Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV

Study Request: 1.8.5	Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project	
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Reduction in production costs	See section 4.9.11.4
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	By increasing the import capability of renewables into the ISO controlled grid and into LCR areas, a transmission upgrade can facilitate the integration of renewables and reduction in renewable energy curtailment to meet increasing renewable portfolio standard (RPS) goals. In quantifying the public-policy benefit of increased renewables, the breakdown of California generation by type was analyzed to calculate the percentage of renewable energy generated to serve ISO load.	The project would not be expected to substantially increase the transmission capability out of any renewable resource areas.
Local Capacity Area Resource requirements	By increasing import capabilities into an LCR area, a transmission upgrade can provide reliability benefits that otherwise would have to be purchased through LCR contracts. This LCR benefit is quantified as the difference between the LCR requirement before and after the transmission upgrade. This benefit is analyzed outside of the production cost model, using reliability models instead. LCR benefits were assessed by performing PV analysis with and without the proposed projects. The LCR benefit was determined from the additional load serving capability provided by the transmission upgrade. The $ per megawatt benefit to reduced local capacity requirement was based on the values used by ISO in its local capacity benefit evaluation of the S-line upgrade as part of the 2017/18 TPP. The high capacity benefit is valued at $75,720/MW-year and the low is half that at $37,860/MW-year.	See section 4.9.11.4
Increase in Identified Congestion	Reduction in production costs	See section 4.9.11.4
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection Generators" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	None	No benefits identified by ISO

Conclusion

The proposed projects are alternatives for reducing the San Diego sub-area and combined Imperial Valley/San Diego/LA Basin area local capacity requirements and are included in the detailed analysis of those local capacity areas, which the ISO selected for detailed analysis. Please refer to section 4.9.11.4 below.

4.8.6 Colorado River 230 kV Bus - Julian Hinds 230 kV Project (Blythe Loop-in Project)

Study request overview

The project, with some subsequent modification, was submitted by AltaGas Services in the 2017-2018 transmission planning cycle and involves converting the existing privately owned Buck Blvd - Julian Hinds 230 kV generation tie-line into a network facility by way of segmenting the gen-tie line and connecting one terminal of both segments into the Colorado River Substation 230 kV bus. It would create a networked facility that would be turned over to ISO control, regulated cost-of-service cost recovery through the ISO transmission access charge, and identified as Colorado River - Julian Hinds 230 kV line. The remainder of the generation tie line would be identified as Buck Blvd - Colorado River 230 kV line, and would be treated as a generator interconnection. 117 Smart Wires Power Guardian 700-1150 devices (~19.58 Ω/phase) would be installed in series with the line on the Colorado River - Julian Hinds 230 kV line, and those along with termination facilities at Colorado River would also be placed under ISO operational control and costs recovered through ISO rates. These Power Guardians would be set to switch into injection mode to limit the power flow on the Julian Hinds - Mirage 230 kV line to avoid potential overloads. The proponent has estimated the capital cost to be included in the participating transmission owner’s rate base to be $67 million with an expected in-service date of June 1, 2020.

Evaluation

Table 4.8-6 summarizes the benefits described in the submission and ISO’s evaluation of the study request.

Table 4.8-6: Evaluating study request – Colorado River 230 kV Bus - Julian Hinds 230 kV Project (Blythe Loop-in Project)

Study Request: 1.8.6	Colorado River 230 kV Bus - Julian Hinds 230 kV Project (Blythe Loop-in Project)	
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	The project creates production cost benefits	See section 4.9.4
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	None	No benefits identified by ISO

Conclusion

Based on information and comments provided in the course of the 2017-2018 transmission planning cycle, the ISO committed at that time to re-examining this economic study request in this 2018-2019 transmission planning cycle. Please refer to section 4.9.4.

4.8.7 Local Capacity Requirement Reduction Benefit Evaluation

Study requirement

In the 2018-2019 transmission planning process, 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. 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.

To prioritize and select the "more than half" areas for study of mitigations, the ISO screened existing areas and sub-areas, filtered out those that were already on the path to being eliminated, and prioritized 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, 22 distinct area and sub-area needs listed in Table 4.8-7 by area were selected for consideration of transmission and hybrid alternatives, representing over 50% of total.

The results of this first phase are set out in Appendix G and also discussed in chapter 6, with other local capacity technical study issues.

The second phase consisted of selecting the most promising of the 22 areas and sub-areas for which alternatives were developed, for more detailed economic assessments of that subset in consideration of potential economic-driven projects for possible approval.

As discussed in chapter 6, alternatives to eliminate or materially reduce local capacity requirements in the 22 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.

<u>Evaluation and Conclusions</u>

Of the 22 areas and sub-areas examined, the subset identified in Table 4.8-7 have been selected for further detailed economic study for potential economic-driven recommendations, set out in section 4.9.

Table 4.8-7: 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 4.9
1	Sierra Area	
2	*- Pease*	*Selected for detailed economic analysis*
3	- South of Rio Oso	
	Bay Area (overall studied only if required)	
4	- Llagas	
5	- San Jose	
6	- South Bay-Moss Landing	
7	- Ames/Pittsburg/Oakland	
	Fresno (overall studied only if required)	
8	*- Hanford*	*Selected for detailed economic analysis*
9	- Herndon	
10	- Reedley	
11	Kern	
12	- Westpark	
13	*- Kern Oil*	*Selected for detailed economic analysis*
14	*LA Basin (combined with San Diego/Imperial Valley)*	*Selected for detailed economic analysis – See 17 and 18*
15	*- Eastern*	*Selected for detailed economic analysis*
	Big Creek/Ventura (overall studied only if required)	
16	*- Santa Clara*	*Selected for detailed economic analysis*
17	*San Diego/Imperial Valley (combined with LA Basin)*	*Selected for detailed economic analysis – see 14 and 18*
18	*- San Diego*	*Selected for detailed economic analysis – see 14 and 17*
19	*- El Cajon*	*Selected for detailed economic analysis*
20	*- Pala*	
21	*- Border*	*Selected for detailed economic analysis*
22	*- Esco*	

The remaining 19 distinct area and sub-area LCR needs not listed on Table 4.8-8 were found to have either lower priority or do not require any studies:

- There was no need to study 6 sub-areas since they do not have any generation in the priority criteria: Eagle Rock, Fulton, Lakeville, Borden, Vestal and Rector.
- The remaining 13 LCR needs in other areas and sub-areas may be studied in future transmission planning cycles.

4.8.8 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 4.8-8 below:

Table 4.8-8: Projects proposed as reliability solutions with potential economic benefits[100]

Storage Projects	Potential Economic Benefits
Cayetano 230 kV_Storage - SATA_Proposals (1-4) (NEET West) Four combinations of battery storage projects were proposed: 1. Option 1A: - 50 MW Battery Storage @ North Dublin - 50 MW Battery Storage @ Vineyard - 150 MW Battery Storage @ Newark 2.Option 1B: - 50 MW Battery Storage @ North Dublin - 50 MW Battery Storage @ Vineyard + increase Las Positas-Newark Emergency Rating 3. Option 2A: - 150 MW Battery Storage @ Vineyard - 150 MW Battery Storage @ Newark 4. Option 2B: - 150 MW Battery Storage @ Vineyard; + increase Las Positas-Newark Emergency Rating	The proposed projects purport to address a transmission reliability need, which could otherwise cause some level of congestion. Their effectiveness at addressing the reliability need was addressed in chapter 2. However, the projects are not effective for reducing sub-area local capacity requirements in the Contra Costa sub-area and the Contra Costa sub-area did not get selected for further detailed analysis. Consequently, no further analysis was undertaken.

[100] 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.

Storage Projects	Potential Economic Benefits
Sycamore 230 kV_Storage - SATA_Proposal (NEET West) Energy Storage connected to Sycamore 230 kV Substation - NEET West – build a new 230 kV bus outside the existing SDG&E Sycamore 230 kV substation. - NEET West – build a 210 MW energy storage and connect it to the new 230 kV bus outside the SDG&E Sycamore substation. - Incumbent – 230 kV cut in and connect to jumper line dead end structures outside of the Sycamore substation.	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 therefore included as an alternative in the detailed analysis for the San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area. Please refer to section 4.9.11.8 below.
San Vicente Energy Storage Project (City of San Diego) The San Vicente Energy Storage Project is a 500 MW pumped storage hydro plant built on the San Vicente reservoir in San Diego, CA. The project consists of four (4) generating units connected into a central 230 kV switchyard via four separate step-up transformers. The submission described two 230 kV lines connect the project switchyard to a switching station looping into both SDG&E's Suncrest to Sycamore Canyon 230 kV lines. However, the project proponent subsequently asked the ISO to change the point of interconnection to the Sycamore 230 kV substation.	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. Please refer to section 4.9.11.6 below.
Delta Reliability Energy Storage (Tenaska) The DRES Project is a proposed 100 MW x 4 hour discharge (400 MWh) energy storage project utilizing a Battery Energy Storage System (BESS) with a planned interconnection to the Delta Switchyard at 230 kV. Alternatively, a connection to the CC-Delta 230 kV line in the near vicinity of the Delta Switchyard can be considered. The project is proposed as a Storage As a Transmission Asset (SATA). For purposes of this submittal, the proponent assumed a 100 MW of BESS capacity to be placed in service in the fourth (4th) quarter of 2021 with a discharge duration of four (4) hours.	The proposed project is an alternative for the reduction of local capacity requirements in the Contra Costa sub-area, which did not get selected for further detailed analysis. Consequently, no further analysis was undertaken.
Sycamore Reliability Energy Storage (Tenaska) The SRES Project is a proposed 350-600 MW energy storage project utilizing a Battery Energy Storage System (BESS) with a planned interconnection to the Sycamore substation at 230 kV. Project is proposed as a Storage As a Transmission Asset (SATA). For purposes of this submittal, the proponent assumed a 350 MW BESS capacity placed in service in fourth quarter 2021 with a discharge duration of approximately 30 to 60 minutes, with potential expansion later up to 600 MW BESS at the project location.	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. Please refer to section 4.9.11.7 below.

Storage Projects	Potential Economic Benefits
Los Padres ACAES Advanced Compressed Air Energy Storage (Hydrostor) The proposal provides options for a 175 MW – 200 MW of Advanced Compressed Air Energy Storage ("A-CAES") connected to the PG&E Mesa 230 kV switchyard and a 200 MW to 300 MW, 4-hour duration A-CAES system. The expected net cost to ISO of such a solution was estimated at $190M to $320M depending on the scale of the project and the associated ability to provide additional market services to the ISO-administered market and/or receive contracted offtake as a storage/resource adequacy asset.	The proposed project focuses on addressing a transmission reliability need and is discussed in Chapter 2. However, the project is not effective for reducing local capacity requirements, and no further analysis was undertaken.
Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra Renewables) ConEd Clean Energy Businesses submitted the Westside Canal Reliability Center -- Storage as Transmission Asset proposal for a 268 MW/4 hour battery energy storage reliability project interconnecting to the 230 kV Imperial Valley (IV) substation. Through a proposed Special Protection System (SPS), the BESS would operate in *load mode* in concert with existing, specified generation west of the overloaded elements. The combined generation increase west of the overload, and load increase via the BESS east of the overload is an alternative to mitigate potential overloading identified for the Suncrest-Sycamore Canyon 230 kV lines under contingency conditions. The BESS/SPS does not fully mitigate an overload identified for the S-line because the battery operating in load mode aggravates the issue. However, Con Ed Clean Energy Businesses mentioned that this issue would be rectified by the approved S-Line project. Furthermore, ConEd indicated that the proposed battery energy storage, when operating in *generation mode,* would be an effective solution to this issue and could serve as a stop-gap solution should S-Line construction be delayed.	The proposed project is an alternative to meeting combined San Diego/Imperial Valley/LA Basin area local capacity requirements, and was included as an alternative in the detailed analysis for the combined San Diego/Imperial Valley/LA Basin area. Please refer to section 4.9.11.9 below.
Southern California Regional LCR Reduction (SDG&E) SDG&E proposed this project as a reliability and economic-driven transmission need that is intended to reduce LCR need in the southern California region. The proposed scope is to construct a new Mission-San Luis Rey-San Onofre 230 kV line, install a 230 kV phase shifter station at Mission Substation, and upgrade various existing 230 kV lines (TL23004, TL23006, TL23022 and TL23023) in the San Diego area.	The proposed project was studied to determine if there were benefits to the San Diego sub-area or San Diego/Imperial Valley area. It was identified that the project only provided local capacity reduction benefits in the Western sub-area of the LA Basin. Notwithstanding that the Western sub-area of the LA Basin was not selected for detailed analysis of local capacity requirement reduction benefits, the results were provided in section 4.9.10 given that the benefits had been studied as part of the overall examination.

4.9 Detailed Investigation of Congestion and Economic Benefit Assessment

The ISO selected the following branch groups and study areas for further assessment, listed in Table 4.9-1, 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. Alternatives also include interregional transmission projects; three such projects were identified as potential options for study of economic benefits as set out in chapter 5:

- Southwest Intertie Project – North (SWIP - North)
- North Gila - Imperial Valley #2 500 kV Transmission Project (NG-IV#2)
- HVDC conversion

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.9-1 for ease of tracking where and how these stakeholder proposals were addressed. The detailed analysis also considers other ISO-identified potential mitigations which have not been listed in Table 4.9-1.

Table 4.9-1: Detailed Economic Benefit Investigation and related Stakeholder Proposals

Congestion area or branch group	Location and facilities	Reason & Direction
California-Oregon Intertie (COI)	Stakeholder-submitted alternatives include: SWIP - North – Interregional Transmission Project	Day ahead congestion experienced in real-time market operation
Giffen		Congestion from generation pocket to system
Path 26 Midway-Vincent	Stakeholder-submitted alternatives include: Ormond-Diablo Canyon	South to north congestion
Eastern SCE Area (outside of the Eastern LA Basin LCR sub-area)	Stakeholder-submitted alternatives include: Blythe Loop-in	Committed in the 2017-2018 transmission planning cycle to review additional information
Local Capacity Reduction Study Areas:		
Sierra Area		
Pease sub-area (Sierra)	Note PG&E provided suggestions.	Selected as potential LCR reduction possibility
Hanford sub-area (Fresno)		Selected as potential LCR reduction possibility
Reedley sub-area (Fresno)		

Congestion area or branch group	Location and facilities	Reason & Direction
Kern Oil sub-area (Kern)		Selected as potential LCR reduction possibility
Santa Clara Sub-area (Big Creek/Ventura Area)		Selected as potential LCR reduction possibility
Eastern sub-area (LA Basin)	Stakeholder-submitted alternatives include: Mira Loma – Red Bluff 500 kV Line (NextEra)	Selected as potential LCR reduction possibility
Western sub-area (LA Basin)	Stakeholder-submitted alternatives include: SDG&E Southern California Regional LCR Reduction Project	The study of this alternative was undertaken as part of the study of the San Diego reinforcements. As the option was found to primarily focus on lowering local capacity requirements in the Western sub-area of the LA Basin, the results were reported accordingly, notwithstanding the Western sub-area not being selected for detailed study.
San Diego sub-area (study in concert with the overall San Diego-Imperial Valley area)[101]	Stakeholder-submitted alternatives include: Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project (PG&E and TransCanyon) similar to San Diego/LA Basin Transmission Interconnection submitted in the 2017-2018 transmission planning cycle Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra Renewables) Sycamore Reliability Energy Storage (Tenaska) Sycamore Substation Energy Storage (NEET West) LEAPS (Nevada Hydro) San Vicente Energy Storage (City of San Diego)	Selected as potential LCR reduction possibility

[101] Since the San Diego sub-area is within the San Diego-Imperial Valley LCR area, the total LCR reduction benefits (or impacts) will be evaluated at the overall LCR level for the San Diego-Imperial Valley area. This is to ensure that the overall area impact (or benefits) are captured in the study.

Congestion area or branch group	Location and facilities	Reason & Direction
San Diego/Imperial Valley (studied in concert with LA Basin)[102] and considering benefits to San Diego sub-area	Stakeholder-submitted alternatives include: Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra) HVDC Conversion Project (SDG&E) – Interregional Transmission Project (Note – similar to Renewable Energy Express HVDC Conversion Project (SDG&E) – submitted in 2017-2018 transmission planning cycle North Gila - Imperial Valley #2 500 kV Transmission Project (ITC Grid Development and Southwest Transmission Partners, LLC) – Interregional Transmission Project Plus projects identified above for San Diego sub-area: Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV project (PG&E and TransCanyon) similar to San Diego/LA Basin Transmission Interconnection submitted in the 2017-2018 transmission planning cycle Westside Canal Reliability Center (ConEd Clean Energy Businesses, formerly Sempra Renewables) Sycamore Reliability Energy Storage (Tenaska) Sycamore Substation Energy Storage (NEET West) LEAPS (Nevada Hydro) San Vicente Energy Storage (City of San Diego)	Selected as potential LCR reduction possibility
El Cajon (San Diego/Imperial Valley)	Stakeholder-submitted alternative: El Cajon Sub-area Local Capacity Requirement Reduction Project (SDG&E)	Selected as potential LCR reduction possibility
Border (San Diego/Imperial Valley)	Stakeholder-submitted alternative: Border Sub-area Local Capacity Requirement Reduction Project (SDG&E)	Selected as potential LCR reduction possibility

[102] The two areas are studied together to determine whether there are LCR impacts due to gas-fired generation requirement reductions to the other area.

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)[103], and potential economic benefits are quantified as reductions of ratepayer costs.

Determining Ratepayer Benefits

In the production benefit assessments, ISO ratepayer's benefits and WECC society benefits are calculated as:

- *ISO ratepayer's production benefit = (ISO Net Payment of the pre-upgrade case) – (the ISO Net Payment of the post-upgrade case)*
- *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*
- *ISO Net Payment = ISO load payment – "ISO owned" generation profit – "ISO owned" transmission revenue*

The above calculation reflects the benefits to ratepayers – offsetting other ratepayer costs – of transmission revenues or generation profits from certain assets whose benefits accrue to 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.

These assets of course are not "owned" by the ISO. However, within production cost modeling, "ownership" is used to track which transmission's revenue and generator's profit will be counted to offset ratepayer's load-related payments, by defining those assets as "ISO owned" in the ISO's production cost model. Accordingly, the terms "ISO owned generation profit" or "ISO generator net revenue benefitting ratepayers" and "ISO owned transmission revenue" are used in the reporting of production cost modeling results in this section, to reflect those profits and revenues accruing to the benefit of ratepayers, and not to reflect actual ownership.

In addition to the production benefit, other benefits were also evaluated as needed. As discussed in section 4.1, 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 dollars.

[103] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Transmission Service

Table 4.9-1 contains a number of battery storage and pumped hydro storage projects. As discussed in chapter 1, 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, is the resource 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)[104];
- Meet an ISO-determined transmission need under the tariff (reliability, economic, public policy)[105]; and,
- "Be the more efficient or cost-effective solution to meet the identified need"[106] 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"*[107] (emphasis added).

Further, if the storage 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 is meeting the need. While the storage projects identified in Table 4.9-1 are concentrated in the San Diego/Imperial Valley area, a single determination is not sufficient as there are both common characteristics and differences in how the projects purport to meet the transmission need, including how local transmission needs would be met. As a result, it is necessary to consider this question individually for each storage project.

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.

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[104] *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.

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

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

[107] ISO Tariff Section 24.4.6.7, re economic needs

4.9.1 California-Oregon Intertie (COI)

The production cost simulations in this planning cycle showed an increase in COI congestion from previous planning cycles. Two alternatives were studied to examine whether mitigating COI congestion could provide benefit to ISO's ratepayers:

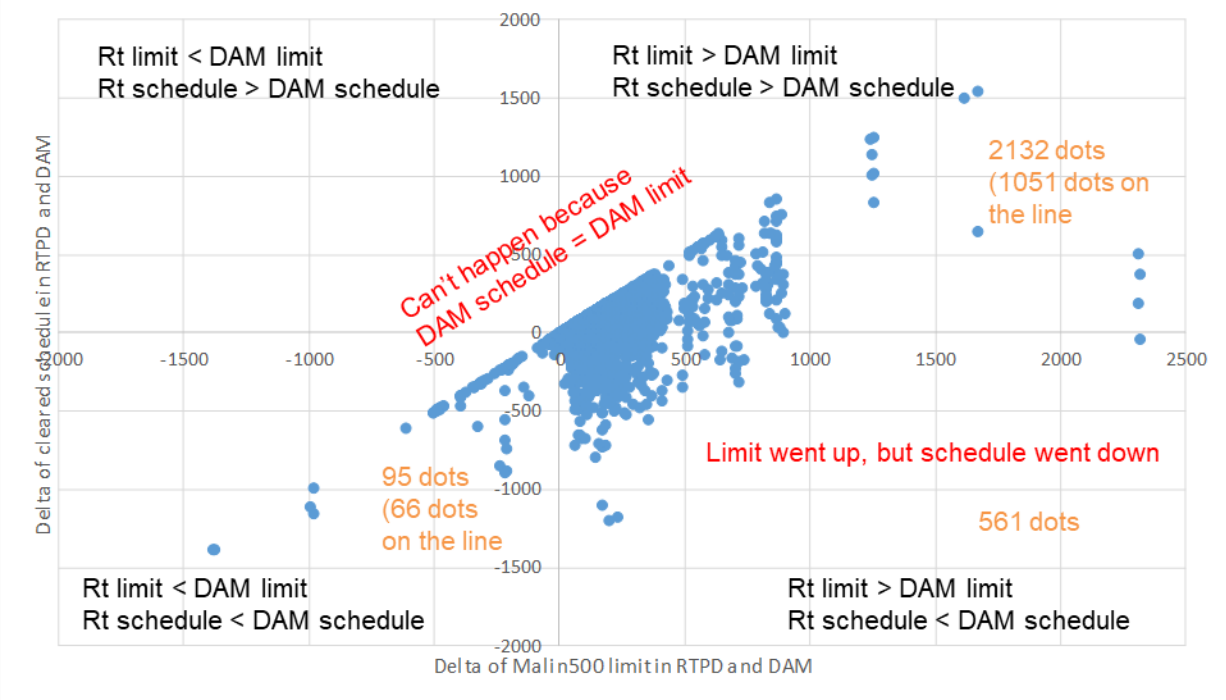
- Alternative 1: Model COI path rating at 5100 MW assuming the N-2 contingency of the two 500 kV lines between Malin and Round Mountain is conditional credible and with necessary revisions to existing SPS.
- Alternative 2: SWIP - North project.

The congestion observed in production cost modeling studies is based on physical congestion, with limits generally established by the physical capabilities. Stakeholders have observed an apparent disconnect in past ISO congestion studies, compared to the day-ahead congestion that has been observed in the ISO markets over the last number of years.

This issue was explored in part by examining the real time conditions when day ahead congestion was found to occur.

Figure 4.9-1 below presents a plot of the delta of Malin 500 kV cleared schedules (between real time and day ahead) versus the delta of the Malin 500 limits (between real time and day ahead) when the day ahead limit was binding, for the year 2016.

Figure 4.9-1: Cleared Schedules versus Limits, between Day Ahead and Real Time at Malin 500



Notes:

- When day ahead market is binding (the cleared schedule is equal to the limit), real time may not be binding
- The changes in cleared schedules from day ahead to real time are always less than the changes in limits (when day ahead is binding)

Upon reviewing the circumstances of day-ahead congestion, the ISO has concluded that a material portion of that congestion relates to a number of reasons:

- Capacity exists, but is only released to the ISO market in real time (ETC rights)
- Capacity exists, but scheduling rights are not available to the ISO market at all despite not being used
- Over scheduling in day ahead market more than the scheduling limits and is corrected in real time
- Over scheduling in day ahead market at levels higher than intended in real time.
- Incomplete information of outside system and the locations of resources could impact calculation of physical flows, but physical flows are not generally binding, so this is likely not material

The first three observations were based on the real time limit climbing from the day-ahead, and the real time schedules climbing to match the new limit. The fourth conclusion was reflected by times where the limit climbs, but the real time schedules climb only a little, or decline.

The greatest opportunity is for the ISO market to gain access to the additional physical capacity that cannot currently be utilized in the ISO market. The ISO is accordingly investigating with its neighbors the possibility of accessing this capacity.

The analysis in this study therefore continues to focus on incremental gains in physical capacity – either by rating increases on the existing facilities or by system reinforcements.

4.9.1.1 5100 MW COI path rating

As a part of the Pacific Northwest informational special study set out in chapter 7, the potential to increase the current WECC Path Rating of the COI from 4800 MW to 5100 MW without any material transmission upgrades was identified as a potential option. The increase in path rating could be achieved through changes to the criteria that was used to establish the current Path Rating. The 5100 MW path rating assumption was based on the investigation of potentially converting the N-2 contingency of the two 500 kV lines between Malin and Round Mountain to a conditional credible N-2 contingency with necessary revisions to existing SPS. The increase in the path rating would need to go through the WECC Path Rating Process for approval. Another option would be to include load shedding in California following the N-2 contingency, which would involve capital expenditures.

The following provides the economic assessment from the production cost simulation of increasing the COI path rating to reduce congestion on COI. The production benefit for ISO's ratepayers and the WECC overall production cost savings of increasing the COI path rating to 5100 MW are shown in Table 4.9-2.

Table 4.9-2: Production Cost Modeling Results for COI path rating at 5100 MW

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,466	-9
ISO generator net revenue benefitting ratepayers	2,526	2,525	-1
ISO owned transmission revenue	199	202	3
ISO Net payment	5,387	5,389	-7
WECC Production cost	16,875	16,876	-1

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

This shows that simply increasing the COI path rating did not bring net benefits to ISO's ratepayers. Further investigation of the COI congestion study results revealed that the majority of COI congestion occurred in the simulation during the hours when COI rating was derated due to scheduled maintenance, as shown in Figure 4.9-2. The path rating derates were determined based on the maintenance outages, and those derates were not impacted by the path rating increase.

The increase in the rating did have impacts in other hours, however. Table 4.9-3 shows the COI congestion changed with modeling the 5100 MW path rating. When the total congestion hours reduced, the congestion cost actually increased. This aligns with the overall result that the increased COI limit negatively impacted ISO ratepayers while having minimal impact on overall WECC production costs.

Figure 4.9-2: COI Limit and Flow in Default Portfolio Base Case

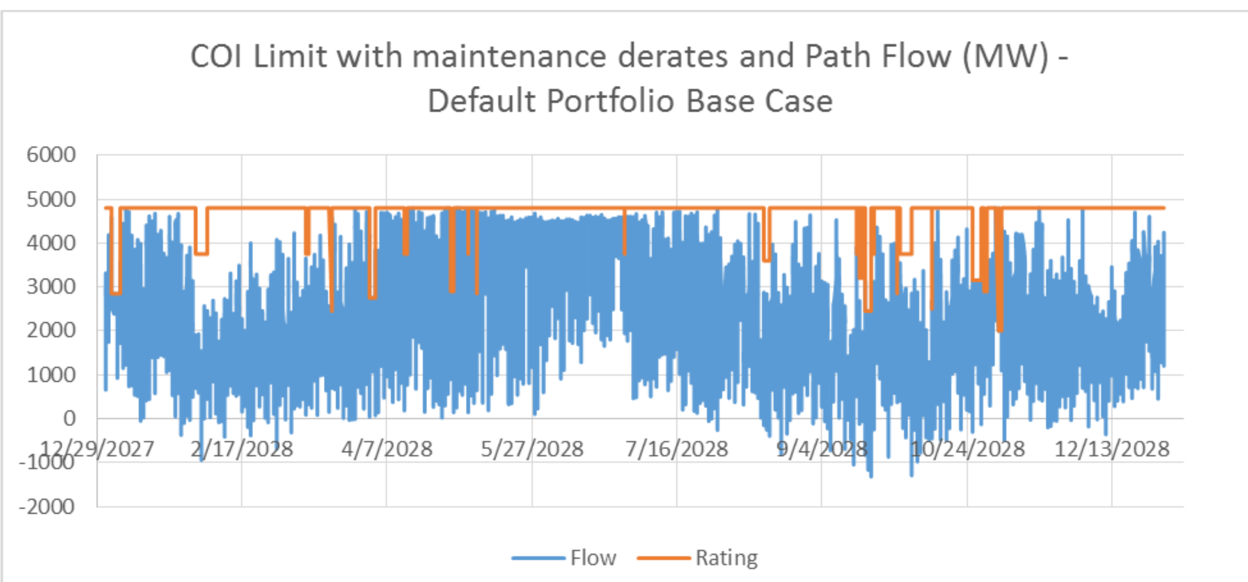


Table 4.9-3 COI congestion changes with modeling 5100 MW COI path rating

	Congestion hour	Congestion cost (M$)
Default portfolio Base case	165	5.06
COI 5100 MW	132	6.07

The congestion change was mainly due to the changes in generation dispatch in ISO areas, as shown in Figure 4.9-3. In Figure 4.9-3 and Figure 4.9-4, CIPB is the area defined in the production cost model for the PG&E Bay area, CIPV is the rest of PG&E areas outside the Bay area, CISC is the SCE area, and CISD is the entire SDG&E area including the San Diego and IV areas.

In modeling the 5100 MW COI rating, PG&E generation overall reduced slightly, particularly the thermal generation. However, the ISO system still needed thermal generation to provide ancillary services and energy in some hours, which resulted in thermal generation increases in Southern California. (Note that lowering congestion into a constrained area doesn't assure lower ISO ratepayer net benefits, as the downward change in LMP within the constrained area does not necessarily outweigh any increase in LMP over the load outside of the constrained area, and generation revenues and transmission revenues also have to be taken into account.)

As the result, the COI path rating increase to 5100 MW did not show benefit to the ISO's ratepayers in this planning cycle's production cost modeling studies.

Another factor to consider regarding potential benefits of COI upgrades or related projects is with respect to ability to access additional capacity from the Northwest that has been stored during energy surplus periods in California due to high solar output. Figure 4.9-4 shows that with the 5100 MW COI path rating modeled, generation output from Northwest regions did not change materially.

Figure 4.9-3: Generation changes in ISO areas with modeling 5100 MW COI path rating

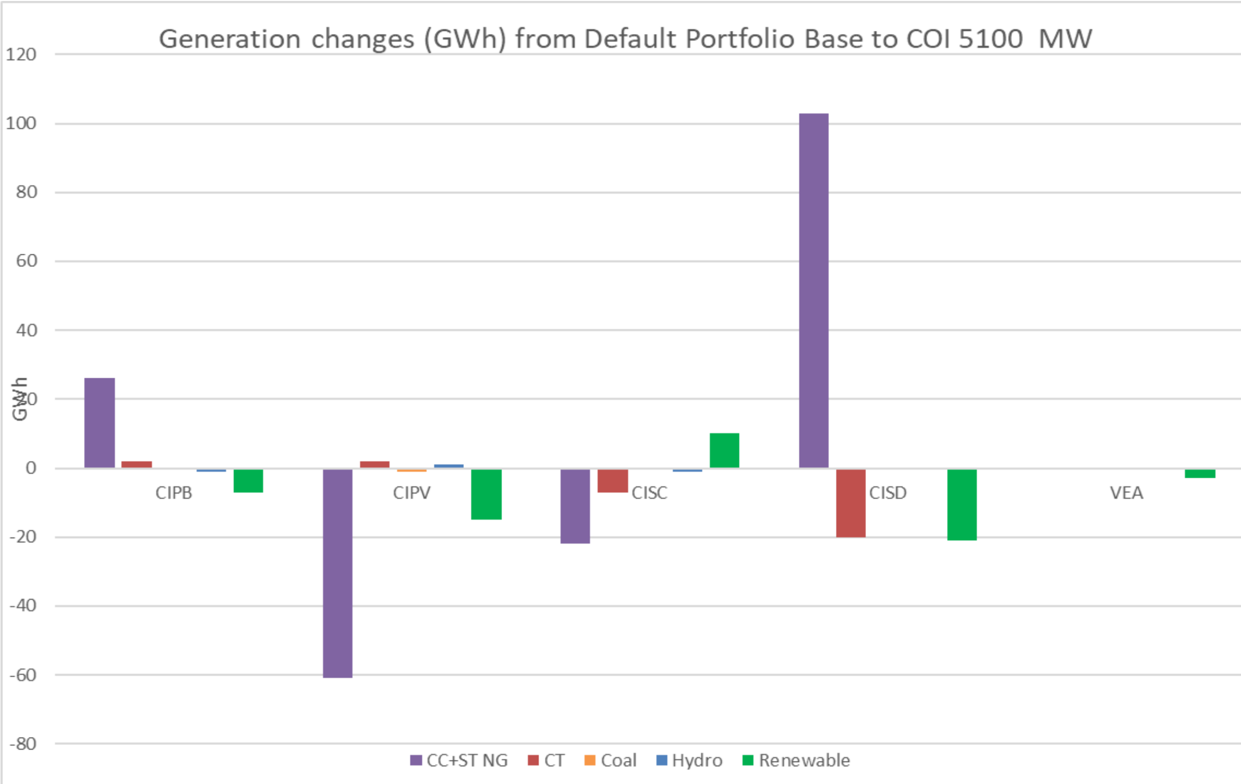
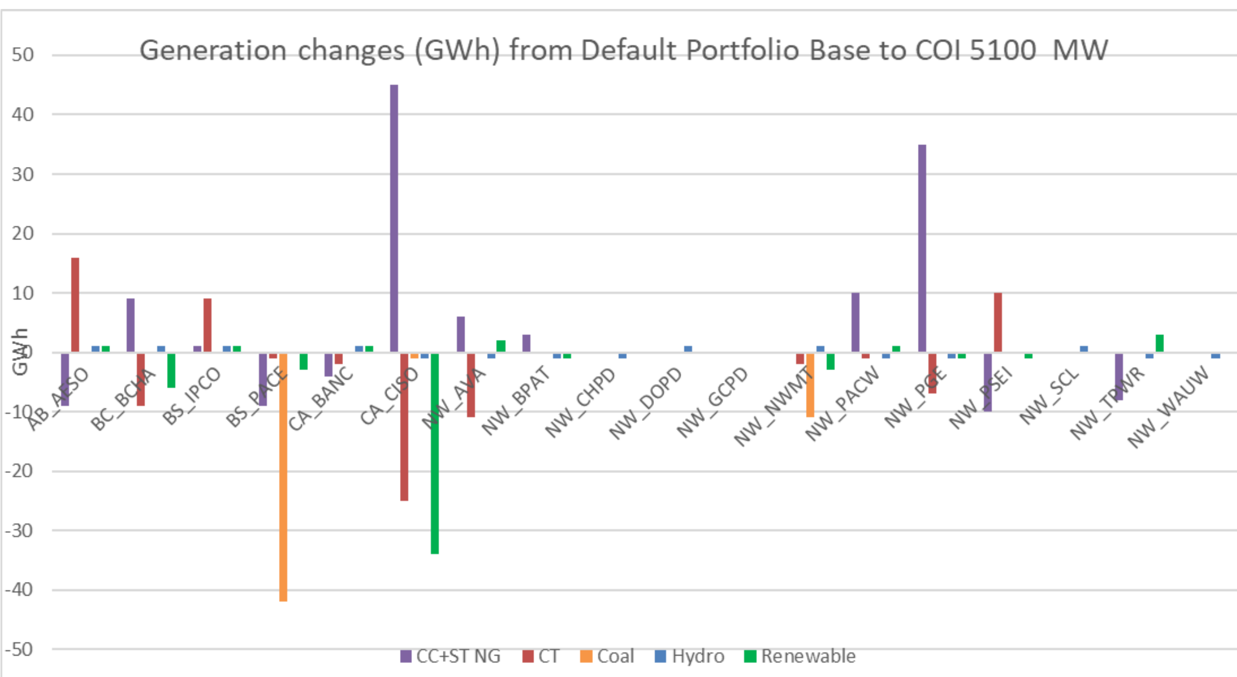


Figure 4.9-4: Northwest and California generation changes with COI 5100 MW path rating



Conclusions

The study results do not support pursuing capital expenditures to achieve a path rating increase at this time. COI congestion and potential benefits of increasing the COI path rating were also investigated in the Pacific Northwest – California Transfer Increase Study, using different hydro conditions, as described in chapter 7. As set out in chapter 7, the issue of the path rating criteria will be monitored, and a path rating increase will be pursued if it can be achieved in the future without requiring capital expenditures.

4.9.1.2 SWIP - North project

The Southwest Intertie Project North (SWIP - North) was submitted as an economic planning study request by LS Power Development, LLC. The project was also submitted in the 2018 Request Window for reliability-driven alternatives as set out in chapter 2 and as an interregional transmission project as set out in chapter 5, in both cases by Great Basin Transmission (GBT), LLC, an affiliate of LS Power.

The SWIP - North transmission project is an approximately 500-mile, 500 kV single circuit AC transmission line that connects the Midpoint 500 kV substation in southern Idaho, the Robinson Summit 500 kV substation, and the Harry Allen 500 kV substation. SWIP - North is parallel to the California-Oregon Interconnection, SWIP - North was modelled in the production cost model to assess if there project provides ISO rate payer benefits per the TEAM methodology and the associated production cost benefits. More comprehensive descriptions are provided in chapter 2 and chapter 5.

The following provides the economic assessment for SWIP - North.

SWIP - North Production Benefits

The production benefit of SWIP - North project for ISO's ratepayers and the production cost savings are shown in Table 4.9-4.

Table 4.9-4: Production Cost Modeling Results for SWIP - North

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,495	-38
ISO generator net revenue benefitting ratepayers	2,526	2,529	-3
ISO owned transmission revenue	199	213	14
ISO Net payment	5,387	5,408	-21
WECC Production cost	16,875	16,869	6

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

These results demonstrate a net increase in ISO ratepayer costs, instead of a saving. They also demonstrate an overall benefit of SWIP – North in lowering production costs over the entire WECC footprint, which is consistent with the intent of production cost modeling to find the lowest overall production cost. In considering why ISO ratepayer costs were climbing while WECC production costs were declining, several issues appear to play a role. The SWIP - North line may not provide incremental import from Northwest regions during some hours when there is no energy surplus in those regions depending on resource and transmission assumptions in Northwest regions in the model. SWIP - North may allow more exports from California to other regions when there are renewable energy surplus within California. In addition, lower priced imports can result in increased profits to out-of-state generation and reduced profits to ISO owned generation in the ISO footprint whose profits accrue to ISO ratepayers.

Conclusions

The SWIP - North project, on a standalone basis and without support from other areas that may benefit from the project, was not supported by the findings in the 2018-2019 transmission planning studies. The ISO expects that dialogue will continue with neighboring planning regions as their own plans evolve, and as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement.

4.9.2 PG&E Fresno Giffen area

The PG&E Fresno Giffen area is a net generation pocket with total 39 MW of existing grid-connected solar PV generation. This generation may cause congestion on the Giffen to Giffen Junction 70 kV line, which is the radial connection to the rest of the system, depending on the seasonal rating of the transmission line. The ISO studied reconductoring the congested 70 kV line to completely mitigate the congestion. The production benefit results for ISO's ratepayers and the overall production cost savings are shown in Table 4.9-5.

Table 4.9-5: Production Cost Modeling Results for Giffen Line Reconductoring

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,443	14
ISO generator net revenue benefitting ratepayers	2,526	2,520	-6
ISO owned transmission revenue	199	198	-1
ISO Net payment	5,387	5,376	7
WECC Production cost	16,875	16,880	-5

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

As discussed in Section 4.6.6, multi-tiered renewable curtailment prices were used in this planning cycle. With such a curtailment price model, all wind and solar would have the same curtailment price, which varies based on the total curtailment amount. Curtailment can be caused by transmission constraints or system constraints, or both. This curtailment price model may potentially impact the results for areas like Giffen area, which has a radial connection to the system and a relatively small amount of renewable generation. In such areas, the renewable curtailment price would still be set based on the system total curtailment amount, although the dominate driver of the curtailment in the local area is the transmission constraint of the radial connection. Therefore, a sensitivity study assuming -$25 curtailment price for the entire year was conducted for Giffen upgrade. A negative $25 curtailment price was selected because the curtailment price in most hours when curtailment happened in the base case study was -$25 or less. The results are shown in Table 4.9-6.

Table 4.9-6: Production Cost Modeling Results for Giffen Line Reconductoring – negative $25 curtailment price

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,564	8,544	20
ISO generator net revenue benefitting ratepayers	2,596	2,595	-1
ISO owned transmission revenue	213	210	-3
ISO Net payment	5,756	5,740	16
WECC Production cost	16,908	16,903	5

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Both base case study and sensitivity studies showed that Giffen upgrade can provide ISO ratepayers with material benefits. The sensitivity did address concerns, however, with the counterintuitive direction of the WECC production cost results.

The present value of the benefit was calculated to be $49 million, using the lower annual benefit between the above two studies of $7 million and assuming a 40 year economic life. The estimated cost of the project is less than $5 million, which translates to a total cost of $6.5 million (present value of annualized costs) using the ISO's 1.3 screening ratio. The benefit to cost ratio then is about 7.5, which provides sufficient economic justification for recommending approval for this project.

Conclusions

The ISO recommends proceeding with the Giffen line reconductoring project as an economic-driven transmission solution.

4.9.3 Path 26 Midway-Vincent

The production cost modeling results demonstrated congestion occurring on Path 26 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 congestion. Two alternatives of mitigating the congestion were studied:

- Alternative 1: Increase Path 26 south to north path rating to 4000 MW by assuming tripping southern generators under contingency conditions by an SPS; and upgrade the Whirlwind to Midway 500 kV line by bypassing the series capacitors and increasing the conductor rating to the same level as the other two 500 kV lines of Path 26.
- Alternative 2: The transmission component of the economic study request CTP DCPP project, which includes a three terminal DC line between SCE's Ormond Beach and Redondo substations and PG&E's Diablo substation. The offshore wind generation discussed in the study request was not considered in this analysis.

4.9.3.1 Path 26 south to north path rating increase to 4000 MW

Path 26 currently has a south to north path rating of 3000 MW. The economic assessment of the production cost benefits of potentially increasing the south to north path rating to 4000 MW was modeled in the production simulation. The increase in the path rating could be achieved with the installation of a remedial action scheme (RAS) to trip generation located south of Path 26 and load located north of Path 26 for certain contingencies. The RAS would be similar to the RAS used to achieve a path rating of 4000 MW in the north to south direction with generation tripped north of Path 26 and load tripped south of Path 26. The increase in the path rating would need to go through the WECC Path Rating Process for approval. The economic assessment from the production cost simulation to increase the Path 26 path rating to reduce congestion on Path 26 is provided below.

Path 26 South to North Path Rating Increase Production Benefits

The production benefit for ISO's ratepayers and the production cost savings are shown in Table 4.9-7.

Table 4.9-7: Production Cost Modeling Results for Path 26 path rating increase

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,445	12
ISO generator net revenue benefitting ratepayers	2,526	2,532	6
ISO owned transmission revenue	199	181	-18
ISO Net payment	5,733	5,733	0
WECC Production cost	16,875	16,877	-2

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Figure 4.9-5 and Figure 4.9-6 show the generation and congestion changes with modeling the Path 26 upgrade, respectively. With the south to north rating increase, Path 26 congestion can be significantly reduced, and correspondingly generation dispatch changed on both sides of Path 26. Renewable generation output did not change as much as thermal generation mainly due to the ISO net export limit was binding in about same amount hours as in the base case and caused renewable curtailment.

Figure 4.9-5: Generation changes with Path 26 south to north path rating increase

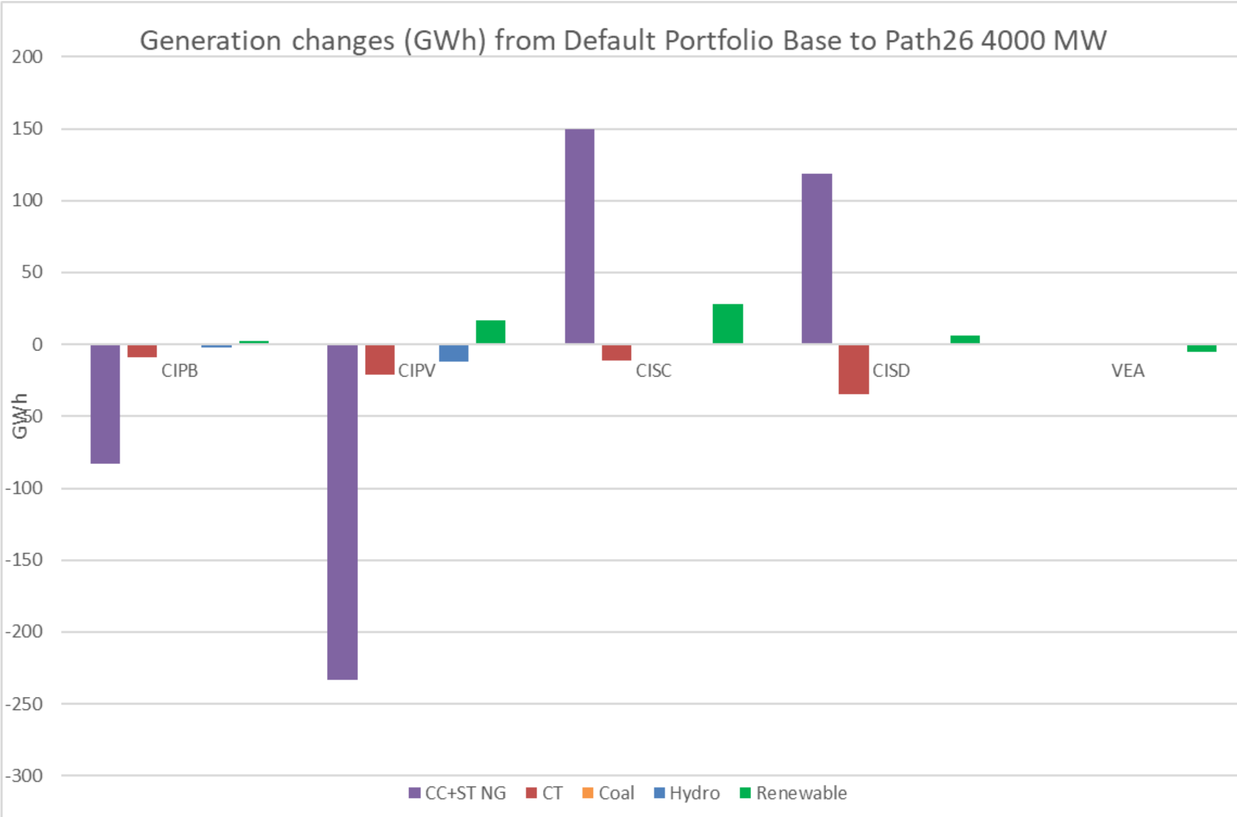
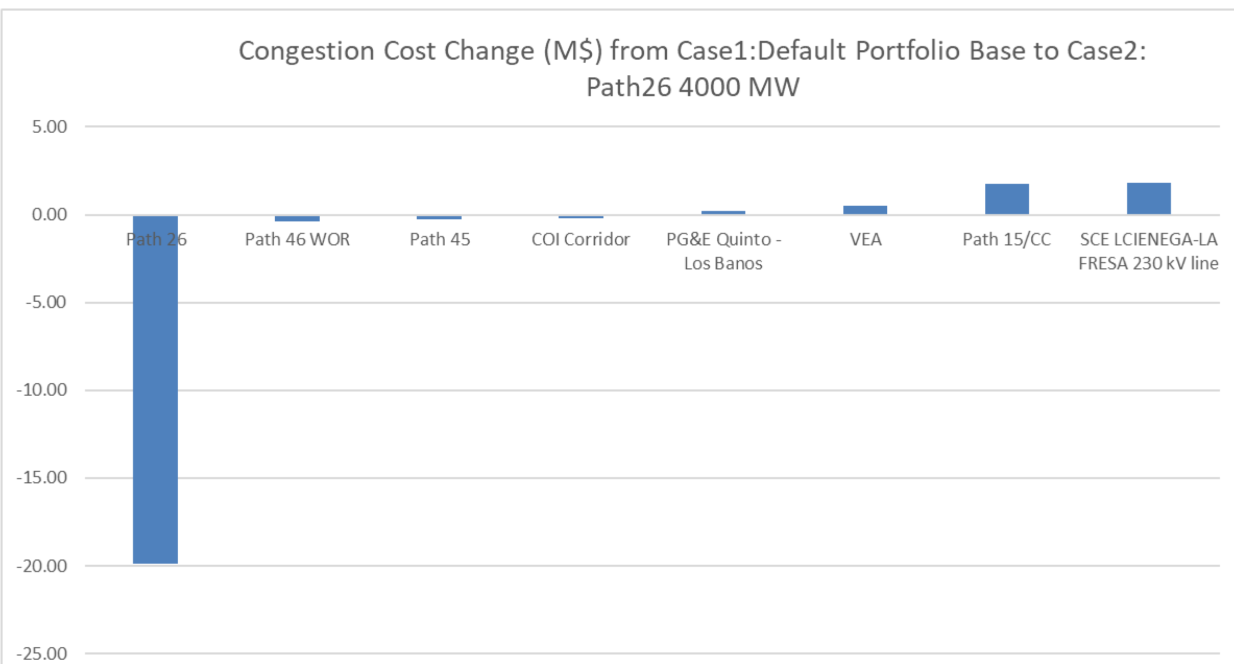


Figure 4.9-6: Congestion changes with Path 26 south to north path rating increase



Conclusions

The study results do not support pursuing a path rating increase at this time. This will be further monitored and investigated in the future planning cycles.

