2021-2022 TRANSMISSION PLAN

California ISO

March 17, 2022
Board Approved

Foreword to Board Approved 2021-2022 Transmission Plan

At the March 17, 2022 ISO Board of Governors meeting, the ISO Board of Governors approved the 2021-2022 Transmission Plan.

Appendix G will be updated with additional technical details prior to the competitive solicitation process.

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Executive Summary

The need for new generation over the next 10 years has escalated rapidly, driving an accelerated pace for new transmission development in this and future planning cycles. The 2020-2021 transmission plan was based on a requirement to add approximately 1,000 MW of new resources per year over the 10-year planning horizon, and next year's plan is expected to be based on over 4,000 MW of new resources per year. This year's 2021-2022 transmission plan is based on an intermediate level of approximately 2,700 MW of new resources per year, and it demonstrates a material step forward in meeting the emerging challenges facing the grid, while recognizing that significant growth will also be needed in future plans.

The accelerated pace of resource development called for over the next 10 years is driven by numerous factors, including (1) the escalating need to decarbonize the electricity grid because of emerging climate change impacts, (2) the expected electrification of transportation and other carbon-emitting industries, which is driving higher electricity forecasts, (3) concerns regarding reduced access to opportunity imports as neighboring systems also decarbonize, (4) greater than anticipated impacts of peak loads shifting to later-in-the-day hours when solar resources are unavailable, and (5) the need to maintain system reliability while retiring the Diablo Canyon Power Plant and gas-fired generation relying on coastal waters for once-through cooling.

These resource requirements, on the path to total grid decarbonization, will demand increased volumes of solar photovoltaic resources and battery storage, as well as greater resource diversity beyond those resource types. Geothermal resources, new out-of-state renewable resources, and offshore resources all are expected to play greater roles.

The transmission system will also need to be expanded, upgraded, and reinforced to access and integrate these resources, as well accommodate the expected resurgence in electricity consumption as transportation and other industries electrify to reduce their carbon impact.

The California Independent System Operator's (ISO) ISO2021-2022 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 based on the trajectory of resource planning established for this planning cycle, and explore projects that can bring economic benefits to consumers.

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

The ISO developed the transmission plan through a comprehensive stakeholder process and coordinated extensively with state energy agencies – the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) – for key inputs and assumptions regarding electricity demand-side forecast assumptions and supply side development expectations. In particular, the plan relies heavily on key inputs from state agencies in translating legislative policy into actionable policy-driven outcomes.

In parallel with enhancements to the transmission planning process, the ISO is also seeking to enhance coordination of state agency resource planning processes and the ISO's resource interconnection process, as well as the overall coordination of the procurement and development of new resources and related transmission network upgrades.

The Transmission Planning Process

The transmission plan primarily identifies three main categories of transmission solutions: reliability, public policy, and economic needs through a sequential study process. Although the ISO's planning process considers reliability, public policy, and economic projects sequentially, it allows the ISO to revisit projects identified in a prior stage if an alternative project identified later can meet the previously identified need and provide additional benefits not considered in the prior stage. Thus, the ISO's iterative planning process ultimately allows the ISO to consider and approve transmission projects with multiple benefit streams (*e.g.,* reliability, public policy, and economic) and to modify or upsize transmission solutions identified in earlier stages to achieve additional benefits. The reliability analysis focuses on meeting all relevant planning standards and criteria to reliably operating the grid, including NERC, WECC and ISO requirements. Although the reliability analysis ensures renewable generation portfolios may reliably connect to the grid, it does not ensure that congestion would preclude achieving state policy goals. The policy-driven transmission analysis focuses on deliverability of those resources.

The ISO's economic planning 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 assess those opportunities. Reliability analysis provides essential information about the electrical characteristics and performance of the ISO-controlled grid, but 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. Other end-use ratepayer cost saving benefits, such as reducing local capacity requirements in transmission-constrained areas, can also provide material benefits.

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. 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 in the same manner it often selects operational solutions in lieu of transmission upgrades. If the ISO identifies a non-transmission solution as the preferred option the ISO then engages with the local regulatory agency to pursue the development of the non-transmission alternative. Further, load modifying preferred resource assumptions are also incorporated into the load forecasts adopted through state energy agency activities that the ISO supports, and they provide an additional opportunity for preferred resources to address transmission needs.

In addition to the power flow, dynamic stability, voltage stability and deliverability studies the ISO conducts annually, the ISO has also incorporated into this study process a review of short circuit studies conducted by the transmission owners, to identify and address proactively potential fault level issues affecting future resource additions.

The transmission planning process has 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, the ISO undertakes a competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan. Phase 3 begins 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 2020-2021 planning cycle, for example, began in January 2020, and the 2020-2021 Transmission Plan was approved in March 2021.

Planning Assumptions and State Agency Coordination

The ISO developed the 2021-2022 planning assumptions and scenarios through the annual agency coordination processes the ISO, CEC and CPUC have in place and undertake each year in connection with infrastructure planning activities. This alignment effort continues to improve infrastructure planning coordination within the three parties' core processes and is being enhanced in:

- The CEC's long term resource planning produced as part of SB 100 related activities and long-term forecasts of energy demand produced as part of its biennial Integrated Energy Policy Report (IEPR);
- The CPUC's biennial Integrated Resource Planning (IRP) proceedings; and,
- The ISO's annual Transmission Planning Process (TPP).

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 provided to the ISO via Decision 21-02-008[1] released on February 11, 2021 base case and sensitivity portfolios for use in this planning cycle. The Decision transmitted to the ISO for its 2021-2022 Transmission Planning Process the reliability and policy-driven base case portfolio that meets the 46 million metric ton (MMT) greenhouse gas (GHG) emissions target by 2031. The Decision also transferred two policy-driven sensitivity portfolios for study purposes:

[1] Decision 21-02-008 released on February 11, 2021 for the purposes of the ISO 2021-22 transmission planning cycle. Page 41 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

1) A portfolio that meets a 38 MMT GHG emissions target by 2031; and,
2) A portfolio to test transmission needs associated with 8 GW of offshore wind, which was accommodated by further lowering the greenhouse gas emissions target to a 30 MMT range. The CPUC stressed that the purpose of the study of this portfolio was to obtain key inputs for capacity expansion modeling to inform future portfolio development, not to suggest that the portfolio used for this study was seen as part of an optimal portfolio overall. Rather, this study is designed to test the transmission implications if barriers were to be removed to large-scale development of offshore wind.

The Decision provided specific direction regarding the treatment of out-of-state wind resources, particularly for the base case. The ISO was requested to study the potential requirements and implications of 1062 MW being injected into the ISO system at Eldorado from Idaho or Wyoming or into Palo Verde from New Mexico in the base case[2]. Further, the CPUC acknowledged that out-of-state transmission would be needed to deliver these volumes to the existing ISO boundary, but such transmission was outside the scope of the policy-driven transmission study request. In subsequent comments in the ISO's stakeholder process, CPUC staff requested the ISO consider, time permitting, possible out-of-state requirements for information purposes only[3].

These portfolios also took into account the announced retirements of approximately 3700 MW of gas-fired generation to comply with state requirements for thermal generation relying on coastal water for once-through cooling, and the announced retirement of the Diablo Canyon Power Plant.

As the CPUC portfolios retain the existing gas-fired generation fleet for system capacity purposes through the foreseeable future, the ISO continued to take a conservative approach in this planning cycle in assigning a benefit value for potentially reducing local gas-fired generation capacity requirements when considering transmission upgrades.

Unlike the portfolios provided to the ISO for the 2020-2021 transmission plan, the CPUC acknowledged that utilizing the electric resource portfolio that meets the 46 MMT GHG emissions target as a reliability and policy-driven base case in the transmission planning process would likely result in the need for new transmission investment to make the portfolio deliverable[4].

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[2] Decision 21-02-008 released on February 11, 2021 for the purposes of the ISO 2021-22 transmission planning cycle. Page 34, "The ISO, in reply comments, suggested that they could study separately the injection of the full amount of energy at both the El Dorado substation representing resources from Wyoming, Idaho, or potentially other locations, and the Palo Verde substation, presentation resources from New Mexico or other Southwest locations, delivering results for further consideration at the end of this TPP cycle. We understand this to be a unique situation where the ISO may be able to offer optionality within the base case analysis, and therefore we will take the ISO up on this offer and work with them to understand better the transmission buildout requirements associated with generation siting in both locations." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

[3] CPUC Staff Comments dated March 11, 2021 re ISO February 25, 2021 stakeholder meeting: "We encourage the ISO's review of possible opportunities for such an informational study of transmission needs outside the ISO system, whether it might be conducted solely by the ISO or jointly with another agency." http://www.caiso.com/InitiativeDocuments/CPUCComments-2021-2022TransmissionPlanningProcess-Feb252021StakeholderCall.pdf

[4] Decision 21-02-008 released on February 11, 2021 for the purposes of the ISO 2021-22 transmission planning cycle. Page 39

The transmission planning assessments utilized the 2020 California Energy Demand (CED) Forecast Update 2020-2030 adopted by the CEC on January 25, 2021[5] using the “mid” demand baseline cases. The 2020 CED Forecast Update also includes 8760-hourly demand forecasts for the PG&E, SDG&E, and SCE “transmission access charge” areas[6].

Consistent with past recommendations, the “mid” Additional Achievable Energy Efficiency (AAEE) scenario was used for system-wide and flexibility studies for the CPUC integrated resource plan portfolios and the ISO transmission planning studies. The ISO continued to use the “low” AAEE scenario for local area studies 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.

Unlike the forecasts used in the 2020-2021 transmission planning cycle that remained relatively flat resulting in part from continued statewide emphasis on energy efficiency and behind-the-meter generation that pushed the peaks to later in the day, forecasts are now showing higher levels of growth. In addition to contributing to the resource needs beyond those required to transition to lower GHG sources, this load growth will also drive reinforcements to serve load.

These assumptions were vetted by stakeholders through the ISO’s stakeholder process which resulted in this year’s study plan.[7]

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 and especially to meet future infrastructure needs based on public policies.