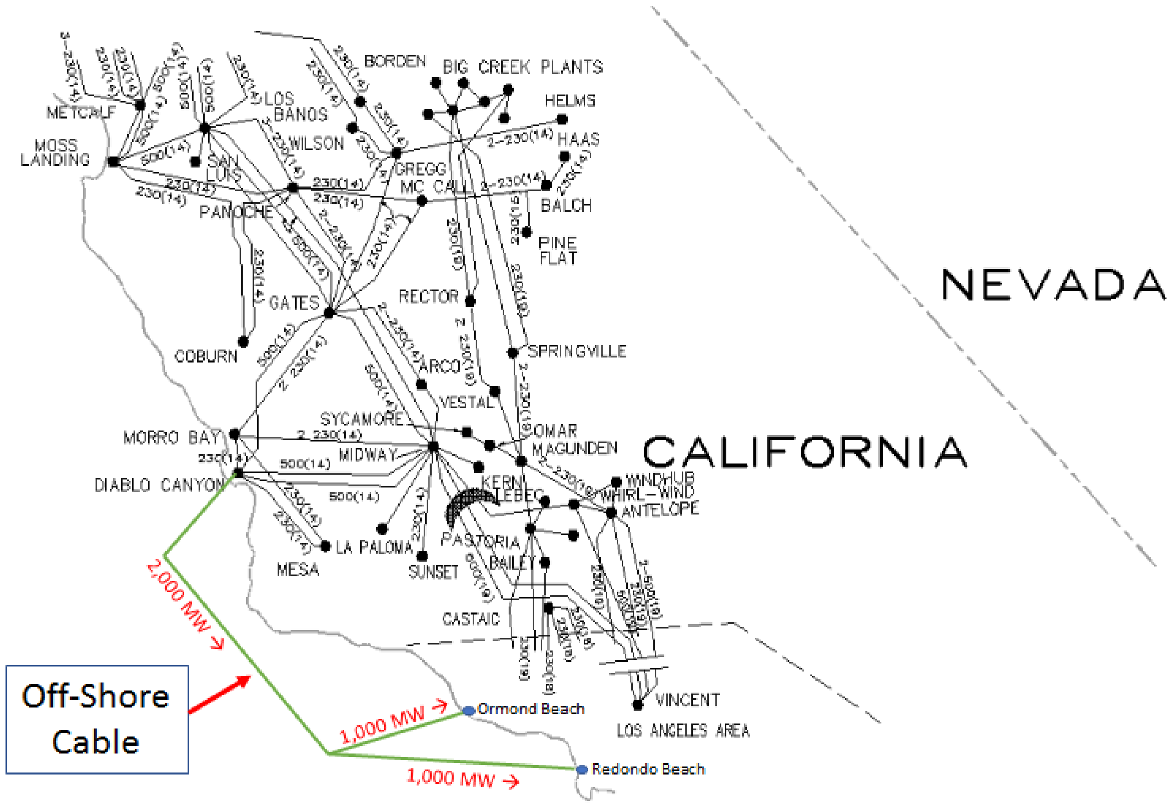
4.9.3.2 Diablo Canyon to Ormond Beach and Redondo Beach (California Transmission Project)

The proposed California Transmission Project (CTP) is a 320 kV HVDC submarine cable that would utilize Voltage Source Converters (VSC) to interconnect with existing HVAC transmission facilities in both the Pacific Gas & Electric and Southern California Edison service areas. The cable would be routed offshore of California in the Pacific Ocean and will have three segments, two between Diablo Canyon and Ormond Beach with approximate lengths of 139 miles and 159 miles. One cable would be positioned farther out into the ocean than the other for potential future interconnection with offshore wind development. The third segment, running between Ormond Beach and Redondo Beach would be approximately 50 miles in length. See Figure 4.9-7 below.

The northern terminus of the CTP is proposed to be the Diablo Canyon 500 kV switching station and would utilize the two BAAH bay positions that will be vacated with the decommissioning of the Diablo Canyon Power Plant. There would be two 1,000 MW VSCs located on shore at Diablo Canyon with switching to enable flexible operations and maintenance while one VSC remains in operation. There would be two separate southern terminals for the CTP, one at Ormond Beach and one at Redondo Beach. At the southern terminals, there will be one 1,000 MW VSC to enable connection to the 220 kV bus at the SCE Ormond Beach 220 kV substation and one 1,000 MW VSC to enable connection to the SCE Redondo Beach 220 kV substation. Both 320 kV HVDC cables, rated at 1,000 MW each, originating at Diablo Canyon will connect to an on-shore HVDC station at Ormond Beach to allow for flexible operations and maintenance. There will be a single 320 HVDC cable running between Ormond Beach and Redondo Beach, also rated at 1,000 MW.

The ISO studied this proposal without the wind generation because that generation was not part of the renewable portfolio provided by the CPUC.

Figure 4.9-7: California Transmission Project



California Transmission Project Production benefits

The production benefit for ISO's ratepayers and the production cost savings were shown in Table 4.9-8.

Table 4.9-8: Production Cost Modeling Results for CTP

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,468	-11
ISO generator net revenue benefitting ratepayers	2,526	2,551	25
ISO owned transmission revenue	199	188	-11
ISO Net payment	5,733	5,730	3
WECC Production cost	16,875	16,876	-1

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Figure 4.9-8 and Figure 4.9-9 show the generation and congestion changes that resulted from modeling the CTP project, respectively. Since the CTP project provides a parallel path to Path 26, Path 26 congestion can be significantly reduced, and correspondingly generation dispatch changed on both sides of Path 26. The overall impact of the CTP project on congestion and generation changes was similar to upgrading Path 26 rating as shown in the previous section. The magnitudes of changes in different location were different from the Path 26 path rating increase study because of the transmission topologies were different. ISO net export limit was still binding in about same amount hours as in the base case and caused renewable curtailment.

Figure 4.9-8: Generation changes with CTP project modeled

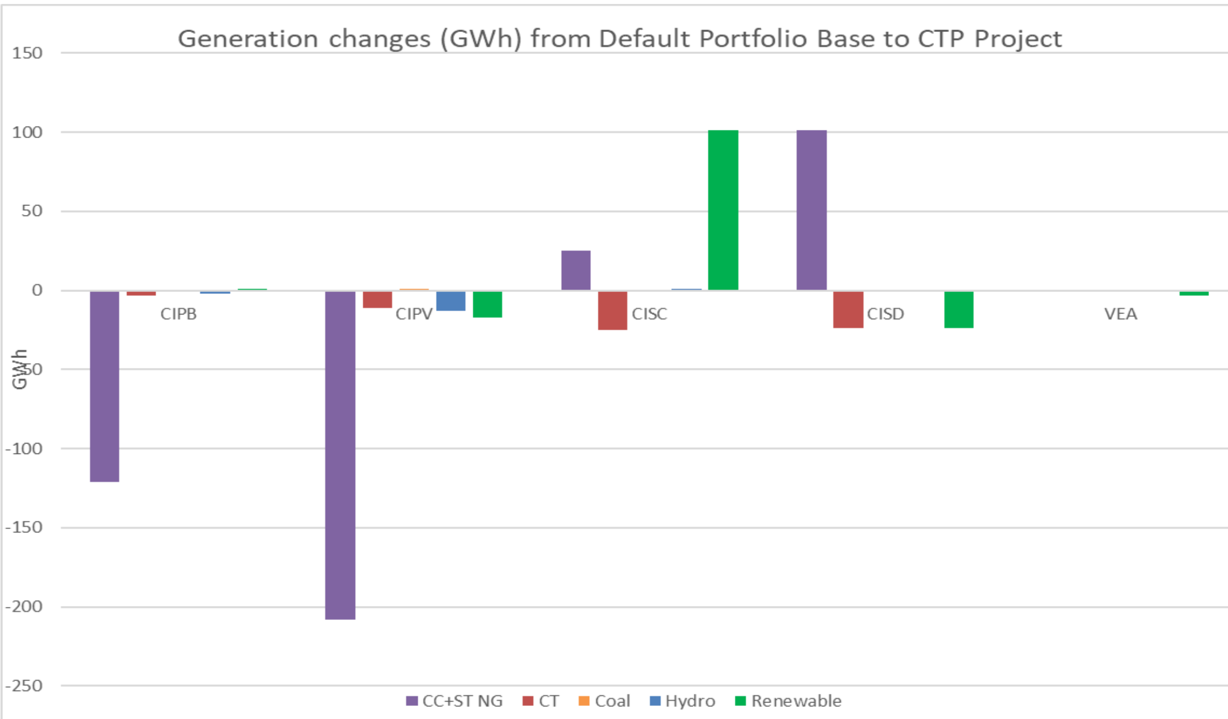
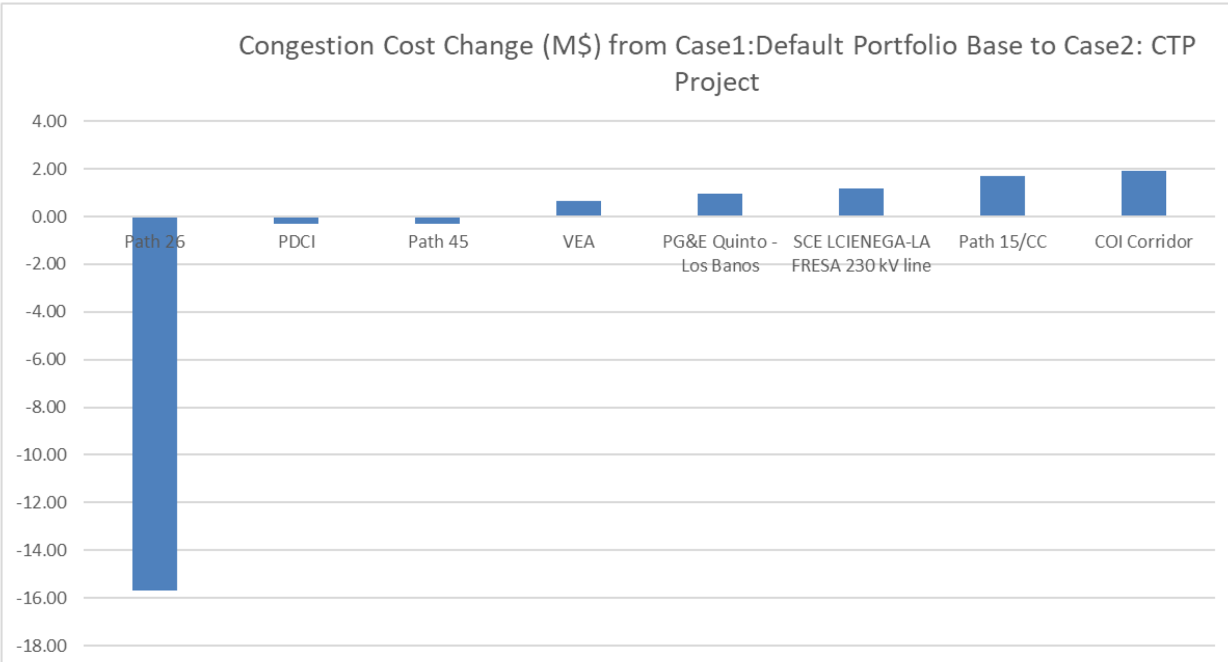


Figure 4.9-9: Congestion changes with CTP modeled



Local Capacity Benefits:

The proposed project connects to the ISO system at Diablo Canyon, Ormond Beach, and Redondo switchyards. Diablo Canyon is not located in a local capacity area. With the planned Pardee-Moorpark #4 230 kV circuit, there will no longer be a Moorpark local capacity sub-area requirement, so Ormond Beach will no longer be located in an LCR sub-area. The overall Big Creek/Ventura area does have a significant local capacity requirement that can be met by resources connecting at Ormond Beach, and only about 300 MW of the overall need is met with GHG-emitting resources. While attributing this amount of benefit to the HVDC project appears overly precise, the ISO has nonetheless reflect a 300 MW potential local capacity requirement reduction benefit associated with the Big Creek/Ventura local area requirements in assessing the potential benefits of the project.

.Redondo is located in the Western LA Basin sub-area. While, as noted earlier, the Western LA Basin sub-area was not selected for detailed economic analysis – which would normally include a comparison of alternatives – the economic benefit of this project to potentially reduce local capacity requirements in the Western LA Basin sub-area was nonetheless estimated.

The Western LA Basin sub-area has been evaluated due to actual and planned OTC generation retirements in the last several transmission planning cycles, and because of the previous extensive evaluation and implementation for OTC generation and San Onofre Nuclear Generating Station (SONGS) retirements, the ISO did not select this sub-area for detailed study in this planning cycle as discussed in section 4.8.7. However, for purposes of this project's economic screening analysis, the ISO assumed that the project would provide approximately

1000 MW of LCR reduction benefits in the Western LA Basin sub-area. No costs were assumed for potential requirements for in-basin upgrades to address localized issues caused by the retirement of any generation the capacity of this project would replace. With the retirement of the OTC generation and SONGS, the retirement of additional generation in the Western LA Basin sub-area could cause localized transmission reliability concerns to be discovered if a detailed LCR study were to be performed on this proposed project.

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 LA Basin, 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 2018-2019 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.

In Table 4.9-9, the benefit of local capacity reductions in the Western LA Basin sub-area and Big Creek/Ventura area are valued based on the cost range for the LA Basin.

Table 4.9-9: LCR Reduction Benefits for California Transmission Project

	California Transmission Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Western LA Basin and BC/Ventura) (MW)	1300	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$21.7	$29.5
LCR increase (San Diego – IV) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$21.7	$29.5

Cost estimates

The cost estimate provided by the project sponsor is $1,830 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 $2,379 million[108].

Benefit to Cost Ratio

In Table 4.9-10 the present value of the sum of the production cost and capacity benefits above are calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-10: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

California Transmission Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$3	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$3	
PV of Prod Cost Savings ($million)	$39	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$21.7	$29.5
PV of LCR Savings ($million)	$299.3	$406.9
Capital Cost		
Capital Cost Estimate ($ million)	$1,830	
Estimated "Total" Cost (screening) ($million)	$2,379	
Benefit to Cost		
PV of Savings ($million)	$338.6	$446.3
Estimated "Total" Cost (screening) ($million)	$2,379	
Benefit to Cost	0.14	0.19

108 The CTP project proponent provided a Project Net Present Value Cost including O&M, taxes, ROE and Debt at a 6% discount rate of $2.82 billion. For screening purposes and consistency, the CAISO applied the ISO's 1.3 factor to estimate the present value of the annualized revenue requirement, resulting in a lower value for the cost.

Conclusions

The economic benefits of the California Transmission Project are not sufficient on a standalone basis to support the project as an economic-driven transmission project based on the findings in the 2018-2019 transmission planning studies. The project provides other 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.

4.9.4 Colorado River – Julian Hinds

The Colorado River– Julian Hinds 230 kV Project, also referred to as the Blythe Loop-in Project in various submissions, was submitted by AltaGas Services in the 2017-2018 transmission planning cycle.

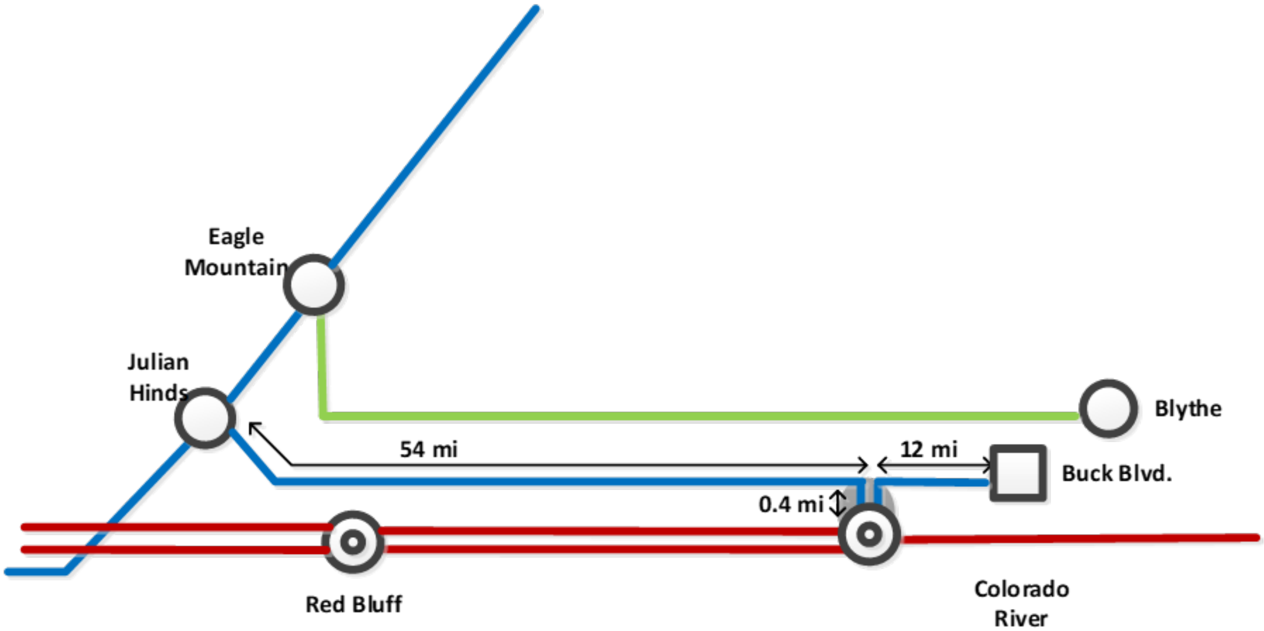
As discussed in section 4.8, the ISO agreed in the course of the 2017-2018 transmission planning cycle to review the project in the 2018-2019 transmission planning cycle, in light of AltaGas proposing modifications to the original scope late in the 2017-2018 planning cycle.

The proposed project consists of:

- Converting the existing privately owned Buck Blvd - Julian Hinds 230 kV generation tie-line into a network facility by way of segmenting the gen-tie line and connecting one terminal of both segments into the Colorado River Substation 230 kV bus. It creates a networked facility identified as Colorado River - Julian Hinds 230 kV line, and a revised 230 kV gen-tie line identified as Buck Blvd - Colorado River 230 kV line.
- Installing 117 Smart Wires Power Guardian 700-1150 devices (~19.58 Ω/phase) on the Colorado River - Julian Hinds 230 kV line in series with the line. These Power Guardians would be set to switch into injection mode to limit the power flow on the Julian Hinds - Mirage 230 kV line to avoid potential overloads.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-10: Colorado River – Julian Hinds 230 kV Project



The project cost was estimated by AltaGas at $67 million with an expected in-service date of June 1, 2020.

The Altagas proposal was submitted as a comprehensive package, including both the re-termination of the Blythe generation at the Buck Blvd substation to the Colorado River substation's 230 kV bus, and the creation of the Colorado River - Julian Hinds 230 kV line by also re-terminating the line running east from Julian Hinds to the Colorado River substation's 230 kV bus. Given the need to properly assess the benefits to ISO ratepayers of this proposal for a potential economic-driven transmission project, the ISO needed to study the benefits of the various components both individually and as well as collectively.

The ISO therefore studied the benefits of:

- Option 1: Re-terminating the line extending west from Buck Blvd substation to Colorado River, but leaving portion of line from approximately Colorado River to Julian Hinds de-energized and not terminated at Colorado River (and not installing the Smart Wires Power Guardian devices).
- Option 2: Looping in the Buck Blvd-Julian Hinds line into Colorado River as proposed.

As well, the ISO acknowledged the risk to ISO ratepayers if the gas-fired generation at Buck Blvd retired, especially if the bulk of the economic benefits were associated with the re-termination of the generation and the Colorado River-Julian Hinds transmission line provided little value. Therefore, a third option was studied:

- Option 3: Re-terminating the portion of line from Julian Hinds into Colorado River, and leave the Buck Blvd substation disconnected and out of service. Note that assessing Option 3 requires a modified base case to be developed for comparative purposes, with the entire Julian Hinds - Buck Blvd 230 kV transmission line and Buck Blvd substation disconnected and de-energized.

The ISO therefore conducted its reliability and production cost modeling on five cases:

- Base case – Existing configuration
- Option 1 – Generation only
- Option 2 – Generation and line
- Modified Base – Julian Hinds – Buck Blvd out of service
- Option 3 – Line only

Reliability Considerations

The need for a similar project was assessed as part of the 2014-15 and 2016-17 ISO transmission planning cycles and was not found to be needed in those planning cycles. The project - now with the inclusion of the Smart Wires devices – was studied in this planning cycle and was not been found to be needed for reliability purposes in this planning cycle. In considering the viability of the project as a potential economic-driven transmission solution, , power flow analysis was performed on the project to test for any negative impacts. It was found that with the project modeled in the 2017-2018 TPP S4 Heavy Renewables sensitivity case, with the Smart Wires devices on the Colorado River - Julian Hinds 230 kV line fully activated, the Julian Hinds - Mirage 230 kV line was heavily overloaded under contingency conditions. However, AltaGas has proposed a RAS that would open the overloaded line created by this proposed project during this contingency condition. While working with AltaGas in previous transmission cycles, the ISO has raised concerns about the use of a RAS to open this proposed transmission line. This new RAS would be in addition to the existing RAS that also drops over 1000 MW of generation. The ISO has also raised concerns that the new RAS proposed by AltaGas would leave the Blythe gas fired generation connected to the Colorado River 230 kV bus and would cause deliverability impacts on the existing generation in the area. AltaGas has requested that the ISO assess this deliverability impact with the proposed revisions to the ISO Generation Deliverability Methodology, once they are finalized. In the interim, AltaGas has also asked the ISO to reevaluate the economic benefits of the proposed project.

Colorado River – Julian Hinds 230 kV Project Production benefits

The ISO conducted its production cost modeling for the five case described above.

In conducting the production costing the ISO identified that due to modeling interactions between the various affected areas containing renewable generation, the levels of local and system curtailment being experienced, and the algorithm used to select and price curtailed renewables, the economic benefits of the options were undervalued using the renewable curtailment multi-tier pricing model. To address this, sensitivities were also performed with a fixed curtailment price of negative $25 to screen those anomalies and provide a more accurate assessment of the benefits of the proposed configuration changes.

Table 4.9-11 shows the TEAM analysis results for this proposed project.

Table 4.9-11: Production Cost Modeling Results for Colorado River – Julian Hinds 230 Projects

	Pre project upgrade ($M)	Option 1		Option 2		Pre project upgrade ($M)	Option 3	
		Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)		Post project upgrade ($M)	Savings ($M)
ISO load payment	8564	8554	10	8554	11	8606	8614	-8
ISO generator net revenue benefitting ratepayers	2596	2598	2	2585	-11	2611	2612	1
ISO owned transmission revenue	213	210	-3	210	-3	210	213	3
ISO Net payment	5756	5746	9	5759	-3	5785	5789	-5
WECC Production cost	16908	16905	3	16904	4	16908	16909	-1

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Cost estimates:

The total cost estimate provided by AltaGas is $76 million for Option 2. The line termination upgrades at Colorado River 230 kV bus were estimated to be $25 million.

Benefit to Cost Ratio

In Table 4.9-12 the benefits are added and their present values are calculated based on a 40 year project life, and then benefit to cost ratios are calculated.

Table 4.9-12: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

	Option 1	Option 2	Option 3
Production Cost Modeling Benefits			
Ratepayer Benefits ($million/ year)	$9	-$3	-$8
Net Market Revenue ($million/ year)	$0	$0	$0
Total PCM Benefits ($million/ year)	$9	-$3	-$8
PV of Prod Cost Savings ($million)	$121.93	-$44	-$111
Capital Cost			
Capital Cost Estimate ($ million)	$25	$76	$76
Estimated "Total" Cost (screening) ($million)	$33	$99	$99
Benefit to Cost			
PV of Savings ($million)	$121.93	-$44	-$111
Estimated "Total" Cost (screening) ($million)	$32.50	$99	$99
Benefit to Cost	3.75	-0.45	-1.12

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Moving the termination of the Buck Blvd substation (the Blythe Energy Center) from Julian Hinds to the Colorado River substation and de-energizing the remainder of the existing Buck Blvd-Julian Hinds transmission line – without regulated cost of service cost recovery for the line - provides the most benefit to ISO ratepayers from both a gross benefit and benefit to cost ratio perspective. These benefits are predicated on the Blythe Energy Center remaining in service into the future.
- Creating a Colorado River-Julian Hinds 230 kV circuit was not supported by the production cost results, whether the generation was in service and connected to Colorado River or was out of service.

- These results will have to be reviewed once the ISO has finalized any changes to its parameters used in its deliverability methodology and assesses the deliverability impact of the proposed project taking the new deliverability methodology into account.

Local Capacity Reduction Study Areas

4.9.5 Pease Sub-area (Sierra)

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Pease 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 2018-2019 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Pease Sub-area is in Appendix G, section 3.2.3.4.

The project would consist of the following:

- Loop in the Pease – Marysville 60 kV line into East Marysville 115 kV substation and install a 115/60 kV transformer at East Marysville substation plus 25 Mvar voltage support.

The planning estimate cost for this alternatives is $26 to $32 million.

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation Production benefit

The looping in of the Pease-Marysville 60 kV line into East Marysville 115 kV substation is not expected to provide production benefits. The Pease Sub-area is a local load pocket with the LCR requirement being for N-1-1 contingencies that result in local area overloads without the generation being on-line.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Pease sub-area.

The looping in of the Pease-Marysville 60 kV line into the East Marysville 115 kV substation was modeled in the 2028 long-term local capacity requirement study case for the Pease sub-area, resulting in the following:

- The local capacity requirement for gas-fired generation in the Pease sub-area was eliminated resulting in a reduction of approximately 92 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 Pease Sub-area, these translated to values of $2,160/MW-year and $1,440/MW-year respectively. In addition within the Pease area, the 47.6 MW Yuba City Energy Center has been designated as a reliability must-run (RMR) generator at a cost of $3.714 million per year[109]. With this the difference between the RMR cost of $78,030

[109] Yuba City energy Center 2022 Annual Fixed revenue Requirement (AFRR) from FERC RMR Settlement: https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=14845682

MW-year compared to the system cost of $25,080 MW-year for a difference of $52,950 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 2018-2019 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.

In Table 4.9-13 the benefit of local capacity reductions in the Pease area is valued based on the cost range for the Fresno area. :

Table 4.9-13 : Pease LCR Sub-area Reduction Benefits

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation			
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	RMR Cost versus System Capacity
LCR reduction benefit (Pease Sub-area) (MW)	92		
Capacity value (per MW-year)	$2,160	$1,440	$52,950
LCR Reduction Benefit ($million)	$0.2	$0.1	$4.9

<u>Cost estimates:</u>

The current cost is about $26 million to $32 million for the suggested mitigation alternative. 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 $33.8 million to $41.6 million range.

<u>Benefit to Cost Ratio</u>

In Table 4.9-14 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

Table 4.9-14 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation			
Local Capacity Benefits			
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	RMR Cost
Net LCR Saving ($million/year)	$0.2	$0.1	$4.9
PV of LCR Savings ($million)	$2.74	$1.83	$67.23
Capitall Cost			
Capital Cost Estimate ($ million)	$32		
Estimated “Total” Cost (screening) ($million)	$42		
Benefit to Cost			
PV of Savings ($million)	$2.74	$1.83	$67.23
Estimated “Total” Cost (screening) ($million)	$41.60		
Benefit to Cost	0.07	0.04	1.62

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project, and the differential between current capacity costs for the reliability must-run generator in the area, and the system capacity costs increase the benefit to cost ratio to 1.62. .

Conclusions

The East Marysville 115/60 kV project is recommended for approval to economically reduce the local capacity requirement in the Pease sub-area.

4.9.6 Hanford Sub-area (Fresno)

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Hanford 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 2018-2019 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Pease Sub-area is in Appendix G, section 3.2.6.2.

Two alternatives were considered, consisting of the following:

- The reconductoring of the McCall-Kingsburg #1 115 kV line for an estimated cost of $9 million.
- The reconductoring of both the McCall-Kingsburg #1 and #2 115 kV lines for an estimated cost of $23.5 million.

Hanford alternative Production benefit

The two alternatives are to reconductor existing 115 kV lines to higher capacity and are not expected to provide production benefits. The Hanford Sub-area is a local load pocket with the LCR requirement being for N-1-1 contingencies that result in local area overloads without the generation being on-line.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Hanford sub-area.

The two alternatives were modeled in the 2028 long-term local capacity requirement study case for the Hanford sub-area, resulting in the following:

- The reconductoring of the McCall-Kingsburg #1 115 kV line reduced the Hanford Sub-area requirement by 39 MW from 125 MW to 86 MW. The estimated cost for this alternative is $9 million.
- The reconductoring of both the McCall-Kingsburg #1 and #2 115 kV lines eliminated the requirement in Hanford Sub-area. The estimated cost for this alternative is $23.5 million.

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 “north of path 26 system” resources. For the Hanford 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 2018-2019 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.

In Table 4.9-15 the benefit of local capacity reductions in the Hanford area is valued based on the cost range for the Fresno area.

Table 4.9-15 : Hanford LCR Sub-area Reduction Benefits

	Reconductor McCall-Kingsburg #1 115kV line		Reconductor McCall-Kingsburg #1 and #2 115kV lines	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Hanford Sub-area) (MW)	39		125	
Capacity value (per MW-year)	$2,160	$1,440	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.1	$0.1	$0.3	$0.2

Cost estimates:

The current cost estimates, based on other actual projects, is about $9 million for the Reconductor McCall-Kingsburg #1 115 kV line alternative and $23.5 million for the Reconductor McCall-Kingsburg #1 and #2 115 kV line alternative.

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 $12 million for the Reconductor McCall-Kingsburg #1 115kV line alternative and $30.55 million for the Reconductor McCall-Kingsburg #1 and #2 115kV line alternative.

Benefit to Cost Ratio

In Table 4.9-16 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

Table 4.9-16 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

	Reconductor McCall-Kingsburg #1 115kV line		Reconductor McCall-Kingsburg #1 and #2 115kV lines	
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.1	$0.1	$0.3	$0.2
PV of LCR Savings ($million)	$1.16	$0.78	$3.73	$2.48
Capital Cost				
Capital Cost Estimate ($ million)	$9		$24	
Estimated "Total" Cost (screening) ($million)	$12		$30.55	
Benefit to Cost				
PV of Savings ($million)	$1.16	$0.78	$3.73	$2.48
Estimated "Total" Cost (screening) ($million)	$11.70		$30.55	
Benefit to Cost	0.10	0.07	0.12	0.08

Conclusions

Based on the ISO's analysis, the identified benefits are not sufficient to support the alternatives studied in this planning cycle.

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 Hanford sub-area for system reasons is achieved.

4.9.7 Kern Oil Sub-area (Kern)

The ISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Kern Oil 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 2018-2019 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the Pease Sub-area is in Appendix G, section 3.5.7.4.

The project would consist of the following:

- Reconductor sections of line between Kern Oil and Kern Oil Junction and increase the scope of the Kern Power-Kern Oil Junction upgrades as a part of the previously approved Kern 115 kV Reinforcement project from rerating to reconductoring sections of the line.

The planning estimate cost for this alternatives is $15 million.

Kern Oil Sub-area Alternative Production benefit

The proposed project is not expected to provide production benefits. The Kern Oil Sub-area is a local load pocket with the LCR requirement being for N-1-1 contingencies that result in local area overloads without the generation being on-line.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Kern Oil sub-area.

Reconductoring of sections of line between Kern Oil and Kern Oil Junction and increasing the scope of the Kern Power-Kern Oil Junction project from rerating to reconductoring sections of the line was modeled in the 2028 long-term local capacity requirement study case for the Pease sub-area, resulting in the following:

- The local capacity requirement for gas-fired generation in the Kern sub-area was eliminated, resulting in a local capacity requirement reduction of approximately 21 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 Kern Oil 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 2018-2019 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.

In Table 4.9-17 the benefit of local capacity reductions in the Kern Oil sub-area is valued based on the cost range for the Kern area.

Table 4.9-17 : Kern Oil LCR Sub-area Reduction Benefits

Reconductor sections of line between Kern Oil and Kern oil Junction and increase the scope of the Kern Power-Kern Oil Junction from rerate to reconductor		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit Kern Oil Sub-area) (MW)	21	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.05	$0.03

Cost estimates:

The current cost is about $15 million for the suggested mitigation alternative. 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 $19.5 million range.

Benefit to Cost Ratio

In Table 4.9-18 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

Table 4.9-18 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Reconductor sections of line between Kern Oil and Kern oil Junction and increase the scope of the Kern Power-Kern Oil Junction from rerate to reconductor		
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.05	$0.03
PV of LCR Savings ($million)	$0.63	$0.42
Capital Cost		
Capital Cost Estimate ($ million)	$15	
Estimated "Total" Cost (screening) ($million)	$20	
Benefit to Cost		
PV of Savings ($million)	$0.63	$0.42
Estimated "Total" Cost (screening) ($million)	$19.50	
Benefit to Cost	0.03	0.02

Conclusions

The cost estimate range for this project is material, and, as discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources. 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 Eastern sub-area for system reasons is achieved.

4.9.8 Big Creek/Ventura Area – Santa Clara Sub-area

In the Big Creek/Ventura area, gas-fired local capacity is declining significantly. Mandalay (560 MW) was retired in 2018 and Ormond Beach (1500 MW) is scheduled to retire at the end of 2020. Ellwood (54 MW) is also expected 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. Procurement of preferred resources and storage is underway in the Santa Clara sub-area to meet the remaining local capacity need.

Assessment of gas-fired generation requirement

Table 4.9-19 provides an assessment of expected gas-fired generation requirement in the Big Creek/Ventura area based on the results of the 2028 local capacity study that is included as Appendix G.

Table 4.9-19: Assessment of Gas-fired Generation Requirement in the Big Creek/Ventura Area

Sub-Area	2028 LCR	Available Resource Capacity	Existing Gas-fired Generation Capacity	Gas-fired Generation Local Capacity Requirement	
	(MW)	(MW, NQC)	(MW, NQC)	MW	Percent of Existing Gas-fired Capacity
Rector	N/A	1,028	0	0	0%
Vestal	465	1,205	54	0	0%
Goleta	42+	>7 (+RFP)	0	0	0%
Santa Clara	318	>199 (+RFP)	184	184	100%
Moorpark	0	>223 (+RFP)	184	0	0%
Overall Big Creek Ventura	2251	>3505 (+RFP)	1696	<442	<26%

Notes:

Available capacity includes existing and already procured preferred resources and storage but does not include resources being procured under the current Santa Clara area RFP

2028 resource capacity values exclude Ormond Beach and Ellwood

Selection of area and sub-areas for this economic study

Based on the above assessment, 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 transmission project.

The Santa Clara sub-area was selected for this further assessment because all of the gas-fired generation in the area will be otherwise needed.

In the greater Big Creek-Ventura area itself, less than 442 MW of 1669 MW (or <26%) of existing gas-fired generation will be needed for local RA. The ongoing Santa Clara sub-area RFP is expected to lower the number to the 278-320 MW range (or 17%-19%). As such, the area was not selected for assessment in the current planning cycle.

Transmission alternative to lower gas-fired LCR in the Santa Clara sub-area

Table 4.9-20 summarizes the results of the 2028 local capacity study for the Santa Clara area. The local capacity requirement can vary depending on the location and reactive power capability provided to the transmission system by the new resource or resources that are being procured to fill the need.

Table 4.9-20: Santa Clara Sub-area 2028 LCR Study Results

Critical Contingency	Limiting Facility/Condition	LCR (MW)
Pardee–Santa Clara 230 kV line followed by Moorpark–Santa Clara #1 and #2 230 kV DCTL	Voltage Collapse	318[(1)(2)]

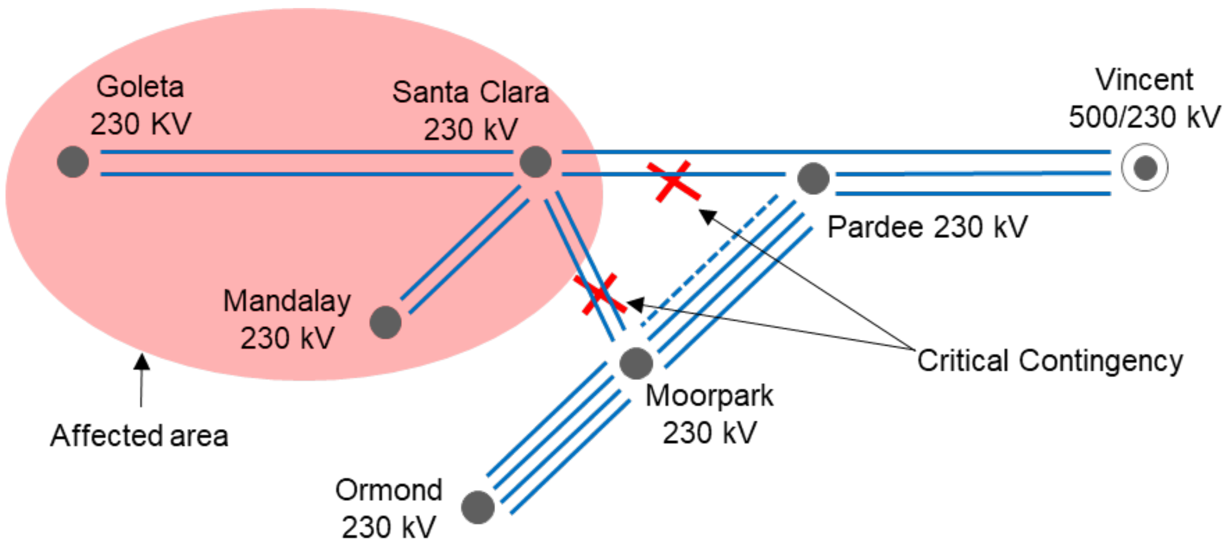
Note:

(1) 120 MW of generic resources with reactive capability were assumed at Goleta to meet the local capacity deficiency. For locational and reactive power effectiveness information, see http://www.caiso.com/Documents/2023LocalCapacityTechnicalAnalysisfortheSantaClaraSub-Area.pdf

(2) The LCR is sufficient to mitigate voltage collapse but it is not sufficient to mitigate overloading of the remaining line (Overload - 126%).

Figure 4.9-11 provides an overview of the transmission system in the Santa Clara and identifies the critical contingency and the affected area.

Figure 4.9-11: Santa Clara Sub-area Transmission System



The following transmission upgrades were identified as a potential alternative to allow lower gas-fired generation requirements in the Santa Clara sub-area:

- Add reactive power device in the area; and
- Increase the rating of the four import lines into the area

Conclusions

The amount of potential reduction in gas-fired local capacity requirement resulting from the transmission upgrades, and the associated economic benefits, depend on the location and characteristics of the preferred resources that will be procured under the ongoing LCR RFP. SCE's target date for CPUC application filing for the LCR RFP is March 2019 with a CPUC decision anticipated later in the year. The technical and economic assessment of the transmission upgrades will be completed, likely in the 2019-2020 planning cycle, once the procurement process has been completed, in the 2019-2020 planning cycle.

4.9.9 Eastern Sub-area (LA Basin)

The Eastern sub-area in the LA Basin was selected for detailed study, as noted in section 4.8.7. One option was proposed by stakeholders to reduce local capacity requirements, and the ISO developed an additional option. These are set out below.

4.9.9.1 Mira Loma Dynamic Reactive Support

The ISO examined a potential transmission option for reducing gas-fired generation requirements in the Eastern LA Basin 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 2018-2019 planning cycle. This option was developed by the ISO.

The project would consist of the following:

- Install approximately 225 Mvar of dynamic reactive support (i.e., synchronous condenser) at Mira Loma Substation. The optimal location would be evaluated further if there is further consideration for this option.

The planning estimate for installing the 225 Mvar synchronous condenser is approximately $30 to $80 million.

<u>Mira Loma Dynamic Reactive Support Production benefit</u>

Installing dynamic reactive support at Mira Loma Substation is not expected to provide production benefits as the contingency driving the local capacity requirements is an "N-1, followed by N-2" contingency established in the ISO tariff's local capacity requirements reliability criteria. This contingency is an extreme event as defined in NERC standards, and the constraint would be expected to have minimal impact on production cost modeling.

<u>Local Capacity Benefits:</u>

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the Eastern LA Basin LCR sub-area.

The 225 Mvar dynamic reactive support at Mira Loma Substation was modeled in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area, resulting in the following:

- The local capacity requirement for gas-fired generation in the San Diego – Imperial Valley area was reduced by approximately 350 MW. The limiting contingency was the overlapping N-1 of the Serrano – Valley 500 kV line, system readjusted, followed by an N-2 of the Devers – Red Bluff 500 kV lines, causing the potential post-transient voltage instability for the Eastern LA Basin sub-area.
- Since local capacity was reduced in the Eastern LA Basin sub-area with the dynamic reactive support modeled, the ISO evaluated potential local capacity impacts to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, then followed by an N-1 contingency for the Mesa – Lighthipe 230 kV line. The limiting transmission, the Mesa – Laguna Bell 230 kV line #1, remained within its emergency rating. Therefore, there was no local capacity impact to the Western LA Basin sub-area.

The Mira Loma dynamic reactive support could potentially reduce local capacity need in the Eastern LA Basin sub-area by about 350 MW[110]. There would be no other local capacity impact due to this local capacity reduction in the Eastern LA Basin sub-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 LA Basin, these translated to values of $16,680/MW-year and $22,680/MW-year respectively. This differential methodology is

[110] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

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 2018-2019 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.

In Table 4.9-21 the benefit of local capacity reductions in the Eastern LA Basin area is valued based on the cost range for the LA Basin:

Table 4.9-21: LCR Reduction Benefits for Mira Loma Dynamic Reactive Support

Mira Loma Dynamic Reactive Support		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Eastern LA Basin) (MW)	350	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.8	$7.9
LCR increase (Western LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$5.8	$7.9

Cost estimates:

The current cost, based on other actual projects, is about $30 million to $80 million for the suggested mitigation option. 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 $39 million to $104 million range.

Benefit to Cost Ratio

In Table 4.9-22 the present value of the capacity benefits above are calculated based on a 50 year project life, and then benefit to cost ratios were calculated for the range of the cost estimates.

Table 4.9-22: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Mira Loma Dynamic Reactive Support		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$5.8	$7.9
PV of LCR Savings ($million)	$80.57	$109.55
Capital Cost		
Capital Cost Estimate ($ million)	$80	
Estimated “Total” Cost (screening) ($million)	$104	
Benefit to Cost		
PV of Savings ($million)	$80.57	$109.55
Estimated “Total” Cost (screening) ($million)	$104.00	
Benefit to Cost	0.77	1.05

The cost estimate range for this project is material, and, as discussed earlier, the ISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources. 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 Eastern sub-area for system reasons is achieved.

4.9.9.2 Red Bluff – Mira Loma 500 kV Transmission Project congestion and capacity benefits

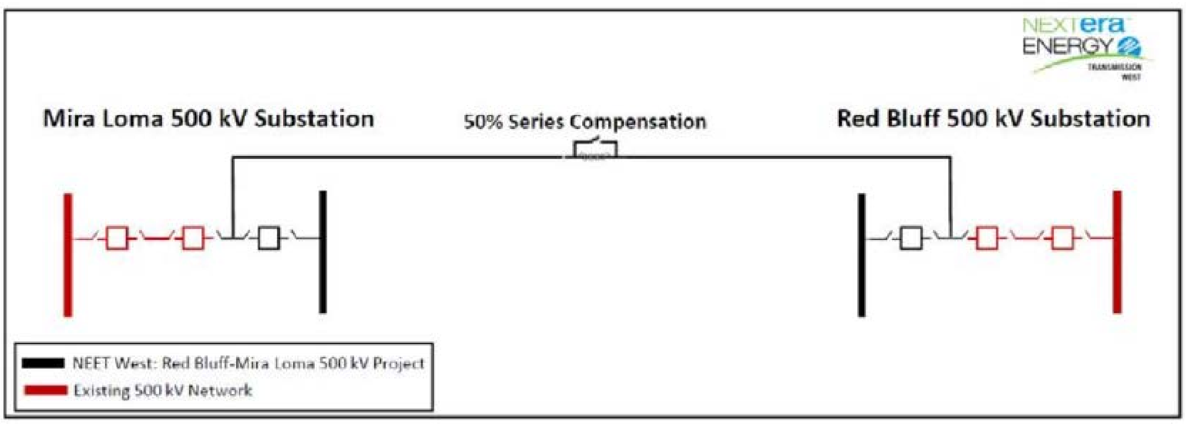
The Red Bluff – Mira Loma 500 kV Transmission Project was submitted by NextEra Energy Transmission West LLC (NEET West) as an economic study request and into the 2018 Request Window as a potential reliability project as noted in section 4.8. As set out in chapter 2, the ISO did not identify a reliability need for this project. The ISO subsequently examined the project for economic benefits.

The project proposal consists of:

- A new 500-kV transmission line (~139 mile) between the Red Bluff substation and the Mira Loma substation with 50% compensation, with line ratings of 3,421 MVA normal and 3,880 MVA emergency.
- Installation of 50% series compensation with the optimal location in the line yet to be determined from more detailed studies. The line series compensation would have a normal rating of 3,291 MVA and an emergency rating of 3,949 MVA.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-12: Red Bluff – Mira Loma 500 kV Transmission Project Configuration



The project's estimated capital cost is $850 million. A preliminary target date of Q4 2024 has been established, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

NEET West stated that the proposed project would address the Desert Area Constraint for interconnecting new renewable generation development, further renewable generation interconnection in the CPUC 42 MMT scenario, and lastly the LCR reduction benefit for the Eastern LA Basin sub-area.

Red Bluff – Mira Loma 500 kV Project Production benefit

Table 4.9-23 shows the TEAM analysis results for this proposed project.

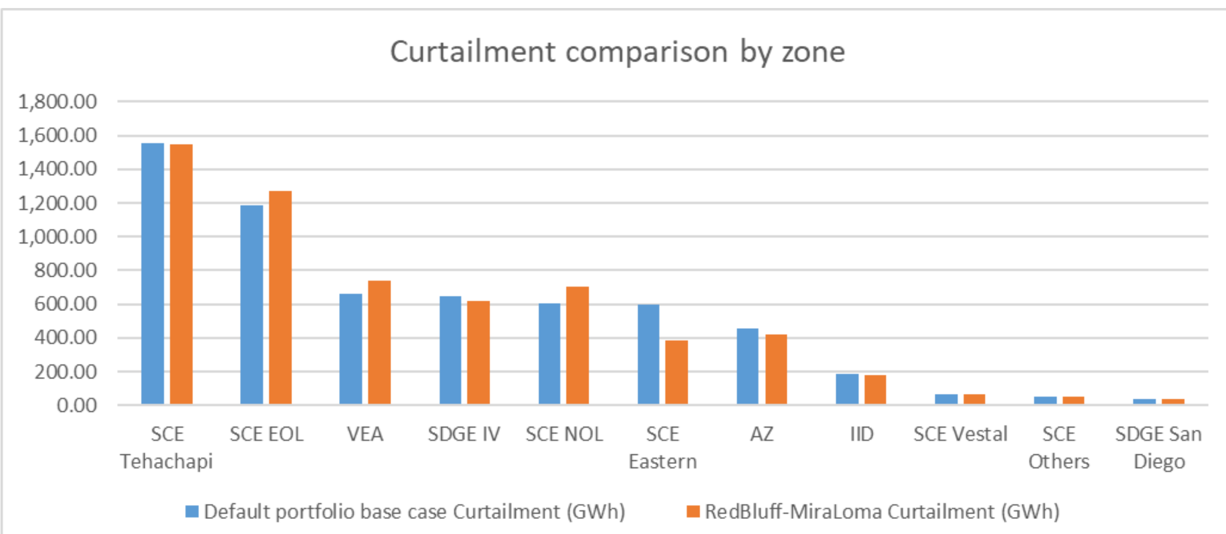
Table 4.9-23: Production Cost Modeling Results for Red Bluff - Mira Loma 500 kV Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8442	15
ISO generator net revenue benefitting ratepayers	2526	2525	0
ISO owned transmission revenue	199	206	8
ISO Net payment	5733	5710	23
WECC Production cost	16875	16866	9

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Production cost simulation results show that this project can reduce renewable curtailment in SCE's Eastern area (Riverside East, including Red Bluff and Colorado River substations). However, curtailment in other areas in Southern California, such as SCE's North of Lugo and East of Lugo areas and VEA area, may increase due to increased congestion on Path 26, Path 61 (Lugo to Victorville), and Bob SS-Mead. Figure 4.9-13 shows the changes of curtailment by zone.

Figure 4.9-13: Curtailment changes by zone with Red Bluff - Mira Loma Project modeled



Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the Eastern LA Basin LCR sub-area.

Modeling the proposed project in the 2028 long-term local capacity requirement study case for the Eastern LA Basin sub-area study resulted in the following:

- The Eastern LA Basin sub-area is subject to post-transient voltage instability due to the overlapping N-1 of Serrano – Valley 500 kV line, system readjusted, followed by an N-2 contingency of the Devers – Red Bluff 500 kV line. The amount of gas-fired generation local capacity requirement reduction in the Eastern LA Basin sub-area was found to be approximately 91 MW. The proposed project does not provide significant transmission improvement for this overlapping contingency because it is connected outside of the impacted area.
- Since the gas-fired generation could be reduced in the Eastern sub-area, the Western LA Basin sub-area local capacity needed to be checked to determine if there would be an adverse impact to its LCR need.
- The power flow study was first restored to normal condition. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line was then studied. This N-1-1 contingency caused an overloading concern on the Mesa-Laguna Bell 230 kV line. An additional 30 MW of local capacity south of Laguna Bell substation (Western LA Basin sub-area) was necessary to mitigate the loading concern.

The proposed project potentially could reduce local capacity requirement in the Eastern LA Basin sub-area by about 91 MW[111], and it was also identified that the Western LA Basin sub-area local capacity requirement would be adversely impacted and would need an additional 30 MW to mitigate the identified impact. The net local capacity benefits for the Eastern LA Basin sub-area are the difference between the local capacity cost increase in the Western LA Basin sub-area and the local capacity cost reduction in the Eastern LA Basin sub-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 LA Basin, 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 2018-2019 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.

[111] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

In Table 4.9-24 the benefit of local capacity reductions in the Eastern LA Basin sub-area and the Western LA Basin area are both valued based on the cost range for the LA Basin.

Table 4.9-24: LCR Reduction Benefits for the Mira Loma - Red Bluff Transmission Project

Mira Loma - Red Bluff 500 kV Line		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Eastern LA Basin) (MW)	91	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$1.5	$2.1
LCR increase (Western LA Basin) (MW)	30	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.5	$0.7
Net LCR Saving ($million/year)	$1.0	$1.4

Cost estimates:

The current cost estimate from NEET West is $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", the $850 million capital translates to a total cost of $1.233 billion.

Benefit to Cost Ratio

In Table 4.9-25, the present value of the sum of the production cost and capacity benefits above are calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-25: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Red Bluff – Mira Loma 500 kV Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$23	
ML-RB Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$23	
PV of Prod Cost Savings ($million)	$317.42	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$1.0	$1.4
PV of LCR Savings ($million)	$14.04	$19.09
Capital Cost		
Capital Cost Estimate ($ million)	$850	
Estimated “Total” Cost (screening) ($million)	$1,105	
Benefit to Cost		
PV of Savings ($million)	$331.46	$336.51
Estimated “Total” Cost (screening) ($million)	$1,105.00	
Benefit to Cost	0.30	0.30

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, the benefit to cost ratio was not sufficient for the ISO to find the need for this project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the LA Basin area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits assessed here - is best addressed within the IRP process.

4.9.10 Western Sub-area (LA Basin)

As discussed in section 4.8.7, the Western LA Basin sub-area was not selected for detailed analysis of alternatives for reducing gas-fired generation local capacity requirements in this cycle. However, proposals submitted for other reasons pointed in part to such reductions in this sub-area as part of those proposals' economic benefits, such as the Diablo Canyon to Ormond Beach and Redondo Beach "California Transmission Project" discussed in section 0 and section 4.9.3.2. Please refer to those sections for a discussion of the potential benefits.

The Southern California Regional LCR Reduction Project was initially studied by the ISO for other reasons, as set out in section 4.8.8, but was found to only have local capacity benefits for the Western LA Basin sub-area, and the results are therefore set out below.

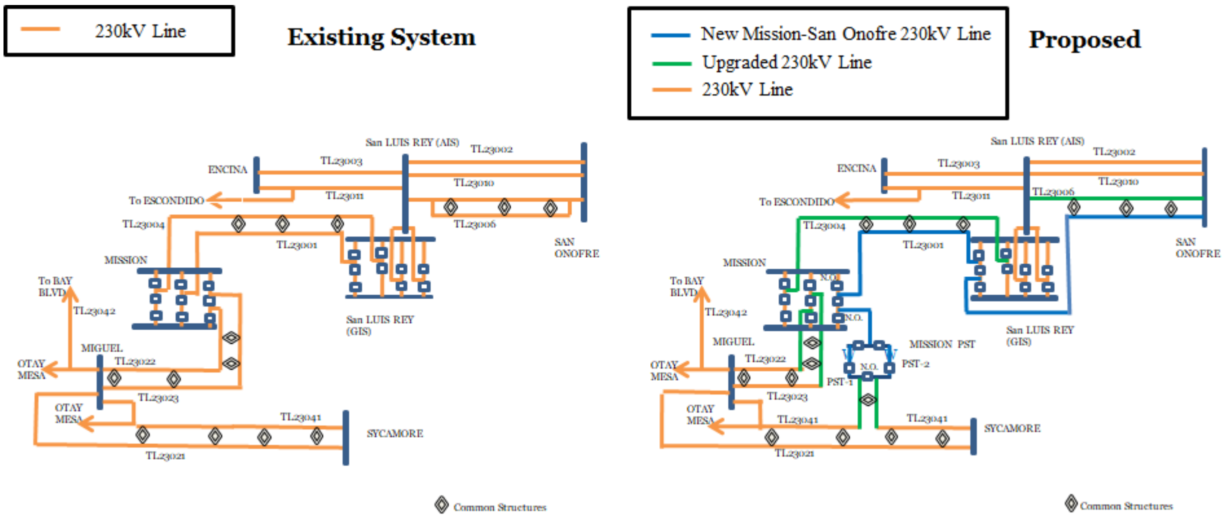
4.9.10.1 Southern California Regional LCR Reduction Project congestion and capacity benefits

The ISO examined the Southern California Regional LCR Reduction Project submitted by SDG&E in the 2018 Request Window, as set out in section 4.8.8. The project would consist of the following:

- Construct a new 230 kV line (2-1033ACSR), Mission-San Luis Rey- San Onofre, by utilizing the existing 230 kV facilities.
- Convert half of the existing 138kV switchyard (Bay 5 to Bay 9) to a 230 kV Phase Shifter Station at Mission Substation (2–600MW PSTs).
- Upgrade TL23004 (Mission-San Luis Rey), TL23006 (San Onofre-San Luis Rey), TL23022 (Miguel-Mission), and TL23023 (Miguel – Mission) with bundled 1033ACSR.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-14: Southern California Regional LCR Reduction Project Configuration



The project's estimated capital cost is between $100 million to $200 million. A preliminary target date of 2023 was estimated, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The upgrades were proposed by SDG&E as a Reliability Transmission Project. SDG&E stated that the proposed project would:

- Mitigate congestion for high San Onofre north bound flow for the P1 reliability violation of the San Luis Rey – Encina 230 kV line and San Luis Rey – Encina – Escondido 230 kV line
- Reduce regional capacity requirements (LCR) of 315 MW generation capacity necessary in 2023 for reliable operation in Orange County area. Increase the ability to deliver both in-state and out-of-state renewable resources into the load centers.
- Increase the transmission capacity, system reliability and operation flexibility in San Diego area.

Southern California Region LCR Reduction Project Production benefit

Table 4.9-26 shows the TEAM analysis results for this proposed project.

Table 4.9-26: Production Cost Modeling Results for Southern California Region LCR Reduction Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8465	-8
ISO generator net revenue benefitting ratepayers	2526	2525	-1
ISO owned transmission revenue	199	201	2
ISO Net payment	5733	5740	-7
WECC Production cost	16875	16878	-3

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

With this project modeled, it was observed that both thermal and renewable generation in the San Diego and Imperial Valley areas increased, because this project did help to reduce some transmission congestions in these areas. However, thermal and renewable generation in the SCE area decreased correspondingly, which resulted an increase in Path 26 congestion in South to North direction. Figure 4.9-15 and Figure 4.9-16 show the generation changes and the congestion changes with this project modeled.

Figure 4.9-15: Generation changes with S. Cal LCR Reduction Project modeled

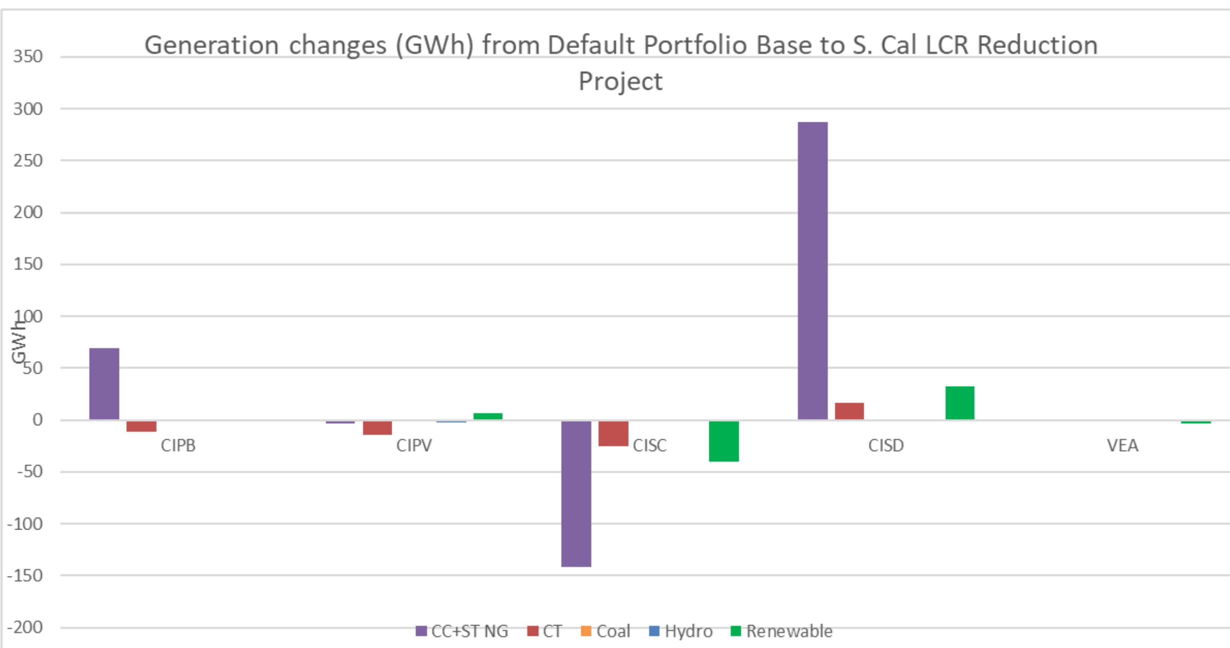
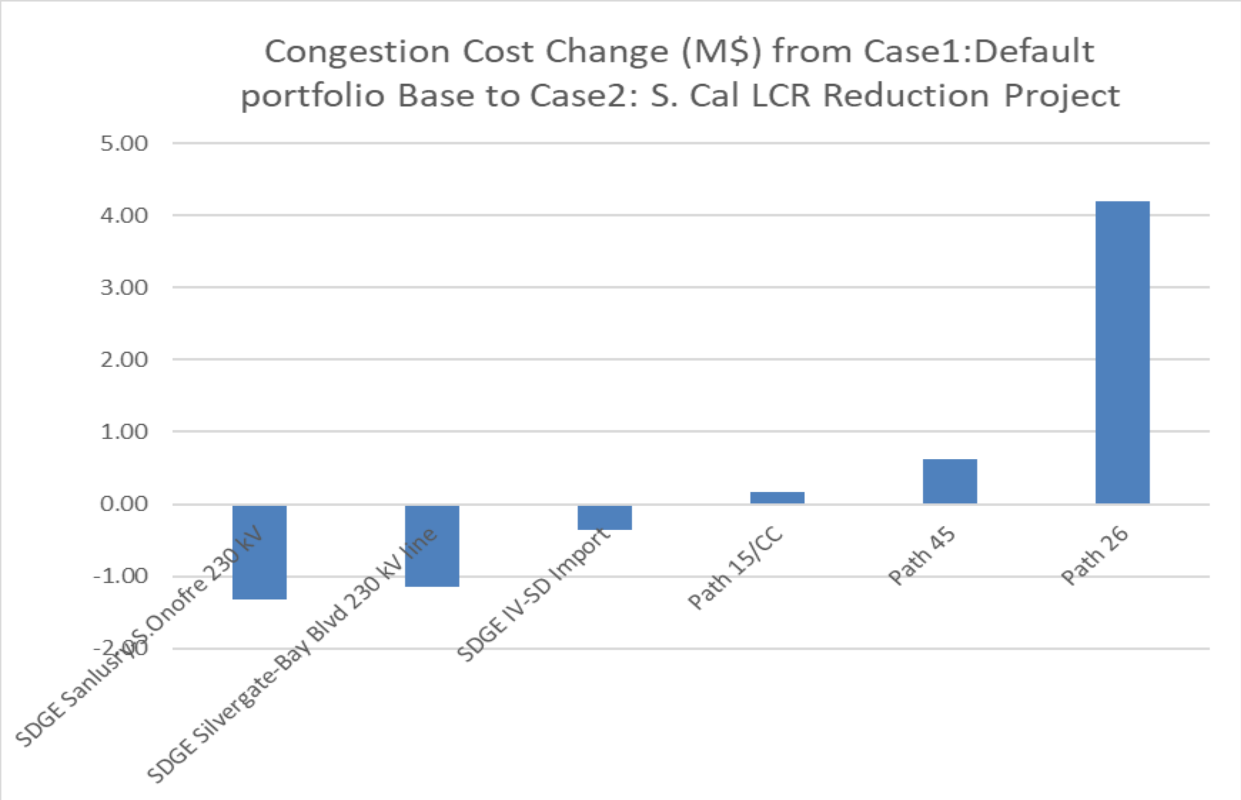


Figure 4.9-16: Congestion changes with S. Cal LCR Reduction Project modeled



Local Capacity Benefits:

The ISO evaluated the project to determine whether it can help reduce the local capacity requirement in the Western LA Basin[112] sub-area. Modeling the proposed project to the 2028 LCR study case to evaluate for the Western LA Basin sub-area resulted in the following:

- The proposed Mission phase shifters were used in the study to send power to the Western LA Basin sub-area to help reduce local capacity need. The phase shifters were utilized to have a total of 850 MW northbound flow. The 850 MW flow is the limit to avoid overloading the Mission – San Luis Rey 230 kV line overloading concern.
- The Western LA Basin sub-area local capacity generation can be reduced by approximately 83 MW before the Mesa – Laguna Bell 230 kV line is overloaded under an overlapping outage of an N-1 of Mesa – Redondo 230 kV line, system adjustment then followed by an N-1 Mesa – Lighthipe 230 kV line.

[112] Note that the Western LA Basin sub-area has been evaluated due to actual and planned OTC generation retirements in the last several transmission planning cycles. Because of the previous extensive evaluation and implementation for OTC generation and San Onofre Nuclear Generating Station retirements, the ISO did not select this sub-area for study in this planning cycle as discussed in section 4.8.7.

- The proposed project potentially could reduce local capacity requirements for gas-fired generation in the Western LA Basin sub-area by about 83 MW.
- The ISO also checked for the potential impact to the San Diego – Imperial Valley local capacity need under an overlapping G-1 of TDM generation, followed by an N-1 of Imperial Valley – North Gila 500 kV line, or vice versa. It was determined that a southbound flow schedule of 40 MW on the Mission phase shifters would be sufficient to mitigate the potential overloading concern on the El Centro 230/92 kV transformer. Therefore, there is no impact to the local capacity requirement for 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 LA Basin, 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 2018-2019 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.

In Table 4.9-27, the benefit of local capacity reductions in the Western LA Basin sub-area are valued based on the cost range for the LA Basin.

Table 4.9-27: LCR Reduction Benefits for Southern California Region LCR Reduction Project

Southern California Region LCR Reduction Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Western LA Basin) (MW)	83	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$1.4	$1.9
LCR increase (San Diego – IV) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$1.4	$1.9

Cost estimates

The current cost estimates from SDG&E range from $100 million to $200 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", the $100 million to $200 million capital translates to a total cost of $145 million to $290 million.

Benefit to Cost Ratio

In Table 4.9-28 the present value of the sum of the production cost and capacity benefits above are calculated based on a 40 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-28 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Southern California Region LCR Reduction Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$7	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	-$7	
PV of Prod Cost Savings ($million)	-$96	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$1.4	$1.9
PV of LCR Savings ($million)	$18.5	$25.1
Capital Cost		
Capital Cost Estimate ($ million)	$200	
Estimated "Total" Cost (screening) ($million)	$260	
Benefit to Cost		
PV of Savings ($million)	-$77.2	-$70.6
Estimated "Total" Cost (screening) ($million)	$260.00	
Benefit to Cost	-0.30	-0.27

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, the benefit to cost ratio was not sufficient for the ISO to find the need for this project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the LA Basin area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits assessed here - is best addressed within the IRP process.
- As this sub-area had not been selected for detailed analysis of alternatives, other potentially viable alternatives have not been developed and considered as alternatives. The ISO expects to complete detailed analysis of the remaining sub-areas that are dependent on gas-fired generation for meeting local capacity requirements in the next transmission planning cycle.

4.9.11 San Diego/Imperial Valley Area (studied in concert with LA Basin) and San Diego Sub-area

Numerous stakeholder proposals were received as alternatives for reducing local capacity requirements in the San Diego/Imperial Valley area, as well as the San Diego sub-area. As noted in section 4.9, because the San Diego sub-area is within the San Diego-Imperial Valley LCR area, the total LCR reduction benefits (or impacts) were evaluated at the overall LCR level for the San Diego-Imperial Valley area. This was to ensure that the overall area impact (or benefits) were captured in the study.

4.9.11.1 S-Line Series Reactor

The ISO developed a series reactor alternative for reducing gas-fired generation in the overall San Diego-Imperial Valley LCR area and examined its benefits. The benefits are incremental to the benefits of upgrading the S-Line itself, which was approved by the ISO in the 2017-2018 transmission planning cycle. The originally approved S-line configuration being coordinated with the Imperial Irrigation District was a double-circuit 230 transmission line; the ISO studied the potential benefits of a series reactor on both that configuration and a single-circuit configuration, recognizing that the transmission line design and siting activities are in progress.

The project would consist of the following:

- Install an equivalent of 25-Ω line series reactor on the upgraded S-line (or 2x50-Ω if there are 2 lines in parallel); and
- Utilize the existing RAS and Imperial Valley phase shifters for mitigating the Sycamore Canyon – Suncrest 230 kV line in the San Diego bulk transmission sub-area.

The transmission option of installing a 230 kV line series reactor is estimated to cost about $30 million. This estimate is based on an actual transmission project that included installation of a 50-Ω line series reactor on the Wilson-Warnerville 230 kV line in PG&E’s service area.

S-Line Series Reactor Production benefit

Production cost benefits for this project were not explored, as the project focuses on reducing local capacity requirements and the production benefits are not expected to be material to a decision given the level of potential LCR reduction benefits and the forecast cost of the project.

Local Capacity Benefits:

The primary benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the line series reactors on the S-line in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The gas-fired local capacity resource requirement for the San Diego – Imperial Valley area would be reduced by approximately 600 MW. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer. The result may still be subject to change pending the final design of the S-line upgrade or changes to the study assumptions regarding future generation retirements, new resource interconnection or changes in future load forecast from the CEC.

- Because local capacity requirements would be reduced in the San Diego-Imperial Valley area with the project in service, the ISO evaluated for potential local capacity impacts to the Western LA Basin sub-area as the LA Basin and San Diego-Imperial Valley areas are electrically dependent since the retirement of SONGS. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, then followed by an N-1 contingency for the Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 was found to be overloaded and an additional 200 MW of local capacity south of Laguna Bell Substation would be required to mitigate its overloading concern.

The S-line series reactors could potentially reduce local capacity need in the San Diego-Imperial Valley by about 600 MW[113], but it was also identified that the LA Basin area local capacity need is adversely impacted by about 200 MW. The net local capacity benefits for the San Diego-Imperial Valley area would need to have the benefits for the San Diego-Imperial Valley area subtracting the local capacity impacts in the Western LA Basin sub-area.

As discussed in section 4.3.4, local capacity requirement reductions in southern California area 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 San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, 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 2018-2019 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.

In Table 4.9-29 the benefit of local capacity reductions in the San Diego-Imperial Valley area is valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

[113] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-29: LCR Reduction Benefits for the S-Line Series Reactor Project

S-Line Series Reactor Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	600	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$7.8	$11.4
LCR increase (Western LA Basin) (MW)	200	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$3.3	$4.5
Net LCR Saving ($million/year)	$4.5	$6.9

Cost estimates:

The current cost estimate, based on an actual project, is about $30 million for the suggested mitigation option. 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.

Benefit to Cost Ratio

In Table 4.9-30, the present value of the benefits is calculated based on a 40 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-30: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

S-Line Series Reactor Project		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$4.5	$6.9
PV of LCR Savings ($million)	$60.15	$92.15
Capital Cost		
Capital Cost Estimate ($ million)	$30	
Estimated “Total” Cost (screening) ($million)	$39	
Benefit to Cost		
PV of Savings ($million)	$60.15	$92.15
Estimated “Total” Cost (screening) ($million)	$39.00	
Benefit to Cost	1.54	2.36

Conclusions

The benefit to cost ratio of this project is encouraging notwithstanding the conservative value assigned to local capacity requirement reductions. The project will be considered in future planning cycles, once the design and configuration of the IID-owned S-Line upgrade is finalized.

Project development activities with IID have continued during the development of the transmission plan and after the above analysis was completed. The ISO is pursuing revisions to the scope of the previously approved S-Line Transmission Upgrade to consist of an appropriately sized single circuit 230 kV circuit, which provides the same local capacity requirement reduction value to the ISO as the original double-circuit line. As well, the ISO is updating the estimated cost to ISO ratepayers of the S-Line upgrade from $32 million to $40 million in light of revised costs estimates provided by IID. This increase in estimated cost would be offset by the savings of no longer needing a new line termination at the Imperial Valley Substation, which was required under the original double circuit configuration.

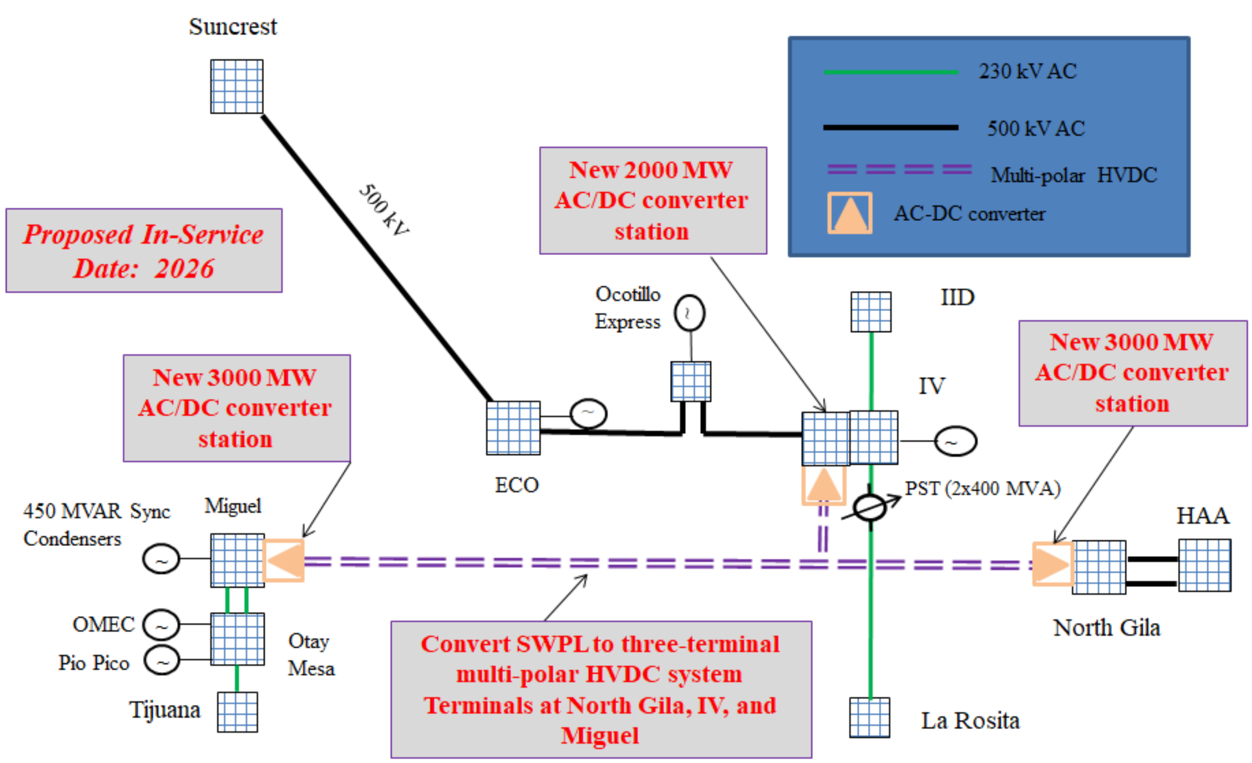
4.9.11.2 HVDC Conversion Project

The ISO examined the HVDC Conversion Project which was submitted by SDG&E as an interregional transmission project in the 2018-2019 transmission planning cycle, and had been previously submitted into the 2017-2018 transmission planning process Request Window as the “Renewable Energy Express”. The project would consist of the following:

- Convert a portion of the 500 kV Southwest Powerlink (SWPL) to a three-terminal HVDC system with two fully independent poles.
- Install terminals at or adjacent to North Gila, Imperial Valley, and Miguel Substations. Each pole will be capable of fully independent operation at its maximum rated capacity.
- The proposed capacity of the proposed HVDC system is 2x1500 MW, bi-directional, for a total transfer capacity of 3000 MW.
- Replace existing loop-in of Southwest Powerlink at ECO with Sunrise Powerlink to replace AC connectivity.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-17: HVDC Conversion Project Configuration



The project’s estimated capital cost is $700 to $900 million. SDG&E proposed a preliminary target date of 2026, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The upgrades were proposed by SDG&E as an interregional transmission project without requesting cost allocation between planning regions. SDG&E stated that the proposed project would provide significant regional and interregional benefits such as solving loop flow issues, increasing transfer capabilities to SDG&E and Southern California, aiding the integration of new transmission and generation projects, reducing Local Capacity Requirements (LCR) and Resource Adequacy (RA) requirements, and increasing the ability to deliver renewable resources (wind, solar, and geothermal) into the Southern California load centers.

As set out in chapter 2, 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 as a reliability-driven project. The ISO subsequently examined the project for further economic benefits.

HVDC Conversion Project's Production benefit

Table 4.9-31 shows the TEAM analysis results for this proposed project.

Table 4.9-31: TEAM analysis for HVDC Conversion Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8,464	-7
ISO generator net revenue benefitting ratepayers	2526	2,515	-11
ISO owned transmission revenue	199	204	5
ISO Net payment	5733	5,746	-13
WECC Production cost	16875	16903	-28

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

It was observed in the simulation results that modeling the HVDC Conversion project increased congestion along the IV to San Diego corridor, mainly on the Suncrest to Sycamore corridor, and on Path 26, although SDG&E Bay Blvd-Silvergate and San Luis Rey to S. Onofre congestions were reduced, as shown in Figure 4.9-18. Renewable curtailment was reduced in the IV area, but increased in most of the other areas in Southern California, as shown in Figure 4.9-19.

Figure 4.9-18: Congestion changes with modeling HVDC Conversion Project

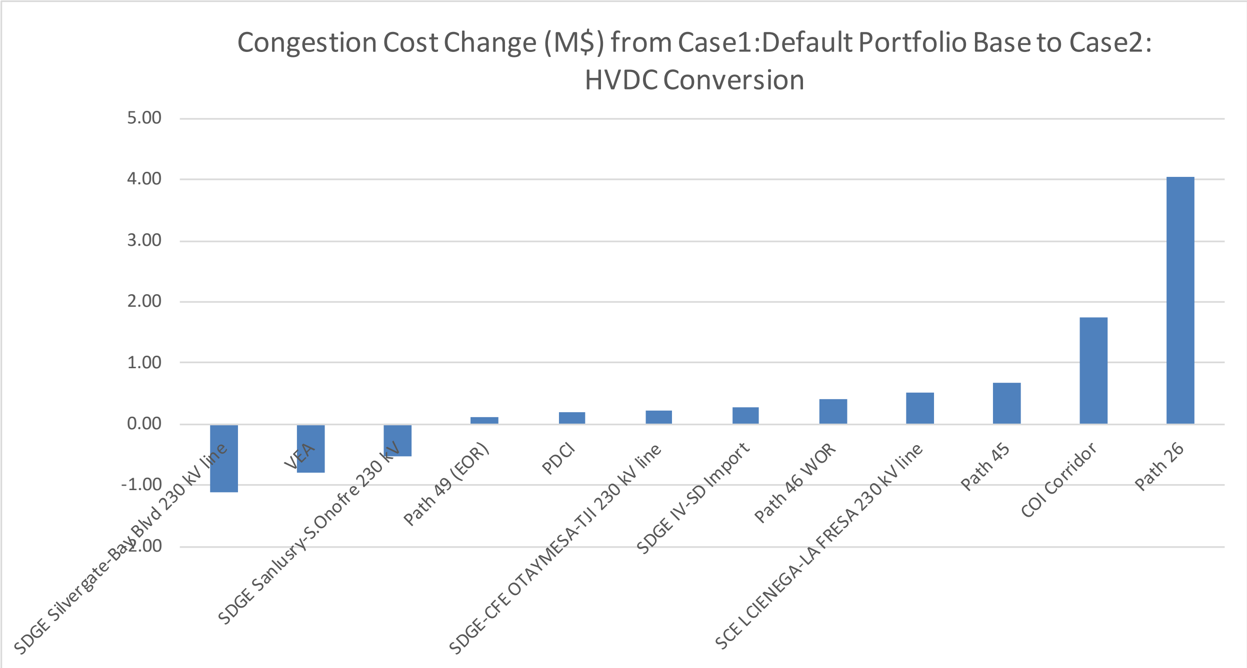
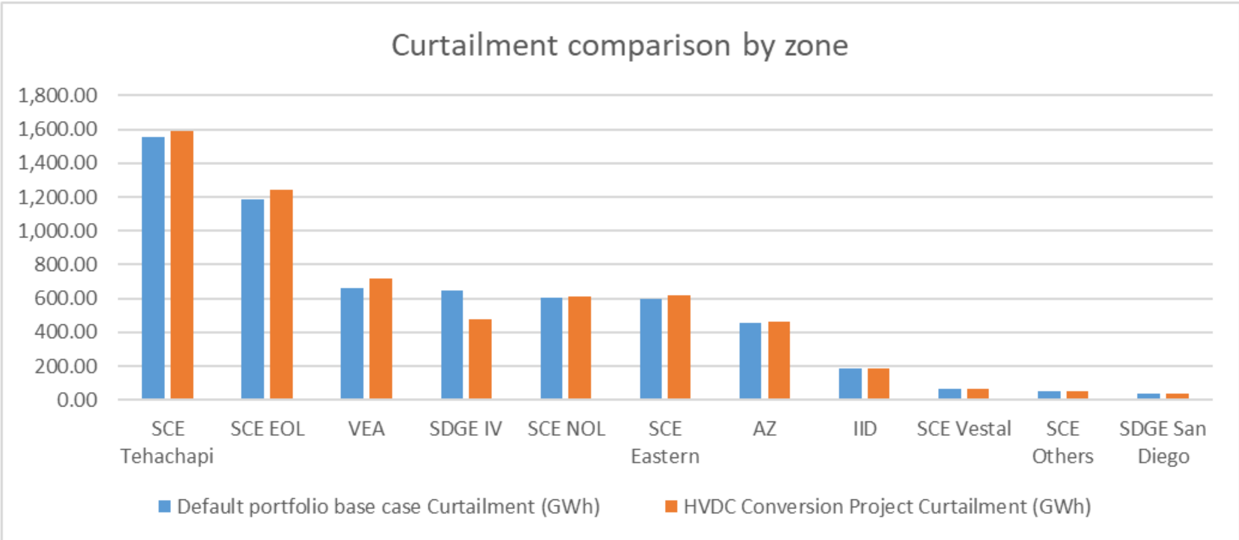


Figure 4.9-19: Curtailment changes by zone with modeling HVDC Conversion Project



Local Capacity Benefits:

Modeling the HVDC Conversion Project in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- With the HVDC flow at 1650 MW, the Bay Blvd. – Silvergate 230 kV line was at its emergency rating under an N-2 contingency of Miguel-Mission 230 kV line, and the amount of gas-fired generation requirement reduction in the San Diego-Imperial Valley area was approximately 690 MW. Since the Bay Blvd. – Silvergate 230 kV line has only a two-hour duration for its emergency rating, the HVDC flow would need to be reduced further to 986 MW to reduce the Bay Blvd. – Silvergate 230 kV line flow to within its continuous rating, post-contingency.
- Since the gas-fired generation requirement could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needed to be checked to determine if there was an adverse impact to its LCR need. With the power flow model restored to normal condition, and with the HVDC at 1650 MW flow, an N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line caused an overloading concern on the Mesa-Laguna Bell 230 kV line. An additional 40 MW of local capacity south of Laguna Bell substation was needed to mitigate the loading concern.

The HVDC Conversion project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 690 MW[114], but it was also identified that the LA Basin area local capacity need would be adversely impacted by about 40 MW. The net local capacity benefits for the San Diego-Imperial Valley area are the difference between the local capacity cost increase in the LA Basin area and the local capacity cost reduction in the San Diego-Imperial Valley 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 San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, 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 2018-2019 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.

In Table 4.9-32, the benefits of local capacity reductions in the San Diego-Imperial Valley area are valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

[114] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-32: LCR Reduction Benefits for HVDC Conversion Project

	HVDC Conversion Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	690	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$9.0	$13.2
LCR increase (Western LA Basin) (MW)	40	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.7	$0.9
Net LCR Saving ($million/year)	$8.4	$12.3

Cost estimates:

The current cost estimates from SDG&E range from $700 to $900 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", the $900 million capital translates to a total cost of $1,170 million.

Benefit to Cost Ratio

In Table 4.9-33 the production benefit and the capacity benefits above are added, their present value is calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-33: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

HVDC Conversion Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$13	
HVDC Conversion Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	-$13	
PV of Prod Cost Savings ($million)	($179.41)	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$8.4	$12.3
PV of LCR Savings ($million)	$115.4	$169.2
Capital Cost		
Capital Cost Estimate ($ million)	$900	
Estimated “Total” Cost (screening) ($million)	$1,170	
Benefit to Cost		
PV of Savings ($million)	-$64	-$10
Estimated “Total” Cost (screening) ($million)	$1,170	
Benefit to Cost	-0.05	-0.01

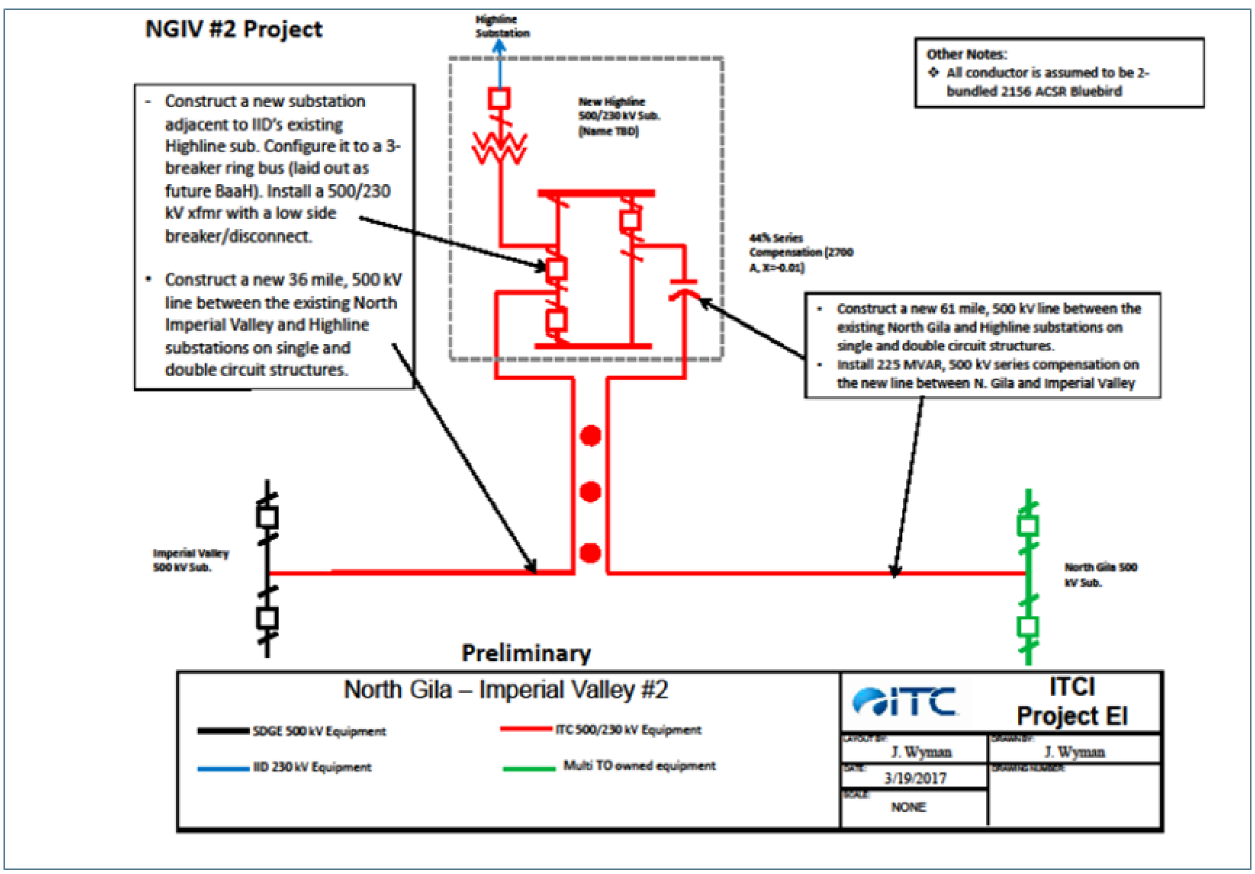
Conclusions

The benefit to cost ratio determined in this study does not support finding this project needed in this planning cycle. Further, the local capacity reduction benefits may be eroded if other options proceed that address the S-Line overload concern that presently sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relied heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process.

4.9.11.3 North Gila – Imperial Valley #2 500 kV Transmission Project congestion and capacity benefits

The ISO examined the North Gila – Imperial Valley #2 500 kV Transmission Project which was submitted by ITC Grid Development and Southwest Transmission Partners, LLC as an interregional transmission project in the 2018-2019 transmission planning cycle as set out in chapter 5. The North Gila-Imperial Valley #2 500 kV Transmission Project was proposed as a 95-mile single circuit 500 kV AC transmission project between southwest Arizona and southern California. The proposed in-service date for the project is Q4 2022. The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-20: North Gila - Imperial Valley #2 500 kV Line Configuration



The project's estimated capital cost for a single circuit line is $291 million. A preliminary target in-service date of Q4 2022 was proposed, and additional siting, permitting and design activities would be necessary to establish the feasibility of that target date.

The proponents stated that the proposed project would provide reliability benefits in addressing an overlapping G-1 (TDM) and N-1 (North Gila – Imperial Valley 500 kV line) contingency, economic benefits associated with reducing local capacity requirement, and increase transmission capacity for accessing generating resources in the Imperial Valley and Arizona areas.

As set out in chapter 2, 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 as a reliability-driven project. The ISO subsequently examined the project for further economic benefits.

North Gila – Imperial Valley #2 500 kV Transmission Project's Production benefit

Table 4.9-34 shows the production cost modeling results for this proposed project.

Table 4.9-34: Production Cost Modeling Results for North Gila-Imperial Valley #2 500 kV Transmission Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8485	-27
ISO generator net revenue benefitting ratepayers	2526	2545	19
ISO owned transmission revenue	199	213	14
ISO Net payment	5733	5727	6
WECC Production cost	16875	16886	-11

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

It was observed in the simulation results that modeling NG – IV #2 line increased congestion in the SDG&E area and on Path 26, as shown in Figure 4.9-21. In turn, renewable curtailment increased in most areas in Southern California, as shown in Figure 4.9-22.

Figure 4.9-21: Congestion changes with modeling NG-IV #2 line

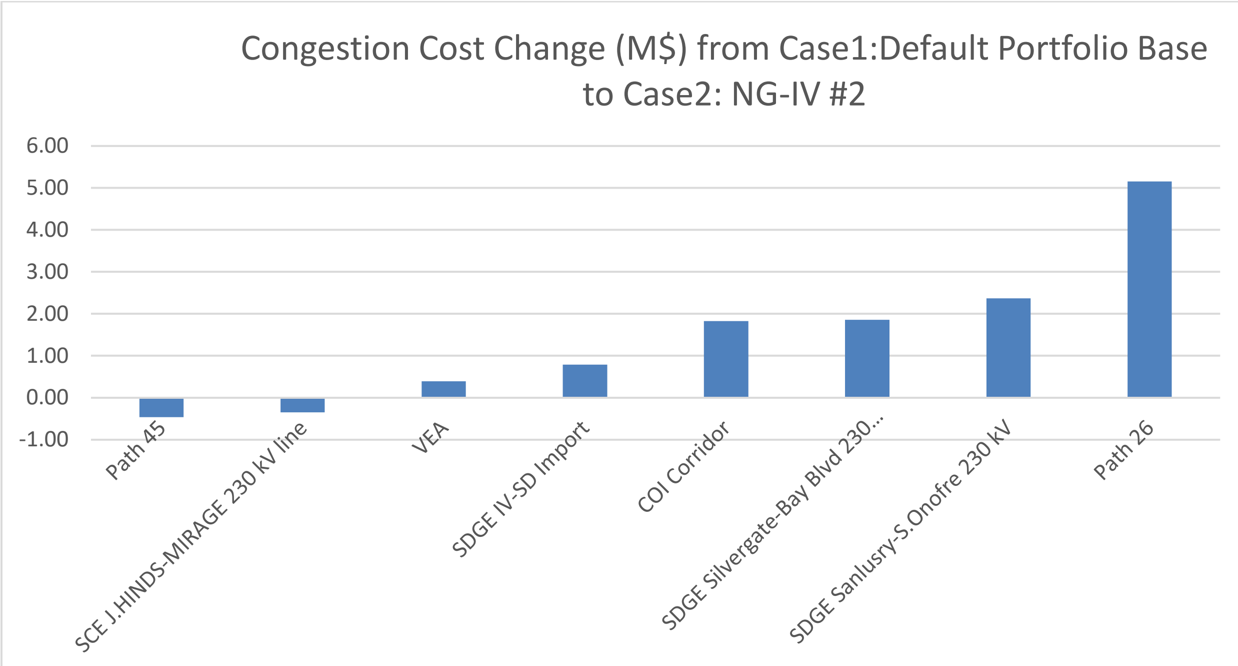
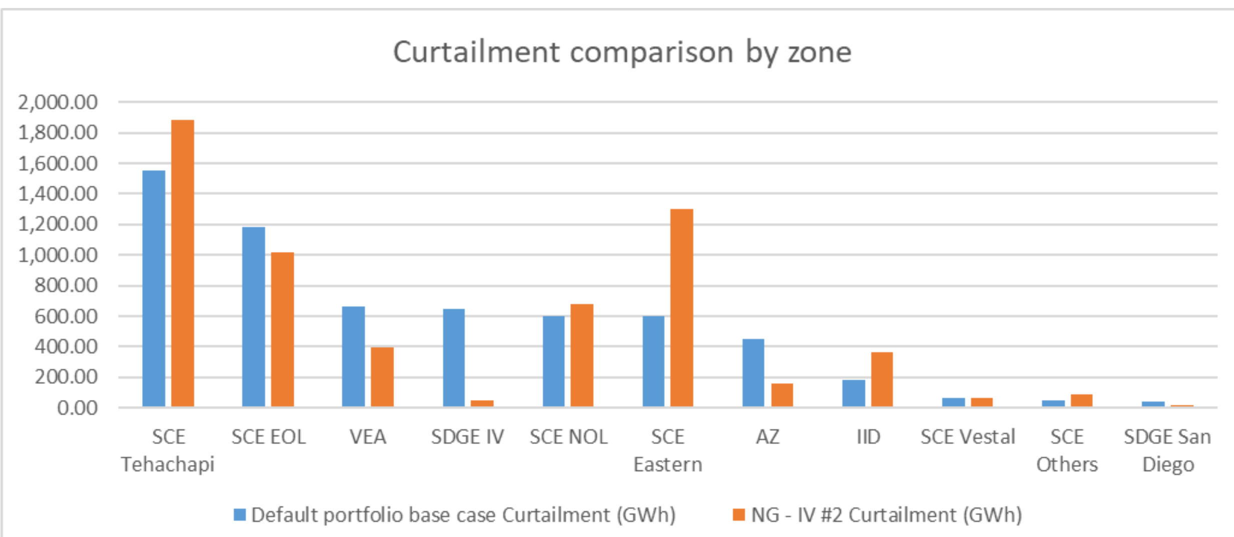


Figure 4.9-22: Curtailment changes by zone with modeling NG-IV #2 line



Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the North Gila – Imperial Valley #2 500 kV line in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The LCR need for gas-fired generation in the San Diego – Imperial Valley area could be reduced by approximately 865 MW with reductions in the San Diego sub-area and Imperial Valley. The limiting contingency is the overlapping N-1 of the North Gila – Imperial Valley #1 500 kV line, system readjusted, followed by the North Gila – Imperial Valley #2 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer. If this transformer is upgraded, the next limiting element for further local capacity reductions was determined to be the Pilot Knob – Yucca 161 kV line, followed by the El Centro 230/161 kV transformer.
- Since local capacity would be reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated the potential local capacity impact to the Western LA Basin sub-area. With the study case restored to normal condition, an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, then followed by an N-1 contingency Mesa – Lighthipe 230 kV line, the Mesa – Laguna Bell 230 kV line #1 was overloaded by 1 percent. An increase in the Western LA Basin sub-area LCR need of 100 MW would mitigate the loading concern.

The North Gila – Imperial Valley #2 500 kV line project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 865 MW[115], but would adversely impact the LA Basin area local capacity need by about 100 MW. The net local capacity benefits for the San Diego-Imperial Valley area are the difference between the local capacity requirement cost increase in the LA Basin area and the local capacity requirement cost reduction in the San Diego-Imperial Valley 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 San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, 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 2018-2019 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.

[115] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

In Table 4.9-35, the benefits of local capacity reductions in the San Diego-Imperial Valley area are valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

Table 4.9-35 : LCR Reduction Benefits for North Gila-Imperial Valley #2 500 kV Transmission Project

North Gila-Imperial Valley #2 500 kV Transmission Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	865	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$11.3	$16.5
LCR increase (Western LA Basin) (MW)	100	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$1.7	$2.3
Net LCR Saving ($million/year)	$9.6	$14.2

Cost estimates:

The cost estimate provided by Southwest Transmission Partners, LLC is $291 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", the $291 million capital translates to a total cost of $378 million.

Benefit to Cost Ratio

In Table 4.9-36 the production benefit and the capacity benefits above are added, their present value is calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-36: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

NG-IV #2 500 kV Transmission Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$6	
NG-IV #2 500 kV Line Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$6	
PV of Prod Cost Savings ($million)	$82.80	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.6	$14.2
PV of LCR Savings ($million)	$133.12	$196.47
Capital Cost		
Capital Cost Estimate ($ million)	$291	
Estimated “Total” Cost (screening) ($million)	$378	
Benefit to Cost		
PV of Savings ($million)	$215.9	$279.3
Estimated “Total” Cost (screening) ($million)	$378	
Benefit to Cost	0.57	0.74

The benefit to cost ratio would be reduced if any potential negative impacts of the NG-IV #2 500 kV line were taken into account. The ISO’s 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. For example, the P6 overloads of Suncrest-Sycamore 230 kV lines (TL23054/TL23055) and the Miguel banks (#80/#81) could increase by 8~16% and 8~14% of their applicable ratings, compared to the system without the project. Similarly, the P6 overload of Silvergate-Oldtown 230 kV lines could increase by 5~12%. The existing potential overloads are planned to be mitigated by RAS and operating procedures, but could be insufficient to address the higher overloads identified in this study. In addition, the project would increase power flow via the CENACE system by about 4% for the P6 outages of any segment of the Imperial Valley-Sycamore path followed by the loss of any segment of the Imperial Valley-Miguel path, or vice versa, which increases exposure of cross-tripping one of the two 230 kV tie lines between SDG&E and CENACE. The ISO previously identified that the cross tripping may jeopardize reliability in the CENACE system and result in potential voltage instability in the Los Angeles Basin and the San Diego area.

Conclusions

The benefit to cost ratio determined in this study does not support finding this project needed in this planning cycle. Further, the project would require mitigations of the reliability concerns in the San Diego sub-area, and the benefits may be eroded if other options proceed that address the S-Line overload concern that presently sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relied heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process.