Key Study Findings

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

- The combination of dramatically increasing the pace of renewable generation and load forecast growth are driving an increase in transmission requirements. The ISO found the need for 23 projects totaling $2,964 million, compared to the average over the last five years of $217 million. The projects developed in this year’s planning cycle represent a transition to expected additional growth in requirements in next year’s transmission planning process, providing reliability, access to renewable generation needed to meet state goals, and providing effective economic benefits into the future.
- Reliability projects driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation represent 16 projects totaling $1,412 million. Most notable are two HVDC projects in the San Francisco South Bay region, primarily serving the San Jose-Silicon Valley Power area and the rebuild of the SCE Antelope 66 kV switchyard to mitigate anticipated increased in local fault current levels.

[5] https://ww2.energy.ca.gov/2019_energypolicy/documents/#demand

[6] https://www.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

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

- In reviewing previously approved projects in the PG&E service territory that were identified in the last planning cycle as needing more review, two projects will continue to be on hold. The need for these projects can be met wholly or largely by appropriately located battery resources that are otherwise needed for system capacity purposes according to the CPUC-provided resource portfolios. Accordingly, the ISO will continue to work with the CPUC and load serving entities to seek to have the battery storage located to meet these needs as well as serving system capacity purposes.
- The ISO found the need for 6 policy-driven transmission projects totaling $1,512 million to meet the renewable generation requirements established in the CPUC developed renewable generation portfolios. The ISO also drew on other supporting information and comments to advance several low-risk projects to smooth out development activity expected to grow in next year's transmission planning process. The most notable are a substantial reinforcement project in the GridLiance/Valley Electric System service territory, a new 500/230 kV substation (Manning) proposed to access Westlands renewable generation, and a new 500/230 kV substation (Collinsville) in the East Bay area creating access for wind resources.
- The ISO conducted several economic studies; the bulk of these helped support the need for the reliability-driven and policy-driven projects referred to above. One additional economic-driven project was found to be needed - a series reactor installation with a capital cost of $40 million.
- As requested by the CPUC, the ISO studied the potential transmission implications and requirements inside the ISO footprint of 1062 MW of out-of-state wind generation being injected at each of Eldorado (representing potential new capacity from Wyoming or Idaho), or Palo Verde (representing potential new capacity from New Mexico). The ISO found that injections from these sources, as part of the base case portfolios provided in this planning cycle, triggered no additional transmission requirements. However, the ISO notes that the resources seeking to interconnect to the ISO queue far exceed the current portfolio amounts – and current needs. Those volumes in the interconnection queue that have already been allocated deliverability for purposes of providing resource adequacy capacity subject to meeting their obligations to advance through to commissioning, would fully utilize existing and planned transmission capacity, if they proceed. The sensitivities conducted with 1500 MW being delivered to both injection points led to the same conclusion.
- The ISO explored the implications of out-of-state transmission needed to bring the base case amounts and sensitivity amounts to the ISO boundary for information purposes. These were conducted in the course of the economic study process, considering and comparing a number of alternative transmission developments including TransWest Express and Cross-Tie accessing Wyoming resources, and the SWIP-North project accessing Idaho resources. The latter was also an economic study request submitted into the planning process. All portfolios provided by the CPUC called for at least 1062 MW of out-of-state wind to be brought into California – there was no scenario that called for zero out-of-state resources requiring additional out-of-state transmission. Thus, the

ISO compared the effectiveness of the different transmission and resource options against each other as opposed to a "no out-of-state" case. The New Mexico out-of-state wind resources were selected as the reference case against which other alternatives were compared, as they provided the least amount of direct interaction with transmission facilities impacted by other different alternatives, and possible transmission upgrades in New Mexico and Arizona such as Sunzia may be moving forward on a subscriber basis. The benefits provided by those projects depend heavily on the resource output profiles of wind resources in those geographically diverse regions.

- Comparing the various alternatives for information purposes became more complex in considering the economic benefits of the SWIP North project as an economic study request. The SWIP North project (and presumably the Cross-Tie project) are being proposed on the basis of receiving regulated, cost-of-service cost recovery as a participating transmission owner asset. The TransWest Express project is being developed on a subscriber basis, without the need for ISO transmission plan approval, to provide transmission service to resources seeking access to California markets. The different cost and cost recovery mechanisms make direct comparisons of benefits, need satisfaction, and benefit-to-cost ratios more challenging. The proponents of SWIP North project also have a pre-existing agreement with NV Energy regarding accessing capacity on the existing Robinson Summit-Harry Allen 500 kV transmission line, further complicating direct comparisons with other projects that access other resources. Some information to help in the assessment may be gleaned by the ISO testing the market interest in accessing Idaho wind resources through the SWIP North project or similarly situated projects. The ISO therefore intends to engage further with industry participants to gauge interest in accessing Idaho resources. This process will require more time than is available before the 2021-2022 Transmission Plan is finalized and submitted to the Board for approval in March, 2022. The ISO will consider this as an extension of the 2021-2022 transmission planning cycle, rather than shifting it to the next 2022-2023 planning cycle. Any recommendations resulting from this effort will be considered for approval as an extension of this 2021-2022 Transmission Plan. The ISO expects this effort to take the form of an open season-type process to assess the market interest and level of competition that exists for accessing the Idaho resources in support of the project.
- Given the sensitivity studies conducted in this planning cycle and the 20-Year Transmission Outlook launched as a separate effort, the ISO did not undertake any additional "special studies" in this year's planning cycle.
- The longer term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined in the CPUC integrated resource planning processes. Indications are that the gas-fired generation fleet – with the exception of the planned retirement of those relying on coastal waters for once-through-cooling – will be relied upon for the foreseeable future for those purposes. Accordingly, the ISO continues to employ the conservative approach used in the 2018-2019 and 2019-2020 transmission planning cycles for assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements in this planning cycle.