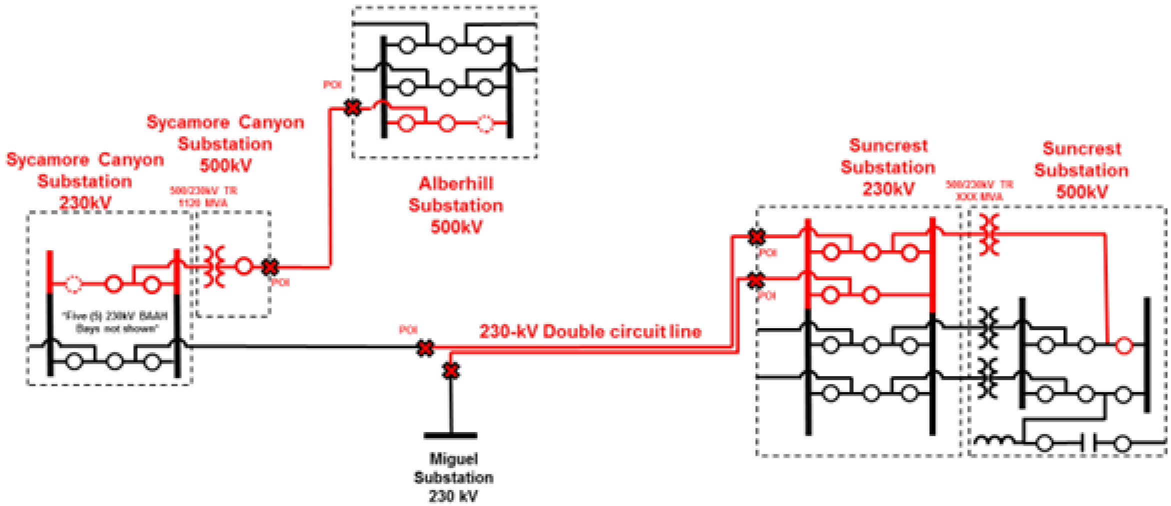
4.9.11.4 Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project congestion and capacity benefits

The ISO examined the Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project submitted by PG&E and TransCanyon as an economic study request. The project would consist of the following:

- Construct a new 500-kV transmission line from the proposed Alberhill substation to a new 500-kV Sycamore Canyon substation with a new 500/230-kV transformer at Sycamore Canyon substation. The CPUC denied the permit application for Alberhill substation project without prejudice in its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF). Since the Alberhill Substation Project was denied by the CPUC, PG&E and TransCanyon would need to modify the Request Window submittal to include the cost for a new switching station in lieu of the Alberhill substation.
- Install a third 500/230-kV transformer at Suncrest Substation and a new double circuit 230 kV transmission line that will loop the existing Miguel – Sycamore Canyon 230 kV transmission line to Suncrest substation.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-23: Alberhill to Sycamore plus Miguel to Sycamore loop into Suncrest 230 kV Project Project Configuration



The proponents provided an estimated capital cost of $500 million. It is noted that this cost estimate does not include the cost to construct a potential new switching substation in lieu of SCE's Alberhill Substation Project. As noted earlier, the CPUC denied this project without prejudice at its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF). A preliminary target date of summer 2025 has been established, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

PG&E and TransCanyon stated that the proposed project would provide additional import capacity into the San Diego, enhance reliability, and reduce LCR requirements and the need to build additional generation in a highly populated area. Furthermore, PG&E and TransCanyon mentioned that the third transformer at Suncrest and the new 230 kV line that loops into the Suncrest substation would enhance the reliability of the 230 kV system under multiple contingencies and prevent overloads on the existing Sycamore Canyon-Suncrest 230 kV lines.

Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project Production benefit

Table 4.9-37 shows the production cost modeling results for this proposed project.

Table 4.9-37: Production Cost Modeling Results for Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8448	9
ISO generator net revenue benefitting ratepayers	2526	2519	-7
ISO owned transmission revenue	199	199	1
ISO Net payment	5733	5730	3
WECC Production cost	16875	16881	-6

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Figure 4.9-25 shows the generation and congestion changes within the ISO footprint with modeling Alberhill – Sycamore project, respectively. In these figures, CIPB is the area defined in the production cost model for the PG&E Bay area, CIPV is the rest of PG&E areas outside the Bay area, CISC is the SCE area, and CISD is the entire SDG&E area including the San Diego and IV areas.

The increase of SDG&E thermal generation was mainly from the thermal generators in the San Diego area, because the project helped to reduce the congestion on San Luis Rey to San Onofre line in the direction from SDG&E to SCE. SDG&E renewable generation reduced though because the project increased congestion on Bay Blvd to Silvergate line, which caused more curtailment in IV area.

Figure 4.9-24: Generation changes with modeling Alberhill – Sycamore project

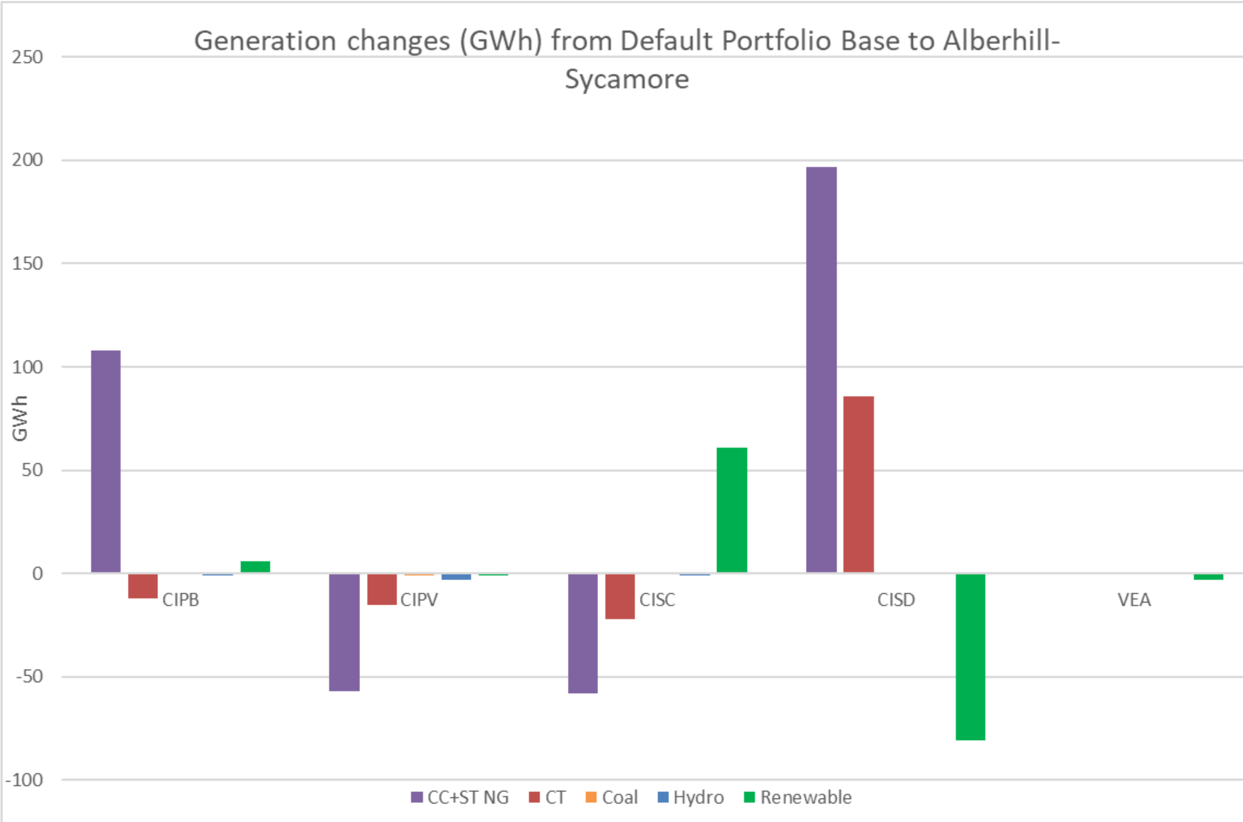
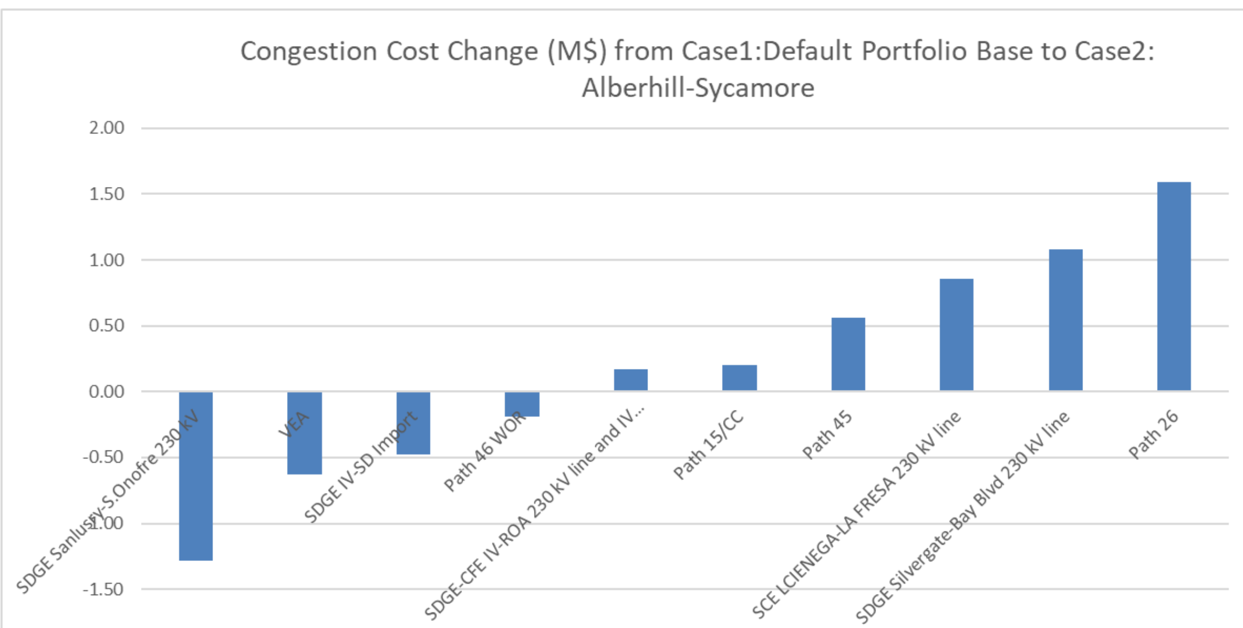


Figure 4.9-25: Congestion changes with modeling Alberhill – Sycamore project



Local Capacity Benefits:

Modeling the proposed project to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The amount of gas-fired generation could be reduced in the San Diego-Imperial Valley area by approximately 942 MW. This was established by the IID-owned El Centro 230/92 kV transformer reaching its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needed to be checked to determine if there was an adverse impact to its LCR need.
- With the power flow model restored to normal condition, an overlapping contingency (N-1-1) was evaluated to determine impact to the LA Basin area LCR need. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line caused the Mesa-Laguna Bell 230 kV line to be overloaded. An additional 170 MW of local capacity south of Laguna Bell substation (Western LA Basin sub-area) was needed to mitigate this loading concern.

The proposed project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 942 MW[116], but it was also identified that the LA Basin area local capacity need would be adversely impacted and will need an additional 170 MW to mitigate the identified reliability concern. The net local capacity benefits for the San Diego-Imperial Valley area would be the difference between the local capacity cost increase in the LA Basin area and the local capacity cost reduction in the San Diego-Imperial Valley 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 San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, 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 2018-2019 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.

In Table 4.9-38 the benefit of local capacity reductions in the San Diego-Imperial Valley area is valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

[116] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-38 : LCR Reduction Benefits for Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV

Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	942	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$12.3	$18.0
LCR increase (Western LA Basin) (MW)	170	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$2.8	$3.9
Net LCR Saving ($million/year)	$9.5	$14.1

Cost estimates:

The current cost estimate from PG&E and TransCanyon is $500.3 million for the proposed project. It is noted that the cost estimate assumed that the Alberhill substation would be approved by the CPUC for SCE to build. However, the CPUC denied without prejudice the Alberhill Substation Project in its environmental permitting process (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M228/K106/228106128.PDF). 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 $500.3 million capital translates to a total cost of $725 million.

Benefit to Cost Ratio

In Table 4.9-38 the production benefit and the capacity benefits above are added, their present value is calculated based on a 50 year project life, and then a benefit to cost ratio is calculated.

Table 4.9-39: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/ year)	$3	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$3	
PV of Prod Cost Savings ($million)	$41.40	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.5	$14.1
PV of LCR Savings ($million)	$130.91	$194.84
Capital Cost		
Capital Cost Estimate ($ million)	$500	
Estimated "Total" Cost (screening) ($million)	$650	
Benefit to Cost		
PV of Savings ($million)	$172.31	$236.24
Estimated "Total" Cost (screening) ($million)	$650	
Benefit to Cost	0.26	0.36

Conclusions

The benefit to cost ratio determined in this study is not sufficient to find the project needed in this transmission planning cycle. As the project relied primarily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process.

4.9.11.5 Lake Elsinore Advanced Pumped Storage (LEAPS) Project congestion and capacity benefits

The Lake Elsinore Advanced Pumped Storage (LEAPS) Project was submitted by Nevada Hydro on February 14, 2018 on the basis of section 24.3.3 of the ISO's tariff, which the ISO indicated would be considered an economic study request,[117] and into the 2018 Request Window on October 1, 2018 to address reliability needs in addition to providing other benefits. As set out in chapter 2, 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 operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further benefits, as an economic study request as stated in the final Unified Planning Assumptions and Study Plan[118].

The LEAPS Project ("Project") scope of work includes the following:

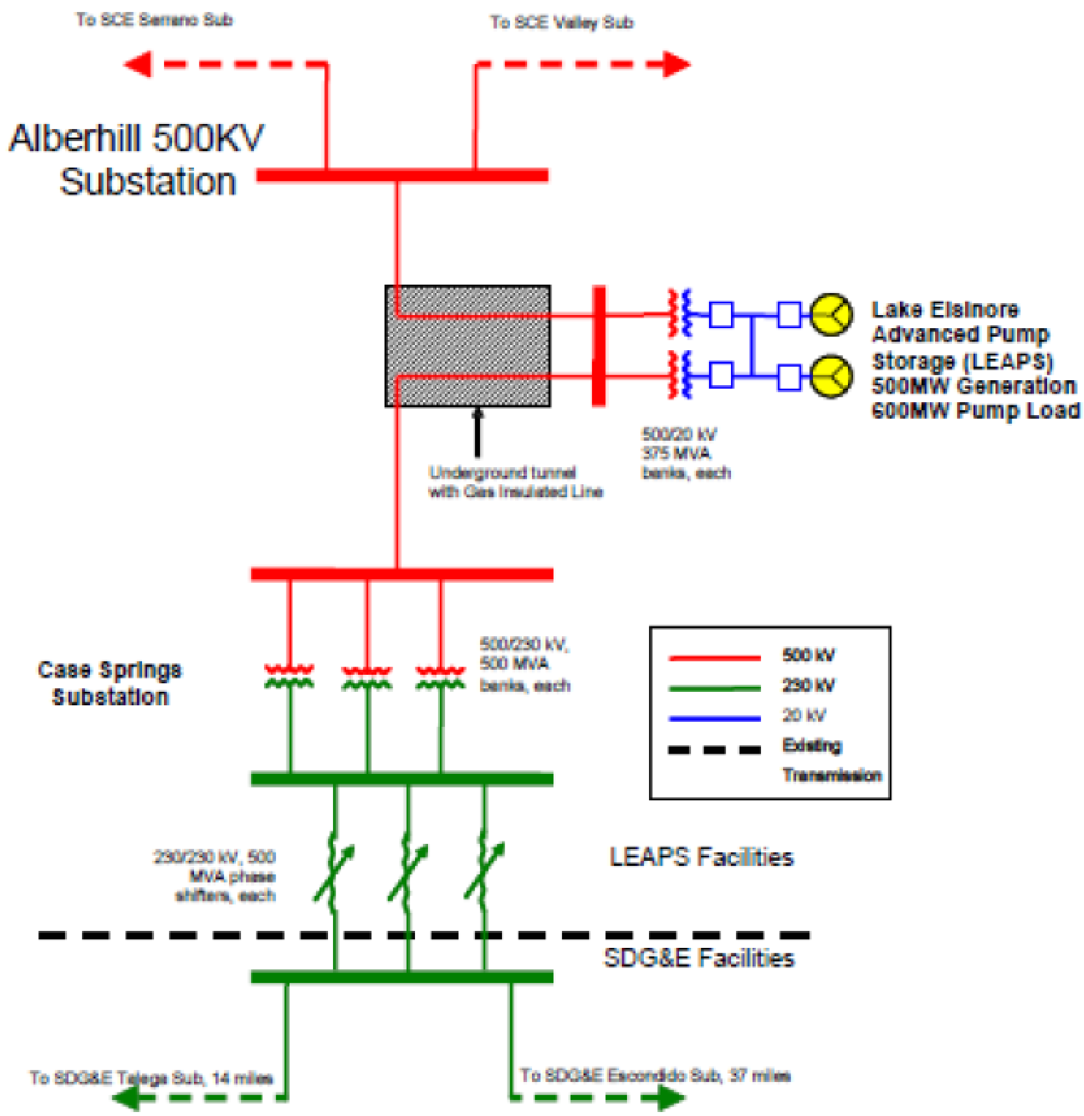
Option 1: Connection to both SCE and SDG&E

- This option interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill 500 kV substation (if approved by the CPUC) 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. The following figure includes the transmission configuration for the proposed project.
- Approximate Project Cost = $2.04 billion

[117] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Draft, February 22, 2018.

[118] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Final, March 30, 2018.

Figure 4.9-26: LEAPS Option 1 Configuration



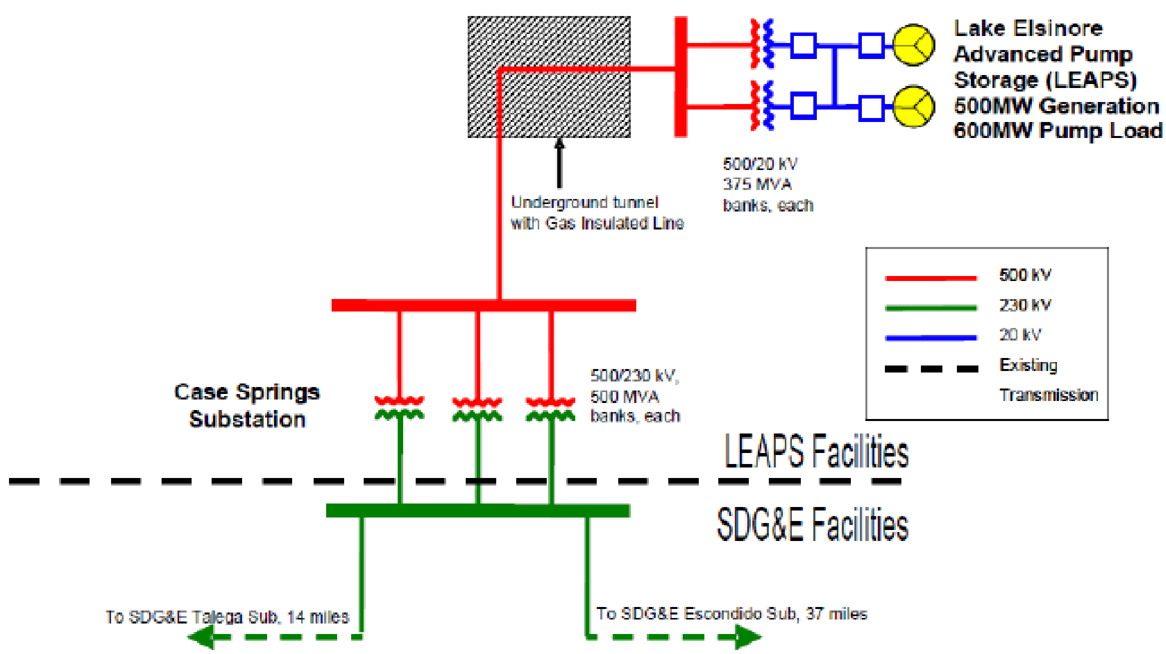
Although the Nevada Hydro proposal does not propose an option of only the transmission development, considering the benefits provided by the transmission lines and phase shifters, and then the incremental benefits of the pumped hydro storage facility also enables a determination of the services being provided by each component of the proposed project. Accordingly, the ISO's analysis of the benefits was based on a phased approach:

- Option 1a – the transmission development without the hydro pumped storage; and,
- Option 1b – the complete proposal, reflecting the addition of the hydro pumped storage facility to the transmission development.

Option 2: Connection to SDG&E only

- Interconnecting to SDG&E's transmission by looping in the Talega – Escondido 230 kV line via the Case Springs 230 kV substation.
- Approximate Project Cost = $1.76 billion

Figure 4.9-27: LEAPS Option 2 Configuration



A preliminary target in-service date of 2025 has been proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The proponent stated that the proposed project would provide congestion mitigation benefits under various N-1 contingencies, economic benefits associated with reducing local capacity requirements, and renewable integration via the use of the pumped storage.

In the course of the reliability assessment set out in chapter 2, the ISO did not identify a reliability need for which a reinforcement in this area would be necessary. Although the pumped storage would be expected to provide reactive power in keeping with the ISO's reactive power requirements set out in the ISO's tariff, the ISO has not identified this as a specific need. Therefore, the analysis centered on the economic benefits LEAPS could provide.

The ISO's evaluation of economic study requests for potential approval of transmission solutions is based on the most current version of the ISO Transmission Economic Evaluation

Methodology (TEAM)[119], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the transmission approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by LEAPS identified in this analysis.

LEAPS Project's Production Benefit

Table 4.9-40 shows the production cost modeling results for options 1a, 1b, and 2.

Table 4.9-40: Production Cost Modeling Results for LEAPS

	Pre project upgrade ($M)	Option 1a		Option 1b		Option 2	
		Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8456	1	8594	-137	8589	-132
ISO generator net revenue benefitting ratepayers*	2526	2529	3	2631	105	2624	99
ISO owned transmission revenue	199	198	-1	199	0	198	-1
ISO Net payment	5733	5729	4	5764	-31	5767	-34
WECC Production cost	16875	16878	-3	16838	37	16825	50

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $73 million--note that LEAPS net revenue is included in Table 4.9-44 and Table 4.9-45.

[119] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Figure 4.9-28 through Figure 4.9-33 show the generation and congestion changes with modeling the above three options of LEAPs project, all compared with the base case with the default portfolio. In these figures, CIPB is the area defined in the production cost model for the PG&E Bay area, CIPV is the rest of PG&E areas outside the Bay area, CISC is the SCE area, and CISD is the entire SDG&E area including the San Diego and IV areas.

With Option 1a modeled, which only considered the transmission component of the project, both the thermal and renewable generation dispatch in San Diego and IV areas increased, and the congestion in the same area decreased. SCE area generation decreased and Path 26 congestion from South to North increased.

With Option 1b modeled, which included the pumped storage, total renewable generation output increased within the ISO, because the pumped storage can absorb the surplus of renewable generation during the hours when renewable generation was otherwise curtailed. However, transmission congestion was not mitigated outside of the congestion in the SDG&E areas. As indicated in the footnote of Table 4.9-40, LEAPS pumped storage had positive net revenue. The main reason of the positive revenue of LEAPS pumped storage was that the LEAPS units normally pumped during the hours when renewable (mainly solar) output was high and LMP was relatively low, and generated during the hours when the LMP was relatively high. Figure 4.9-34 shows the pumped storage output in three typical days in April. This indicates that the positive net revenue is primarily due to arbitraging wholesale energy market prices.

With Option 2 modeled, the results were similar to the Option 1b results. The magnitude of changes in SCE and SDG&E areas were different between these two options mainly because the transmission configurations were different; hence, the impacts on generation dispatch were different. Also, the responses of rest of the system to the addition of the LEAPs project were slightly different in all three options.

Figure 4.9-28: Generation changes with LEAPS Option 1a

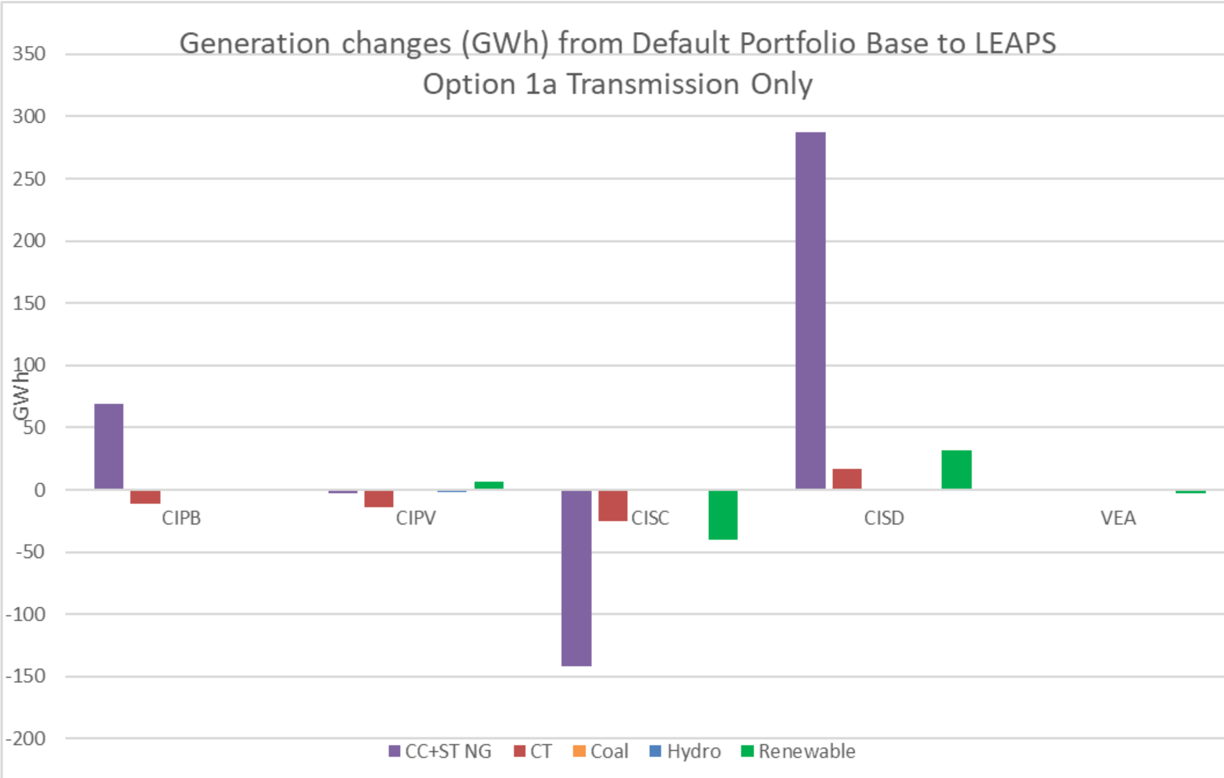


Figure 4.9-29: Congestion changes with LEAPS Option 1a

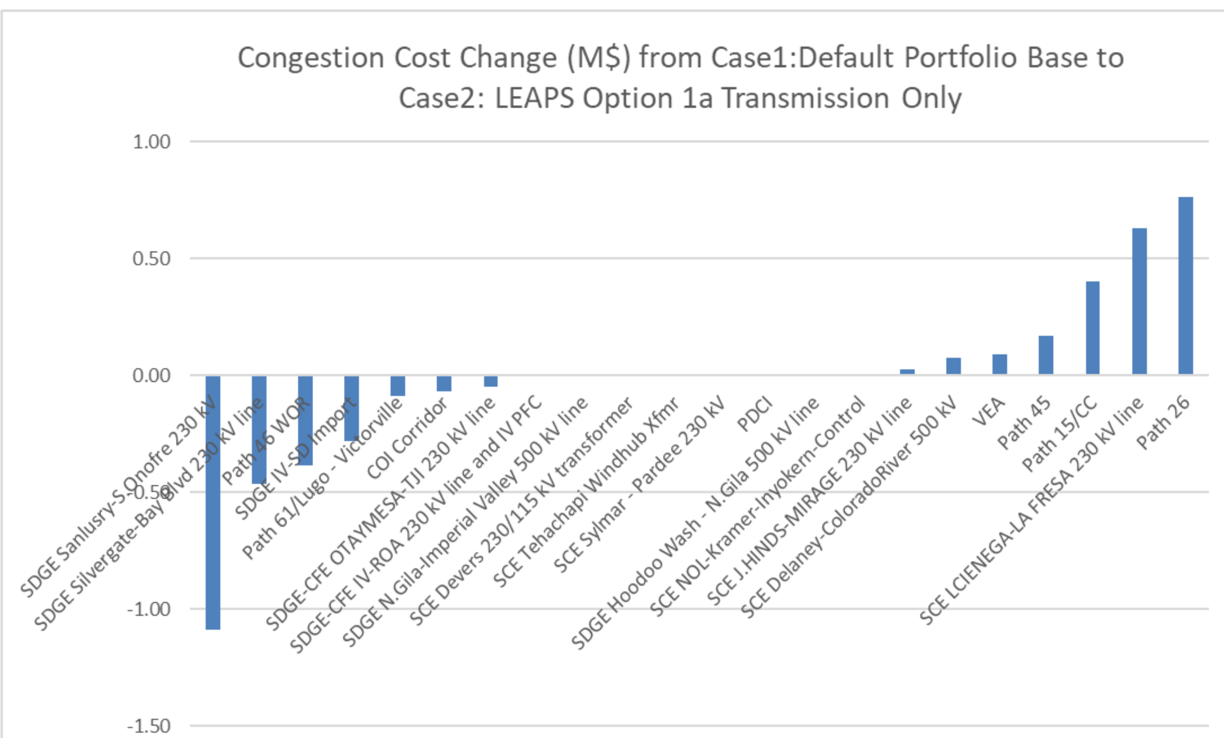


Figure 4.9-30: Generation changes with LEAPS Option 1b

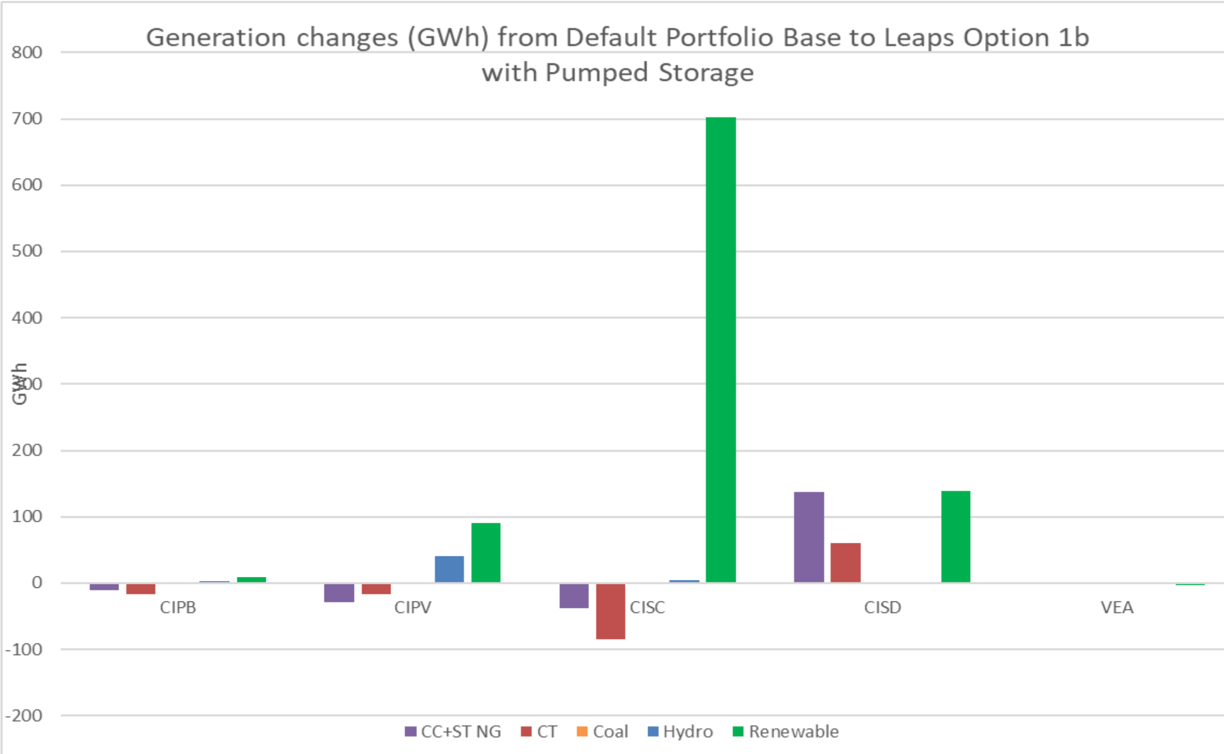


Figure 4.9-31: Congestion changes with LEAPS Option 1b

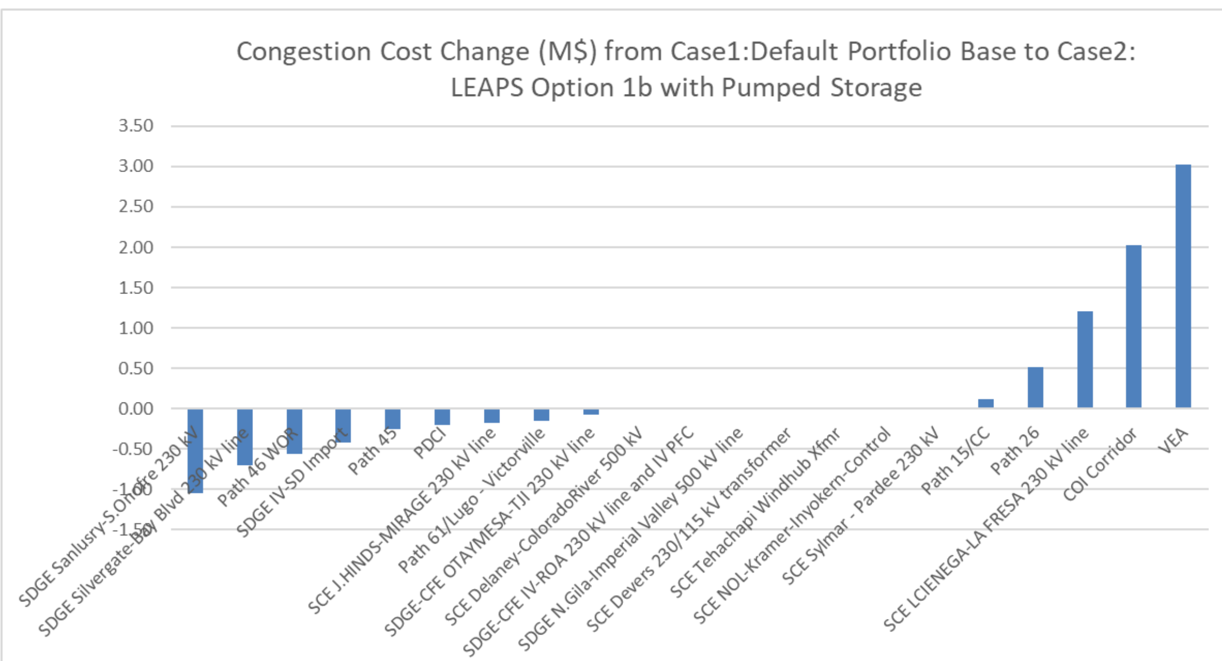


Figure 4.9-32: Generation changes with LEAPS Option 2

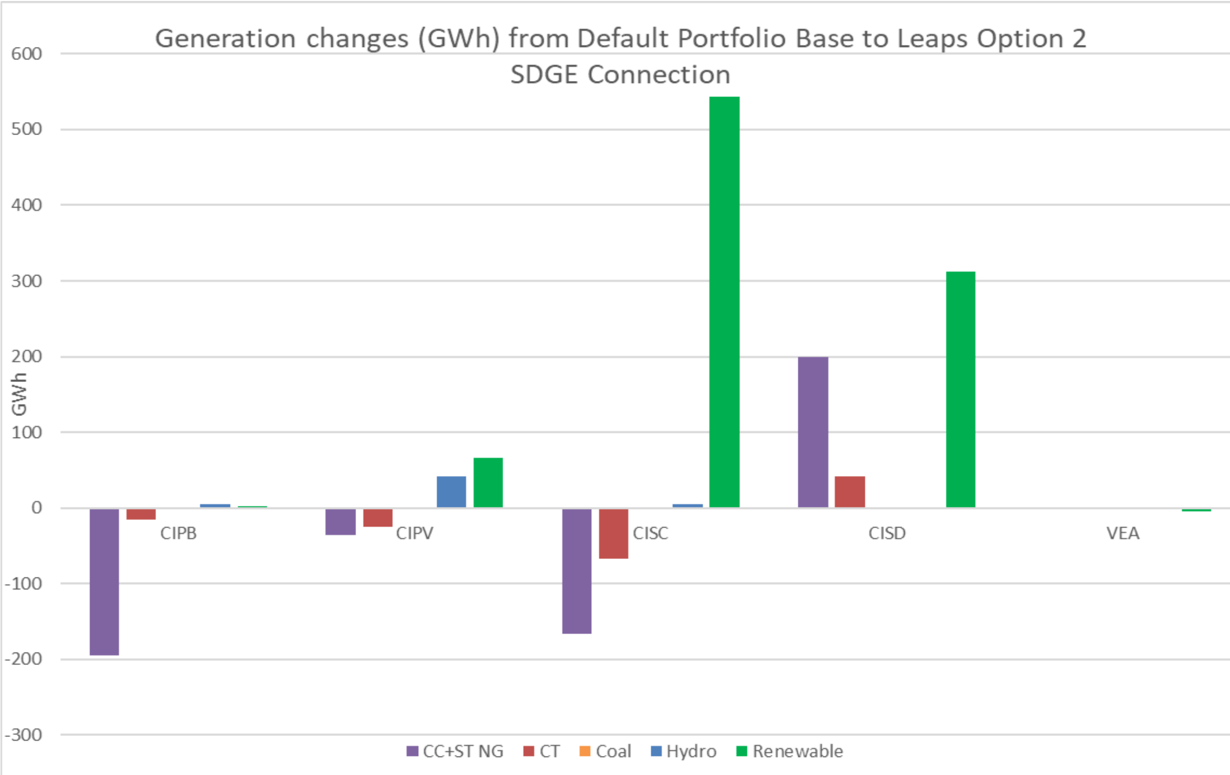


Figure 4.9-33: Congestion changes with LEAPS Option 2

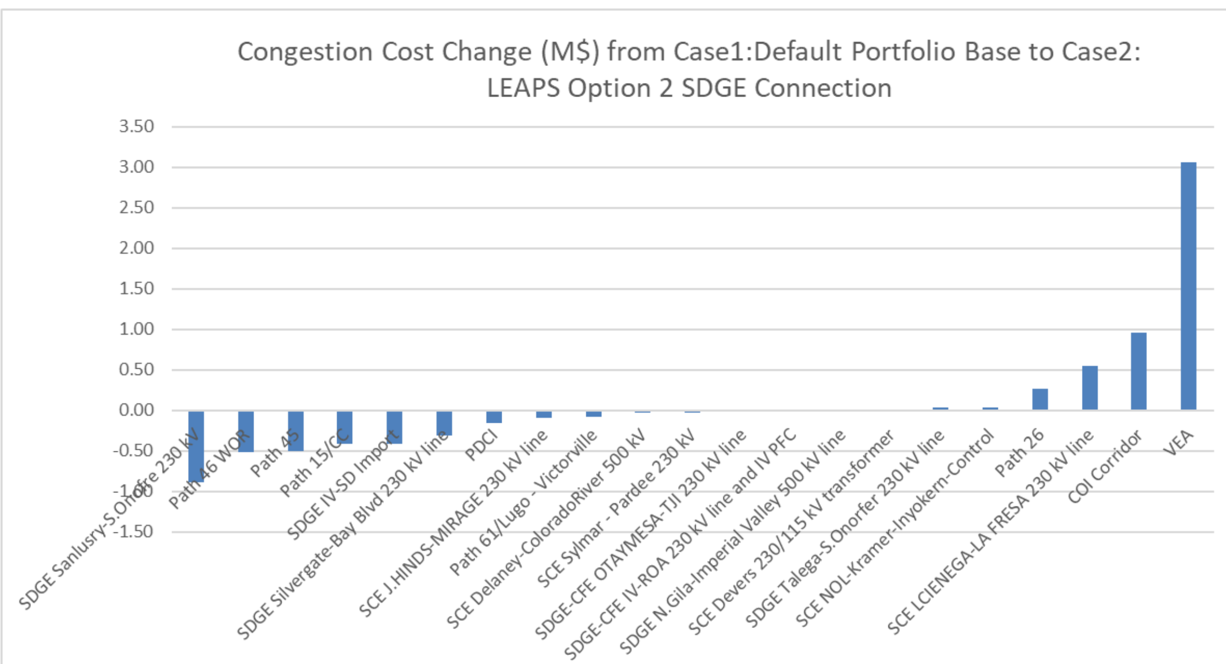
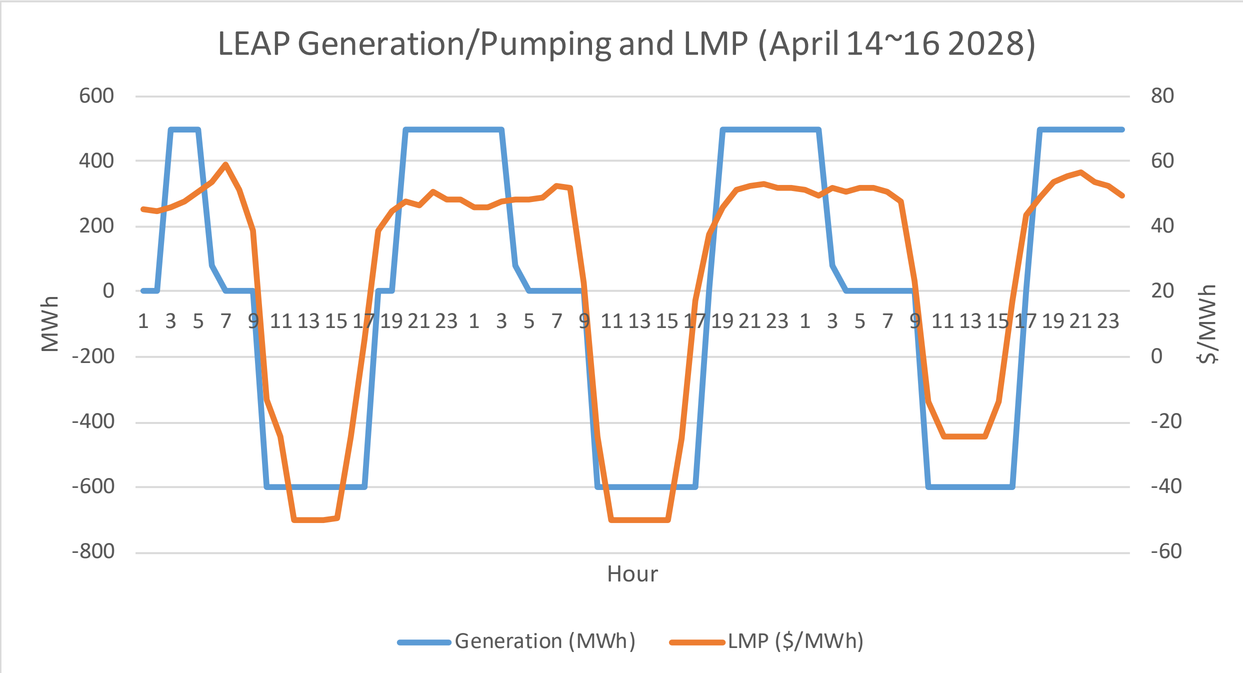


Figure 4.9-34: Pumped Storage output in typical days



To more fully understand the nature of the GridView production cost modeling results and locational impacts, the ISO also examined the impact of modeling the LEAPS pumped storage facilities connected to the Lugo bus, which was chosen as a relatively unconstrained location in southern California. A comparison of these results is set out in Table 4.9-41.

Table 4.9-41: Production Cost Modeling Lugo Sensitivity for LEAPS

	Option 1b		Option 2		Lugo Connection (sensitivity)	
	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8594	-137	8589	-132	8591	-134
ISO generator net revenue benefitting ratepayers	2631	105	2624	99	2630	105
ISO owned transmission revenue	199	0	198	-1	197	-1
ISO Net payment	5764	-31	5767	-34	5764	-31
Storage net revenue		73		73		75
ISO Net payment including storage revenue		42		39		44
WECC Production cost	16838	37	16825	50	16842	33

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

While the ISO ratepayer benefits were consistent across all three options, the WECC production cost benefits appeared somewhat higher for the LEAPS Option 2 configuration. It appeared that the results were somewhat affected by the choice of renewable generation curtailed for system reasons and associated curtailment prices. To test the impact of the multi-tiered renewable curtailment model, the ISO conducted a sensitivity with the renewable curtailment price set at negative $25.

Table 4.9-42: Production Cost Modeling Lugo Sensitivity for LEAPS with -$25 fixed renewable curtailment price

	Option 1b		Option 2		Lugo Connection (sensitivity)	
	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,659	-94	8,657	-92	8,656	-91
ISO generator net revenue benefitting ratepayers	2,677	81	2,667	72	2,674	78
ISO owned transmission revenue	206	-7	209	-5	208	-5
ISO Net payment	5,775	-20	5,781	-25	5,774	-18
Storage net revenue		68		67		70
ISO Net payment including storage revenue		48		42		52
WECC Production cost	16,852	55	16,856	52	16,855	53

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

The results of the production cost models are generally consistent within the multi-tiered renewable curtailment price model analysis whether the pumped storage is connected via Option 1b or Option 2, or located at Lugo. While there was somewhat of a variation in the Option 2 WECC production costs for the multi-tiered renewable curtailment price analysis, a review of the generation graphs provided in Figure 4.9-30 and Figure 4.9-32 suggested that the differences were driven by the selection of renewable generation for curtailment between Imperial Valley and within SCE's footprint, which in turn had other impacts on gas-fired generation dispatch, rather than due to the LEAPS pumped storage behaving markedly different in the function it provided. In the sensitivity with fixed renewable curtailment prices, the WECC production cost savings remained constant across all three cases; Option 1b, Option 2, or the Lugo sensitivity connection, supporting the original conclusion, with only minor variations as would be expected for different interconnection configurations.

In addition to the above comparison of LEAPS to the relatively unconstrained Lugo location, the ISO also considered the less location-dependent results available in its informational studies on the benefits of large (pumped hydro) storage. The ISO's informational study of the zonal system benefits of a generic 500 MW pumped storage facility was updated this year as set out in chapter 7, utilizing PLEXOS and a number of different planning assumptions, in particular using the CPUC's "hybrid conforming" generation portfolio coming out of its 2017-2018 integrated resource planning process. That "hybrid conforming" portfolio achieves a higher renewables portfolio standard that the CPUC default portfolio used in the 2018-2019 transmission planning cycle. That PLEXOS analysis demonstrated a total WECC production cost benefit of $46.4 million and a net revenue of $73.6 million per year. These results collectively are directionally consistent with the LEAPS study results, and further support the conclusion that the bulk of the production cost savings provided by the large pumped storage facility are largely system in nature.

From the production cost modeling results, it therefore appears that the production cost benefits are derived from the LEAPS facility essentially functioning as an energy or capacity resource in the ISO market. As the benefits seem consistent with the pumped storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits do not support the pumped storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area. These benefits are analyzed and considered exclusively as a ratepayer benefit.

Option 1 – Connecting to both SCE and SDG&E

Modeling the LEAPS (Option 1) in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- *Option 1a* – the transmission development alone, without the LEAPS pumped storage, provides about 443 MW of local (gas-fired) capacity requirement reduction benefits for the San Diego – Imperial Valley LCR area under the critical G-1/N-1 contingency of the TDM power plant (593 MW) and the Imperial Valley – North Gila 500 kV line.
- However, removing 443 MW of local gas-fired resources in the San Diego-Imperial Valley area without local capacity replacement would adversely impact the local capacity need in the Western LA Basin sub-area. Modeling the study case without the pumped storage and removing 443 MW of local capacity (gas-fired) resources in the San Diego-Imperial Valley area resulted in the need for an additional 150 MW of local capacity resources in the Western LA Basin sub-area to mitigate the overloading concern on the Mesa-Laguna Bell #1 230 kV line under an overlapping N-1-1 contingency of the Mesa-Redondo 230 kV line and the Mesa-Lighthipe 230 kV line.
- *Option 1b* – the pumped storage with the transmission development could reduce the gas-fired local capacity resource requirement for the San Diego – Imperial Valley area by approximately 514 MW in the San Diego area. The LEAPS pumped storage provides local capacity to the San Diego and San Diego-Imperial Valley area and can act to replace capacity otherwise provided by gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer.

- Since local capacity could be reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed LEAPS project with transmission (Option 1b).
- Note that because the LEAPS connection to SCE is outside of the LA Basin area, the lack of impact on the Western LA Basin sub-area is driven by the potential power flow from LEAPS south into the SD&E system which then interacts with the LA Basin area needs. Also, the number of MW of gas-fired requirement reduction is slightly larger than LEAPS' capacity; this is due to the relative effectiveness of the point of interconnection compared to the gas-fired generation inside the SDG&E system.

Option 2 - Connecting to SDG&E Only

- By modeling the LEAPS (Option 2) in the 2028 long-term local capacity requirement study case, the gas-fired local capacity resources for the San Diego – Imperial Valley area could be reduced by approximately 533 MW in the San Diego area. The LEAPS pumped storage provides local capacity to the San Diego and San Diego-Imperial Valley area and replaces the gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer. The potential reduction in gas-fired generation local capacity requirement is larger than the capacity of the pumped hydro storage, and also larger than the benefit from Option 1, again supporting the increased effectiveness of the interconnection point in San Diego.
- Because local capacity is reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed LEAPS (Option 2).

The ISO notes that the local capacity benefits are a function of the amount of generating capacity of the pumped storage and the effectiveness of the interconnection point. While there are variations depending on relative effectiveness[120] of the configuration of the interconnection

[120] Note that the effectiveness factors listed in the 2028 Local Capacity Technical Study described in section 6.1 and provided in Appendix G show a range for generation in the San Diego and Imperial Valley combined area of 11.88% to 25.42%. Effectiveness was measured as the impact on the flow on the constrained transmission facility as a percent of output from the local capacity resource. In other words, some existing resources are more than twice as effective as others at addressing the limiting constraint, due to the physical location of the resources.

to the grid and the location of the gas-fired resources being displaced as providers of local capacity, this is consistent with variations seen in the effectiveness of the resources currently providing the local capacity requirements in the San Diego/Imperial Valley area. The benefits therefore relate to substituting one type of local capacity resource – gas-fired generation – with another – the generating capacity of the pumped storage.

Valuing Local Capacity Requirement Reduction Benefits for Options 1a, 1b, and 2

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 San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin, 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 solutions that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 transmission planning cycle to assets 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.

In Table 4.9-43 the benefit of local capacity reductions in the San Diego-Imperial Valley area for each of the three options are valued based on the ranges for San Diego, and the impact for option 1a on the Western LA Basin sub-area is based on the cost range for the LA Basin.

Table 4.9-43: LCR Reduction Benefits for all Options

	Option 1a		Option 1b		Option 2	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego) (MW)	443		514		533	
Capacity value (per MW-year)	$13,080	$19,080	$13,080	$19,080	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.8	$8.5	$6.7	$9.8	$7.0	$10.2
LCR increase (LA Basin) (MW)	150		0		0	
Capacity value (per MW-year)	$16,680	$22,680	N/A	N/A	N/A	N/A
LCR increase cost ($million)	$2.5	$3.4	0	0	0	0
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2

Further, the contingencies and potential overloads are observed to be “upstream“, easterly, of the San Diego area, and the connection of LEAPS into the San Diego area. The ISO has not identified a difference in the function being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

Option 1a: Nevada Hydro did not provide a separate cost estimate for the development of the transmission line project with associated switching substation cost without the LEAPS pumped storage. However, the cost for the development of the line can be estimated by removing the cost for the pumped storage facility from the Nevada Hydro Company’s website for the proposed project (http://leapshydro.com/wp-content/uploads/2017/10/Process-Costs-and-Financing.pdf). The cost estimate for the transmission facilities without the pumped storage is approximately $829 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, referred to as the “total” cost”, the $829 million capital translates to a total cost of $1,202 million.

Option 1b: The current cost estimate from Nevada Hydro includes $2.04 billion for the proposed project Option 1. 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 $2.04 billion capital translates to a total cost of $2.958 billion.

Option 2: The current cost estimate from Nevada Hydro includes $1.765 billion for the proposed project Option 2. 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 $1.765 billion capital translates to a total cost of $2.559 billion.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

The net present values of those annual revenue streams were estimated over 50[121] years as set out in Table 4.9-44.

[121] 50-year life is used as this would have involved new construction for transmission project.

Table 4.9-44: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

	Option 1a		Option 1b		Option 2	
Production Cost Modeling Benefits						
Ratepayer Benefits ($million/year)	$4		-$31		-$34	
LEAPS Net Market Revenue ($million/ year)	$0		$73		$73	
Total PCM Benefits ($million/year)	$4		$42		$39	
PV of Prod Cost Savings ($million)	$55.20		$579.63		$538.23	
Local Capacity Benefits						
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2
PV of LCR Savings ($million)	$45.44	$69.70	$92.78	$135.35	$96.21	$140.35
Capital Cost						
Capital Cost Estimate ($ million)	$829		$2,040		$1,765	
Estimated "Total" Cost (screening) ($million)	$995		$2,448		$2,118	
Benefit to Cost						
PV of Savings ($million)	$100.64	$124.90	$672.42	$714.98	$634.44	$678.58
Estimated "Total" Cost (screening) ($million)	$994.80		$2,448		$2,118	
Benefit to Cost	0.10	0.13	0.27	0.29	0.30	0.32

<u>Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)</u>

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. Because these include benefits that do not accrue directly to the benefit of ratepayers, who would fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-45: Benefit to Cost Ratios (Production Cost Savings – Information Only)

	Option 1a		Option 1b		Option 2	
Production Cost Modeling Benefits						
WECC PCM Cost Reduction ($million/year)	-$3		$37		$50	
LEAPS Net Market Revenue ($million/ year)	$0		$73		$73	
Total PCM Benefits ($million/ year)	-$3		$110		$123	
PV of Prod Cost Savings ($million)	-$41.40		$1,518.08		$1,697.49	
Local Capacity Benefits						
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2
PV of LCR Savings ($million)	$45.44	$69.70	$92.78	$135.35	$96.21	$140.35
Capital Cost						
Capital Cost Estimate ($ million)	$829		$2,040		$1,765	
Estimated "Total" Cost (screening) ($million)	$995		$2,448		$2,118	
Benefit to Cost						
PV of Savings ($million)	$4.04	$28.30	$1,610.87	$1,653.43	$1,793.71	$1,837.84
Estimated "Total" Cost (screening) ($million)	$994.80		$2,448		$2,118	
Benefit to Cost	0.00	0.03	0.66	0.68	0.85	0.87

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the LEAPS net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the LEAPS project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of LEAPS - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other non-transmission benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to LEAPS performing a transmission function operating to meet an ISO-identified transmission need:
  - There were no identified reliability needs in the planning horizon driving the need for the project;
  - The production cost benefits associated with the pumped storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
  - The local capacity benefits associated with the pumped storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

4.9.11.6 San Vicente Energy Storage Project congestion and capacity benefits

The ISO examined the San Vicente Energy Storage Project submitted by the City of San Diego into the 2018 Request Window. As set out in chapter 2, 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 operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The San Vicente Energy Storage ("Project") scope includes the following:

- The energy storage plant is configured with four individual generating units connected to the SDG&E-owned Sycamore 230 kV substation. Total generating capacity is 500 MW.
- Two 230 kV generation tie line circuits extend from the project switchyard to the proposed point of interconnection at Sycamore Canyon 230 kV substation.

The proponent provided an approximate project cost estimate of $1.5 billion to $2 billion. A preliminary target in-service date of Q1 2028 was proposed, and additional siting, permitting and design activities would be necessary to establish the feasibility of that target date.

The Project Proponent stated that the proposed project would provide the following benefits:

- System, flexible and local capacity needs
- Renewable integration via the use of pumped storage to minimize renewable resource curtailments
- Economic benefits associated with reducing local capacity requirements
- Reliability benefits for mitigating various overlapping N-1-1 contingencies

The ISO's evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[122], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted the economic study analysis for this project assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery

[122] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the San Vicente Energy Storage Project identified in this analysis.

San Vicente Energy Storage Project's Production benefit

Table 4.9-46 shows the production cost modeling results for this proposed project.

Table 4.9-46: Production Cost Modeling Results for the San Vicente Energy Storage Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8557	-100
ISO generator net revenue benefitting ratepayers *	2526	2602	77
ISO owned transmission revenue	199	199	0
ISO Net payment	5733	5756	-23
WECC Production cost	16875	16838	37

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $54 million--note that San Vicente net revenue is included in Table 4.9-48 and Table 4.9-49.

These results are aligned with the results found for the LEAPS pumped storage unit, which is relatively similarly situated with LEAPS having higher storage capacity (10 hour discharge at 500 MW output) compared to San Vicente (8 hour discharge at 500 MW output) reasonably accounting for LEAPS having generally higher ISO ratepayer net payment, WECC production cost, and pumped storage net revenue.

The ISO conducted detailed analysis and sensitivities of the LEAPS project to ascertain if the production cost modeling benefits were attributable generally to the participation of the resource in the ISO market, or if other factors were at play. That analysis led to the conclusion that the production cost benefits were derived from the LEAPS facility essentially functioning as an energy or capacity resource in the ISO market. Further, as the benefits seemed consistent with the pumped storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits did not support the pumped storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Given the alignment of results here for the San Vicente project the same conclusions apply to the San Vicente project.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the San Vicente Energy Storage Project in the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The local capacity requirement for gas-fired resources for the San Diego – Imperial Valley area could be reduced by approximately 690 MW in the San Diego area. Location is important in mitigating the critical contingency that triggers the need for local capacity resources. The San Vicente pumped storage is located nearer to the critical loading element, resulting in a greater effectiveness than the gas-fired resources currently providing local capacity. The proposed project provides local capacity to the San Diego and San Diego-Imperial Valley area and can act to replace capacity otherwise provided by gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer.
- Since local capacity is reduced in the San Diego-Imperial Valley area with the project modeled, the ISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed San Vicente Energy Storage Project.

The ISO notes that the local capacity benefits are a function of the amount of generating capacity of the pumped storage and the effectiveness of the interconnection point. While there are variations depending on relative effectiveness[123] of the configuration of the interconnection to the grid and the location of the gas-fired resources being displaced as providers of local capacity, this is consistent with variations seen in the effectiveness of the resources currently providing the local capacity requirements in the San Diego/Imperial Valley area. The benefits therefore relate to substituting one type of local capacity resource – gas-fired generation – with another – the generating capacity of the pumped storage.

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 San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local

[123] Note that the effectiveness factors listed in the 2028 Local Capacity Technical Study described in section 6.1 and provided in Appendix G show a range for generation in the San Diego and Imperial Valley combined area of 11.88% to 25.42%. Effectiveness was measured as the impact on the flow on the constrained transmission facility as a percent of output from the local capacity resource. In other words, some existing resources are more than twice as effective as others at addressing the limiting constraint, due to the physical location of the resources.

capacity requirements but do not provide additional system resources, and is also being applied in the 2018-2019 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.

In Table 4.9-47 the benefit of local capacity reductions in the San Diego-Imperial Valley area for this project are shown.

Table 4.9-47: LCR Reduction Benefits for San Vicente Energy Storage Project

San Vicente Energy Storage Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	690	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$9.0	$13.2
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$9.0	$13.2

Further, the contingencies and potential overloads are observed to be "upstream", easterly, of the San Diego area, and the connection of the project into the San Diego area. The ISO has not identified a difference in the function being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

The current cost estimate from the City of San Diego is a range of $1.5 billion to $2.0 billion 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", the $2.0 billion capital translates to a total cost of $2.6 billion. It is noted that the submitted project cost was based on the original point of interconnection to the Sycamore – Suncrest 230 kV lines rather at the Sycamore Canyon 230 kV substation which would require a longer transmission line to connect.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

The net present values of those annual revenue streams were estimated over 50 years as set out in Table 4.9-48.

Table 4.9-48 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

San Vicente Energy Storage Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$23	
San Vicente Net Market Revenue ($million/ year)	$54	
Total PCM Benefits ($million/year)	$31	
PV of Prod Cost Savings ($million)	$427.82	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.0	$13.2
PV of LCR Savings ($million)	$124.55	$181.69
Capital Cost		
Capital Cost Estimate ($ million)	$2,000	
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost		
PV of Savings ($million)	$552.38	$609.51
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost	0.21	0.23

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-49 : Benefit to Cost Ratios (WECC Benefits per TEAM)

San Vicente Energy Storage Project		
Production Cost Modeling Benefits		
WECC PCM Cost Reduction ($million/year)	$37	
San Vicente Net Market Revenue ($million/year)	$54	
Total PCM Benefits ($million/year)	$91	
PV of Prod Cost Savings ($million)	$1,255.87	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.0	$13.2
PV of LCR Savings ($million)	$124.55	$181.69
Capital Cost		
Capital Cost Estimate ($ million)	$2,000	
Estimated "Total" Cost (screening) ($million)	$2,600	
Benefit to Cost		
PV of Savings ($million)	$1,380.42	$1,437.56
Estimated "Total" Cost (screening) ($million)	$2,600	
Benefit to Cost	0.53	0.55

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the San Vicente Energy Storage Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the San Vicente Energy Storage Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the San Vicente Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the San Vicente Energy Storage Project performing a transmission function operating to meet an ISO-identified transmission need:
    - There were no identified reliability needs in the planning horizon driving the need for the project;
    - The production cost benefits associated with the pumped storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
    - The local capacity benefits associated with the pumped storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

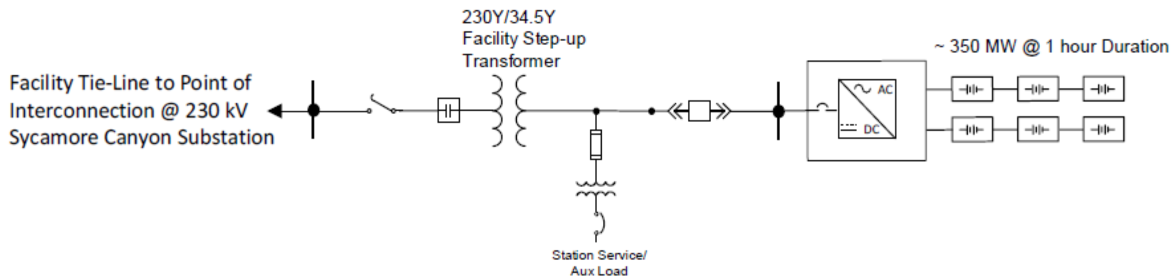
4.9.11.7 Sycamore Reliability Energy Storage (SRES – 381 MW) Project congestion and capacity benefits

The ISO examined the Sycamore Reliability Energy Storage (SRES) Project submitted by Tenaska to the 2018- Request Window. The project would consist of the following:

- Construct a 381[124] MW battery energy storage system (BESS) with one-hour discharge duration. It is noted that for local Resource Adequacy consideration, the resource would need to be available for at least 4 hours.
- Construct facility tie-line and grid interconnection to Sycamore 230 kV substation.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-35: Sycamore Reliability Energy Storage Configuration



Sycamore Reliability Energy Storage (SRES)

The project's estimated capital cost ranges from $108 million to $178 million. It is noted that this cost estimate is only for 1-hour discharge battery energy storage. Additional cost would be needed to provide larger bank of batteries for a 4-hour duration as required for the local Resource Adequacy (RA) need. A preliminary target date of Q4 2021 was proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The project was proposed by Tenaska as a Reliability Transmission Project. The proponent was also seeking to qualify the proposed project as a SATA (Storage as a Transmission Asset) facility. Tenaska stated that the proposed project would increase the capacity, efficiency, reliability, and operating flexibility of the transmission system and to mitigate the reliability issues identified by the ISO in the 2018-2019 Transmission Planning Process. Tenaska stated that the proposed project effectively mitigates the N-1 or overlapping N-1-1 line overloading concern on the Sycamore-Suncrest 230 kV line without having to use the RAS for generation tripping. Lastly, the project was proposed to reduce potential congestion.

As set out in chapter 2, 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 as a reliability-driven project.

[124] Tenaska provided a power flow model for a 381 MW battery energy storage system.

The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The ISO's evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[125], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the Sycamore Reliability Energy Storage (SRES) Project identified in this analysis.

Sycamore Reliability Energy Storage (SRES) Project Production benefit

Table 4.9-50 shows the production cost modeling results for this proposed project.

[125] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.9-50: Production Cost Modeling Results for Sycamore Reliability Energy Storage Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8528	-71
ISO generator net revenue benefitting ratepayers*	2526	2590	65
ISO owned transmission revenue	199	200	1
ISO Net payment	5733	5738	-5
WECC Production cost	16875	16853	22

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $35 million--note that Sycamore Reliability Energy Storage net revenue is included in Table 4.9-54 and Table 4.9-55.

To more fully understand the nature of the GridView production cost modeling results and locational impacts, the ISO also examined the impacts of modeling the Sycamore Reliability Energy Storage Project connected to the Lugo bus, which was chosen as a relatively unconstrained location in southern California. A comparison of these results is set out in Table 4.9-51. These results show that the WECC production cost modeling results obtained if the same project were connected to the Lugo bus would be the same or better than if it were located at Sycamore, and with approximately the same net revenue earned by the storage facility.

Table 4.9-51 Production Cost Modeling Sensitivity for Sycamore Reliability Energy Storage Project

	SRES Project		Lugo Connection (sensitivity)	
	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8528	-71	8534	-77
ISO generator net revenue benefitting ratepayers	2590	65	2590	64
ISO owned transmission revenue	200	1	197	-2
ISO Net payment	5738	-5	5748	-15
Storage net revenue		35		36
ISO Net payment including storage revenue		30		21
WECC Production cost	16825	22	16846	28

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

From the production cost modeling results, it therefore appears that the production cost benefits were derived from the Sycamore Reliability Energy Storage Project facility essentially functioning as an energy or capacity resource in the ISO market. As the benefits seem consistent with the storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits do not support the storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the proposed project at 381 MW, as provided by Tenaska in its power flow model to the ISO, to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The IID-owned El Centro 230/92 kV transformer is at its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line. The amount of gas-fired generation requirement reduction in the San Diego-Imperial Valley area is approximately 391 MW.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needs to be checked to determine if there is adverse impact to its LCR need. The power flow study is restored to normal condition. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line. This N-1-1 contingency could cause an overloading concern on the Mesa-Laguna Bell 230 kV line. However, a check on the Mesa – Laguna Bell 230 kV line loading indicated that it is 99.9% at its emergency rating limit.

The proposed project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 391 MW[126]. There was no identified local capacity impact to the LA Basin area as the replacement of gas-fired generation is the capacity from the proposed battery energy storage. The net local capacity benefits for the San Diego-Imperial Valley area is approximately 391 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 San Diego area, these translated to values of \$13,080/MW-year and \$19,080/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 2018-2019 transmission planning cycle to resources such as storage recognizing the

[126] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

need for further coordination with the CPUC's integrated resource planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.9-52 the benefit of local capacity reductions in the San Diego-Imperial Valley area for this project are shown.

Table 4.9-52: LCR Reduction Benefits for Sycamore Reliability Energy Storage (SRES) Project

	Sycamore Reliability Energy Storage Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	391	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.1	$7.5
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$5.1	$7.5

Further, the contingencies and potential overloads are observed to be "upstream", easterly, of the San Diego area, and the connection of the Sycamore Reliability Energy Storage Project into the San Diego area. The ISO has not identified a difference in the service being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

The current cost estimate received from Tenaska is $108 million to $178 million for the proposed project. It is noted that the cost estimate assumes a maximum discharge of one hour only. For consideration for local capacity need, a resource would need to have at least a four-hour availability. The ISO, using the cost estimate provided by Tenaska, modified the cost estimate for a four-hour battery energy storage system, as shown in Table 4.9-53.

Table 4.9-53: Cost Estimate Adjustments

Description	Planning Level Estimate for 1-hour BESS ($M)	Planning Level Estimate for 4-hour BESS ($M)
350 MW / 175-350 MWh BESS Facility (Design/Procure/Construct)	100 - 170	((100+170)/2)*4=540
Facility Tie-Line (Design/Procure/Construct/ROW Acquisition)	1	1
Grid Interconnection (assumes Substation tie-in)	7	7
Total	108 - 178	548

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Summing the production benefit and the capacity benefits described above yields the total benefits. The calculated levelized fixed cost for the project and the benefit to cost ratio are shown in Table 4.9-54.

Table 4.9-54 Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Sycamore Reliability Energy Storage Project				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	-$5			
Sycamore RES Net Market Revenue ($million/ year)	$35			
Total PCM Benefits ($million/ year)	$30			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$5.1		$7.5	
Capital Cost				
Capacity (MW)	381			
Cost Estimate Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$548		$548
Capital Cost $/kW	$1,660	$1,438	$1,660	$1,438
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$130	$150	$130
Benefit to Cost				
Savings ($million/year)	$35	$35	$38	$38
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$130	$150	$130
Benefit to Cost	0.23	0.27	0.25	0.29

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.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-55: Benefit to Cost Ratios (Production Cost Savings – Information Only)

Sycamore Reliability Energy Storage Project				
Production Cost Modeling Benefits				
WECC PCM Cost Reduction ($million/ year)	$22			
Sycamore RES Net Market Revenue ($million/ year)	$35			
Total PCM Benefits ($million/ year)	$57			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$5.1		$7.5	
Capital Cost				
Capacity (MW)	381			
Cost Estimate Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$381		$381
Capital Cost $/kW	$1,660	$1,000	$1,660	$1,000
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$90	$150	$90
Benefit to Cost				
Savings ($million/year)	$62	$62	$64	$64
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$90	$150	$90
Benefit to Cost	0.41	0.69	0.43	0.71

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.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the Sycamore Reliability Energy Storage Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the Sycamore Reliability Energy Storage Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the Sycamore Reliability Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the Sycamore Reliability Energy Storage Project performing a transmission function operating to meet an ISO-identified transmission need:
  - There were no identified reliability needs in the planning horizon driving the need for the project;
  - The production cost benefits associated with the storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
  - The local capacity benefits associated with the storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide material benefits and benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

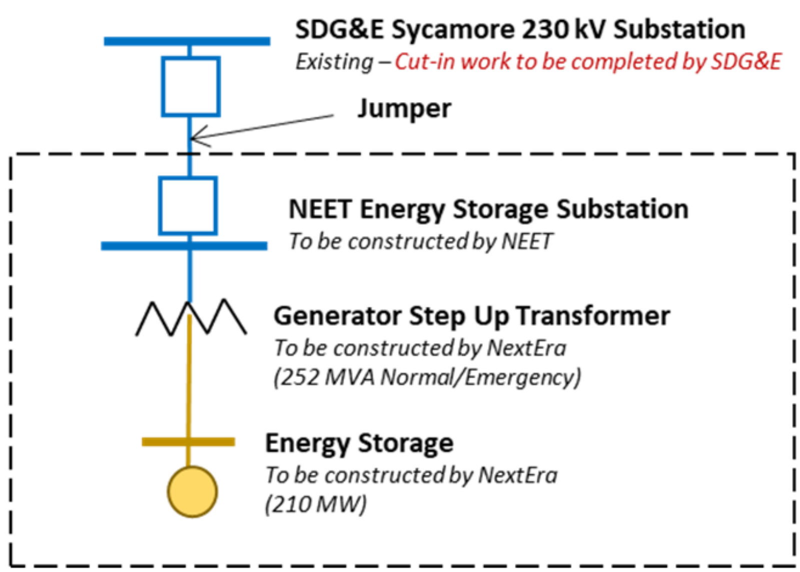
4.9.11.8 Sycamore 230 kV Energy Storage Project (SES – 210 MW) congestion and capacity benefits

The ISO examined the Sycamore 230 kV Energy Storage (SES) Project submitted by NextEra Energy Transmission West in the 2018 Request Window. The project would consist of the following:

- Build a new 230 kV bus outside the existing SDG&E Sycamore 230 kV substation.
- Build a 210 MW energy storage and connect it to the new 230 kV bus outside the SDG&E Sycamore substation.
- Cut in and connect to 230 kV jumper line dead end structures outside of the Sycamore substation.

The following figure illustrates the transmission configuration of the proposed project.

Figure 4.9-36: Sycamore 230 kV Energy Storage Project Configuration



The project's estimated capital cost was provided at $200 million. NEET West did not specify whether this cost estimate is for 4-hour discharging capability. For the purpose of this economic analysis, the ISO assumed that the proposed project would have 4-hour discharging capability based on per unit cost derived from other submitted 4-hour battery energy storage system. If this assumption is incorrect, additional costs would be needed to provide a minimum 4-hour duration as required for the local Resource Adequacy (RA) need. A preliminary target date of 12/1/2024 has been proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The project was proposed by NEET West as a Reliability Transmission Project. The proponent is also seeking to qualify the proposed project as a SATA (Storage as a Transmission Asset) facility. NEET West submitted the proposed as transmission alternative to the ISO-proposed solutions of utilizing existing operating procedures, Remedial Action Schemes, and dispatching of preferred resources to meet various reliability concerns in the 2018-2019 Transmission Planning Process. NEET West stated that the proposed project effectively mitigates various overlapping N-1-1 line or transformer overloading concerns without having to use the above-mentioned mitigations.

As set out in chapter 2, 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 existing operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The ISO's evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[127], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the Sycamore 230 kV Energy Storage (SES) Project identified in this analysis.

Sycamore 230 kV Energy Storage (SES) Project Production benefit

Table 4.9-56 shows the TEAM analysis results for the proposed project.

[127] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.9-56: Production Cost Modeling Results for Sycamore 230 kV Energy Storage Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8494	-37
ISO generator net revenue benefitting ratepayers*	2526	2561	35
ISO owned transmission revenue	199	198	-1
ISO Net payment	5733	5736	-3
WECC Production cost	16875	16865	10

Note that ISO ratepayer "savings" are a <u>decrease</u> in load payment, but an <u>increase</u> in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an <u>increase</u> in ISO owned transmission revenue. WECC-wide "Savings" are a <u>decrease</u> in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $20 million--note that Sycamore 230 kV Energy Storage net revenue is included in Table 4.9-58 and Table 4.9-59.

These results are aligned with the results found for the Sycamore Reliability Energy Storage (SRES) Project, which is relatively similarly situated and has higher capacity of 381 MW compared to the Sycamore 230 kV Energy Storage Project's 210 MW. The difference in capacity, with a similar duration, reasonably accounts for the generally lower benefit results for the Sycamore 230 kV Energy Storage Project in terms of ISO ratepayer net payment, WECC production cost, and storage net revenue.

The ISO conducted a detailed analysis of the Sycamore Reliability Energy Storage (SRES) Project, including a sensitivity, to ascertain if the production cost modeling benefits were attributable generally to the participation of the resource in the ISO market, or if other factors were at play. That analysis led to the conclusion that the production cost benefits were derived from the Sycamore Reliability Energy Storage (SRES) Project essentially functioning as an energy or capacity resource in the ISO market. Further, as the benefits were consistent with the storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits did not support the storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Given the alignment of results here for the Sycamore Reliability Energy Storage (SRES) Project, the same conclusions apply to the Sycamore 230 kV Energy Storage Project.

<u>*Local Capacity Benefits:*</u>

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the proposed project at 210 MW, as provided by NEET West in its power flow model to the ISO, to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- The IID-owned El Centro 230/92kV transformer is at its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line. The amount of gas-fired generation requirement reduction in the San Diego-Imperial Valley area is approximately 230 MW.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needs to be checked to determine if there is adverse impact to its LCR need.
- The power flow study was then restored to normal condition. An N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line was studied. This N-1-1 contingency could cause an overloading concern on the Mesa-Laguna Bell 230 kV line. However, a check on the Mesa – Laguna Bell 230 kV line loading indicated that it was within its emergency rating limit.

The proposed project potentially could reduce local capacity need in the San Diego-Imperial Valley by about 230 MW[128]. There was no identified local capacity impact to the LA Basin area as the replacement of gas-fired generation is the capacity from the proposed battery energy storage. The net local capacity benefits for the San Diego-Imperial Valley area would be approximately 230 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 San Diego area, these translated to values of $13,080/MW-year and $19,080/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 2018-2019 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.

In Table 4.9-57 the benefit of local capacity reductions in the San Diego-Imperial Valley area for this project are shown.

[128] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

Table 4.9-57 : LCR Reduction Benefits for the Sycamore 230 kV Energy Storage Project

	NEET Sycamore 230 kV Energy Storage Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	230	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$3.0	$4.4
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$3.0	$4.4

Further, the contingencies and potential overloads are observed to be “upstream“, easterly, of the San Diego area, and the connection of the project into the San Diego area. The ISO has not identified a difference in the service being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

The current cost estimate from NEET West is $200 million for the proposed project. It is noted that NEET West did not specify whether the cost is for one-hour or four-hour battery energy storage system. The ISO assumed that this cost is for a four-hour battery energy storage system at this time. For consideration for local capacity need, a resource would need to have at least a four-hour availability.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Summing the production benefit and the capacity benefits described above yields the total benefits. The calculated levelized fixed cost for the project and the benefit to cost ratio are shown in Table 4.9-58.

Table 4.9-58: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

NEET Sycamore 230 kV Energy Storage Project				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/year)	-$3			
NEET Sycamore 230 kV Energy Storage Net Market Revenue ($million/year)	$20			
Total PCM Benefits ($million/year)	$17			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	210			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$200		$200.0
Capital Cost $/kW	$1,660	$952	$1,660	$952
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost				
Savings ($million/year)	$20	$20	$21	$21
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost	0.24	0.42	0.26	0.45

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.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-59: Benefit to Cost Ratios (Production Cost Savings – Information Only)

NEET Sycamore 230 kV Energy Storage Project				
Production Cost Modeling Benefits				
WECC PCM Cost Reduction ($million/ year)	$22			
NEET Sycamore 230 kV Energy Storage Net Market Revenue ($million/year)	$20			
Total PCM Benefits ($million/year)	$42			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	210			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$200		$200.0
Capital Cost $/kW	$1,660	$952	$1,660	$952
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost				
Savings ($million/year)	$45	$45	$46	$46
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost	0.54	0.95	0.56	0.98

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.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the Sycamore 230 kV Energy Storage Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the Sycamore 230 kV Energy Storage Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the San Vicente Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the Sycamore 230 kV Energy Storage Project performing a transmission function operating to meet an ISO-identified transmission need:
    - There were no identified reliability needs in the planning horizon driving the need for the project;
    - The production cost benefits associated with the storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
    - The local capacity benefits associated with the storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

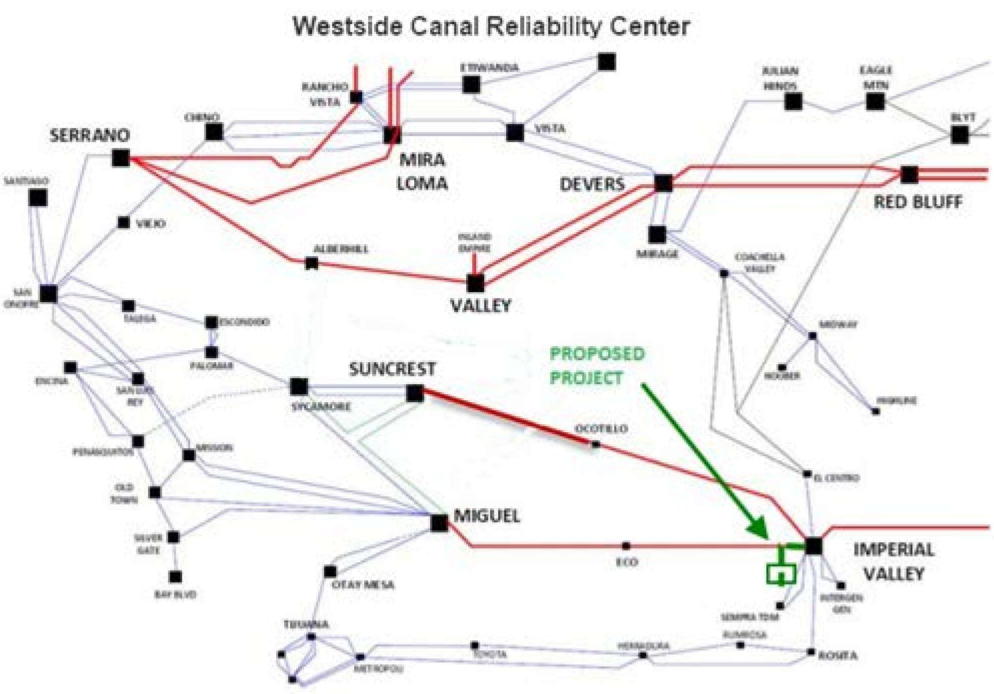
4.9.11.9 Westside Canal Reliability Center Project congestion and capacity benefits

The ISO examined submitted Westside Canal Reliability Center (Westside) Project submitted by ConEd Renewables[129] to the 2018 Request Window. The project would consist of the following:

- Construct a 268 MW battery energy storage system with 4-hour discharge capability with interconnection to the 230 kV Imperial Valley substation. The project would be located at south side of Mandrapa Rd/Westside Canal and directly south of the intersection of Mandrapa Rd and Liebert Rd in El Centro CA 92243. The point of interconnection for the proposed project would be at the 230 kV bus at the Imperial Valley Substation.

The following figure provides the general high-level location of the proposed project.

Figure 4.9-37: Westside Canal Reliability Center Configuration



The project's estimated capital cost was provided at $304 million. A preliminary target date of 12/31/2021 was proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The project was proposed by ConEd Renewables as a Reliability Transmission Project. The Project Proponent is also seeking to qualify the proposed project as a SATA (Storage as a Transmission Asset) facility. ConEd Renewables stated that the project is proposed to mitigate thermal overloads identified in the ISO's 2018-2019 Reliability Assessment results. Based on the information provided in the Request Window Submittal, the project is proposed to work in

129 The project was initially submitted by Sempra Renewables.

concert with a Remedial Action Scheme to dispatch effective generating resources in the San Diego – Imperial Valley area, and switching between charging (load) mode and discharging (generating) mode, depending on where the thermal constraint is located. The proponent also noted that in the charging mode, the proposed combination of the battery energy storage system and the Remedial Action Scheme does not fully mitigate identified contingency loading concerns for the S-line prior to implementation of its upgrade in the summer peak load case because the battery operating in charging mode would aggravate the loading concern. The proponent noted that this would not be an issue after the implementation of the S line upgrades. The proponent also suggested that the proposed battery energy storage system, working in discharging (generating) mode could be used as an alternative to the S line upgrade in the event that its construction is delayed.

As set out in chapter 2, 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 as a reliability-driven project. The ISO subsequently examined the project for further benefits, recognizing that the proposed project is an alternative to meeting San Diego sub-area and combined San Diego/Imperial Valley/LA Basin area local capacity requirements, potentially reducing the local capacity requirements for gas-fired generation.

The ISO's evaluation of economic study requests for potential approval of transmission projects is based on the most current version of the ISO Transmission Economic Evaluation Methodology (TEAM)[130], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The ISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, however, the ISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

As discussed earlier in this section, an important consideration in evaluating storage projects as an option to meet transmission needs is whether or not the storage facility is providing a transmission function – and addressing an identified transmission need – or is functioning as a capacity or supply resource. The direction set out in section 1.9 provides that the determination of eligibility for designation as a transmission asset – and for regulated cost-of-service recovery through the ISO tariff – is not only based on whether the storage project meets an identified transmission need, but also on how the storage project is operating as transmission to meet the

[130] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

need. The ISO has therefore considered this issue in assessing ratepayer benefits provided by the Westside Canal Energy Reliability Center Project identified in this analysis.

Westside Canal Reliability Center Project Production benefit

Table 4.9-60 shows the production cost modeling results for this proposed project.

Table 4.9-60: Production Cost Modeling Results for Westside Canal Reliability Center

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8504	-47
ISO generator net revenue benefitting ratepayers*	2526	2578	52
ISO owned transmission revenue	199	198	0
ISO Net payment	5733	5728	5
WECC Production cost	16875	16857	18

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO owned generation profits (ISO generator net revenue benefitting ratepayers) and an increase in ISO owned transmission revenue. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Note *: excludes pumped storage net revenue of $24 million--note that Westside Canal Reliability Center net revenue is included in Table 4.9-62 and Table 4.9-63.

These results are aligned with the results found for the Sycamore Reliability Energy Storage (SRES) Project, which is relatively similarly situated and has a higher capacity of 381 MW compared to the Westside Canal Reliability Center Project's 268 MW. The difference in capacity, with a similar duration, reasonably accounts for the generally lower benefit results for the Westside Canal Reliability Center Project in terms of ISO ratepayer net payment, WECC production cost, and storage net revenue.

The ISO conducted a detailed analysis of the Sycamore Reliability Energy Storage (SRES) Project, including a sensitivity, to ascertain if the production cost modeling benefits were attributable generally to the participation of the resource in the ISO market, or if other factors were at play. That analysis led to the conclusion that the production cost benefits were derived from the Sycamore Reliability Energy Storage (SRES) Project essentially functioning as an energy or capacity resource in the ISO market. Further, as the benefits seemed consistent with the storage being able to operate in a relatively unconstrained basis but otherwise not dependent on transmission location, the benefits did not support the storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources" per 24.4.6.7 of the tariff.

Given the alignment of results here for the Westside Canal Reliability Center Project, the same conclusions apply to the Westside Canal Reliability Center Project.

Local Capacity Benefits:

A benefit to ISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area.

Modeling the proposed project at 268 MW in discharging (generating) mode, as provided by ConEd Renewables in its power flow model to the ISO, to the 2028 long-term local capacity requirement study case for the San Diego-Imperial Valley area resulted in the following:

- The IID-owned El Centro 230/92 kV transformer is at its rating limit under an overlapping G-1 (TDM) and N-1 of Imperial Valley – North Gila 500 kV line. The amount of gas-fired generation local capacity requirement reduction in the San Diego-Imperial Valley area was found to be approximately 430 MW.
- Since the gas-fired generation could be reduced in the San Diego-Imperial Valley area, the LA Basin area local capacity needed to be checked to determine if there was an adverse impact to its LCR need. The power flow study was restored to normal condition, and an N-1 of the Mesa-Redondo 230 kV, system readjusted, then followed by an N-1 of the Mesa-Lighthipe 230 kV line was studied. This N-1-1 contingency could cause an overloading concern on the Mesa-Laguna Bell 230 kV line. A check on the Mesa – Laguna Bell 230 kV line loading indicated that it was at 101.1% of its emergency rating limit. To mitigate this loading concern, an additional 100 MW of local resource capacity was modeled south of the Laguna Bell substation.

The proposed project potentially could reduce local capacity need for gas-fired generation in the San Diego-Imperial Valley by about 430 MW[131]. There was an impact of an increase of 100 MW in local capacity requirement in the Western LA Basin sub-area. The net local capacity benefits for the San Diego-Imperial Valley area are the difference between the local capacity cost increase in the LA Basin area and the local capacity cost reduction in the San Diego-Imperial Valley 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 San Diego area, these translated to values of $13,080/MW-year and $19,080/MW-year respectively. For the LA Basin 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 2018-2019 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.

[131] The amount of local capacity reduction is an estimate at this time and will be subject to change due to unforeseen changes in the assumptions for generation retirements, new resource additions, new transmission upgrades and future demand forecast.

In Table 4.9-61 the benefit of local capacity reductions in the San Diego-Imperial Valley area is valued based on the cost range for San Diego, and the impact on the Western LA Basin sub-area is based on the cost range for the LA Basin.

Table 4.9-61: LCR Reduction Benefits for Westside Canal Reliability Center Project

Westside Canal Reliability Center Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	430	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.6	$8.2
LCR increase (LA Basin) (MW)	100	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$1.7	$2.3
Net LCR Saving ($million/year)	$4.0	$5.9

Further, the contingencies and potential overloads are observed to be "upstream", easterly, of the San Diego area, and the connection of the project into the San Diego area. The ISO has not identified a difference in the function being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

It was noted that this proposed solution had a noticeably higher effectiveness in displacing other resources than the other storage projects evaluated in this planning cycle. However, its comparative effectiveness remained within the reasonable range of effectiveness factors[132] found for existing resources providing local capacity in the San Diego/Imperial Valley area.

Cost estimates:

The cost estimate from ConEd Renewables is $304 million for the submitted project.

132 Note that the effectiveness factors listed in the 2028 Local Capacity Technical Study described in section 6.1 and provided in Appendix G show a range for generation in the San Diego and Imperial Valley combined area of 11.88% to 25.42%. Effectiveness was measured as the impact on the flow on the constrained transmission facility as a percent of output from the local capacity resource. In other words, some existing resources are more than twice as effective as others at addressing the limiting constraint, due to the physical location of the resources.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Summing the production benefit and the capacity benefits described above yields the total benefits. The calculated levelized fixed cost for the project and the benefit to cost ratio are shown in Table 4.9-62.

Table 4.9-62: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

ConEd Renewables Westside Canal Reliability Center				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	$5			
Westside Canal Net Market Revenue ($million/ year)	$24			
Total PCM Benefits ($million/ year)	$29			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	268			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$304		$304.0
Capital Cost $/kW	$1,660	$1,134	$1,660	$1,134
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost				
Savings ($million/year)	$32	$32	$33	$33
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost	0.30	0.44	0.32	0.46

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.

Benefit to Cost Ratios (ISO Production Cost Savings – Information Only)

The ISO also calculated the benefit to cost ratio based on ISO production cost savings. As these include benefits that do not accrue directly to the benefit of ratepayers, who would however fund the project if it proceeded through regulated cost-of-service rate recovery, this is provided on an information basis only.

Table 4.9-63: Benefit to Cost Ratios (Production Cost Savings – Information Only)

Westside Canal Reliability Center				
Production Cost Modeling Benefits				
WECC PCM Cost Reduction ($million/ year)	$18			
Westside Canal Net Market Revenue ($million/ year)	$24			
Total PCM Benefits ($million/ year)	$42			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	268			
Capital Cost Soruce	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$304		$304.0
Capital Cost $/kW	$1,660	$1,134	$1,660	$1,134
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost				
Savings ($million/year)	$45	$45	$46	$46
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost	0.43	0.62	0.44	0.64

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.

Conclusions

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the Westside Canal Reliability Center Project net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the ISO to find the need for the Westside Canal Reliability Center Project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The ISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of the San Vicente Energy Storage Project - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and ISO ratepayer benefits suggests that there are other benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The ISO did not identify benefits that directly related to the Westside Canal Reliability Center Project performing a transmission function operating to meet an ISO-identified transmission need:
  - There were no identified reliability needs in the planning horizon driving the need for the project;
  - The production cost benefits associated with the storage facility arise from the resource functioning as a market resource and participating in the ISO market; and,
  - The local capacity benefits associated with the storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.
- Other storage projects in the local capacity area studied in this planning cycle also provide benefit to cost ratios in the same range as found in this study. These would also need to be reassessed when the CPUC's IRP process provides direction on expectations for the gas-fired generation fleet in the area.

4.9.12 San Diego Non-Bulk Sub-areas

SDG&E submitted three projects in the 2018 Request Window that would potentially reduce or eliminate local capacity requirements in the El Cajon, Border and Pala sub-areas.

El Cajon Sub-area Local Capacity Requirement Reduction Project

The 2028 LCR study identified that the most critical contingency for the El Cajon sub-area was the Category C contingency of the Granite-Los Coches 69 kV Nos.1&2 lines, which would overload the El Cajon-Los Coches 69 kV line. The project proposed by SDG&E would reconductor the limiting Los Coches-El Cajon 69 kV line to a minimum continuous rating of 77 MVA. The estimated project cost provided by SDG&E is $28~$43 million.

However, the San Diego/Imperial Valley area local capacity requirement would also need to be reduced in order to reduce the need for the gas-fired generation in the El Cajon sub-area. Taking the lowest cost option for that constraint, the S-Line Series Reactor option described in section 4.9.11.1 would be one low cost option for accomplishing this reduction, and the cost of that project is estimated at $30 million. Combining the cost of the reconductoring project and the S-Line Reactor option would increase the cost to the point that the benefits of reducing the El Cajon sub-area local capacity requirements would not exceed the costs of the upgrades.

Without a broader strategy to reduce local capacity requirements in the Imperial Valley/San Diego area, it is not economic to proceed unilaterally on the proposed project.

Border Sub-area Local Capacity Requirement Reduction Project

The 2028 LCR study identified that the most critical contingency for the Border sub-area was the Category C outage of the Bay Boulevard-Otay 69 kV Nos.1&2 lines, which would overload the Imperial Beach-Bay Boulevard 69 kV line. The project proposed by SDG&E would reconductor the Imperial Beach-Bay Boulevard 69 kV line to a minimum continuous rating of 110 MVA. The estimated project cost provided by SDG&E is $6~$10 million. The project could potentially reduce the local LCR need from 70 MW to 18 MW.

However, the San Diego/Imperial Valley area local capacity requirement would also need to be reduced in order to reduce the need for the gas-fired generation in the Border sub-area. Taking the lowest cost option for that constraint, the S-Line Series Reactor option described in section 4.9.11.1 would be one low cost option for accomplishing this reduction, and the cost of that project is estimated at $30 million. Combining the cost of the reconductoring project and the S-Line Reactor option would increase the cost to the point that the benefits of reducing the Border sub-area local capacity requirements would not exceed the costs of the upgrades.

Without a broader strategy to reduce local capacity requirements in the Imperial Valley/San Diego area, it is not economic to proceed unilaterally on the proposed project.

4.10 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; three such projects were identified as potential options for study of economic benefits as set out in chapter 5:

- Southwest Intertie Project – North (SWIP - North)
- North Gila - Imperial Valley #2 500 kV Transmission Project (NG-IV#2)
- HVDC conversion

Overall, 11 areas, sub-areas, and transmission paths were studied, and potential benefits impacting a 12th area were also assessed for several projects. This entailed consideration of 25 proposals 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.

Table 4.10-1 summarizes the overall economic planning study results in the 2018-2019 planning cycle.

Table 4.10-1: Summary of economic assessment in the 2018-2019 planning cycle

Congestion or study area	Benefits Consideration	Economic Justification
COI 5100 MW path rating increase	Production cost ratepayer benefits not sufficient	No
SWIP - North	Production cost ratepayer benefits not sufficient	No
Giffen Line Reconductoring Project	Production cost ratepayer benefits sufficient	Yes
Path 26 4000 MW South to North path rating increase	Production cost ratepayer benefits not sufficient	No
California Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Colorado River – Julian Hinds	Production cost ratepayer benefits not sufficient	No
Pease sub-area	Local capacity benefits not sufficient	No
Hanford sub-area (2 options)	Local capacity benefits not sufficient	No
Kern Oil sub-area	Local capacity benefits not sufficient	No
Mira Loma Dynamic Reactive Support	Local capacity benefits not sufficient	No
Red Bluff – Mira Loma 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Southern California Regional LCR Reduction Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
S-Line Series Reactor	Production cost benefits sufficient, needs further assessment when S-	No

Congestion or study area	Benefits Consideration	Economic Justification
	Line Upgrade configuration is finalized[133]	
HVDC Conversion	Production cost ratepayer benefits and local capacity benefits not sufficient	No
North Gila – Imperial Valley #2 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Lake Elsinore Advanced Pumped Storage (LEAPS) Project (2 options)	Production cost ratepayer benefits and local capacity benefits not sufficient	No
San Vicente Energy Storage Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore Reliability Energy Storage (SRES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore 230 kV Energy Storage (SES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Westside Canal Reliability Center (Westside) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
El Cajon Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No
Border Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No

[133] The ISO is pursuing revisions to the scope of the previously approved S-Line Transmission Upgrade to consist of an appropriately sized single circuit 230 kV circuit, which provides the same local capacity requirement reduction value to the ISO as the original double-circuit line. As well, the ISO is updating the estimated cost to ISO ratepayers of the S-Line upgrade from $32 million to $40 million in light of revised costs estimates provided by IID. This increase in estimated cost would be offset by the savings of no longer needing a new line termination at the Imperial Valley Substation, which was required under the original double circuit configuration. The impact this change may have on benefits associated with other project proposals will be considered in future planning cycles.

In summary, one transmission solution – the Giffen Line Reconductoring Project, estimated to cost less than $5 million – was found to be needed as an economic-driven project in the 2018-2019 transmission planning cycle.

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 2018-2019 transmission planning cycle marks the beginning of the second biennial cycle since these coordination processes were put in place, replacing other mechanisms that pre-dated FERC Order No. 1000. This cycle reflects the complete transition from old process to new, taking into account the status of the policy drivers and the progress achieved in implementing the new interregional processes.

The first biennial coordination process was conducted in conjunction with the ISO's 2016-2017 and 2017-2018 annual transmission planning cycles. As discussed in Chapter 1, state directives then and now continue to focus on increasing California's renewable energy goals beyond 33 percent, and it was necessary to transition to the new processes taking into account the activities underway and the status of policy direction at the time. Clearly, an outcome of SB 350 was the consideration that new investments in the state's electric transmission system would be required to achieve the renewable energy goals being established by the state. To assist in this effort, the ISO partnered with the CEC and the CPUC to conduct the Renewable Energy Transmission Initiative (RETI) 2.0. The ISO was uniquely positioned to participate in this process to help identify potential transmission opportunities that could access and integrate renewable energy opportunities from regions outside of California. Through its involvement in interregional coordination activities, the ISO considered the ITPs proposed in the 2016-2017 interregional coordination cycle as a reasonable measure to assess the potential out-of-state transmission opportunities for California and as such, proposed they be considered within the RETI 2.0 assessment framework. As a result, these ITPs were assessed and considered in the ISO's 2016-2017 and 2017-2018 planning cycles as "special studies" of the 50% RPS that had been established at that time. The ISO concluded its consideration of these special studies in its 2017-2018 planning cycle and documented its results in that transmission plan and a 2016-2017 transmission plan supplemental report.