Four interregional transmission projects were submitted to the ISO in the 2020-2021 transmission planning cycle, the first year of the biennial interregional coordination process the ISO has established with our neighboring planning regions and the "intake" year for new interregional transmission projects to be proposed. Following the submission and successful screening of the Interregional Transmission Project (ITP) submittals, the ISO coordinated its ITP evaluation with the other relevant planning regions; NorthernGrid and WestConnect. None of the projects were selected through the interregional coordination process with the ISO's neighboring planning regions for further review in the second year of the biennial process and no further steps were taken under the FERC Order No. 1000 interregional coordination process in the ISO tariff. In response to the recent FERC Advance Notice of Proposed Rulemaking (ANOPR) regarding transmission planning, cost allocation, and generator interconnection,[8] the ISO has acknowledged that the interregional coordination process has not met expectations and noted there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly the ISO is exploring a few alternative courses of action to pursue potential interregional opportunities in addition to complying with all expectations, responsibilities, requirements, and obligations under the ISO's interregional coordination tariff provisions.

- Overall, the 2021-2021 Transmission Plan includes a dramatic increase in new reliability and policy-driven transmission needs.
- 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. The following projects are eligible for competitive solicitation, and the ISO will provide a schedule for those processes in March, 2022:
    - New Collinsville 500 kV substation
    - New Manning 500 kV substation
    - San Jose Area HVDC Lines (Newark to NRS)
    - San Jose Area HVDC Line (Metcalf – San Jose)

[8] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Advance Notice of Proposed Rulemaking, 176 FERC ¶61,024 (2021).

Other Studies

As in past transmission planning cycles, the ISO undertook additional studies to help inform future transmission planning issues. The ISO has identified the need to perform a number of these studies on an ongoing basis, at least for the foreseeable future, and has therefore documented these studies in the “other studies” in chapter 6, instead of categorizing them as “special studies”.

Frequency Response and Dynamic System Modeling

Consistent with the 2018-2019 and 2019-2020 transmission planning cycles, the ISO undertook frequency response studies and reported on associated modeling improvement efforts as an ongoing study process inside the annual planning cycle despite not being a tariff-based obligation.

Wildfire Impact Assessment

The ISO, as part of this planning cycle, conducted studies to assess impact of various Public Safety Power Shutoffs (PSPS) scenarios in the SCE and SDG&E area. The ISO conducted studies to assess the potential risks of de-energizing ISO-controlled facilities in the High Fire Risk Area’s (HFRA) for SCE, and SDG&E should it become necessary for PSPS or wildfire events and potentially develop mitigation options to alleviate impacts. The ISO also updated the assessment of PSPS events in the North Coast and North Bay area of the PG&E system that were undertaken in the 2020-2021 transmission planning process. The ISO identified no opportunities for transmission projects to reasonably mitigate the impacts of PSPS events. The ISO will continue to coordinate with PG&E, SCE and SDG&E to evaluate mitigation options within the utilities’ wildfire mitigation plans to be able to exclude the high-impact facilities identified from the future PSPS events and continue to assess need for the similar assessment in other parts of the system in future planning cycles.

Conclusions and Recommendations

The 2021-2023 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 23 transmission projects, estimated to cost a total of $2,964 million, as needed to maintain the reliability of the ISO transmission system and unlock access to renewable generation resources to meet state energy needs.

As well, the ISO will conduct additional stakeholder and market outreach regarding the SWIP North project, as a continuation of the 2021-2022 transmission planning cycle.

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Chapter 1

1 Overview of the Transmission Planning Process

1.1 Introduction

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 a ISO Board of Governors (Board) approved, comprehensive transmission plan.

As the needs are primarily tied directly or indirectly to the electric system's transformation to a cleaner grid, the ISO relies extensively on coordination with the state energy agencies in conducting its transmission planning process. The ISO relies in particular on the California Public Utilities Commission (CPUC) — which takes the lead role in developing resource forecasts for the 10-year planning horizon with input from the California Energy Commission (CEC) and the ISO — and on the CEC for its lead role in forecasting customer load requirements. These roles have and will continue to evolve.