In the context of the ISO's completion of these "special studies", it is important to remind stakeholders that the ISO's consideration of the ITPs in the 2016-2017 interregional coordination cycle exceeded the study obligations the tariff requires of the ISO and other western planning regions (WPRs). In reality, the "special studies" performed by the ISO, while providing useful information for the California's RPS initiatives, went beyond obligations of Order No. 1000, as the ISO advised stakeholders during the 2016-2017 and 2017-2018 transmission planning cycles. Hence, that is why the ISO referred to them as "special studies".

Moving forward into the 2018-2019 interregional coordination cycle, the ISO has considered and documented its results of those ITPs that were proposed in its 2018-2019 transmission plan under the processes specified in the ISO tariff. This aligns with the policy direction and input received from the CPUC and CEC. Section 24 of the ISO tariff and the BPM for the Transmission Planning Process provide detail of the ISO's interregional coordination responsibilities. As such, chapter 5 of this transmission plan transmission plan intends to provide the reader with a clearer understanding of the interregional coordination process and how the ISO meets its Order No. 1000 interregional coordination responsibilities and presents its most current engagement with WECC on the Anchor Data Set.

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. FERC issued its final rule in July 2011[134] and adopted certain reforms to the electric transmission planning and cost allocation requirements for 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. These additional reforms affected the ISO's existing regional transmission planning process and resulted in the ISO collaborating more closely with neighboring transmission utility providers and planning regions across the Western Interconnection to develop a coordinated process for considering interregional projects. These regional and interregional reforms were designed to work together to ensure an opportunity for more transmission projects to be considered in transmission planning processes on an open and non-discriminatory basis both within planning regions and across multiple planning regions.

Although the ISO's prior tariff was largely compliant with order, some adjustments were necessary to fully align with the order's requirements in a number of areas, including the establishment of the ISO as one of four western planning regions established within the Western Interconnection. The ISO implemented these adjustments in early 2014.

Regarding interregional requirements, the WPRs developed a common interregional tariff that became effective in 2015. Through the common tariff and coordination efforts among the WPR members, certain business practices were developed 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 have been 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 its activities in past planning cycles, the ISO has 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. Although Order No. 1000 left some ambiguity regarding aspects of interregional coordination 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

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

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. ITP submittals must indicate whether or not they are seeking cost allocation from the planning region, list all WPRs that they have submitted their ITP to, and 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.

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

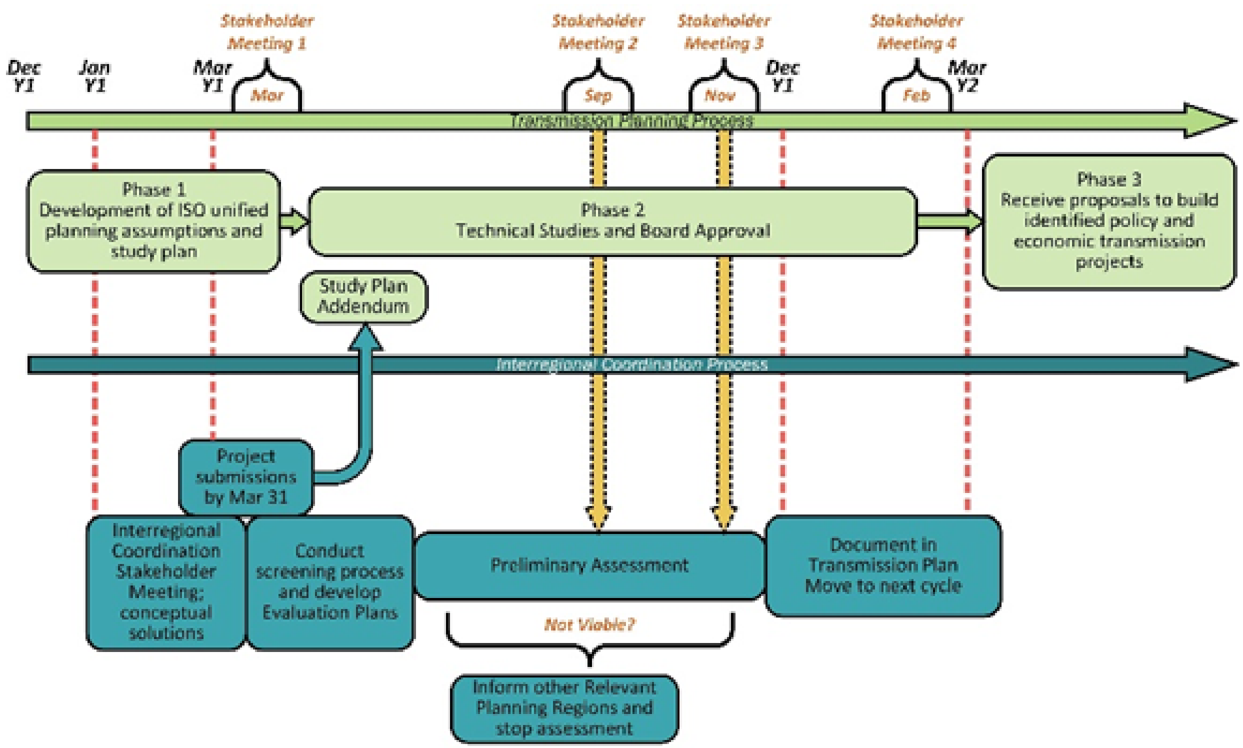
The even year ITP assessment begins when the relevant planning regions initiate the coordinated ITP evaluation process. This evaluation process constitutes the relevant planning regions' formal process to identify and jointly evaluate transmission facilities that are proposed to be located in planning 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

Figure 5.3-1 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



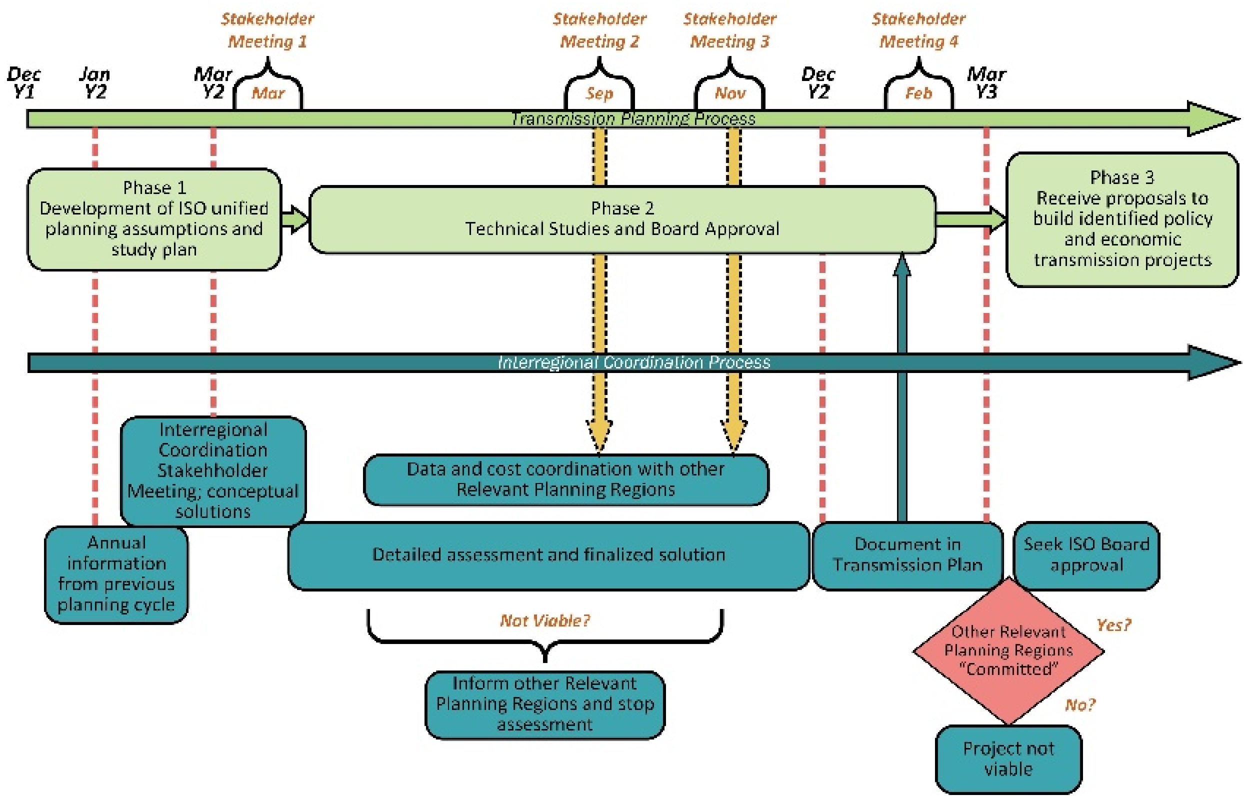
The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation to continue or not continue assessment of the ITP in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission 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.

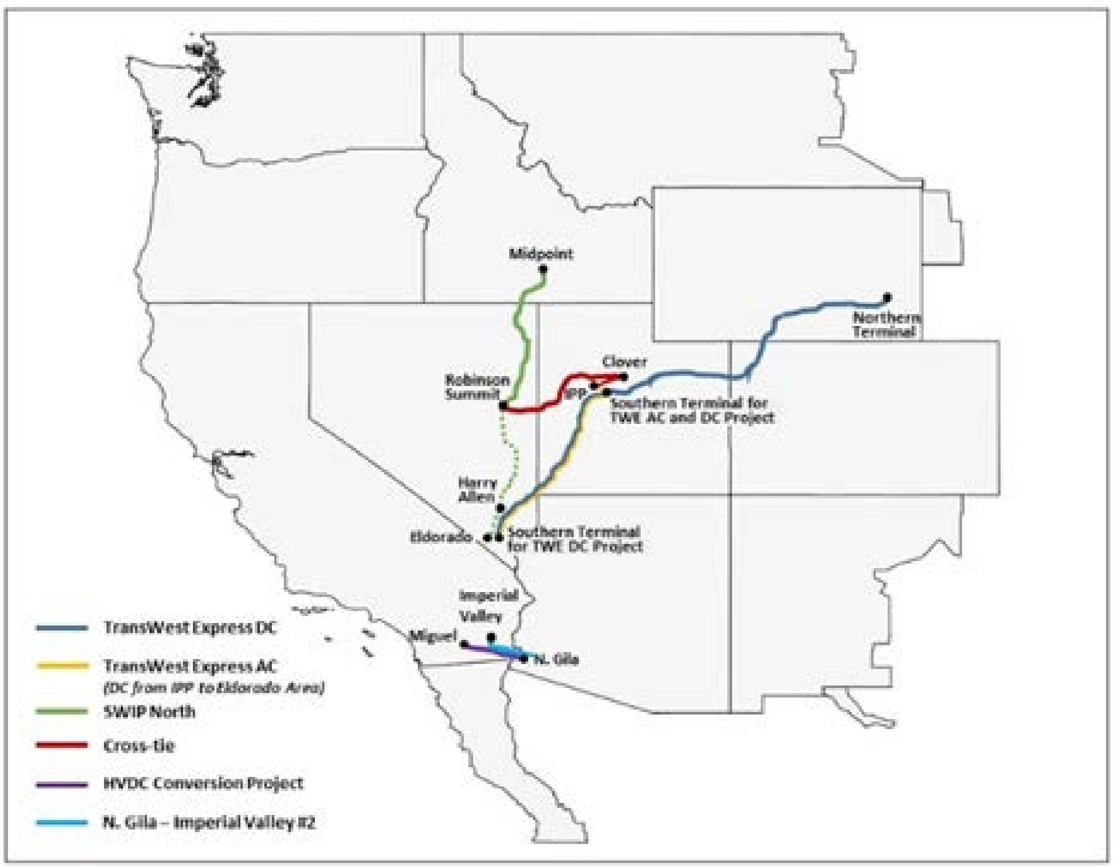
If the ISO determines that the proposed ITP is a more efficient or cost effective solution to meet an ISO-identified regional need and the ITP can be constructed and operational in the same timeframe as the regional solution, the ISO will then consider the ITP as the preferred solution in the ISO transmission 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 2018-2019 Interregional Transmission Coordination ITP Submittals to the ISO

The ISO hosted its 2018-2019 ITP submission period in the first quarter of 2018 in which proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2018-2019 transmission planning process. The submission period began on January 1st and closed March 31st where six interregional transmission projects and their documentation[135] were submitted for consideration by the ISO. Of the six projects submitted, four projects were submitted into the 2016-2017 interregional transmission coordination cycle and were resubmitted into the 2018-2019 cycle. The submitted projects are shown in Figure 5.4-1.

Figure 5.4-1 Interregional Transmission Projects Submitted to the ISO



135 http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

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, a result of which was the coordinated development of "ITP Evaluation Process Plan(s)" for each of the ITPs submitted to the ISO[136]. Given the intent of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP, these evaluation plans satisfy that intent and as such, fulfills Order 1000's requirement of the relevant planning regions to jointly coordinate regional planning processes that evaluate an the ITP. In doing so, the evaluation plans document a common framework, coordinated by the WPRs, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process. The ISO then utilizes this information in its development of all planning data and information that is required for the ISO to assess the ITP in its transmission planning process. Specifically, the information in the evaluation plans is considered an addendum to the approved Transmission Planning Process Unified Planning Assumptions and Study Plan.

5.4.1 2018-2019 Interregional Transmission Coordination ITP Submittals

During the course of this year's planning cycle, the ISO considered all six ITPs that were submitted during the ITP submission period. The proposed ITPs, their sponsor's identified need, and the ISO's identified need as determined by the ISO's assessment are summarized in Table 5.4-1. Where appropriate, additional assessment information in provided in section 0 through section 5.4.1.6.

Table 5.4-1: ITPs Submitted into the 2018-2019 Submission Period

Proposed ITP	Sponsor Identified Need	Cost Allocation	ISO Identified Need in this Planning Cycle
Cross-Tie	Strengthen interconnection between PacifiCorp and Nevada; facilitate California's RPS and GHG needs	ISO, NTTG, WestConnect	None: Based on 2018-2019 plan assumptions
HVDC Conversion	Improve/remove existing reliability limitation; decrease San Diego and greater IV/San Diego LCR requirement	Not Requested	Reliability: None Economic: None - BCR less than 1.0
NG-IV#2	Decrease San Diego and greater IV/San Diego LCR requirement	ISO, WestConnect	Reliability: None Economic: None - BCR less than 1.0
SWIP - North	Economic, policy, reliability, reduce congestion on COI, facilitate access to renewables in PacifiCorp	ISO, NTTG, WestConnect	Reliability: None Economic: None - BCR less than 1.0
TransWest Express AC/DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions
TransWest Express DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions

136 Id.

5.4.1.1 Cross-Tie Transmission Project

A summary of the ITP information submitted to the ISO is shown in Table 5.4-2.

Table 5.4-2: ITP Submittal Information for the Cross-Tie Transmission Project

Project Submitted To:	California ISO, Northern Tier Transmission Group ("NTTG") and WestConnect
Relevant Planning Regions:	NTTG and WestConnect
Cost Allocation Requested From:	California ISO, NTTG and WestConnect

Stated Purpose of the Project

The stated purpose of the Cross-Tie Project is that it would couple with the planned Gateway South Project (Aeolus – Clover), the existing One Nevada Line (Robinson Summit – Harry Allen) and the currently under construction Harry Allen – Eldorado 500 kV transmission project and would provide needed transmission capacity between the Intermountain West (Utah/Wyoming) region of NTTG and the Desert Southwest portion of WestConnect. The project proponent states that this additional transmission capacity would facilitate access between the significant renewable resources in Wyoming/Utah and diverse utility load profiles in Desert Southwest/California. Also, this interregional project would result in lowering the cost of RPS compliance for the Desert Southwest and California while enhancing opportunities to balance the renewable resource mix between the Desert Southwest, California and the Intermountain West. The project would also facilitate the ISO in meeting California's RPS and GHG requirements by providing transmission access to high capacity wind resources in Utah and Wyoming.

Project Description

TransCanyon, LLC (TransCanyon) submitted the 213-mile Cross-Tie Transmission Project (Cross-Tie Project) for consideration as an ITP. The Cross-Tie project is a proposed 1500 MW, 500 kV HVAC transmission project that would be constructed between central Utah and east-central Nevada (see Figure 5.4-2), connecting PacifiCorp's proposed 500 kV Clover substation (in the NTTG planning region) with NV Energy's existing 500 kV Robinson Summit substation (in the WestConnect planning region). The proposed project would include series compensation at both ends of the Cross-Tie transmission line. In addition, series compensation would be needed on the existing Robinson Summit to Harry Allen 500-kV line along with phase shifting transformers at Robinson Summit 345-kV.

The project would be required to satisfy the requirements of the National Environmental Policy Act (NEPA) and the Bureau of Land Management (BLM). A significant portion of the routing of the line has been previously studied under the Southwest Intertie Project Environmental Impact Statement, which received federal approval in a Record of Decision published in 1994 but was not constructed. Further, the project would be subject to the state approval processes applicable for Nevada and Utah. According to TransCanyon, the project could be in-service as early December 2024.

Figure 5.4-2 : Cross-Tie Project Overview

Reliability Assessment

None performed

Economic Assessment

None Performed

Conclusions

The stated purpose of the Cross-Tie Project is a transmission solution that would “provide needed transmission capacity between the Intermountain West (Utah/Wyoming) region of NTTG and the Desert Southwest portion of WestConnect” and “facilitate access between the significant renewable resources in Wyoming/Utah and diverse utility load profiles in Desert Southwest/California.” However the study assumptions and the reliability, policy, and economic regional assessments documented in this study do not support finding this project needed in this planning cycle.

5.4.1.2 HVDC Conversion Project

A summary of the ITP information submitted to the ISO is shown in Table 5.4-3.

Table 5.4-3: ITP Submittal Information for the HVDC Conversion Project

Project Submitted To:	California Independent System Operator (California ISO), WestConnect
Relevant Planning Regions:	California ISO, WestConnect
Cost Allocation Requested From:	Not requested

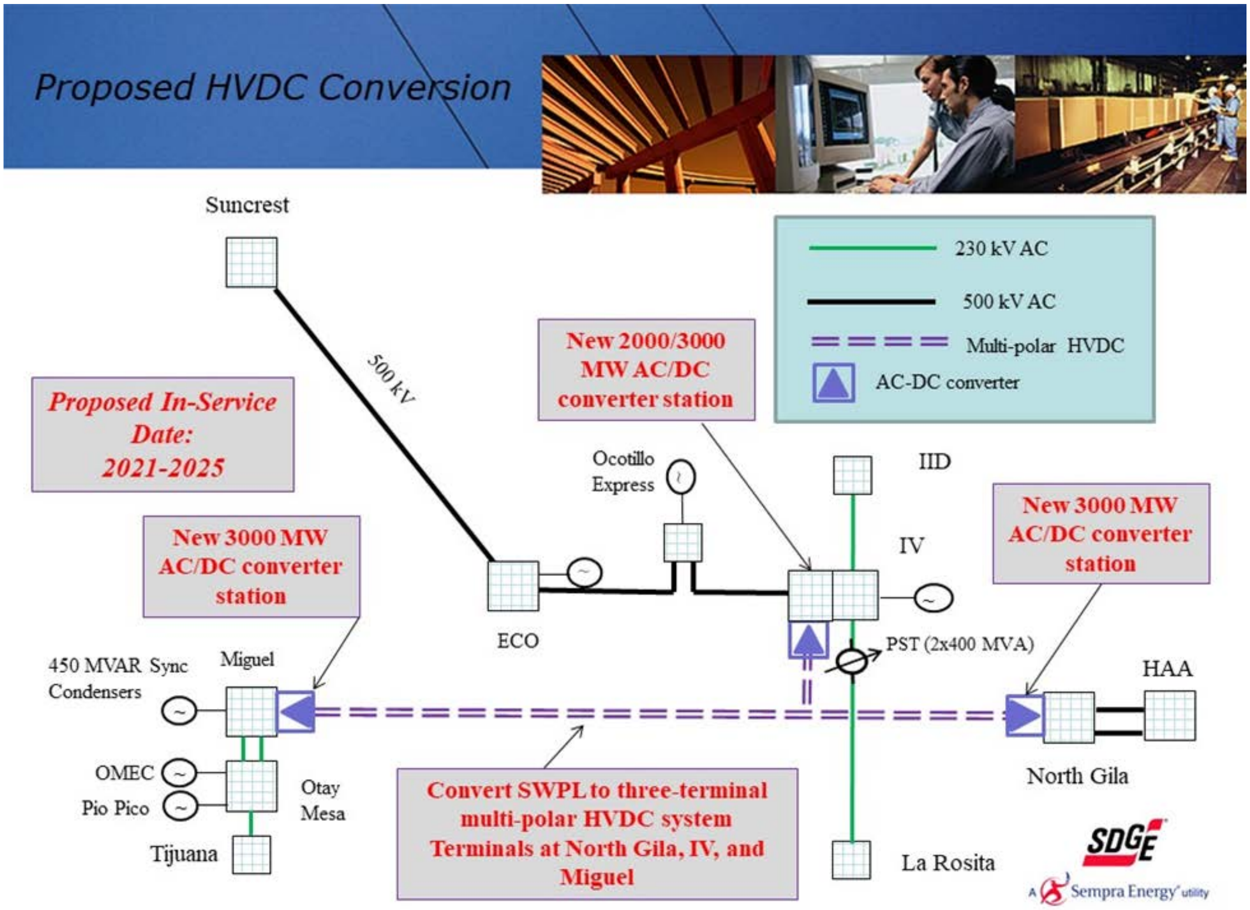
Stated Purpose of the Project

The stated purpose of the HVDC Conversion Project is that it would optimize the transfer capability on existing infrastructure leading significant interregional benefits such as solving an existing loop flow issue for multiple parties (APS, SDG&E, IID, and CENACE), reducing the interdependency of the southern West of River 500 kV system with IID's bulk power system, minimizing permitting and new ROW requirements, and integrating with newly installed synchronous condenser installations. The proposed project would be constructed within existing rights of way and within or adjacent to existing substations thus minimizing environmental and permitting related impacts.

Project Description

San Diego Gas and Electric (SDG&E) submitted the HVDC Conversion Project to WestConnect and the California ISO as an ITP. The proposed project would convert a portion of the 500 kV Southwest Powerlink (SWPL) to a multi-terminal, multi-polar HVDC system with terminals at North Gila (500 kV), Imperial Valley (500 kV), and Miguel Substations (230 kV). A project map of the proposed project is shown in Figure 5.4-3.

Figure 5.4-3: HVDC Conversion Project



Reliability Assessment

The HVDC Conversion Project would be part of the SDG&E area and its reliability assessment was considered as part of the overall assessment of the existing LCR areas in the SDG&E and LA Basin areas. The details of these LCR results are documented in section 4.8.7 and section 4.9.11.2.

Economic Assessment

An economic assessment of the HVDC Conversion Project was performed to determine any economic benefits that could be assigned to this project. The results of the economic analysis is discussed in detail in Section 4.9.11.2.

Production Cost Assessment

Production cost analysis was performed with and without the HVDC Conversion Project transmission project to quantify any production cost benefits that would result from the project. In general the assessment showed that adding the project to the network would increase congestion along the IV to San Diego corridor and on Path 26. Renewable curtailment was reduced in the IV area but increased in most other southern California areas. The results of the production cost assessment showed an ISO Net Payment or cost to the ISO ratepayer of approximately -$13M/year. The net present value of these annual payments is approximately -$82.80M.

Local Capacity Benefits

A primary benefit that the HVDC Conversion Project transmission project could bring to ISO ratepayers is a reduction in LCR in the San Diego-Imperial Valley area. Studies with and without the HVDC Conversion Project transmission project were performed to assess the impact of this project on the LCR in the SDG&E and SCE areas. In general the results of the LCR analysis showed that the HVDC Conversion Project transmission project would reduce LCR need in the San Diego – Imperial Valley area by approximately 690 MW. However, due to the reduced generation dispatched in the SDG&E area, the LCR need in the western LA Basin increased by approximately 40 MW. The net LCR benefit of the HVDC Conversion Project transmission project is the difference between the LCR cost increase in the LA Basin and the LCR cost reduction in the San Diego-Imperial Valley area.

As discussed in section 4.3.4 the basis for the local price may depend on the circumstances within the local capacity area. For the evaluation of the HVDC Conversion Project transmission project the LCR reductions in southern California were valued as the difference between local and system capacity and between local and “south of path 26 system” resources. The results of the LCR analysis showed that the net LCR benefits that could be attributed to the HVDC Conversion Project transmission project would be $20.7M/year. The net present value of these annual LCR benefits would be approximately $284.6M.

Benefit to Cost Ratio

The benefit to cost ratio is based on the results of the production cost and LCR analyses the net present value of their resultant benefits based on a 50 year project life. Based on the net present value of benefits discussed above the calculated benefit to cost ratio of the HVDC Conversion Project is:

- -0.05 for local versus system capacity cost
- -0.01 for local versus SP 26 capacity cost.

Conclusions

The benefit-to-cost ratio determined in this study does not support finding this project needed in this planning cycle. Further, the local capacity reduction benefits may be eroded if other options proceed that address the S-Line overload concern that presently sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relies heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC’s integrated resource planning process.

5.4.1.3 North Gila-Imperial Valley #2 Transmission Project

A summary of the ITP information submitted to the ISO for the North Gila-Imperial Valley #2 (NG-IV#2) Transmission Project is shown in Table 5.4-4.

Table 5.4-4: ITP Submittal Information for the North Gila-Imperial Valley #2 Transmission Project

Project Submitted To:	California Independent System Operator (California ISO), and WestConnect
Relevant Planning Regions[137]:	California ISO, and WestConnect
Cost Allocation Requested From:	California ISO, and WestConnect

Stated Purpose of the Project

The stated purpose of the NG-IV#2 project is that it would improve reliability for the southern California and southwest Arizona areas, especially for contingencies involving loss of the existing North Gila – Imperial Valley line, and increase the West of Colorado River (WECC Path 46) and East of Colorado River (WECC Path 49) transfer capability. The proponents state that from the Project would enable access to additional renewable resources in the solar and geothermal rich areas of Imperial Valley and Arizona to for the benefit of California's Renewable Portfolio Standard and Greenhouse Gas reduction targets. Also, the project may also provide quantifiable economic benefits in the form of production cost savings, congestion relief and reduced Local Capacity Requirements in the southern region of the ISO.

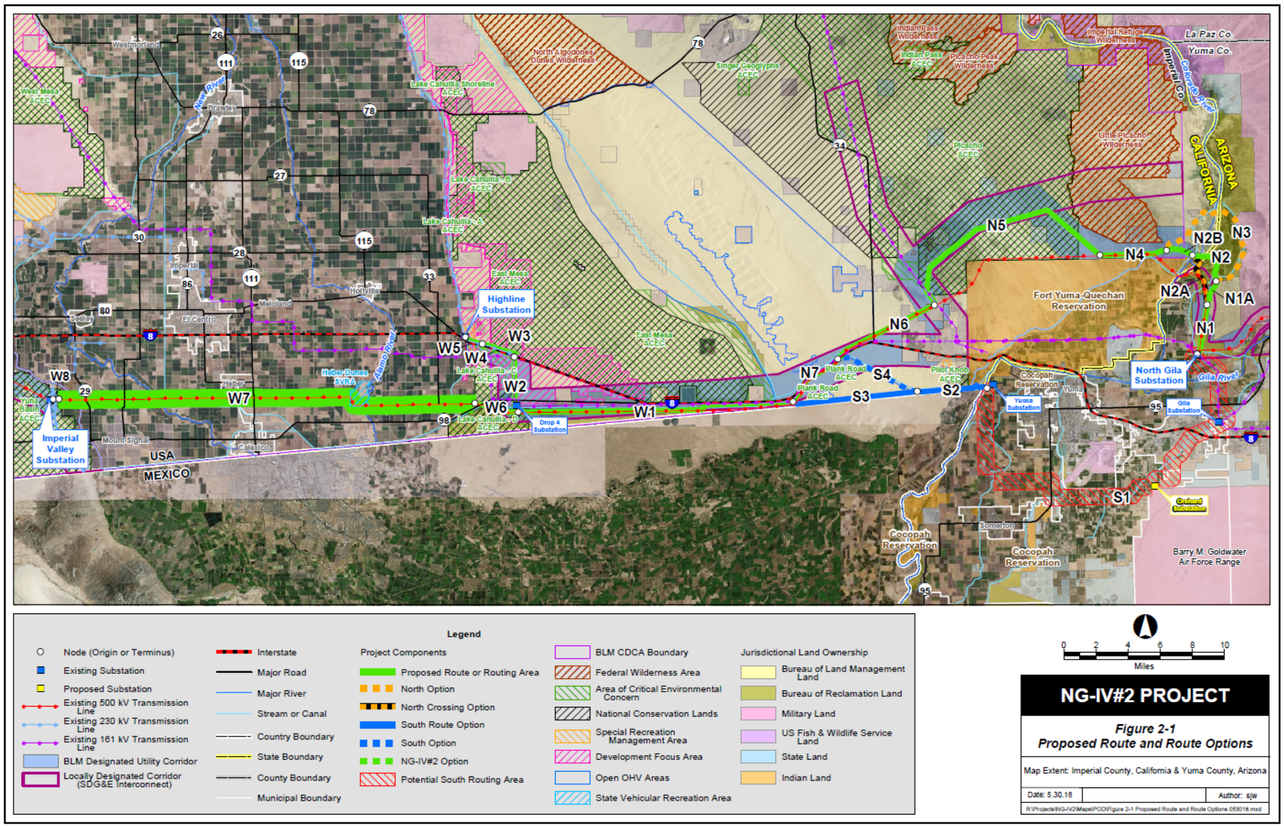
Project Description

Southwest Transmission Partners, LLC (Southwest Transmission Partners) and ITC Grid Development, LLC (ITC Grid Development) submitted the 97-mile North Gila-Imperial Valley #2 (NG-IV#2) Transmission Project for consideration as an ITP. The NG-IV#2 transmission project is a proposed 500 kV HVAC transmission project that could be constructed between southwest Arizona and southern California (see Figure 5.4-4). The line would parallel the existing North Gila-Imperial Valley line, also known as the Southwest Power Link (SWPL), and would connect the existing 500 kV North Gila substation (in the WestConnect planning region) with the existing 500 kV Imperial Valley substation (in the California ISO planning region) through an interconnection with a new 500/230 kV Highline substation (in the WestConnect planning region), interconnecting to the existing IID Highline 230 kV substation. It is expected that this project would become an additional component of the West of Colorado River path (Western Electricity Coordination Council (WECC) path 46) and could increase the East of Colorado River path (WECC path 49) transfer capability as well. Series compensation could be added to the project to balance flows between this new circuit and the existing SWPL line.

[137] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

The project submitters have initiated the National Environmental Policy Act (NEPA) process with several proposed alternative proposed routes and have a National Program team from BLM assigned and engaged to lead the NEPA process. According to Southwest Transmission Partners and ITC Grid Development, the project could be in-service as early as December 2022.

Figure 5.4-4 : North Gila-Imperial Valley #2 Transmission Project Overview



Reliability Assessment

The NG-IV#2 transmission project would be part of the SDG&E area and its reliability assessment was considered as part of the overall SDG&E area assessment which is discussed in detail in Section 2.9 of this transmission plan.

The reliability assessment of the SDG&E area without the NG-IV#2 project identified several system performance issues in SDG&E's main and sub-transmission systems. After consideration of proposed transmission solutions submitted to the ISO through its request window, the ISO found that non-transmission alternatives were the more cost effective or efficient regional solutions to meet the reliability needs identified in SDG&E area studies. An analysis of the SDG&E area with the NG-IV#2 transmission project was performed to assess the impact of the project on SDG&E's main and sub-transmission systems. The results of this assessment showed that the NG-IV#2 transmission project would increase flows into the SDG&E area and worsen identified system performance issues already identified in the regional assessment to the point that the identified regional solutions would no longer be sufficient to address the system performance issues identified in the regional assessment. Study results also showed that part of the increased flow into the SDG&E area would increase power flow across the CENACE system and negatively impact reliability in the CENACE system and result in potential voltage instability in the Los Angeles Basin and the San Diego area.

Economic Assessment

An economic assessment of the NG-IV#2 transmission project was performed to determine any economic benefits that could be assigned to this project. The results of the economic analysis is discussed in detail in Section 4.9.11.3.

Production Cost Assessment

A production cost analysis was performed with and without the NG-IV#2 transmission project to quantify any economic benefits that would result from the project. In general the assessment showed that the proposed project could bring an annual ISO Ratepayer Net Payment of approximately $6M/year. The net present value of these ISO ratepayer savings is approximately $82.80M.

Local Capacity Benefits:

A primary benefit that the NG-IV#2 transmission project could bring to ISO ratepayers is a reduction in LCR in the San Diego-Imperial Valley area. Studies with and without the NG-IV#2 transmission project were performed to assess the impact of this project on the LCR in the SDG&E and SCE areas. In general the results of the LCR analysis showed that the NG-IV#2 transmission project would reduce LCR need in the San Diego – Imperial Valley area by approximately 865 MW. However, due to the reduced generation dispatched in the SDG&E area, the LCR need in the western LA Basin increased by approximately 100 MW. The net LCR benefit of the NG-IV#2 transmission project is the difference between the LCR cost increase in the LA Basin and the LCR cost reduction in the San Diego-Imperial Valley area.

As discussed in section 4.3.4 the basis for the local price may depend on the circumstances within the local capacity area. For the evaluation of the NG-IV#2 transmission project the LCR reductions in southern California were valued as the difference between local and system capacity and between local and “south of path 26 system” resources. The results of the LCR analysis showed that the net LCR benefits that could be attributed to the NG-IV#2 transmission project would be $23.8M/year. The net present value of these ISO ratepayer savings is approximately $329.6M

Benefit to Cost Ratio

The benefit to cost ratio is based on the results of the production cost and LCR analyses the net present value of their resultant benefits based on a 50 year project life. Based on the net present value of benefits discussed above the calculated benefit to cost ratio of the NG-IV#2 transmission project is

- 0.57 for local versus system capacity cost
- 0.74 for local versus SP 26 capacity cost

Conclusions

The benefit to cost ratio determined in this study does not support finding this project to be needed in this planning cycle. Further, the project would require mitigations of the reliability concerns in the San Diego sub-area, and the benefits may be eroded if other options proceed that address the S-Line overload concern that sets the requirement for San Diego/Imperial Valley local capacity requirements. As the project relies heavily on local capacity requirement reduction benefits, the conservative assumptions used in this planning cycle to assess those benefits have a material effect on the outcome, and the project may need to be revisited in future planning cycles when longer term direction regarding gas-fired generation is received through the CPUC's integrated resource planning process.

5.4.1.4 SWIP - North Project

A summary of the ITP information submitted to the ISO for the SWIP - North Project is shown in Table 5.4-5.

Table 5.4-5: ITP Submittal Information for the SWIP - North Project

Project Submitted To:	California Independent System Operator ("California ISO"), Northern Tier Transmission Group ("NTTG") and WestConnect
Relevant Planning Regions:	California ISO, NTTG and WestConnect
Cost Allocation Requested From:	California ISO, NTTG and WestConnect

Stated Purpose of the Project

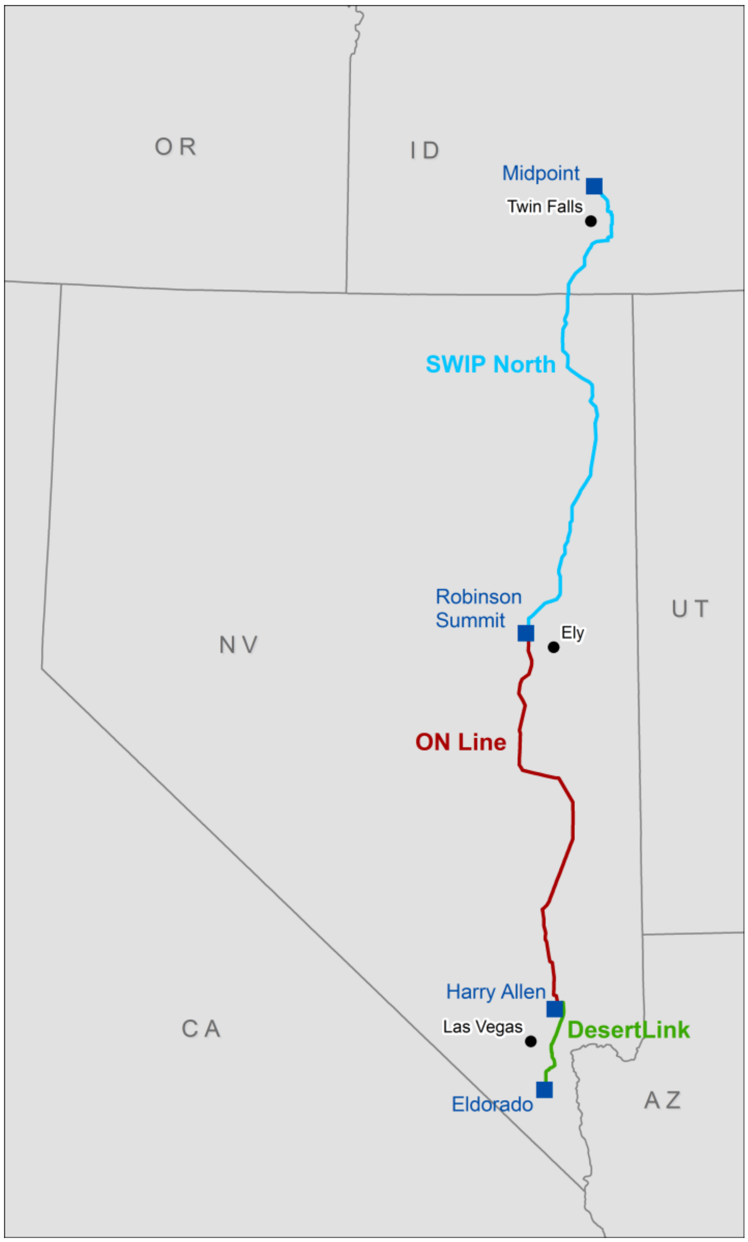
The stated purpose of the SWIP - North Project is that it would provide a new backbone for the western grid that would provide not only economic benefits, but additional reliability benefits and insurance against emergency outage scenarios. The proponent also states that the project would provide benefits related to congestion relief on COI, energy market value, integrating renewables that support GHG and RPS policy goals, EIM benefits, increased capacity benefits, increased load diversity, wheeling revenues, insurance value and reliability benefits.

Project Description

As set out in Chapter 2, the SWIP - North Project was submitted in the 2018 Request Window as a transmission solution to address thermal overloads on the 500 kV and 230 kV systems in northern California and to improve low voltage issues in northern California during summer peak conditions with high COI N-S flows. The project was also proposed by a non-PTO, Great Basin Transmission (GBT), LLC, an affiliate of LS Power, as a Reliability Transmission Project and as part of an economic study request as set out in chapter 4.

The SWIP - North Project connects the Midpoint 500 kV substation (in NTTG) to the Robinson Summit 500 kV substation (in WestConnect) via a 275-mile, 500kV single circuit AC transmission line (see Figure 5.4-5). The project is expected to have a bi-directional WECC-approved path rating of approximately 2000 MW. Upon completing a new physical connection at Robinson Summit a capacity sharing arrangement would be triggered between GBT and NV Energy across the already in-service ON-Line Project and SWIP-N that would provide GBT with control of ~1,000 MW bi-directional capacity between Midway and Harry Allen.

Figure 5.4-5: SWIP-N Map of Preliminary Route



Reliability Assessment

The SWIP - North project was considered in the system assessment of PG&E's bulk transmission system which is discussed in section 2.4.4 of this transmission plan. Based on the reliability assessments performed in this planning cycle, the ISO did not identify any reliability needs that the project was required to mitigate.

The ISO considers the SWIP - North project to be an ITP due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and NTTG planning regions, respectively, and is not physically connected to ISO-controlled facilities. The scheduling capacity from the Harry Allen end of the ISO's approved Harry Allen-Eldorado transmission line to Robinson Summit also creates opportunity for the submitted project to provide benefits to the ISO, in which case the ISO can select to participate in the project – if that is found to be the preferred solution to meeting the ISO's regional need.

Economic Assessment

An economic assessment of the SWIP - North transmission project was performed to determine any economic benefits that could be assigned to this project. The results of the economic analysis is discussed in detail in section 4.9.1.2.

Production Cost Assessment

A production cost analysis was performed with and without the SWIP - North project to quantify any economic benefits that would result from the project. These results showed that there would be a net increase in ISO ratepayer costs of approximately -$21M/year while at the same time an overall WECC benefit through lower production costs over the entire WECC footprint. It is worth noting that while ISO ratepayer costs increased and WECC production costs increased, the ISO concluded that the SWIP - North transmission project may not provide incremental import from Northwest regions during some hours when there is no energy surplus in those regions. While the presumption of this result depends on resource and transmission assumptions in northwest regional models, it appears that this project may allow more exports from California to other regions when there are renewable energy surpluses within California. In addition, lower priced imports can result in increased profits to out-of-state generation and reduced profits to ISO owned generation in the ISO footprint whose profits accrue to ISO ratepayers.

Local Capacity Benefits

None performed

Benefit to Cost Ratio

None performed

Conclusions

The SWIP - North project, on a standalone basis and without support from other areas that may benefit from the project, was not supported by the findings in the 2018-2019 transmission planning studies. The ISO expects that dialogue will continue with neighboring planning regions as their own plans evolve, and as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement.

5.4.1.5 TransWest Express AC/DC Project

A summary of the ITP information submitted to the ISO for the TransWest Express AC/DC Project is shown in Table 5.4-6.

Table 5.4-6: ITP Submittal Information for the TransWest Express AC/DC Project

Project Submitted To:	**California Independent System Operator (California ISO), Northern Tier Transmission Group (NTTG), WestConnect**
Relevant Planning Regions[138]:	California ISO, NTTG, WestConnect
Cost Allocation Requested From:	California ISO, WestConnect

Stated Purpose of the Project

The stated purpose of the TWE AC/DC Project is that it would provide needed transmission capacity between the Desert Southwest and California regions, represented by ISO and WestConnect, and the Rocky Mountain region, represented by NTTG and WestConnect. This additional transmission capacity would facilitate access between diverse renewable resources and diverse utility load profiles. The proponent states that the TWE AC/DC Project would facilitate access to the Desert Southwest/California market to Wyoming's vast renewable wind resources and would lower the cost of RPS compliance for the Desert Southwest while simultaneously providing the vast solar resources in the Desert Southwest with access to Rocky Mountain regional markets, such as the Denver and Salt Lake City metro areas.

Project Description

The TWE AC/DC Project consists of a proposed 406-mile, phased 1,500/3,000 MW, ±500 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and central Utah, and a 324- mile, 1,500 MW 500 kV alternating current transmission system with terminals in central Utah and southeastern Nevada.

The TWE AC/DC Project northern terminal will be interconnected at 230 kV to the existing PacifiCorp 230 kV transmission line between the Platte and Latham substations and the planned 500 kV Gateway West D.2 segment in the NTTG planning region, and to the 3,000 MW Chokecherry and Sierra Madre Wind Energy Project.[139] The TWE AC/DC Project design provides for connecting the northern terminal to the existing 230 kV Western Area Power Administration system in the WestConnect planning region near the Miracle Mile substation.

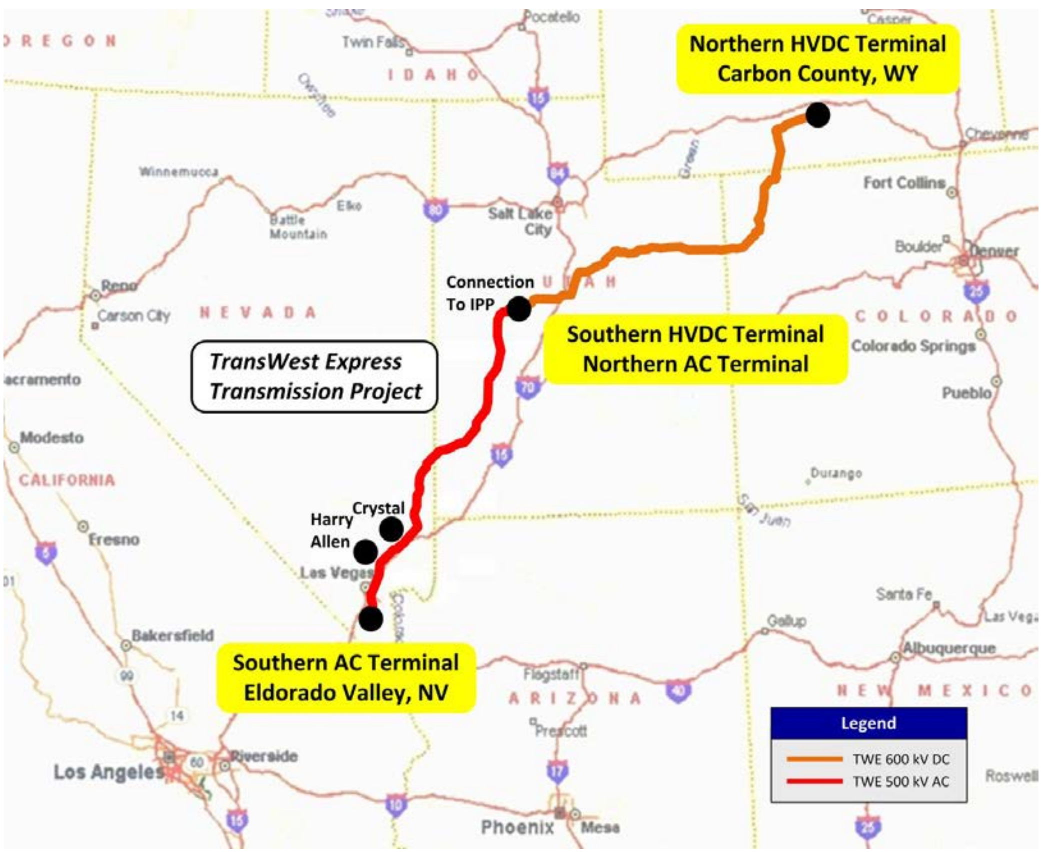
[138] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

[139] The Chokecherry and Sierra Madre Wind Energy Project is being developed in two 1,500 MW phases by Power Company of Wyoming LLC, an affiliate of TransWest. More information about PCW and the CCSM Project is available at www.powercompanyofwyoming.com.

The TWE AC/DC Project's Utah, or southern DC, terminal will be interconnected to the 345 kV Intermountain Power Plant substation in the WestConnect planning region. The 500 kV AC line will connect the Utah terminal to the 500 kV McCullough substation and the 500 kV Mead to Marketplace transmission line in the WestConnect planning region.

The TWE AC/DC Project has an in-service date of 2022 and to date has obtained rights-of-way over all of the federal land along the route, which represents about 66% of the route. In 2016 and 2017, following eight years of environmental analysis under the National Environmental Policy Act, four federal agencies -- the Bureau of Land Management (BLM), U.S. Department of the Interior; Western Area Power Administration (WAPA), U.S. Department of Energy; United States Forest Service (USFS), U.S. Department of Agriculture; and the Bureau of Reclamation (BOR), U.S. Department of the Interior) -- issued records of decision finalizing and approving the route for the TWE Project on federal lands.[140] WAPA acted as a joint lead agency with the BLM on the Environmental Impact Statement (EIS) and is considering further participation in the TWE Project through its Transmission Infrastructure Program. The BLM and WAPA published the Final Environmental Impact Statement (FEIS) for the TWE AC/DC Project on May 1, 2015. The route for the TWE AC/DC Project is shown in Figure 5.4-6.

Figure 5.4-6: TransWest Express AC/DC Project map



[140] See BLM ROD TransWest December 2016, WAPA ROD TWE Project , January 2017, USFS ROD TWE Project , May 2017, BOR ROD TWE Project , June 2017

Reliability Assessment

None performed

Economic Assessment

None performed

Conclusions

The stated purpose of the TWE AC/DC Project is to facilitate access between diverse renewable resources and diverse utility load profiles in California as well as facilitate access by the Desert Southwest/California market to Wyoming's vast renewable wind resources. As discussed in Chapter 2 of this transmission plan, California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and "informational" policy analysis for the 2018-2019 transmission planning cycle provide direction that all renewable procurement to achieve the 50% RPS goal to be considered by the California ISO's planning process be obtained from within California. In addition, the ISO's assessment of the need for public policy transmission solutions under the tariff did not identify a need for this project.

The ISO concluded that based on the study assumptions and regional assessments performed, a finding of need was not identified in this planning cycle for this project.