In the 10-plus years since the ISO redesigned its transmission planning process, and subsequently adapted it to meet the provisions of FERC Order No. 1000, the challenges placed on the electricity system – and correspondingly on the transmission system -- have evolved and grown. The ISO understands that the industry is now at an inflection point marking a significant increase in the rate of growth in renewable resources and renewable integration resources. Last year's transmission plan was based on state agency-provided forecasts calling for approximately 1000 megawatts (MW) of additional generating capacity per year over the next 10 years. This year's plan is based on a 10-year projection adding 2700 MW of generating capacity per year, and current drafts being proposed for next year's plan call for over 4000 MW per year[9]. This latter value represents a fourfold increase in annual requirements from the 2020-2021 Transmission Plan approved in March, 2021. The 2021-2022 transmission plan provides a transitional step recognizing the ISO and industry at-large are not yet positioned within this single planning cycle to address the full impact of the pivot to these new challenges. In addition to considering significantly larger resource portfolios than in last year's transmission plan, the ISO is also considering in this planning cycle more extensive system upgrades in several areas that are supported by relevant considerations and information beyond the resource portfolios provided by the CPUC. This approach (1) recognizes that the requirements expected in next year's transmission planning process will call for an even faster pace of resource development, and (2) allows several low-risk projects to proceed now, smoothing out the development workload given that more development is expected to be initiated next year. The increased capacity provided by those upgrades, being more than strictly called for in the current year's portfolios, will also create some additional options for the load-serving entities conducting procurement to meet mid-term resource requirements.

[9] Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, http://www.caiso.com/InitiativeDocuments/Day2Presentation-2021-2022TransmissionPlanningProcessSep27-28-2021.pdf

The accelerating pace of resource development called for over the next 10 years is driven by numerous factors, including (1) the escalating need to decarbonize the electricity grid because of emerging climate change impacts, (2) the expected electrification of transportation and other carbon-emitting industries, which is driving higher electricity forecasts, (3) concerns regarding reduced access to opportunity imports as neighboring systems also decarbonize, (4) greater than anticipated impacts of peak loads shifting to later-day hours when solar resources are not available, and (5) the need to maintain system reliability while retiring gas-fired generation relying on coastal waters for once-through cooling and the Diablo Canyon Power Plant. These resource requirements, on the path to total decarbonization of the grid and discussed in more detail in section 1.4, will call for greater volumes of solar photovoltaic resources and battery storage, as well as greater diversity beyond the current focus on those resource types. Geothermal resources, new out-of-state renewable resources and offshore resources all are expected to play greater roles. This will create unique challenges in the planning and interconnection processes. Meeting those challenges requires adaptations and enhancements to existing processes and efforts.

Simultaneous with this shift in longer term resource requirements, the CPUC authorized midterm procurement totaling 11.5 GW in its June 24, 2021 Decision that is beyond the amount on which last year's 10-year plan was based. This was the largest single procurement authorization ever by the CPUC. Reacting to these signals and previously approved authorizations, the resource development industry responded with a record-setting number of new interconnections requests in April, 2021. The ISO received 373 new interconnection requests in its Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[10] The 605 projects totaling 236,225 MW now in the queue exceeds mid-term requirements by an order of magnitude. This level of hyper-competition actually creates barriers to moving forward effectively with the resources that do need to be added to the grid, and takes up precious planning, engineering and project management resources from the ISO and transmission owners.

In parallel with enhancements in the transmission planning process, the ISO is also pursuing enhancements in the coordination of state agency resource planning processes and the ISO's resource interconnection process, and in the overall coordination of the procurement and construction of new resources and related transmission network upgrades.

Transmission Planning:

In addition to the incremental improvements the ISO makes in each year's transmission planning cycles, the ISO has re-examined the effectiveness of certain planning processes due to emerging concerns in our own footprint and also in response to the recent FERC Advance Notice of Proposed Rulemaking (ANOPR) regarding transmission planning, cost allocation, and generator interconnection.[11]

[10] ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, http://www.caiso.com/Documents/Briefing-Renewables-GeneratorInterconnection-Queue-Memo-July-2021.p

[11] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Advance Notice of Proposed Rulemaking, 176 FERC ¶61,024 (2021).

The ISO noted in its comments on the ANOPR[12] that the

> "CAISO's existing transmission planning and generator interconnection processes reflect many of the reforms and concepts discussed in the ANOPR. That being said, the ISO has escalating challenges arising from existing supply conditions, the need to accelerate and then sustain the pace of procurement and interconnection to meet climate goals, and an "overheated" generation interconnection queue. Accordingly, the ISO must "get in front" of these issues and move forward with transmission planning and generation interconnection process enhancements ahead of the likely timeline for any Final Rule in this proceeding."

Enhancements and improvements to the ISO regional transmission planning processes are already moving forward, including the introduction of a 20-Year Transmission Outlook framework that is outside of the tariff-based project approval planning process. This 20-Year Outlook framework has also been coordinated with, and supported by, the CEC and CPUC, particularly in the development of customized 2040 resource portfolios under the auspices of the CEC's SB 100 related activities to support longer term conceptual envisioning for the transmission system.