5.4.1.6 TransWest DC Project

A summary of the ITP information submitted to the ISO for the TransWest DC Project is shown in Table 5.4-7.

Table 5.4-7: ITP Submittal Information for the TransWest DC Project

Project Submitted To:	**California Independent System Operator (California ISO), Northern Tier Transmission Group (NTTG), WestConnect**
Relevant Planning Regions[141]:	California ISO, NTTG, WestConnect
Cost Allocation Requested From:	California ISO, WestConnect

Stated Purpose of the Project

The stated purpose of the TWE DC Project is that it would provide direct bidirectional transmission capacity from Wyoming wind resources and the diverse Rocky Mountain load centers to replace and support a portion of the Public Policy and Economic Regional Needs of the three planning regions. The proponent also states that the project would support meeting Regional Needs within the California ISO, NTTG, and WestConnect by providing "Public Policy"

[141] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

and “Economic” benefits to each of the three Relevant Planning Regions and as defined by Arizona, California, and Nevada.

Project Description

The TWE DC Project is a proposed 730-mile, phased 1,500/3,000 MW, ±600 kV, bi-directional, two-terminal, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and southeastern Nevada.

The TWE DC Project northern terminal would be interconnected at 230 kV to the existing PacifiCorp 230 kV transmission line between the Platte and Latham substations and the planned 500 kV Gateway West D.2 segment in the NTTG planning region, and to the 3,000 MW Chokecherry and Sierra Madre Wind Energy Project. The TWE DC Project design would provide for connecting the northern terminal to the existing 230 kV Western Area Power Administration system in the WestConnect planning region near the Miracle Mile substation.

The TWE DC Project southern terminal would be interconnected to the 500 kV Eldorado substation in the ISO planning region. It also would also be interconnected to the 500 kV McCullough substation and the 500 kV Mead to Marketplace transmission line in the WestConnect planning region.

According to the project sponsor the TWE DC Project could be in-service as early as 2022 and to date has obtained rights-of-way over all of the federal land along the route, which represents about 66% of the route. In 2016 and 2017 the Bureau of Land Management (BLM), U.S. Department of the Interior; Western Area Power Administration (WAPA), U.S. Department of Energy; United States Forest Service (USFS), U.S. Department of Agriculture; and the Bureau of Reclamation (BOR), U.S. Department of the Interior) issued records of decision finalizing and approving the route for the TWE DC Project on federal lands.

A project map of the proposed project is shown in Figure 5.4-7.

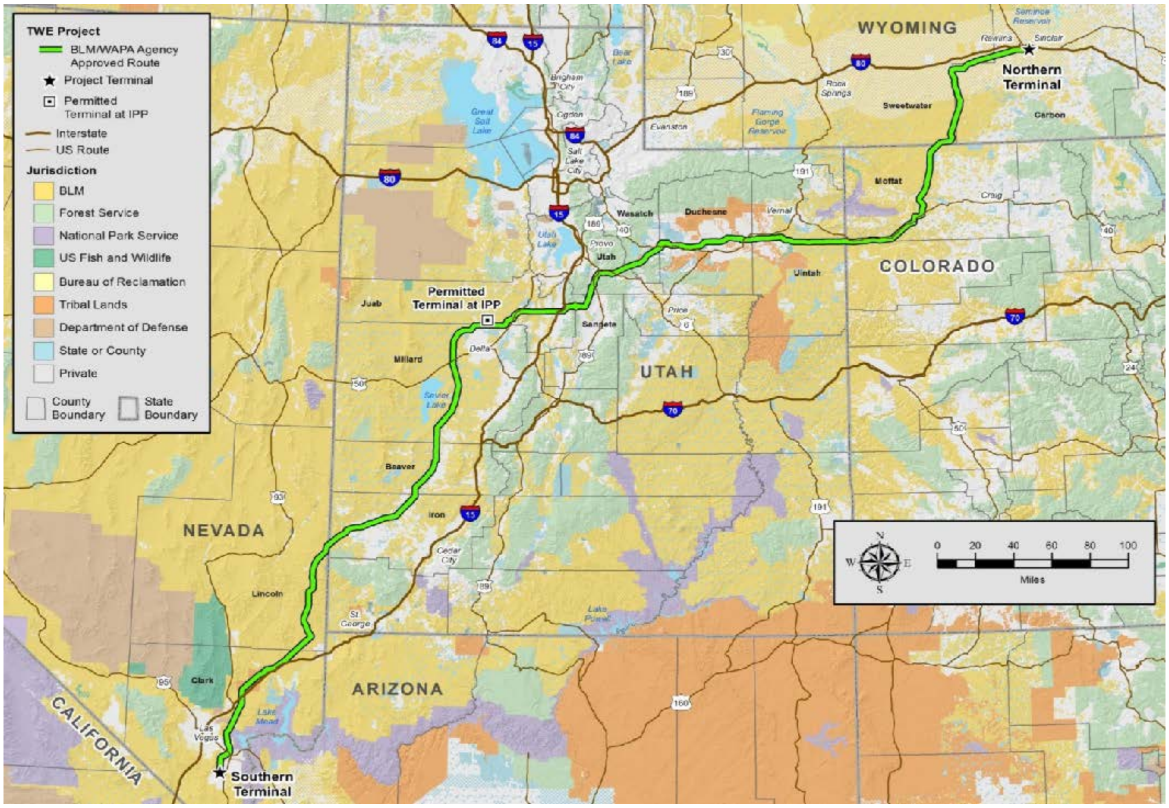
Reliability Assessment

None performed

Economic Assessment

None performed

Figure 5.4-7: TransWest Express DC Project Map



Conclusions

The stated purpose of the TWE DC Project is to provide direct bidirectional transmission capacity from Wyoming wind resources and would replace and support a portion of the Public Policy and Economic Regional Needs of the ISO. As discussed in Chapter 2 of this transmission plan, California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and “informational” policy analysis for the 2018-2019 transmission planning cycle provide direction that all renewable procurement to achieve the 50% RPS goal to be considered by the California ISO’s planning process be obtained from within California. In addition, the ISO’s assessment of the need for public policy transmission solutions under the tariff did not identify a need for this project.

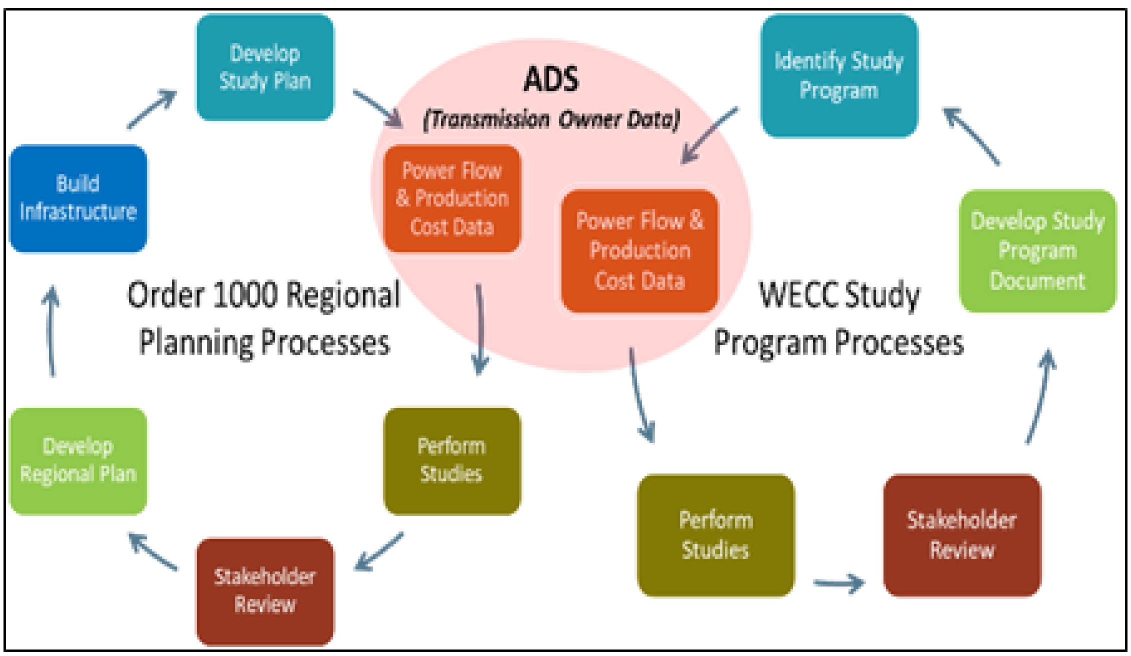
The ISO concluded that based on the study assumptions and regional assessments performed a finding of need was not identified in this planning cycle for this project.

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 (see Figure 5.5-1).

Figure 5.5-1 - The ADS Links WPR/WECC Processes



The Western Planning Regions utilize the ADS to develop their planning cases and through their regional processes, provide current information to update the ADS in preparation for their next planning cycle. In turn, WECC utilizes the ADS to develop their study program cases for their annual study program. As a result, the ADS will reflect the most current information from their regional plans which in turn will provide WECC a foundational dataset based on Order 1000 regional processes from which their study program datasets can be developed.

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. WECC began developing the 2028 ADS dataset in early 2018. Commensurate with the developing the ADS dataset, the WECC Reliability Assessment Committee (RAC) formed the ADS Task Force, the members of which include representatives from the Western Planning Regions and other WECC member representatives. The ADSTF is actively engaged in implementation of the ADS and is charged with considering and proposing any recommended changes that may need to be considered to facilitate the successful implementation of the ADS.

Consistent with the ADS proposal, the first official version (version 1.0) of the 2028 ADS was completed and posted on June 29, 2018. Although the ADS proposal explored many of the processes that would need to be developed and implemented, during its effort to implement the ADS process the ADSTF learned that certain aspects of the ADS process had not been identified or clearly defined in the ADS proposal that was adopted by the WECC Board. As such, based on experience garnered in the development of the June 29 dataset, the focus of the ADSTF has been to identify, discuss, and recommend improvements and/or modifications that may need to be made to the ADS process to ensure that it will be consistent and repeatable. In particular, the ADSTF is providing leadership and direction in the following areas:

1. Develop the ADS Process Guide

   The ADS Process Guide, once developed, will be approved by the RAC and will contain all documentation associated with the ADS. This documentation includes but is not limited to the ADS process approval approved by the WECC Board and amended as is necessary to reflect the process, protocols, and data manuals associated with developing, modifying, and/or deleting information or data from the ADS dataset. The ADS Process Guide will also include the Power Flow Data Preparation Manual and the PCM Data Development and Validation Manual both of which provide, in unambiguous detail, an outline of the data requirements and submission procedures that are necessary to meet all data requirements of the ADS;

2. ADS Responsibility Assignment Matrix (RACI Matrix)

   Developing the ADS requires coordination between the transmission owners who provide the data to WECC; RAC and its subcommittees/workgroups that determine data requirements and validate data that is received, and WECC staff who collect and populate the ADS datasets. A RACI matrix is being developed to support the management of the ADS process by assigning responsibility for the various tasks of the ADS from the point that planning data and information is requested to its final representation in the ADS. The RACI matrix will be an integral part of the ADS Process Guide;

3. ADS Process Workflow

   Commensurate with the RACI matrix, the ADS process workflow is a project oriented milestone schedule that is being developed to facilitate coordination of the flow of data and information between the RACI matrix tasks and the ADS two-year cycle. The ADS process workflow will also be an integral part of the ADS Project Guide.

Why the ADS is Important to the ISO

The ISO supports developing and implementing the ADS and has remained actively engaged in this process over the last two planning cycles. In general, the Western Planning Regions consider full implementation of the ADS to be a significant step towards meeting their need of resolving existing data inconsistencies and applications, while facilitating a common dataset that accurately represents the regional plans of all four planning regions. Each year the ISO builds over 100 power flow cases to perform its reliability assessment of the ISO controlled grid. In addition, the ISO builds 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.

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, and a system frequency response 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 2019. 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 2018. A short-term analysis was conducted for the 2019 system configuration to determine the minimum local capacity requirements for the 2019 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 15, 2018. For detailed information on the 2019 LCT Study Report please visit:

http://www.caiso.com/Documents/Final2019LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2023 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 2023 LCT Study Report was published on May 15, 2018 and for detailed information please visit:

http://www.caiso.com/Documents/Final2023Long-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 agencies, they are done on every other year cycle.

The most recent ten-year LCR study was prepared in this year's 2018-2019 transmission planning process. The ISO undertook a more comprehensive study of local capacity areas in this planning cycle than in the past, 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 of the 2018-2019 Transmission Plan.

As shown in the LCT reports and indicated in the LCT 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 160 MW. In contrast, the requirements of the Los Angeles Basin are approximately 8,000 MW. The short- and long-term LCR needs from this year’s studies are shown in Table 6.1-2.

Table 6.1-2: Local capacity areas and requirements for 2019, 2023 and 2028

LCR Area	LCR Capacity Need (MW)		
	2019	2023	2028
Humboldt	165	169	170
North Coast/North Bay	689	553	883
Sierra	2,247	1,924	1,510
Stockton	777	439	507
Greater Bay Area	4,461	4,752	5,600
Greater Fresno	1,671	1,688	1,728
Kern	478	182	140
Los Angeles Basin	8,116	6,793	6,590
Big Creek/Ventura	2,614	2,792	2,251
Greater San Diego/Imperial Valley	4,026	4,132	3,908
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	25,244	23,424	23,287

Notes:

For more information about the LCR criteria, methodology and assumptions please refer to the ISO LCR manual.[142]

For more information about the 2019 LCT study results, please refer to the report posted on the ISO website.

For more information about the 2023 LCT study results, please refer to the report posted on the ISO website.

For more information about the 2028 LCT study results, please refer to the Appendix G of the 2018-2019 Transmission Plan.

[142] "Final Manual 2019 Local Capacity Area Technical Study," December 2017, http://www.caiso.com/Documents/2019LocalCapacityRequirementsFinalStudyManual.pdf.

6.1.2 Resource adequacy import capability

The ISO has established the maximum resource adequacy (RA) import capability to be used in year 2019 in accordance with ISO tariff section 40.4.6.2.1. These data can be found on the ISO website[143]. The entire import allocation process[144] 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 2028.

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

http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2019-2028.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2021 to accommodate renewable resources development in this area that ISO has established in accordance with Reliability Requirements BPM section 5.1.3.5. The import capability from IID to the ISO is the combined amount from the IID-SCE_BG and the IID-SDGE_BG.

The 10-year increase in MIC from current levels out of the IID area is dependent on transmission upgrades in both the ISO and IID areas as well as new resource development within the IID and ISO systems, and, for the ISO system, on the West of Devers upgrades in particular. The increase to the target level is expected to take place when the West of Devers upgrades are completed and depends on all necessary upgrades being completed in both the ISO and IID areas. 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.

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

[143] "California ISO Maximum RA Import Capability for year 2019," available on the ISO's website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2019.pdf.

[144] See general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

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 2017 LT CRR study leveraged the base case network topology used for the annual 2017 CRR allocation and auction process. Regional transmission engineers responsible for long-term grid planning incorporated all the new and ISO approved transmission projects into the base case and a full alternating current (AC) power flow analysis to validate acceptable system performance. These projects and system additions were then added to the base case network model for CRR applications. The modified base case was then used to perform the market run, CRR simultaneous feasibility test (SFT), to ascertain feasibility of the fixed CRRs. A list of the approved projects can be found in the 2018-2019 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 2018 that there are no existing released LT CRRs at-risk" that require further analysis. Thus, the transmission projects and elements approved in the 2018-2019 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 has undertaken 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. In the 2018-2019 planing cycle, 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 from the 2018-2019 planing cycle.

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 the 2015-2016 ISO Transmission Plan built on the analysis. In the 2018-2019 transmission planning cycle the study was updated, using the latest dynamic stability models.

Reliability Standard BAL-003-1.1 (Frequency Response and Frequency Bias Setting)

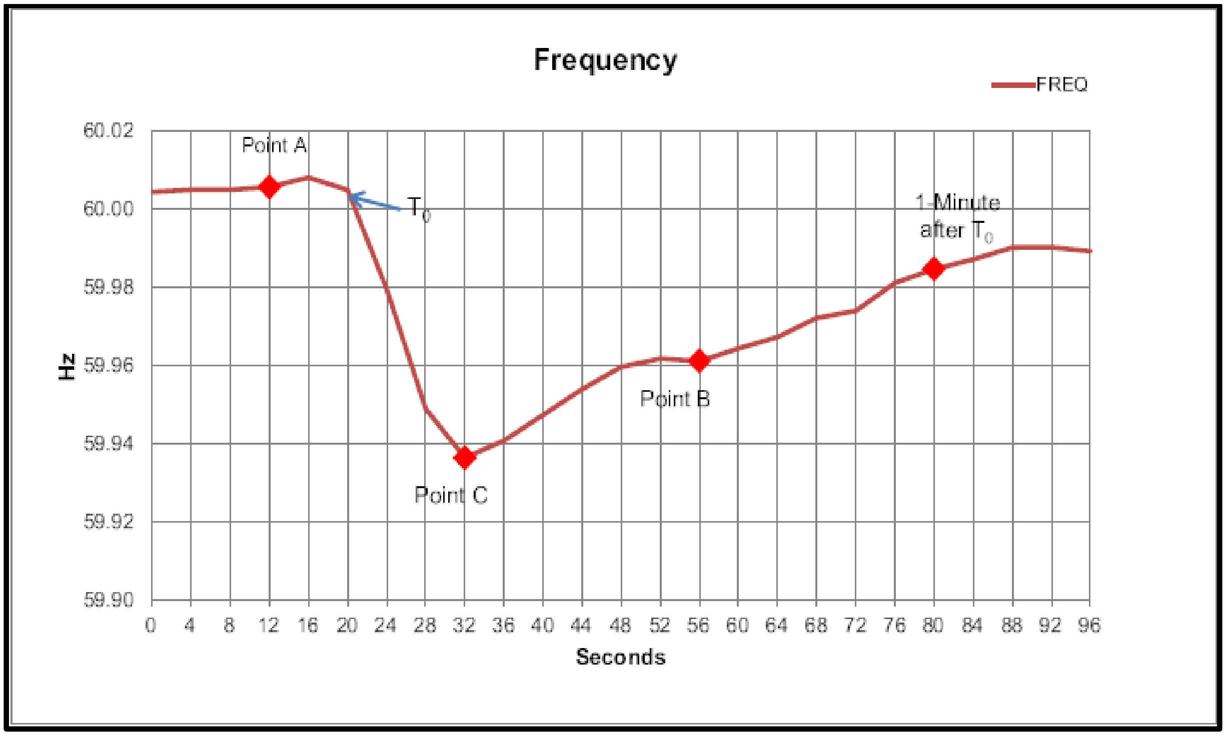
On November 12, 2015 FERC approved Reliability Standard BAL-003-1.1 (Frequency Response and Frequency Bias Setting), as submitted by North American Reliability Corporation (NERC). This standard was an update of the Standard BAL-003-1 that created an obligation for balancing authorities, including the ISO, to demonstrate sufficient frequency response to disturbances that result in decline of the system frequency by measuring actual performance against a predetermined obligation.

NERC has established a methodology for calculating frequency response obligations (FRO). A balancing authority's FRO is determined by first defining the FRO of the interconnection as a whole, which is referred to as the Interconnection Frequency Response Obligation (IFRO). The methodology then assigns a share of the total IFRO to each balancing authority based on its share of the total generation and load of the interconnection. The IFRO of the WECC Interconnection is determined annually based on the largest potential generation loss, which is the loss of two units of the Palo Verde Nuclear Generation Station (2,740 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 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.

Figure 6.3-1 illustrates a generic system disturbance that results in frequency decline, such as a loss of a large generating facility. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 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.

Frequency response of the Interconnection (Frequency Response Measure or FRM) is calculated as

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 Analysis4. 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[145].

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

145 "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

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.

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.

2014-2015 and 2015-2016 Transmission Plan Study Results

The ISO assessed in the 2014-2015 and in 2015-2016 transmission planning processes the potential risk of oversupply conditions – a surplus of renewable generation that needs to be managed - in the 2020-2021 timeframe under the 33 percent renewables portfolio standard (RPS) and evaluated frequency response during light load conditions and high renewable production. Those studies also assessed factors affecting frequency response and evaluated mitigation measures for operating conditions during which the FRO couldn't be met.

The ISO 2014-2015 Transmission Plan[146] in section 3.3 and the ISO 2015-2016 Transmission Plan[147] in section 3.2 discuss reliability issues that can occur during oversupply conditions when inverter-based renewable generation output is high, and also describe frequency performance metrics and study results.

[146] "2014-2015 Transmission Plan," ISO Board Approved March 27, 2015, http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf

[147] "2015-2016 Transmission Plan," ISO Board Approved March 28, 2016, http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf

Studies performed in the previous transmission planning processes showed that the total frequency response from WECC was above the interconnection's frequency response obligation, but the ISO had insufficient frequency response when the amount of dispatched renewable generation was significant. When the study results and, in particular, response of some individual generation units was compared with the real time measurements during frequency disturbances, the results of the simulations did not match the actual measurements showing higher response to frequency deviations. Thus, the study results appeared to be too optimistic, and the actual frequency response deficiency may be higher than the studies showed.

6.3.2 2018-2019 Transmission Plan Frequency Response Study

Study assumptions and methodology

As in the previous ISO frequency response studies, this 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 details.

Dynamic stability data used the latest WECC Master Dynamic File with the updates on the models received by the ISO at the time of the study. Missing dynamic stability models for the new renewable projects were added to the dynamic file by using typical models according to the type and capacity of the projects. The latest models for inverter-based generation recently approved by WECC were utilized. For the new wind projects, the models for type 3 (double-fed induction generator) or type 4 (full converter) were used depending on the type and size of the project. For the solar PV projects, three types of models were used: large PV plant, small PV plant and distributed solar PV generation. Distributed solar PV generation was modeled with the latest dynamic stability model DER_A. All the load in the WECC system was modeled with the composite load dynamic model that had the stalling of the single-phase air-conditiners enabled. The composite load model also included behind-the-meter distributed generation. This generation was modeled with the latest dynamic stability model DER_A, which is more detailed than the models for distributed solar PV generation used previously.

The goal of the study was to determine if the ISO can meet its FRO with the most severe credible contingency under the conditions studied. Other goals were to determine under which conditions the FRO may not be met.

In addition to evaluating the system frequency performance and the WECC and ISO governor response, the study evaluated the impact of unit commitment and the impact of generator output level on governor response. For this evaluation, such metrics as headroom or unloaded synchronized capacity, speed of governor response, and number of generators with responsive governors were estimated.

In addition to the 2023 Spring off-Peak with high renewable and low gas generation output starting case (Case 1), two more cases were studied. The first case (Case 2) was created by turning off the units for which governor response was unreasonable and re-dispatching their generation to the neighboring units. It was assumed that the units with the unreasonable governor response might have errors in their models. The response of the generators with responsive governors was considered to be unreasonable either when it was negative (generation decreases with decrease in frequency), or when it was too high – higher than 9%. With the standard governor droop of 5%, the response to the change in frequency equal to the maximum delta frequency of 0.248 Hz established by NERC will be approximately 8.3%. If the droop is 4%, the response to such change in frequency will be 10.3%. Since the change in frequency in the study was less than the maximum delta frequency and majority of the governors have the droop of 5%, it was assumed that the units with the response of higher than 9% might have errors in their models. The “suspicious” models will be reported to WECC so that they could be checked and the generators re-tested if it appears that the models are indeed erroneous. The second sensitivity case (Case 3) was the case with decreased headroom on the frequency responsive units. It was created from the Case 2. To achieve reduction in headroom, frequency responsive generators at the same station or hydro generators on the same river with the low output were turned off, and their output was re-dispatched to the units on the same station or the same river or to the neighboring non-responsive units.

A summary of the load and generation in the cases studied is shown in Table 6.3-1. As can be seen from the table, in these cases, renewable (solar PV and wind) generation dispatch was 39.4% of the total generation dispatch in the ISO and 17.7% of the total dispatch in WECC.

Table 6.3-1: Generation and load in the cases studied and metrics of responsive generation

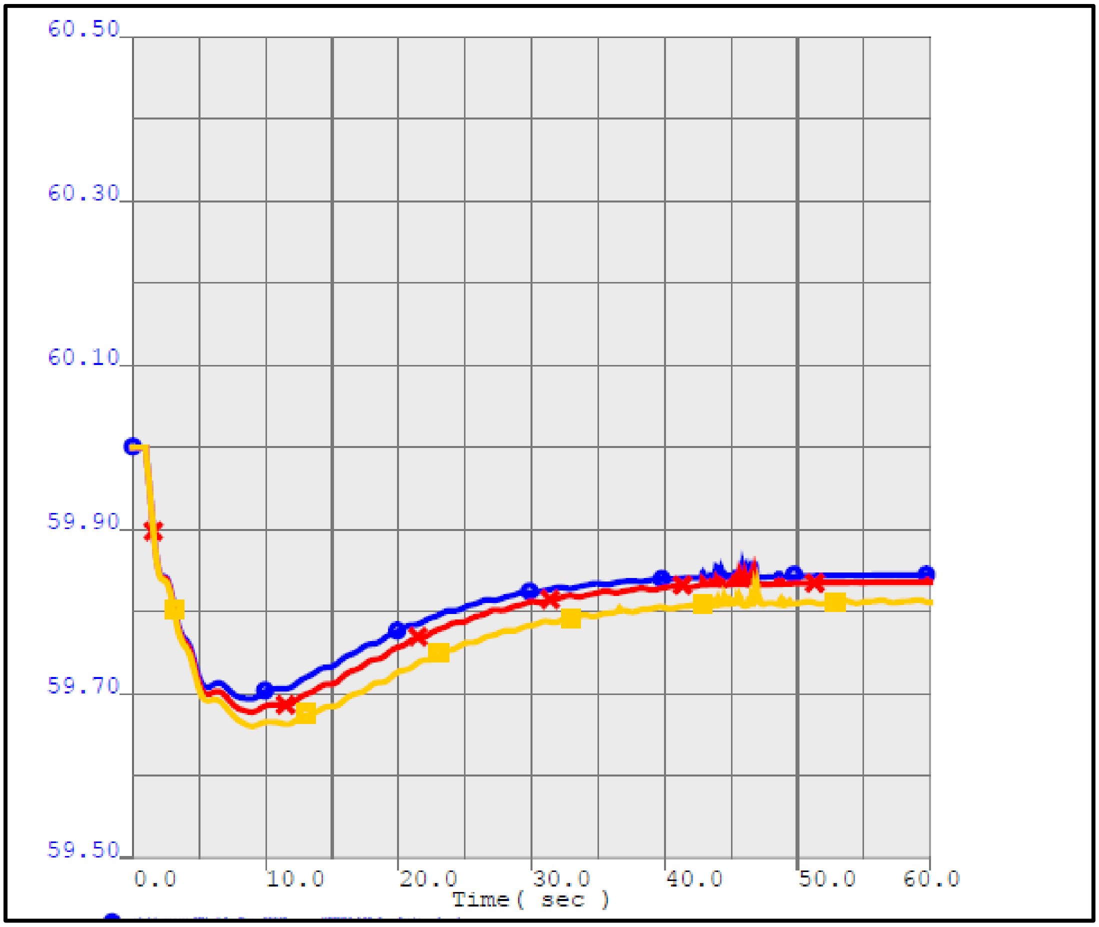
Case		2023 spring off-peak high renewables	Case 2 - high and negative response units off	Case 3 - reduced headroom
Load, including pumps and motors, MW	ISO, incl. MUNI	27,108	27,108	27,108
	Total WECC	92,609	92,609	92,609
Generation total dispatch , incl. DER, MW	ISO, incl. MUNI	29,483	29,531	29,531
	Total WECC	95,313	95,320	95,311
Generation with responsive governors, MW	ISO, incl. MUNI, dispatch	7,210	7,122	6,023
	ISO, incl. MUNI, capacity	9,515	9,108	7,851
	Total WECC, dispacth	30,974	31,009	27,519
	Total WECC, capacity	45,544	44,868	38,422
Renewable, non responsive, including DER, dispatch MW	ISO, incl. MUNI	11,615	11,615	11,615
	Total WECC	16,882	16,822	16,822
Conventional non responsive, MW	ISO, incl. MUNI	10,658	10,794	11,893
	Total WECC	47,457	47,489	50,970
Dispatch of responsive generation, % of capacity	ISO, incl. MUNI	75.8%	78.2%	76.7%
	Total WECC	68.0%	69.1%	71.6%
Kt – ratio of responsive generation to total, %	ISO, incl. MUNI	29.9%	28.9%	25.0%
	Total WECC	41.4%	41.1%	36.2%

Study results

The dynamic simulation results for an outage of two Palo Verde generation units for the 2023 Spring Off-Peak case with high renewable generation output shows the frequency nadir of 59.675 Hz at 7.7 seconds (6.7 seconds after the disturbance) and the settling frequency after 60 seconds at 59.844 Hz. For Case 2, the frequency nadir is 59.670 Hz at 8.3 seconds (7.3 seconds after the disturbance) and the settling frequency after 60 seconds is at 59.835 Hz. For Case 3, the frequency nadir is 59.650 Hz at 9.seconds (8 seconds after the disturbance) and the settling frequency after 60 seconds is at 59.812 Hz.

The frequency plot for the Midway 500 kV bus for the three cases studied is shown in Figure 6.3-2. As can be seen from the plot, the lower is the headroom on the frequency responsive units, the lower is the nadir and the settling frequency, and the frequency nadir occurs at the later time. The curves slope after the disturbance, which depends on the system inertia appeared to be the same for all three cases.

Figure 6.3-2: Frequency Plot for the Midway 500kV Bus



As can be seen fromFigure 6.3-2, the frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz for all three cases. For this contingency, voltages on all the buses were within the required limits in all the cases studied.

The study evaluated the governor response of the units that had responsive governors. For the starting case, the highest response in MW was from large hydro units in Washington State, with the highest from Grand Coulee unit #22 at 64 MW and Grand Coulee unit #23 at 55 MW. These are large units (825 MW each) that were loaded only to approximately one-quarter and of their capacity in the base case. Other generation units that showed high governor response are the Intermountain coal-fired power plant in Utah operated by LADWP; and unit #4 of the San Juan coal plant in New Mexico, as well as hydro power plants in Alberta. If measured in percentage from the generator's capacity, an average response was 5.2 percent, but it varied from less than 1 percent for the units that were loaded up to their capacity to around 20 percent for the units that possibly had modeling errors.

For the starting case, total frequency response from WECC was 2,476 MW, or 1,587 MW/0.1Hz, which is well above the WECC Frequency Response Obligation. For the ISO - the response was 450 MW, or 288 MW/0.1 Hz, which is also above the ISO FRO of 257.4

MW/0.1Hz. The calculated headroom in WECC was 14,580 MW with 656 frequency-responsive units, and in the ISO the headroom was 2,310 MW with 147 responsive units.

Such a significant difference in the relative ISO and WECC frequency response is explained by large amount of renewable, primarily inverter-based, generation in the ISO, and relatively small amount of the renewable generation in WECC modeled in the case.

For Case 2, total frequency response from WECC was 2,446 MW, or 1,482 MW/0.1Hz, which is also well above the WECC Frequency Response Obligation. For the ISO - the response was 442 MW, or 268 MW/0.1 Hz, which is above the ISO FRO of 257.4 MW/0.1Hz. The calculated headroom in WECC was 13,870 MW with 629 frequency-responsive units, and in the ISO the headroom was 1,990 MW with 142 responsive units.

For Case 3, total frequency response from WECC was 2,412 MW, or 1,283 MW/0.1Hz, which is also well above the WECC Frequency Response Obligation. For the ISO - the response was 463 MW, or 246 MW/0.1 Hz, which is below the ISO FRO of 257.4 MW/0.1Hz. The calculated headroom in WECC was 12,390 MW with 613 frequency-responsive units, and in the ISO the headroom was 1,910 MW with 139 responsive units.

The study results are summarized in Table 6.3-2.

Table 6.3-2: Frequency Study Results for an Outage of two Palo Verde Units

Case		2023 spring off-peak high renewables	Case 2 - high and negative response units off	Case 3 - reduced headroom
Headroom, MW	ISO, incl. MUNI	2,310	1,990	1,910
	Total WECC	14,580	13,870	12,390
Responsive units	ISO, incl. MUNI	147	142	139
	Total WECC	656	629	613
Response, MW	ISO, incl. MUNI	450	442	463
	Total WECC	2,476	2,446	2,412
Response, MW/0.1Hz	ISO, incl. MUNI	288	268	246
	Total WECC	1,587	1,482	1,283
Nadir, Hz		59.675	59.670	59.650
Settling frequecy, Hz		59.844	59.835	59.812
Kt – ratio of responsive generation to total, %	ISO, incl. MUNI	29.9%	28.9%	25.0%
	Total WECC	41.4%	41.1%	36.2%

Thus, the values of approximately 2,000 MW of the headroom and approximately 29 percent of the responsive generation capacity may be considered to be the minimum values to provide the sufficient frequency response from the ISO to meet the BAL-003 standard. However, it should be noted that these values were determined only for this particular case. In the case when the starting generation dispatch on the responsive units is lower, the minimum required headroom will appear to be higher.

Results of the frequency studies from the 2015-2016 transmission plan showed that the required headroom at the ISO should be around 2500 MW for the ISO to meet its FRO, and the responsive generation capacity should be around 30%. Results of the frequency studies from the 2014-2015 transmission plan showed that the required headroom at the ISO should be around 4400 MW for the ISO to meet its FRO, and the responsive generation capacity should be also around 30%. The large number for the required headroom in the 2014-2015 studies was explained by the low generation dispatch on the responsive units in this case. Thus, the studies of the current transmission plan also show that the percentage of the frequency responsive capacity is a more universal measure for the expected frequency response than the headroom.

2018-2019 Study Conclusions

- The initial study results indicated acceptable frequency performance both within WECC and the ISO for the base case studied (Spring Off-Peak of 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 isuse that was observed in real system operation was withdrawal of the governor response that was not observed in the simulations.

6.3.3 New NERC Standards MOD-032 and MOD-033 Modeling Requirements

NERC standards MOD- 032 and MOD -033 also set direction for improved generator modeling.

According to the NERC Standard MOD-032, each Balancing Authority, Planning Authority and Planning Coordinator should establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. The NERC MOD-032 standard is related to the NERC Standard MOD-033. The MOD-032 standard requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 requires each Planning Coordinator to implement a documented process to perform model validation within its planning area. The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by FERC recommendations and directives.

Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner and Planning Coordinator according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner. If the Planning Coordinator or Transmission Planner has technical concerns regarding the data, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall either provide the updated data or explain the technical basis for maintaining the current data. Each Planning Coordinator shall make available models for its planning area reflecting the provided data to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide cases that include the Planning Coordinator's planning area. For the ISO, Transmission Planners and generation owners are responsible for providing the data, and the ISO is responsible for the model validation.

The purpose of the NERC Standard MOD-033-1 is to establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

The focus of validation in this standard is not Interconnection-wide phenomena, but events on the Planning Coordinator's portion of the existing system, although system-wide disturbances can also be used for model validation. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

The MOD-033-1 standard requirements include comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other real-time data sources. Such model validation has to be done at least once in the 24 months. The standard includes guidelines needed to be used to determine unacceptable difference in the model's performance. The standard states that each Reliability Coordinator and Transmission Operator shall provide actual system behavior data to any Planning Coordinator performing validation such as, state estimator case or other real-time data necessary for actual system response validation.

The reliability standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. In accordance with the MOD-033 standard, the ISO developed a Power System Model Validation Process in 2017 that includes guidelines on how to perform model validation. It also includes a methodology of comparison of the ISO performance in planning power system model and dynamic stability response simulations to actual system behavior. These guidelines explain how to determine unacceptable differences in the evaluated performances for the planning power flow and dynamic model and how to resolve them. The Model Validation Process is followed by Reliability Coordinators, Transmission Operators and Transmission and Generation Owners.

6.3.4 Model Validation with Online Dynamic Security Assessment

The ISO is involved in a continuous model validation effort using real-time snapshots from ISO's online DSA (Dynamic Security Assessment). Voltage, frequencies and flows are compared with those observed in PMU and SCADA data. Model validation efforts have led to correction of baseload flags in the input dynamic data for DSA and modification of initialization rules to accommodate wind and solar models that are at very low or zero output in the state estimation solutions. Model validation is a continuous effort that is being conducted in collaboration with Peak Reliability.

The ISO also performed dynamic stability analysis of the disturbance that occurred on March 3, 2016 that caused the WECC–wide frequency to drop to about 59.84Hz.

The simulation results generally matched the measurements. The simulated frequency nadir was higher than the measured, which indicates that the simulated frequency response of the generators is too optimistic. Due to lack of measurements at generating plants, it could not be determined which generator models cause the discrepancy between the simulation and actual performance. The results demonstrated the need to perform field testing to verify generator dynamic models, and installing PMUs at the generating plant would greatly improve the model validation.

These studies are described in the 2017-2018 Transmission Plan. Validation of the dynamic stability models based on the recordings of the actual system disturbances in an on-going work performed by the ISO Grid Planning together with the Operation Engineering.

6.3.4.1 2018-2019 Progress

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:

a. Category 1 - Participating generators connected to the Bulk Electric System (BES):
   1. Individual generating unit with nameplate capacity greater than 20 MVA, or
   2. Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 75 MVA.

b. Category 2 – Participating generators connected to facilities 60 kV and above, and not covered in category 1:
   1. Individual generating unit with nameplate capacity greater than 10 MVA, or
   2. Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 20 MVA.

c. Category 3 - Participating generators connected to BES or facilities above 60KV with generation output lower than the category 1 or 2 modeling requirement thresholds.
   1. Individual generating unit with nameplate capacity less than 10 MVA, or
   2. Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity less than 20 MVA.

d. 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.

e. 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 will send a data request letter to the participating generator identifying the specific data requirements for the generating unit. The data request letter will contain 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 will start 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, must submit the required generator modeling data within one hundred and twenty calendar days of achieving commercial operation in the ISO market. The required data will be 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.

6.3.5 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.

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.

7.1 Pacific Northwest – California Transfer Increase Study

On February 15, 2018, the ISO received a request from Robert B. Weisenmiller, Chair of the CEC and Michael Picker, President of the CPUC[148], that the ISO undertake specific transmission sensitivity studies within the 2018-2019 transmission planning process considering the potential to increase the transfer of low-carbon supplies to and from the Northwest. Expanded transmission capability, and increasing the transfer of low-carbon supplies to and from the Northwest in particular, was seen to be one of the multiple puzzle pieces that the agencies must examine to build a cumulative phase out strategy of Aliso Canyon usage and address potential impacts on the gas-fired generation fleet. The letter provided the following synopsis for the sensitivity study:

- Increase the Capacity of AC and DC Interties
- Increase Dynamic Transfer Capability (DTC)
- Implementing sub-hourly scheduling on PDCI
- Assigning Resource Adequacy (RA) Value to firm zero-carbon imports

The ISO worked collaboratively with CEC, CPUC, BPA, LADWP as well as other owners and operators of AC and DC interties to ensure alignment on all aspects of this informational special study. Details of the studies and analysis of the results are provided in Appendix H. A high level summary for each of the studies is provided in the following sections:

7.1.1 Increase the Capacity of AC and DC Interties

LADWP is performing an engineering and planning study to identify the system upgrades required to increase the PDCI transfer capability from 3,220 MW to 3,800 MW. The study includes a system impact assessment as well as identifying the required upgrades to the HVDC transmission line and the convertor station at Sylmar. Details of the study scope are provided in Appendix H and the study is expected to be completed by the end of Q3, 2019.

Given the timeline of LADWP studies, it was decided to use the existing ratings of the PDCI in this informational study.

[148] http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf

7.1.1.1 Near-term Assessment (Year 2023)

The focus of the near-term analysis was to assess the potential to maximize the utilization of the existing transmission system. Energy Transfer and Resource Shaping were the two scenarios studied with high intertie flows. The study showed that the N-S COI limit could be increased from 4,800 MW to 5,100 MW if the outage of two adjacent 500 kV lines is treated as conditionally credible. Otherwise, to increase the COI limit beyond 4,800 MW, some load in California must be shed to address reliability issues after the N-2 outage. A WECC path rating process is required to increase the rating of COI. In the existing WECC path rating process, the outage of two adjacent circuits is considered to be always credible. The WECC path rating process is under review and the updated process may include conditionally credible contingencies. The upgrading of the COI north to south path rating may take some time to accomplish through the WECC Path rating process but the studies indicated that limited capital updgrades would be required to reduce the congestion and and increase transfer capability from north to south on COI. The economic benefits of increasing the COI north to south transfer capabitliy were examined in section 4.9.1.1 of chapter 4.

PDCI flow is operationally limited to 1000 MW in the S-N direction by LADWP. The results of this study showed that there is potential to increase the S-N limit to 1,500 MW under favorable conditions.

7.1.1.2 Long-term Assessment (Year 2028)

The objective of the long-term assessment was perform production simulation to explore the benefits of higher intertie capacities in the long term. WECC Anchor Data Set (ADS) production cost model (PCM) was used as a starting point and was updated using the PNW hydro information provided by Northwest Power and Conservation Council (NWPCC). Production simulation was done for three PNW water scenarios; low, medium and high water condition with 100 TWh, 148 TWh, and 172 TWh of electricity generated in the year, respectively. Study results showed that the number of hours with COI congestion are 49, 349, and 1597 hours for how, medium and high scenarios. Medium hydro year was simulated with 5,100 MW COI limit and the congested hours decreased from 349 hours to 265 hours.

In the S-N direction, no congestion was observed on COI in any of the hydro conditions. However Path 26 was congested for more than 1,100 hours. PDCI modelled at its WECC path rating didn’t show any congestion but a simulation with a 1,000 MW S-N PDCI limit indicated 67 hours of congestion under medium hydro conditions.

7.1.2 Increase Dynamic Transfer Capability (DTC)

Dynamic transfer capability refers to the capability of the PNW system to accommodate variations on 5-minute scheduling on PNW AC Interties (NWACI). Currently the DTC on NWACI is limited to 600 MW mainly to prevent excessive voltage fluctuations and reactive switching. The current manual RAS arming process could become another limitation on DTC at higher levels. The followings are potential solutions to address excessive voltage fluctuations to increase DTC:

- Employ Real-time Allocation of DTC
- Apply DTC Limit to Actuals (instead of schedules)
- Use DTC Nomogram Instead of a Fixed Limit.
- Real-Time Voltage Assessment Tools
- Coordinated Voltage Controls (CVC)
- Control State Awareness and Analytics

Upon completion of the above assessment and implementation of the mitigation measures, there would be no limit on DTC and 5-minute scheduling will be similar to 15-minute scheduling. The details of the issues and BPA's plans to address them are provided in "BPA DTC Roadmap" in Attachment 1 of Appendix H.

7.1.3 Implementing sub-hourly scheduling on PDCI

PDCI scheduling is currently limited to hourly scheduling. Having 5-minute or even 15-minute scheduling capability on PDCI would facilitate further utilization of PNW hydro to supply California load especially during morning and evening ramps. To facilitate sub-hourly scheduling on PDCI, it is required to automate PDCI RAS as well as the AGC and EMS systems. A detailed system impact assessment on both BPA and LADWP systems is planned to be performed through a joint study. The outcome of that study will determine the next steps.

7.1.4 Assigning Resource Adequacy (RA) Value to firm zero-carbon imports

Comparing the historical available capacity on COI and PDCI for RA contracts, with the actual RA showings indicates that except for summer months, the RA showings are less than available capacity. Historical data also show that while RA showings are lower than the capacity, the actual real time flows on COI and PDCI for some months are significantly higher than the RA showings and are closer to the available capacity. This may imply that the surplus energy in PNW will flow to California even without an RA contract. The future generation development scenarios in the Pacific Northwest system will potentially create uncertainty about the amount of available capacity and energy, increasing or decreasing, which can be exported to California in the longer term. This is due to the potential early retirement of coal units, load growth or a shift to more renewable integration in the Pacific Northwest. To ensure availability of Pacific Northwest resources to supply load in California in the long term, some market or policy initiatives and regulations may be required. Details of such market structures or policies were beyond the scope of this study. Market and policy initiatives such as the ISO's resource adequacy enhancement stakeholder initiative or the CPUC's integrated resource plan and resource adequacy proceedings may address some of the uncertainties of the Pacific Northwest resources to supply load in California in the long term.

7.1.5 Conclusions and Next Steps

To ensure availability of Pacific Northwest resources to supply load in California in the long term, some market or policy initiatives and regulations may be required. Details of such market structures, policies or regulations were beyond the scope of this study. The ISO has initiated a resource adequacy enhancements stakeholder initiative[149] that will include an assessment of the rules for import resource adequacy and a review of the maximum import capability. In addition the CPUC has ongoing resource adequacy[150] and integrated resource plan[151] proceedings. Stakeholders are encouraged to participate in these initiatives and proceedings.

The ISO will continue to monitor and participate in the WECC path rating process review. If the WECC path rating process is updated to recognize the concept of using the conditionally credible contingency of the adjacent 500 kV lines in the same right-of-way on separate towers, the ISO will work with the owners of the COI facilities to initiate a WECC path rating process to increase the rating of COI to 5,100 MW. The ISO will also continue to monitor the progress of LADWP on the identified further study work of PDCI and BPA on the dynamic transfer capability and implementing sub-hourly scheduling on PDCI.

[149] http://www.caiso.com/informed/Pages/StakeholderProcesses/ResourceAdequacyEnhancements.aspx

[150] http://www.cpuc.ca.gov/RA/

[151] http://www.cpuc.ca.gov/irp/

7.2 System Capacity Requirements and Large Storage System Benefits

Over the past several transmission planning cycles, the ISO has conducted a number of special studies examining the system-wide needs for gas-fired generation capacity, and the benefits provided by potential large storage projects. These special studies were generally documented as two separate special studies, despite generally relying on common assumptions and modeling – and in particular, depending on analysis conducted using Energy Exemplar's PLEXOS production cost modeling software.

System-wide requirements for gas-fired generation capacity:

- The study examines the need for gas-fired generation capacity, together with the proposed renewable portfolio, to serve system load and meet reserve requirements to maintain the reliability of the ISO system.
- Note that the study of local capacity requirements, characteristics of those requirements, and potential mitigations to reduce the need for reliance on gas-fired generation is explored in the long term local capacity study in chapter 6, and detailed economic analysis of a number of those potential mitigations is explored in chapter 4.

System-wide benefits provided by large storage projects:

- The system-wide models developed for assessing grid capacity needs also provide useful insights in to the benefits provided by large storage on a system basis
- Note that storage projects are also being proposed in the in the tariff-based transmission planning cycle as potential reliability or economic solutions to addressing local needs, and with the potential for providing system-wide benefits as well. Please refer to chapter 4.

The ISO recognizes that its PLEXOS modeling, which is primarily conducted for supporting the CPUC's integrated resource planning (IRP) process focusing on a system-wide basis, can continue also provide useful background and context to supplement the transmission planning studies and provide a broader perspective to stakeholders by being included in the transmission plan. It also continues to useful platform for sensitivities such as assessing the benefits of large storage from a system perspective.

The PLEXOS modeling results for both system-wide studies have been combined into a single report in the 2018-2019 Transmission Plan, setting out and based on a common set of assumptions developed for the two special studies.

7.2.1 Common Assumptions for the PLEXOS Modeling

As required by SB 350, the California Public Utilities Commission (CPUC) is leading the Integrated Resources Plan (IRP) process for its jurisdictional Load Serving Entities (LSEs). The 2017-2018 IRP cycle looks out to 2030 to develop a long-term resource procurement plan. The plan needs to achieve the state targets of greenhouse gas (GHG) emission reduction and Renewable Portfolio Standard (RPS).

The 2017-2018 IRP first developed a Reference System Plan (RSP) for the ISO service area. The RSP was developed for year 2018, 2022, 2026 and 2030 based on the following key assumptions:

- Demand: the California Energy Commission (CEC) 2017 Integrated Energy Policy Report (IEPR) load forest;
- New resources: new resources, including renewable, battery, demand response, and pumped storage, are selected based on least-cost rule using the RESOLVE capacity expansion model, subject to assumed resource potentials in specific regions;
- Transmission: the existing transmission capability only, therefore new resources are selected using both Full Capacity Deliverability Status (FCDS) capacity and Energy Only capacity; and
- Thermal generation resources: all existing thermal generation resources, except the once through cooling (OTC) thermal generation plants, the Diablo Canyon nuclear plant and the plants for which mothball or retirement plans have been announced, will stay on through 2030.

The CPUC directed the LSEs to develop their individual plans that conform to the RSP. The LSE IRP plans filed back to the CPUC deviate from the RSP significantly. The CPUC then combined the LSE IRP plans and made adjustments according to the existing transmission capabilities and assumed resource potentials in the regions. Based on that, the CPUC developed a Hybrid Conforming Plan (HCP) and proposed to adopt the HCP as the Preferred System Plan (PSP) of the 2017-2018 IRP process.[152] In the HCP, the CPUC not only made changes to the selection of new resources, it also retired all gas-fired thermal generation resources that are 40 year or older.