In its ANOPR comments, the ISO also acknowledged that the interregional coordination process has not met expectations and noted there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly the ISO is exploring a few alternative courses of action to pursue potential interregional opportunities in addition to complying with all expectations, responsibilities and obligations under the ISO's interregional coordination tariff provisions. The ISO intends to continue to participate in the ANOPR process and seek broader reforms within that process as well.

Resource Interconnection:

Consistent with the ISO comments on the ANOPR, the ISO has initiated a stakeholder process focused specifically on the interconnection process and enhancements. Accordingly, the 2021 Interconnection Process Enhancement (IPE) initiative is discussing and addressing interconnection-related issues the ISO and stakeholders have identified given current circumstances, and seeks to resolve concerns that have surfaced since the last IPE initiative in 2018.[13] The ISO seeks to consider potential changes to address the rapidly accelerating pace of new resources needing connection to the grid to meet system reliability needs and exponentially increasing levels of competition among developers resulting in excessive levels of new interconnection requests being received.

[12] COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON ADVANCE NOTICE OF PROPOSED RULEMAKING, Docket No. RM21-17-000, Oct. 12, 2021. http://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf

[13] For more information on the 2018 IPE initiative, please refer to the initiative webpage at: California ISO - Interconnection process enhancements (caiso.com).

Procurement and Project Execution:

In addition to the above processes, the ISO is also taking on additional efforts to:

- Coordinate with the CPUC, CEC, and the Governor's Office of Business and Economic Development (GO-Biz) to identify and help mitigate issues that could delay new resources meeting in-service dates.
- Together with the CPUC, work with the participating transmission owners to improve the transparency of the status of transmission projects focusing on network upgrades approved in prior ISO transmission plans, or that resources with executed interconnection agreements are dependent on.
- Provide more information publicly regarding where resources are able to connect to the grid with no or minimal network upgrade requirements, to assist load serving entities to shape their procurement activities towards areas and resources that are better positioned to achieve necessary commercial operation dates.
- Coordinate with the CPUC regarding the progress of procurement activities by load serving entities and assessing the timeliness of those procured resources meeting near and mid-term reliability requirements.

These enhancements and coordination efforts will collectively support and enable the state to reliably reach its renewable energy objectives.

1.2 Purpose of the Transmission Planning Process

The comprehensive transmission plan identifies needed transmission solutions and once approved by the ISO Board of Governors 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 2021-2022 planning cycle.

Within this context, the transmission plan's primary purpose is to identify – using the best available information at the time this plan was prepared – needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy, and economic needs. The ISO may also identify in the transmission plan any transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects, or provide for merchant transmission projects. In recommending solutions for identified needs, the ISO takes into account an array of considerations. Furthering the state's objectives of a cleaner future grid plays a major part in those considerations.

Reliability-driven needs:

The ISO identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria, and ISO transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2021-2022 planning cycle, the ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable NERC reliability standards. The ISO performed this analysis across a 10-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions. The ISO assessed the transmission facilities under ISO operational control, which range in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns considering upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and examining the potential for conventional and non-conventional resources (preferred resources including storage) to meet these needs. Although the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades and work with the relevant parties and agencies to seek their implementation. This transmission plan documents ISO inputs, reliability analyses, results, and mitigation plans.[14] These topics are discussed in more detail below.

Policy-driven needs:

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support local, 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. In the past, the focus of the goals was the renewables portfolio standard (RPS) set out in various legislation; first the trajectory to achieving the 33% renewables portfolio standard set out in the state directive SBX1-2 , and then the 60% renewables portfolio standard by 2030 objective in Senate Bill (SB) 100[15] that became law in September, 2018. More recently, the focus has shifted to the more aggressive 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the California Public Utilities Commission (CPUC) and California Energy Commission

[14] 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 CAISO 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 CAISO 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 CAISO 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.

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

(CEC), as directed by Senate Bill (SB) 350[16] that would also meet or exceed the renewables portfolio standard requirement and reasonably establish a trajectory to meeting 2045 RPS goals established in SB 100. Section 1.4 provides specific details.

Economic-driven needs:

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 solutions to mitigate renewable integration challenges and potential reductions to the generation fleet located in local capacity areas.

Over the past three planning cycles, the ISO has programmatically studied the economic benefits of transmission, and combinations of transmission upgrades and storage to reduce reliance on gas-fired generation in local capacity areas. In this 2021-2022 transmission planning study, the focus has been concentrated on specific economic study requests whether in local capacity areas or outside of those areas.

Comprehensive planning:

Although the ISO's planning process considers reliability, public policy, and economic projects sequentially, it allows the ISO to revisit projects identified in a prior stage if an alternative project identified in a subsequent stage can meet the previously identified need and provide additional benefits not considered in the prior stage. Thus, the ISO's iterative planning process ultimately allows the ISO to consider and approve transmission projects with multiple benefit streams (e.g., reliability, public policy, and economic) and to modify or upsize transmission solutions identified in earlier stages in order to achieve additional benefits. For example, the ISO's transmission planning process does not allow earlier-identified reliability projects to reduce the benefits potential economic projects might produce, because the ISO's sequential process allows it to "back out" of previously identified reliability projects inside the planning cycle and count the avoided cost of a separate reliability project as an economic benefit. This is an important distinction, as it is critical to avoid the misconception that a project must be supported by solely reliability benefits, *or* policy benefits, *or* economic benefits exclusively, *i.e.*, the ISO does not approve projects through a siloed approach.