The ISO special studies documented herein use the assumptions of the CPUC IRP HCP and are for year 2030 only. Table 7.2-1 below summarizes the assumptions of the ISO generation resources in the RSP and the HCP in 2030.

[152] The HCP data are available at http://www.cpuc.ca.gov/General.aspx?id=6442459406

Table 7.2-1: Assumptions of ISO Generation Resources in the RSP and the HCP in 2030

Capacity (MW)	RSP	HCP	Change
Battery	**3,429**	**2,480**	**-949**
1-hour	2,144	217	-1,927
4-hour	1,285	2,263	978
BTM PV	**19,295**	**19,295**	**0**
Renewable	**33,381**	**34,094**	**714**
Biomass	725	888	163
Geothermal	2,683	1,487	-1,197
Small Hydro	763	763	0
Solar	18,767	19,658	891
Wind	10,443	11,299	856
Thermal	**25,770**	**22,543**	**-3,227**
CCGT	15,720	14,642	-1,078
CHP	2,932	1,078	-1,854
GT	7,108	6,813	-295
ST	10	10	0
Gas			
Hydro	**6,890**	**6,890**	**0**
Pumped Storage	**1,831**	**1,831**	**0**
Demand Response	**1,752**	**1,752**	**0**
Import Capability	**10,341**	**10,341**	**0**

Transitioning from the RSP to the HCP, the total loss of capacity is 3,463 MW; 3,227 MW of that total loss is retirement of gas-fired thermal generation resources.

With the increase of solar and behind-the-meter (BTM) PV, the peak of net load[153] (load minus solar, BTM PV and wind generation) and the peak of net sales (load minus BTM PV) is shifting to the early evening hours, specifically hour-ending 19 to 21 (HE 19-21) in the summer. By then, grid connected solar will have near zero generation and wind will have generation output of around 25% of its installed capacity. Taking that into consideration, the capacity loss of generation available at time of net sales moving from the RSP to the HCP is actually about 4,995 MW. Also, the HCP has 5,649 GWh less renewable generation than the RSP, which results in even lower hourly renewable generation.

[153] The ISO uses the term “net sales” to refer to the energy delivered to customers, adjusted for losses. “Gross consumption” is used to refer to the actual energy usage of the customers, before being reduced to net sales through the customer’s use of behind-the-meter generation. “Net load” refers to the net sales, minus the output of the grid-connected renewable generation. This is the energy profile that the rest of the generation fleet – gas-fired generation, hydro, nuclear, etc. - must supply.

7.2.2 Development of PLEXOS Models

The ISO developed two PLEXOS models, one deterministic and one stochastic, to support the CPUC IRP process and to use for the special studies in this transmission planning cycle.

The deterministic model simulations produce detail results matching exactly with the 2017 IEPR load forecast and the inputs of renewable, battery, demand response, and pumped storage resources. The detailed deterministic results can be used for in-depth analyses of the causes of renewable curtailment, CO2 emission, capacity shortfall, etc.

The stochastic modeling examines a wide range of system conditions. Its multiple-iteration Monte Carlo simulations produce probabilistic results. It is especially useful to identify the likelihood and magnitudes of capacity shortages.

The two new IRP models were developed on the basis of the models developed in the past CPUC Long Term Procurement Plan (LTPP) proceedings.[154] During that process, the LTPP models were discussed thoroughly with the involved parties, made available to the public, and used by many other parties for various studies.

The new IRP models have similar structures as the LTPP models and share some parameters, such as the topology and some operating characteristics of generators. However, the new IRP models have most of the data updated, including the assumptions of the HCP as summarized in Table 1.2-1, and the data from the WECC ADS PCM dataset for non-ISO regions in the models.

7.2.3 System Requirements for Gas-fired Generation Capacity

As the amount of renewable generation on the ISO system grows – whether grid-connected or behind-the-meter at end customer sites – and the OTC and nuclear plants continue to be phased out, the generation fleet is dealing with profound changes in the dynamics of market performance. These changes drive increased reliance on the gas-fired generation fleet and other resources for dynamic performance to support the operational needs of California's energy infrastructure and, at the same time, reduce the need for overall energy production from those resources.

The IRP HCP reflects the trend of reducing reliance on GHG-emitting gas-fired generation resources. It adopted the assumption that all gas-fired thermal generation resources 40 years or older will be retired before year 2030 together with the trimmed down renewable portfolio of the HCP. That is an aggressive assumption cutting into the supply fleet of the ISO system. This special study specifically focused on the sufficiency of supply in the ISO system in year 2030 with the IRP HCP.

[154] CAISO testimonies about production cost modeling filed into the CPUC 2014 LTPP proceeding http://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf and http://www.caiso.com/Documents/Nov20_2014_Liu_StochasticStudyTestimony_LTPP_R13-12-010.pdf

7.2.3.1 Study Approach and Methodology

This study used both the deterministic and stochastic models, each for different purposes.

The deterministic modeling produced the details results showing how each MW of capacity is exactly utilized with hourly granularity when there is a capacity shortfall. The stochastic model Monte Carlo simulations produced the likelihood and magnitudes of capacity shortages in the ISO system. The local capacity adequacy requirements were assumed to be met in this analysis.

The deterministic simulation was run for one iteration and stochastic simulations were run for 500 iterations. Both simulations were run chronologically in hourly intervals for the whole year of 2030.

In the deterministic modeling, shortfalls occur when supply is insufficient to meet the combination of load and requirements of ancillary services and load following. When that happens, there is a priority order to use the available supply to meet load and the different reserve requirements, similar to that in the ISO market scarcity pricing mechanism. The supply will be used to meet load first, followed by regulation-up, frequency response, spinning, non-spinning, and load following-up. Therefore, supply shortfall occurs first in load following-up. If the shortfall is larger than load-following up requirements, it spills over to non-spinning, spinning, frequency response requirements, regulation-up and finally to unserved energy (load shedding).

The stochastic modeling adopted reliability metrics specified in the CPUC's IRP process through an Administrative Law Judge ruling, which defines:[155]

- A loss of load (LOL) event: a day with insufficient capacity to meet the sum of load and requirements for regulation, frequency response, and spinning reserve for at least one hour
- Loss of load expectation (LOLE) criterion: the average of LOL events of all iterations of full-year simulations should be no higher than 0.1 (day/year)

So, for 500-iteration (500 years) Monte Carlo simulations, 50 LOL events or fewer are allowed in order to meet the LOLE criterion.

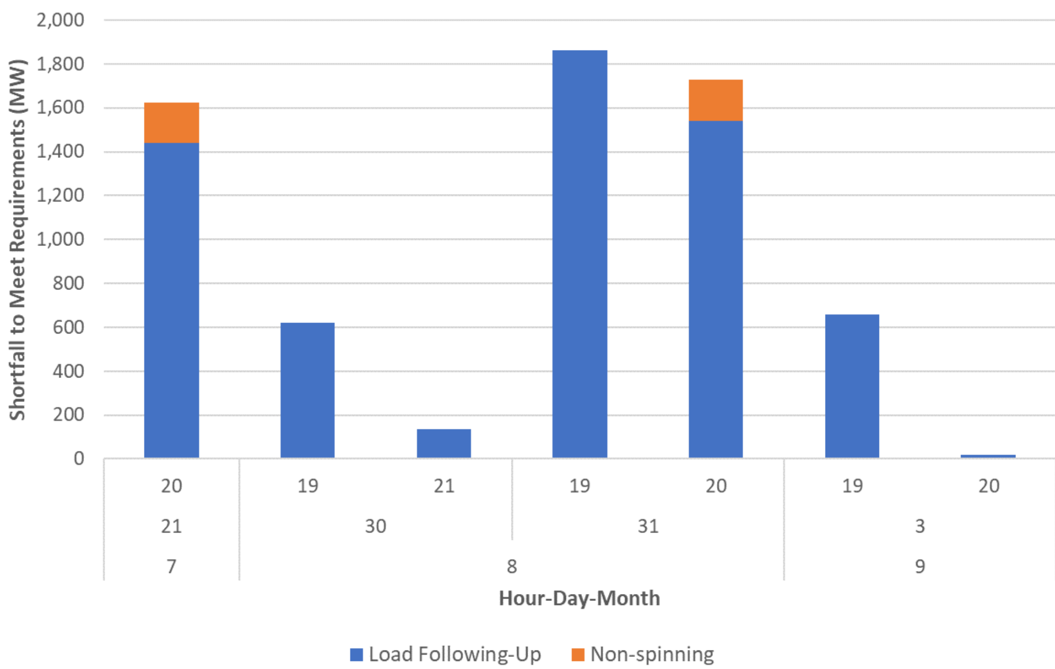
7.2.3.2 Study Results and Analyses

Deterministic Simulation Results

In the deterministic simulation, capacity shortfalls to meet load-following up and non-spinning reserve were found in 7 hours, as shown in Figure 7.2-1. All the hours are in the evening, between hour 19 and 21.

[155] Administrative Law Judge Ruling Directing production Cost Modeling Requirements, September 23, 2016 (http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451199)

Figure 7.2-1: Capacity Shortfall Events in Deterministic Simulation



To understand how the supply capacity was utilized during the hours with capacity shortfalls, the hourly detailed results of August 31, 2030 were examined.

First, the overall load and supply balance was examined shown in Table 7.2-2.

Table 7.2-2: ISO Load and Supply Balance on August 31, 2030

Hour	Load (MW)	Generation (MW)											Net Import (MW)	Reserve Shortfall	
		Total Generation	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage		Load Following-Up	NonSpin Reserve
1	32,447	22,227	0	6,683	616	0	335	6,894	84	5,252	0	2,363	10,221	0	0
2	30,705	20,510	0	6,096	590	0	335	6,894	0	5,231	0	1,363	10,195	0	0
3	29,396	19,055	0	6,027	590	0	335	6,894	0	5,205	0	4	10,341	0	0
4	28,802	19,006	0	6,055	573	0	335	6,894	0	5,149	0	0	9,796	0	0
5	28,843	18,830	0	6,125	573	0	335	6,894	0	4,903	0	0	10,013	0	0
6	28,891	19,283	71	6,197	580	0	332	6,894	0	4,483	0	726	9,608	0	0
7	31,436	26,035	2,822	5,370	543	0	252	6,161	0	10,886	0	0	5,402	0	0
8	32,316	28,820	6,722	5,471	516	0	252	1,041	0	14,819	0	0	3,496	0	0
9	37,093	35,585	10,446	5,471	523	0	252	2,039	0	16,853	0	0	1,508	0	0
10	41,783	40,473	13,504	5,507	516	0	252	2,125	0	18,571	0	0	1,310	0	0
11	43,973	42,656	15,255	5,585	516	0	252	1,245	0	19,804	0	0	1,317	0	0
12	46,472	45,079	15,763	5,720	523	0	252	2,834	0	19,987	0	0	1,393	0	0
13	48,735	47,412	15,953	6,014	523	0	252	4,037	0	20,632	0	0	1,323	0	0
14	48,994	47,732	14,578	6,310	533	0	252	5,587	0	20,472	0	0	1,262	0	0
15	49,024	47,812	12,815	6,881	554	0	252	6,891	0	20,419	0	0	1,212	0	0
16	48,525	45,948	9,867	9,187	628	0	332	6,889	199	18,846	0	0	2,577	0	0
17	47,619	42,847	6,400	10,878	719	0	1,312	6,889	813	15,835	0	0	4,772	0	0
18	45,953	39,100	2,524	12,667	1,078	0	3,456	6,890	1,831	10,644	10	0	6,853	0	0
19	44,635	35,729	65	13,493	1,078	1,168	3,811	6,890	1,831	5,523	10	1,858	8,907	1,862	0
20	45,811	36,167	0	13,609	1,078	1,168	3,866	6,890	1,831	5,504	10	2,210	9,644	1,538	189
21	43,689	33,348	0	13,393	1,071	0	3,772	6,890	1,831	5,827	10	554	10,341	0	0
22	40,204	30,019	0	12,537	747	0	2,189	6,890	1,831	5,821	4	0	10,185	0	0
23	36,718	27,724	0	11,198	734	0	1,949	6,891	1,340	5,609	4	0	8,995	0	0
24	33,472	24,919	0	10,034	695	0	1,061	6,891	581	5,657	0	0	8,552	0	0

The ISO has significant renewable and BTM PV generation in the mid-day. This generation output went down starting in the afternoon. Thermal and hydro generation, storage and imports ramped up to fill in the gap at the same time.

Table 7.2-3 shows the breakdown of renewable generation. The two tables demonstrate that BTM PV and solar generation dropped quickly from hour 14 on. By hour 19-20, solar had almost no contribution to meeting the load and reserves. Wind was generating at about 25% of installed capacity.

With the increase of solar, and wind and BTM PV in the portfolio, the peak of net load – being served by other resources - shifted to the evening. The shortfalls occurred at hour 19 and 20 on August 31, 2030.

Table 7.2-3: ISO Hourly Renewable Generation on August 31, 2030

Hour	Biogas	Biomass	Geothermal	Small Hydro	Solar PV	Solar Thermal	Wind	Total
16	187	690	1,329	454	13,274	943	1,967	18,846
17	187	690	1,329	440	10,613	566	2,009	15,835
18	187	690	1,329	453	5,976	164	1,844	10,644
19	187	690	1,329	456	4	0	2,857	5,523
20	187	690	1,329	457	0	0	2,841	5,504
21	187	690	1,329	443	0	0	3,177	5,827

As shown Table 7.2-4, the load modifiers reducing grid demand from customer gross consumption to net sales have some effect for hour 19, but not for hour 20. August 31, 2030 is a Saturday. Compared to the weekdays of the same week, the profile for August 31 had about 2,000 MW less Additional Achievable Energy Efficiency (AAEE), more than double the California Department of Water Resource (CDWR) pumping load, and higher Electric Vehicle (EV) charging load. The load after adjustment was actually higher than before for hour 20 and 21. All that made this Saturday a high net load day.

Table 7.2-4: ISO Hourly Load and Load Modifiers on August 31, 2030

Hour	Load Forecast	AAEE	Pump Load	EV	TOU	Load with Modifiers
16	51,565	4,596	1,158	681	-282	48,525
17	50,532	4,532	1,160	759	-299	47,619
18	48,486	4,194	1,159	795	-292	45,953
19	46,750	3,892	1,274	794	-292	44,635
20	45,791	3,714	1,394	2,630	-289	45,811
21	42,970	3,468	1,424	2,636	127	43,689

Because of the shift of the peak net load to the evening, the supply resources available to serve load and meet reserve and load-following requirements are not simply as indicated by the installed capacity in the HCP. Table 7.2-5 shows the utilization of all available supply capacity in the ISO during the evening hours on August 31, 2030.

Table 7.2-5: ISO Hourly Utilization of Available Supply Capacity on August 31, 2030

Hour	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage	Net Import
Generation and Import (MW)											
16	9,867	9,187	628	0	332	6,889	199	18,846	0	0	2,577
17	6,400	10,878	719	0	1,312	6,889	813	15,835	0	0	4,772
18	2,524	12,667	1,078	0	3,456	6,890	1,831	10,644	10	0	6,853
19	65	13,493	1,078	1,168	3,811	6,890	1,831	5,523	10	1,858	8,907
20	0	13,609	1,078	1,168	3,866	6,890	1,831	5,504	10	2,210	9,644
21	0	13,393	1,071	0	3,772	6,890	1,831	5,827	10	554	10,341
Provision of Upward Load-following and Reserves (MW)											
16	0	3,063	0	0	1,462	0	300	0	0	1,642	0
17	0	1,459	0	0	1,882	0	900	0	0	2,481	0
18	0	1,358	0	0	3,058	0	0	0	0	2,481	0
19	0	533	0	0	2,667	0	0	0	0	623	0
20	0	416	0	0	2,624	0	0	0	0	272	0
21	0	633	0	0	2,718	0	0	0	0	1,927	0
Outages (MW)											
16	0	28	0	0	301	0	374	0	0	0	0
17	0	616	0	0	298	0	0	0	0	0	0
18	0	616	0	0	298	0	0	0	0	0	0
19	0	616	0	0	333	0	0	0	0	0	0
20	0	616	0	0	321	0	0	0	0	0	0
21	0	616	0	0	321	0	0	0	0	0	0
Total Usage (MW)											
16	9,867	12,278	628	0	2,095	6,889	873	18,846	0	1,642	2,577
17	6,400	12,954	719	0	3,492	6,889	1,713	15,835	0	2,482	4,772
18	2,524	14,642	1,078	0	6,812	6,890	1,831	10,644	10	2,482	6,853
19	65	14,642	1,078	1,168	6,812	6,890	1,831	5,523	10	2,482	8,907
20	0	14,642	1,078	1,168	6,812	6,890	1,831	5,504	10	2,482	9,644
21	0	14,642	1,071	0	6,812	6,890	1,831	5,827	10	2,482	10,341
Total Available Capacity (MW)											
16	9,867	14,642	1,078	1,168	6,813	6,889	1,831	18,846	10	2,482	10,341
17	6,400	14,642	1,078	1,168	6,813	6,889	1,831	15,835	10	2,482	10,341
18	2,524	14,642	1,078	1,168	6,813	6,890	1,831	10,644	10	2,482	10,341
19	65	14,642	1,078	1,168	6,813	6,890	1,831	5,523	10	2,482	10,341
20	0	14,642	1,078	1,168	6,813	6,890	1,831	5,504	10	2,482	10,341
21	0	14,642	1,078	1,144	6,813	6,890	1,831	5,827	10	2,482	10,341

The table demonstrates that:

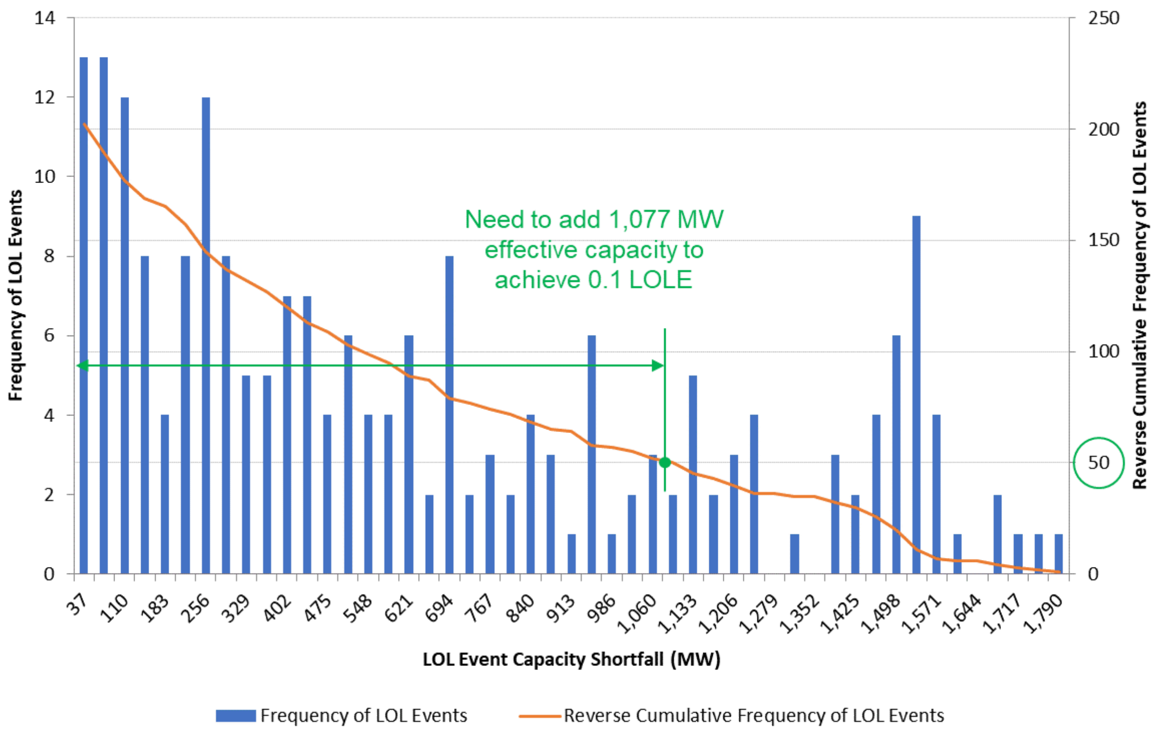
- About 5,000 to 7,000 MW capacity was needed to provide upward reserves and load-following services. Battery storage provided a large share of it as it was the most efficient among all the types of resources to do so;
- CCGT has about 4.2% capacity on outage and GT has 4.8%;
- Available capacity of renewable and BTM PV was dropping quickly;
- Available capacities of all types of resources, except import, were fully utilized in hour 19 and 20;
- Demand response had total capacity of 1,752 MW (see Table 1.2-1). Some of the demand response programs are not available on weekends. The available demand response capacity on August 31, 2030 was only 1,168 MW at hour 19 and 20; and,
- Net import for hour 19 and 20 was below the 10,341 MW maximum import capability, even though there is shortfall in supply.

The stochastic stimulation results provide an indication of the amount of gas-fired generation capacity the ISO needs to maintain the reliability of its system.

Stochastic Simulation Results

With the stochastic model, the Monte Carlo simulation was run for 500 iterations (years). The results were then measured against the reliability metrics as described in Section 1.2.3.1. The results show 202 LOL events in 500 years were identified, which is equivalent to about 0.4 LOLE. The frequency distribution (histogram) of the LOL events is plotted in Figure 7.2-2.

Figure 7.2-2: Histogram of LOL Events in 500 Iterations for Year 2030



To get to 0.1 LOLE, which is a maximum of 50 LOL events for this number of simulations, an additional 1,077 MW effective capacity was needed during the critical periods. Effective capacity is not simply installed capacity. It is the capacity that can be dispatched when it is needed, adjusted by outages to reflect the amount actually available.

The HCP assumed 3,227 MW gas-fired generation resources will be retired by 2030 based on the 40-year retirement rule (see Table 1.2-1). That led to the shortfall of 1,077 MW effective capacity. The ISO stochastic simulation results indicate that less than 2,150 MW gas-fired generation resources that are 40 years or older can be retired in order to meet the 0.1 LOLE reliability criterion.

7.2.3.3 Conclusions

From the study results, it can be concluded that:

- The HCP does not have sufficient capacity to serve load and meet requirements of reserves and load-following serve, without adjusting the retirement assumption;
- Less than 2,150 MW out of 3,277 MW gas-fired generation resources that are 40 years or older can be retired – or would need to be replaced;
- If 1,077 MW effective capacity of other types of new resources, such as renewable, except solar, storage, demand response, and AAEE are added, all 3,277 MW gas-fired generation resources that are 40 years or older could be retired without causing reliability problems; and,

7.2.4 Benefits Analysis of Large Energy Storage

7.2.4.1 Introduction

In this 2018-2019 transmission planning cycle, the ISO has updated the production cost modeling study results of studies conducted in the previous two planning cycles regarding the system benefits of large (hydro) storage. However, the ISO has not updated the comprehensive assessment of the capacity benefits of these resources, as the comprehensive consideration of those benefits is being conducted within the CPUC's IRP process. In 2016-2017 and 2017-2018 transmission planning cycles, the ISO undertook information – only studies of the benefits large scale energy storage projects may provide to ratepayers in the ISO footprint as the state moves from the 33 percent RPS to a 50 percent RPS. The 2017-2018 effort consisted of additional sensitivities based on the cases studied in the 2016-2017 analysis, and did not move to the new models used in the 2017-2018 transmission plan for decision-making purposes

At the same time, large storage projects have been proposed to the ISO for consideration as potential reliability or local capacity requirement reduction mitigations, which need to be considered in the context of the formal tariff-based transmission planning process, and are discussed in chapter 4 of this transmission plan.

7.2.4.2 Study Approach

This study was conducted based on the assumptions set out in section 7.2.1.

Two new bulk energy storage resources – a 500 MW and a 1400 MW resource - were added in turn to the production simulation model developed with the CPUC 2017-2018 IRP Hybrid Conforming Plan (HCP) to evaluate its contribution to reduction of renewable curtailment, CO2 emission, and production cost.

In the previous cycles of transmission planning cycles, the bulk energy storage studies calculated the benefits of storage reducing the amount of renewable "overbuild" necessary to achieve the 50% RPS target. In the 2017-2018 IRP proceeding, sufficient renewable resources were selected that exceeded the RPS 50% target of the 2017-2018 IRP cycle even after considering curtailment.[156] In addition, there are also some “banked” renewable energy certificates (RECs) available to be used in 2030 taking the achieved level even higher. Therefore, the benefits of storage reducing the “overbuild” of wind and solar capacity were not calculated, and instead the GHG pricing addresses those benefits.

Assumptions for New Pumped Storage Resources

The pumped storage resources selected for this study were a 500 MW resource and a 1400 MW resource. Table 7.2-5 and Table 7.2-6 show the assumptions for the 500 and 1,400 MW pumped storage resources. The ISO made the assumptions based on a review of publically available information.

Table 7.2-5: Assumptions of the New 500 MW (Gen) Pumped Storage Resource

Item	Assumption
Number of units	2
Max pumping capacity per unit (MW)	300
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	250
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	50
Generation ramp rate (MW/min)	250
Round-trip efficiency	83%
VOM Cost ($/MWh)	3.00
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	Variable speed
Reserves can provide in generation and pumping modes	Regulation, spinning and load following
Reserves can provide in off-line modes	Non-spinning
Location	SCE zone

156 See http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2.%20CPUC%20Staff%20Proposed%20Pref%20System%20Portfolio%20for%20IRP%202018_20190107final.pdf

Table 7.2-6: Assumptions of the New 1,400 MW (Gen) Pumped Storage Resource

Item	Assumption
Number of units	4
Max pumping capacity per unit (MW)	422
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	350
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	50
Generation ramp rate (MW/min)	250
Round-trip efficiency	83%
VOM Cost ($/MWh)	3.00
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	18.8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	Variable speed
Reserves can provide in generation and pumping modes	Regulation, spinning and load following
Reserves can provide in off-line modes	Non-spinning
Location	SCE zone

Based on the assumptions, the pumped storage resource has a maximum usable storage volume that can support generation at maximum capacity for up to 12 hours without additional pumping. The resource can ramp from minimum to maximum generation in 1 minute and from minimum to maximum pumping in 5 minutes. It can provide ancillary services and load-following in both pumping and generation modes.

7.2.4.3 Study Results - System Benefits

Table 7.2-7 summarizes the simulation results of overall system impacts for the two configurations of pumped storage resources that were studied.

Table 7.2-7: Energy Balance and CO2 Emissions

Case	Hybrid Conforming Plan	500 MW Pumped Storage		1,400 MW Pumped Storage	
		Results	Change from Base	Results	Change from Base
ISO CO2 Emission (MM Ton)					
By In-ISO Generation	23.45	23.09	-0.36	22.51	-0.94
CCGT	18.94	18.75	-0.19	18.39	-0.55
CHP	2.63	2.62	-0.01	2.61	-0.02
GT	1.89	1.73	-0.16	1.52	-0.37
ST	0.00	0.00	0.00	0.00	0.00
From Import	17.91	17.89	-0.03	17.91	0.00
Import - NW	6.47	6.51	0.04	6.56	0.09
Import - others	11.45	11.38	-0.06	11.35	-0.09
Sum	41.37	40.98	-0.39	40.42	-0.95
CO2 Emission Offset	-2.80	-2.80	0.00	-2.80	0.00
Total	38.57	38.18	-0.39	37.62	-0.95
WECC-Wide CO2 Emission (MM Ton)	303.64	303.78	0.14	303.86	0.23
Native Load (GWh)	254,541	254,541	0	254,541	0
Retail Sales (GWh)	202,464	202,464	0	202,464	0
Total Generation (GWh)	205,590	204,963	-628	203,815	-1,776
BTMPV	36,301	36,301	0	36,301	0
CCGT	52,156	51,662	-494	50,700	-1,457
CHP	5,110	5,091	-19	5,077	-33
DR	17	13	-4	7	-10
GT	4,152	3,831	-321	3,400	-752
Hydro	19,380	19,380	0	19,380	0
Pumped Storage	-145	-346	-201	-697	-552
Renewable	89,135	89,549	415	90,181	1,046

Case	Hybrid Conforming Plan	500 MW Pumped Storage		1,400 MW Pumped Storage	
		Results	Change from Base	Results	Change from Base
ST	0	0	0	0	0
Storage	-515	-519	-3	-534	-19
Net Import	48,951	49,579	628	50,727	1,776
Import - NW	15,114	15,200	86	15,320	206
Import - others	43,284	43,134	-151	43,072	-212
Export	-9,448	-8,755	693	-7,665	1,783
Renewable Generation (GWh)	103,083	103,497	415	104,131	1,049
In-State	90,649	91,063	415	91,697	1,049
Out-State (all OOS RPS generation)	12,434	12,434	0	12,434	0
RPS Achieved (excluding banked RECs)	52.5%	52.7%	0.2%	52.7%	0.5%
Renewable Curtailment (GWh)	3,328	2,913	-415	2,279	-1,049
Production Cost ($million)					
WECC	13,042	12,996	-46	12,926	-116
CAISO	2,869	2,818	-51	2,735	-134
In-ISO Generation CO2 Emission (MT/MWh)	0.114	0.113	-0.001	0.110	0.112
ISO Import CO2 Emission (MT/MWh)	0.307	0.307	0.000	0.307	0.307

Further, the performance of the pumped storage is set out in Table 7.2-8.

Table 7.2-8: Performance of Pumped Storage

Values	500 MW Pumped Storage	1,400 MW Pumped Storage
Sum of Generation (GWh)	1,124	3,055
Sum of Pump Load (GWh)	1,355	3,680
Sum of Total Generation Cost ($000)	3,719	10,102
Sum of Pump Cost ($000)	11,521	42,457
Sum of Energy Revenue ($000)	71,901	186,388
Sum of Reserves Revenue ($000)	16,975	30,287
Sum of Net Revenue ($000)	73,636	164,116

7.2.4.4 Study Conclusions

Based on the results of the study, it can be concluded that:

- The new pumped storage resources brought significant benefits to the system, including:
  - Reduced renewable curtailment;
  - Lower production costs; and,
  - The flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes.
- The new pumped storage resources also took advantage of low cost out-of-state energy during hours without renewable curtailment. They also resulted in higher net import to California and slightly increased CO2 emissions[157] within the California footprint.
- The net market revenue of the pumped storage resources provided a material contribution towards the levelized annual revenue requirements. However, pumped storage resources would need other sources of revenue streams, including consideration of capacity benefits, which could be developed through resource procurement and policy decisions.
- The annual system cost reductions (benefits), shown in Table 7.2-7, are not included in the net market revenue, but may be attributed to the pumped storage resources – especially in considering procurement policy.

The results of the study are sensitive to the assumptions, especially those listed in Table 7.2-1.

[157] The slightly increased CO2 emissions result from the assumptions regarding the GHG adder relied upon in the study and the assumption that the pumped storage would pump when low cost energy is available regardless of source. Higher GHG adders or other restrictions on these pumping opportunities would mute this impact, albeit with some corresponding impact on benefits.

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 $50M

No	Project	PTO	Expected In-Service Date
1	Estrella Substation Project	NEET West/PG&E[158]	Nov-23
2	Bellota 230 kV Substation Shunt Reactor	PG&E	Apr-19
3	Borden 230 kV Voltage Support	PG&E	May-19
4	Cascade 115/60 kV No.2 Transformer Project	PG&E	Jan-22
5	Clear Lake 60 kV System Reinforcement	PG&E	Feb-22
6	Coburn-Oil Fields 60 kV system project	PG&E	Feb-20
7	Contra Costa Sub 230 kV Switch Replacement	PG&E	Completed
8	Cooley Landing 115/60 kV Transformer Capacity Upgrade	PG&E	Jun-19
9	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	May-19
10	Cortina No.3 60 kV Line Reconductoring Project	PG&E	Completed
11	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	Nov-21
12	Delevan 230 kV Substation Shunt Reactor	PG&E	Aug-20
13	Diablo Canyon Voltage Support Project	PG&E	Canceled
14	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-21

[158] 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	Fulton-Hopland 60 kV Line Project	PG&E	Mar-20
16	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	Dec-19
17	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	Jan-21
18	Helm-Kerman 70 kV Line Reconductor	PG&E	Completed
19	Herndon-Bullard 115 kV Reconductoring Project	PG&E	Jan-21
20	Ignacio 230 kV Reactor	PG&E	Aug-19
21	Ignacio Area Upgrade	PG&E	Dec-23
22	Jefferson-Stanford #2 60 kV Line	PG&E	Canceled
23	Kearney – Hearndon 230 kV Line Reconductoring	PG&E	Jan-19
24	Kearney-Caruthers 70 kV Line Reconductor	PG&E	Apr-19
25	Kern PP 230 kV Area Reinforcement	PG&E	Apr-21
26	Lakeville 60 kV Area Reinforcement	PG&E	Dec-21
27	Lemoore 70 kV Disconnect Switches Replacement	PG&E	Completed
28	Lodi-Eight Mile 230 kV Line	PG&E	Completed
29	Los Banos-Livingston Jct-Canal 70 kV Switch Replacement	PG&E	Completed
30	Los Esteros 230 kV Substation Shunt Reactor	PG&E	Apr-20
31	Maple Creek Reactive Support	PG&E	Jul-22
32	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	May-19
33	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	Apr-22
34	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	Nov-26
35	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	Dec-22
36	Missouri Flat – Gold Hill 115 kV Line	PG&E	Completed
37	Monta Vista 230 kV Bus Upgrade	PG&E	Aug-20
38	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Mar-21
39	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	May-21
40	Morro Bay 230/115 kV Transformer Addition Project	PG&E	Canceled

No	Project	PTO	Expected In-Service Date
41	Mosher Transmission Project	PG&E	Dec-20
42	Moss Landing–Panoche 230 kV Path Upgrade	PG&E	Jan-19
43	Newark-Lawrence 115 kV Line Limiting Facility Upgrade	PG&E	Dec-19
44	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	Jun-19
45	North Tower 115 kV Looping Project	PG&E	Dec-21
46	NRS-Scott No. 1 115 kV Line Reconductor[159]	PG&E	Mar-19
47	Oakland Clean Energy Initiative	PG&E	Aug-22
48	Oro Loma 70 kV Area Reinforcement	PG&E	May-20
49	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	Dec-20
50	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	Mar-20
51	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	May-22
52	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	Dec-20
53	Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects)	PG&E	May-21
54	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Jun-22
55	Rio Oso Area 230 kV Voltage Support	PG&E	Jun-22
56	Ripon 115 kV Line	PG&E	Apr-19
57	San Bernard – Tejon 70 kV Line Reconductor	PG&E	Dec-19
58	San Jose-Trimble 115 kV Series Reactors	PG&E	Feb-19
59	Semitropic – Midway 115 kV Line Reconductor	PG&E	Mar-21
60	Series Reactor on Warnerville-Wilson 230 kV Line	PG&E	Completed
61	South of San Mateo Capacity Increase	PG&E	May-19 & Mar-26
62	Stockton 'A' –Weber 60 kV Line Nos. 1 and 2 Reconductor	PG&E	May-19
63	Trimble-San Jose B 115 kV Line Limiting Facility Upgrade	PG&E	Feb-19
64	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	Aug-22

[159] 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
65	Vierra 115 kV Looping Project	PG&E	Feb-23
66	Warnerville-Bellota 230 kV line reconductoring	PG&E	Nov-23
67	West Point – Valley Springs 60 kV Line	PG&E	Dec-19
68	Wheeler Ridge Voltage Support	PG&E	Apr-21
69	Wheeler Ridge-Weedpatch 70 kV Line Reconductor	PG&E	Mar-19
70	Wilson 115 kV Area Reinforcement	PG&E	May-23
71	Wilson 115 kV SVC	PG&E	Dec-20
72	Wilson-Le Grand 115 kV line reconductoring	PG&E	Dec-20
73	2nd Escondido-San Marcos 69 kV T/L	SDG&E	Dec-20
74	2nd Pomerado - Poway 69kV Circuit	SDG&E	Jun-20
75	Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously-approved New Sycamore - Bernardo 69 kV line)	SDG&E	Sep-19
76	IID S-Line Upgrade[160]	SDG&E	Dec-21
77	Miramar-Mesa Rim 69 kV System Reconfiguration	SDG&E	Dec-20
78	Mission Bank #51 and #52 replacement	SDG&E	Jun-18
79	Reconductor TL 605 Silvergate – Urban	SDG&E	Dec-21
80	Reconductor TL663, Mission-Kearny	SDG&E	Jun-19
81	Reconductor TL676, Mission-Mesa Heights	SDG&E	Mar-19
82	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	Sep-21
83	Rose Canyon-La Jolla 69 kV T/L	SDG&E	Jan-19
84	San Ysidro 69 kV Reconductoring	SDG&E	Jun-22
85	Second Miguel – Bay Boulevard 230 kV Transmission Circuit	SDG&E	Jun-19
86	Suncrest 500/230 kV Transformer Rating Increase	SDG&E	Complete
87	Sweetwater Reliability Enhancement	SDG&E	Sep-20

[160] The ISO is pursuing revisions to the scope of the previously approved S-Line Transmission Upgrade to consist of an appropriately sized single circuit 230 kV circuit, which provides the same local capacity requirement reduction value to the ISO as the original double-circuit line. As well, the ISO is updating the estimated cost to ISO ratepayers of the S-Line upgrade from $32 million to $40 million in light of revised costs estimates provided by IID. This increase in estimated cost would be offset by the savings of no longer needing a new line termination at the Imperial Valley Substation, which was required under the original double circuit configuration.

No	Project	PTO	Expected In-Service Date
88	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	Dec-21
89	TL600: "Mesa Heights Loop-in + Reconductor	SDG&E	Dec-19
90	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Jun-21
91	TL633 Bernardo-Rancho Carmel Reconductor	SDG&E	Sep-19
92	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Jun-19
93	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	Jun-20
94	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	Jun-26
95	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Sep-20
96	Laguna Bell Corridor Upgrade	SCE	Mar-22
97	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-20
98	Method of Service for Wildlife 230/66 kV Substation	SCE	Jun-23
99	Eagle Mountain Shunt Reactors	SCE	Complete
100	PDCI Upgrade (to 3220 MW)	SCE	Complete
101	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	Jun-21
102	Big Creek Rating Increase Project	SCE	Jun-19
103	Moorpark-Pardee No. 4 230 kV Circuit	SCE	Dec-20
104	Tie line Phasor Measurement Units	PG&E, SCE, VEA	Dec-20
105	Bob-Mead 230 kV Reconductoring	VEA	Dec-20

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-21
2	Suncrest 300 Mvar dynamic reactive device	NEET West	Dec-19
3	Atlantic-Placer 115 kV Line	PG&E	Canceled
4	Cottonwood-Red Bluff No. 2 60 kV Line Project	PG&E	May-21
5	Gates #2 500/230 kV Transformer Addition	PG&E	Dec-19
6	Gates-Gregg 230 kV Line	PG&E/MAT	Canceled
7	Kern PP 115 kV Area Reinforcement	PG&E	Dec-23
8	Lockeford-Lodi Area 230 kV Development	PG&E	Dec-24
9	Martin 230 kV Bus Extension	PG&E	Oct-22
10	Midway – Kern PP #2 230 kV Line	PG&E	May-23
11	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)[161]	PG&E	On hold
12	New Bridgeville – Garberville No. 2 115 kV Line	PG&E	Canceled
13	Northern Fresno 115 kV Area Reinforcement	PG&E	Dec-20
14	South of Palermo 115 kV Reinforcement Project	PG&E	Nov-22
15	Vaca Dixon Area Reinforcement	PG&E	Dec-21
16	Wheeler Ridge Junction Substation	PG&E	May-24
17	Artesian 230 kV Sub & loop-in TL23051	SDG&E	Mar-20
18	South Orange County Dynamic Reactive Support – San Onofre (now 1-225 Mvar synchronous condenser)[162]	SDG&E	Complete
19	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-21

[161] 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 is recommended in this 2018-2019 Transmission Plan.

[162] The South Orange County Dynamic Reactive Support project was initially approved in the 2012-2013 Transmission Plan and initially awarded to SDG&E as it was expected to be located in the San Onofre area in SDG&E's service territory. In 2014, the project was split due to siting issues, replacing two synchronous condensers at a single site with instead locating one at the San Onofre substation and the second being awarded to SCE and located in the Santiago substation. This was reflected in system modeling and noted on Page 159 and in Table 3.2.6 in the 2014-2015 Transmission Plan, but Table 7.1-2 (line number 5) was inadvertently not updated to reflect the change.

No	Project	PTO	Expected In-Service Date
20	Sycamore-Penasquitos 230 kV Line	SDG&E	Complete
21	Alberhill 500 kV Method of Service	SCE	Sep-22
22	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	Dec-20
23	Lugo-Mohave series capacitor upgrade	SCE	Dec-20
24	Mesa 500 kV Substation Loop-In	SCE	Mar-22
25	South Orange County Dynamic Reactive Support - Santiago Synchronous Condenser - SCE's component (1-225 Mvar synchronous condenser)[163]	SCE	Complete
26	Harry Allen-Eldorado 500 kV transmission project	DesertLink LLC	May-20

[163] Refer to the preceding footnote.

8.2 Transmission Projects found to be needed in the 2018-2019 Planning Cycle

In the 2018-2019 transmission planning process, the ISO determined that 11 transmission projects were needed to mitigate identified reliability concerns; no policy-driven projects were needed to meet the 33 percent RPS. Two 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 2017 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	Tyler 60 kV Shunt Capacitor	PG&E	2022	$5.8-$7M
2	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	2022	$8.5M-$10.5M
3	Gold Hill 230/115 kV Transformer Addition Project	PG&E	2022	$22M
4	Jefferson 230 kV Bus Upgrade	PG&E	2022	$6M-$11M
5	Christie-Sobrante 115 kV Line Reconductor	PG&E	2022	$10.5M
6	Moraga-Sobrante 115 kV Line Reconductor	PG&E	2023	$12M-$18M
7	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	2019	$0.1M-$0.2M
8	Tesla 230 kV Bus Series Reactor project	PG&E	2023	$24M-$29M
9	South of Mesa Upgrade	PG&E	2023	$29.6-59.2M
10	Round Mountain 500 kV Dynamic Voltage Support[164]	PG&E	2024	$160M-$190M
11	Gates 500 kV Dynamic Voltage Support	PG&E	2024	$210M-$250M

[164] Further review of the engineering detail for the termination of the Round Mountain 500 kV Reactive Project is required due to siting issues at Round Mountain for the project. Board of Governor approval is recommended, and the additional detail will be posted as an addendum to the transmission plan. The competitive procurement process for the project will commence after that has taken place.

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 2018-2019 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
1	Giffen Line Reconductoring Project	PG&E	TBD	$5M
2	East Marysville 115/60 kV Project	PG&E	2022	$26-32M

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 2018-2019 Transmission Plan. In some areas, such as the LA Basin, this reliance has been overt through the testing of various resource portfolios being considered for procurement, and in other areas through reliance on demand side resources such as additional achievable energy efficiency and other existing or forecast preferred resources.

As set out in the 2018-2019 Tranmission 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 Tables 2.7-5 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 repurposed 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.

Moorpark and Santa Clara Sub-areas

As set out in section 2.7.5.3, 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 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.

The ISO has identified the following regional transmission solutions recommended for approval in this 2018-2019 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

Reliability-driven Projects:

- Gates 500 kV Dynamic Reactive Support Project
- Round Mountain 500 kV Dynamic Reactive Support Project

The descriptions and functional specifications for the facilities eligible for competitive solicitation can be found in Appendix I.

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.

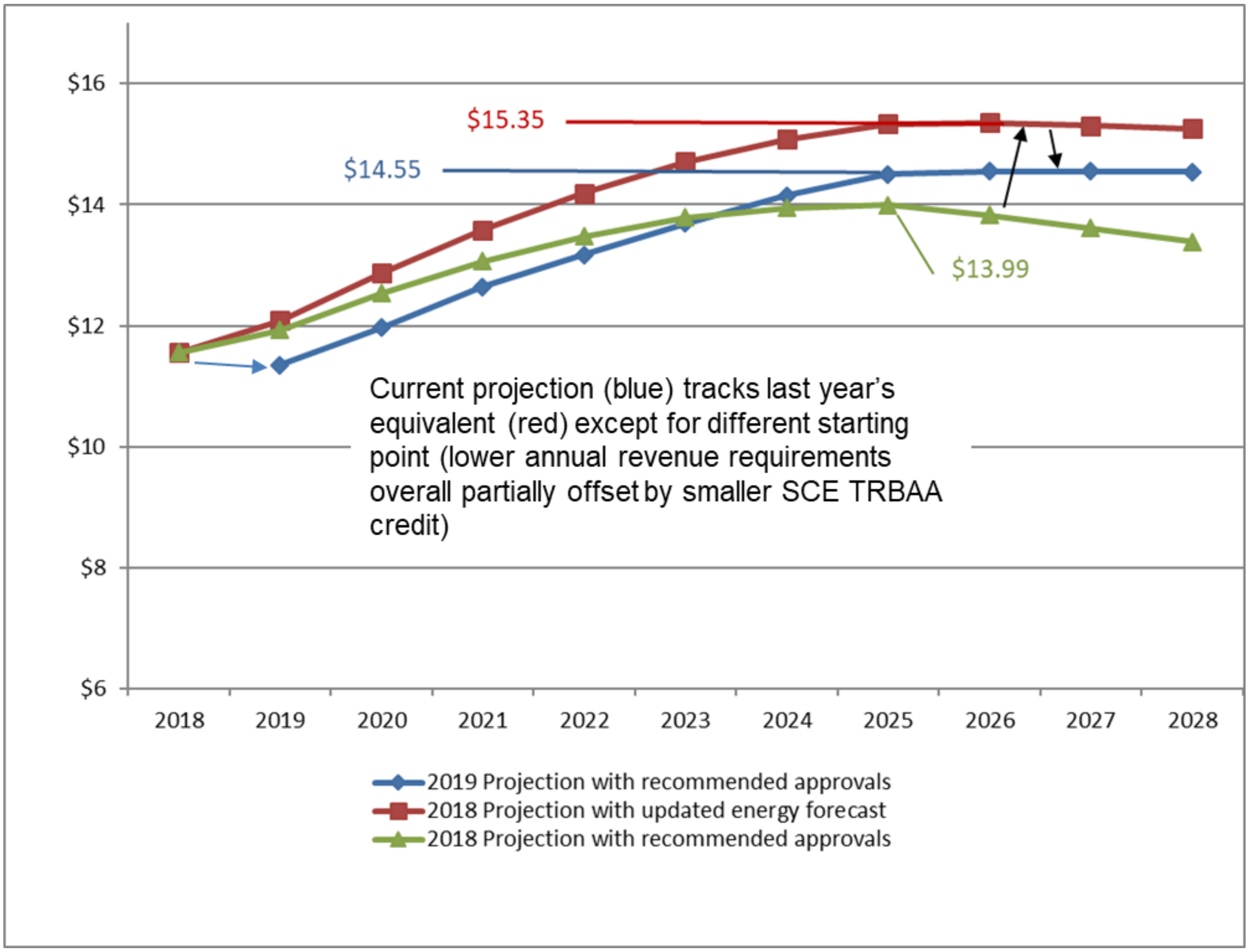
The ISO has also continued the practice from past cycles to base this year's analysis of future transmission projects on an average of 11% as the long term forecast return on equity. While stakeholders have suggested that a 10% return may be appropriate, the ISO has considered this as a lower bound. The overall return values for existing rate base assets are drawn from the PTO's actual approved revenue requirements. An updated estimate from the 2017-20178 transmission planning process has been provided for comparison.

The estimate provided below reflects the latest updated costs for all previously approved projects and the revised scopes for projects with recommended scope changes. All projects recommended to be canceled have been removed from the estimate, and projects on hold are included in the estimate.

In cycles prior to the 2016-2017 Transmission Plan, adjustments had been made to maintain annual reliability-driven projects approvals above a certain threshold once it had been initially exceeded. However, consistent with the 2016-2017 Transmission Plan, only the cost of approved transmission projects and projects recommended to be approved have been included.

As in past planning cycles, a 1% load growth had been assumed in overall energy forecast over which the high voltage transmission revenue requirement is recovered for comparison purposes. However, a sensitivity was included in the 2017-2018 transmission plan reflecting a forecast year over year decrease of 0.31% in energy served, consistent with the CEC's 2016 IEPR forecast. The 2018-2019 results provided below were also based on this same year over year forecast for consistency in comparisons.

Figure 8.5-1: Forecast of ISO HIgh Voltage Transmission Access Charge Trended from First Year of Transmission Plan



In reviewing the latest estimate, several observations can be made. As noted in Figure 8.5-1, the 2019 TAC value for the 2019 projection is lower than the 2018 value from the 2018 projection. This stemmed from ower overall transmission revenue requirements, primarily for the investor-owned utilities. Other than the offset in initial TAC rates, the trend demonstrated last year remains relatively consistent with the trend this year, with new capital projects being recommended for approval in this plan being offset to some extent by canceled projects. Adjustments to federal income tax rates are also expected to have put downward pressure on the initial 2019 TAC rate as well as the impact of new capital additions.