[16] SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. Among other provisions, the law established clean energy, clean air, and greenhouse gas (GHG) reduction goals, including reducing GHG to 40% below 1990 levels by 2030 and to 80% below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50% by 2030 that have now been superseded by the provisions of Senate Bill 100.

Other study efforts:

In addition to the consideration of reliability, policy-driven, and economic-driven needs and solutions, this year's transmission plan also considered:

1. Local Capacity Requirement Studies: Near and mid-term local capacity technical studies were prepared for 2022 and 2026, respectively, as part of the annual study process supporting the state's resource adequacy program for the 2022 resource adequacy compliance year. These studies also provide the basis for determining the need for any ISO "backstop" capacity procurement that may be needed once the load-serving entity procurement is submitted and evaluated. Consistent with past practices, each of these studies identified the extent to which storage could meet the needs in local capacity areas in lieu of gas-fired generation. The ISO also conducts a long-term local capacity requirements study every second year to further support state resource planning efforts. The long-term local capacity requirements study was performed in the 2020-2021 planning cycle, and the ISO did not include a long-term 10-year study in the 2021-2022 planning cycle.
2. Interregional Planning Coordination: The 2021-2022 transmission planning cycle was the second year of the two-year interregional coordination planning process that the ISO conducts with its neighboring planning regions WestConnect and Northern Grid. The two-year process calls for projects that have been screened and selected by the ISO and at least one other planning region in the first year to receive detailed analysis in the second year. No interregional projects met that criteria last year, so no interregional projects were carried forward into this planning cycle for further analysis.

The 2021-2022 Transmission Plan also continued migrating certain special studies (*e.g.*, frequency response studies and flexible capacity deliverability analysis into a more permanent category of "other studies" within the transmission plan itself, now that the ISO has identified a need to perform these analyses on an annual basis.

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 2020-2021 planning cycle began in January 2020 and concluded in March 2021.

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.

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.

Consistent with past transmission planning cycles and as discussed above in section 1.2, development of the unified planning assumptions for this planning cycle continued to benefit from the ongoing coordination efforts between the CPUC and the 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:

- The CEC's long-term resource planning produced as part of SB 100-related activities and long-term forecasts of energy demand produced as part of its biennial Integrated Energy Policy Report (IEPR);
- The CPUC's biennial Integrated Resource Planning (IRP) proceedings; and,
- The ISO's annual Transmission Planning Process (TPP).

The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolios, and are discussed in more detail in section 1.4.

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 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 an analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[17] which is intended to

[17] 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 CAISO 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.

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.[18] 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 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

[18] 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.

solicitation for sponsors to compete to build and own eligible regional transmission facilities reflected in the final Board-approved plan.[19]

1.3.3 Phase 3

Phase 3 takes place after the Board approves the plan if there are projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional transmission facilities (*i.e.*, transmission facilities 200 kV and above) except for regional transmission solutions that are upgrades to existing facilities. Transmission facilities below 200 kV are not subject to competitive solicitation unless they span more than two participating transmission owner service territories or extend from the ISO balancing authority area to another balancing authority area.

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.

1.4 Key Inputs

This section 1.4 provides background and detail on key load and resource forecast inputs into the 2021-2022 transmission planning process.

1.4.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

1.4.1.1 Base Forecasts

As discussed earlier, the ISO continues to rely on load forecasts and load modifier forecasts prepared by the CEC through its Integrated Energy Policy Report (IEPR) processes. The combined effect of changing customer load patterns and evolving load modifiers is particularly important, and has driven the need for far more attention not only on peak loads and total energy consumption but also on the shape of the aggregate customer load shape on an hourly, daily, and seasonal basis.

The rapid deployment of behind-the-meter rooftop generation in particular has driven changes in forecasting, planning and operating frameworks for both the transmission system and generation fleet. It 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

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

transmission system is lower and shifted out of the window when grid-connected solar generation is available to later times of the day.

The transmission planning assessments utilized the 2020 California Energy Demand (CED) Forecast Update 2020-2030 adopted by the CEC on January 25, 2021[20] using the "mid" demand baseline cases. The 2020 CED Forecast Update also includes 8760-hourly demand forecasts for the PG&E, SDG&E, and SCE "transmission access charge" areas[21].

During 2019, the CEC, CPUC and the 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 2020 IEPR final report recommended using the "mid" Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC integrated resource plan portfolios and the ISO transmission planning studies. However, for local area studies, 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 scenario continued to be prudent at this time.

The CEC forecast information is available on the CEC website at:

https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03

1.4.1.2 Further Demand Side Drivers

Through the Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiatives, the ISO has been actively engaged in enhancing the ability of distributed energy resources (DERs) to participate in the ISO markets.

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

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

1.4.2 Resource Planning and Portfolio Development

As discussed earlier, the ISO relies extensively on coordination with the state energy agencies; in particular with the CPUC that takes the lead role in developing resource forecasts for the 10-year planning horizon with input from the CEC and the ISO. This relationship was set out in a memorandum of understanding developed between the CPUC and the ISO to improve process coordination and streamline planning activities.[22] These resource forecasts are provided in the

[20] https://ww2.energy.ca.gov/2019_energypolicy/documents/#demand

[21] https://www.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

[22] https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/c/6442462040-cpucmoudecisiononrevisedtransmissionplanningprocess-20190715.pdf

form of resource portfolios, with input also received on other key assumptions. In recent years, the focus has been on achieving the 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the CPUC and CEC, as directed by Senate Bill (SB) 350[23], which d also meet or exceed the current 2030 renewables portfolio standard requirement established by Senate Bill 100[24]. The past focus has also been on reasonably establishing a trajectory to meeting 2045 renewables portfolio standard goals that were also established in SB 100.

The requirements identified for use in this year's 2021-2022 transmission planning cycle demonstrate an inflection point marking a significant increase in the rate of growth in renewable resources and renewable integration resources.

Last year's transmission plan was based on state agency-provided forecasts calling for approximately 1,000 MW of generating capacity additions per year over the next 10 years. This year's plan is based on a 10-year projection adding 2,700 MW of new generating capacity per year, and current drafts being proposed for next year's plan call for over 4,000 MW per year[25]. This latter value represents a fourfold increase in annual requirements from the 2020-2021 Transmission Plan approved in March, 2021.

The accelerating pace of resource development called for over the next 10 years are driven by numerous factors, including (1) the escalating need to decarbonize the electricity grid because of emerging climate change impacts, (2) the expected electrification of transportation and other carbon-emitting industries, which is driving higher electricity forecasts, (3) concerns regarding reduced access to opportunity imports as neighboring systems also decarbonize, (4) greater than anticipated impacts of peak loads shifting to later-day hours when solar resources are not available, and (5) the need to maintain system reliability while retiring gas-fired generation relying on coastal waters for once-through cooling and the Diablo Canyon Power Plant. Meeting these resource requirements, on the path to total decarbonization of the grid, will require increased volumes of solar photovoltaic resources and battery storage. It will also require greater resource diversity beyond these resource types. Geothermal resources, new out-of-state resources and offshore resources all are expected to play greater roles in the future. This will create unique challenges in the planning and interconnection processes. Meeting those challenges requires adaptations and enhancements to existing processes and efforts.

[23] SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. Among other provisions, the law established clean energy, clean air, and greenhouse gas (GHG) reduction goals, including reducing GHG to 40% below 1990 levels by 2030 and to 80% below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50% by 2030 that have now been superseded by the provisions of Senate Bill 100.

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

[25] Proposed Decision, DECISION ADOPTING 2021 PREFERRED SYSTEM PLAN, Rulemaking 20-05-003, December 22,2021: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K547/434547053.pdf Also see: Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, http://www.caiso.com/InitiativeDocuments/Day2Presentation-2021-2022TransmissionPlanningProcessSep27-28-2021.pdf

The need to accelerate the pace of resource development played out over several key milestones through the 2019-2020 integrated resource planning process. Those milestones provide useful context for the corresponding acceleration in transmission planning and approval activities.

2020-2021 Transmission Plan - 2017-2018 Preferred System Portfolio:

Decision 20-03-028 called for the 46 MMT[26] 2017-2018 Preferred System Portfolio adopted in Decision 19-04-040[27], with updates to the baseline and some generation locations as detailed in the current decision, as the reliability base case and the policy-driven base case for use in last year's 2020-2021 transmission planning cycle. This represented approximately 10.4 GW of new resources to be added to the grid over a 10 year period.

2019-2020 Reference System Plan:

The Reference System Plan developed in the 2019-2020 integrated resource planning (IRP) proceeding increased resource requirements significantly from the 46 MMT[28] 2017-2018 Preferred System Portfolio adopted in Decision 19-04-040[29] and used in last year's transmission planning cycle. Decision 20-03-028 noted the concern that the location of too much capacity in the portfolios developed in the more current 2019-2020 IRP cycle was considered too uncertain to jump directly to transmission investments at that stage with either of those portfolios. The CPUC acknowledged that this inherently separated the transmission investment decisions from the procurement direction given to the load serving entities via the adoption of the 2019-2020 Reference System Plan. The CPUC also acknowledged that more real-world experience with how and where the load-serving entities are making investments toward the realization of the 2019-2020 Reference System Plan is necessary to have higher confidence in the need for transmission in specific locations to support these generation and storage resources.

[26] Decision 20-03-028 clarified that 46 MMT is equivalent to the 42 MMT target set in D.18-02-018, because it includes certain combined heat and power projects in the electric sector that were previously attributed to the industrial sector. Page 2, Decision 20-03-028. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

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

[28] Decision 20-03-028 clarified that 46 MMT is equivalent to the 42 MMT target set in D.18-02-018, because it includes certain combined heat and power projects in the electric sector that were previously attributed to the industrial sector. Page 2, Decision 20-03-028. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

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

November 2019 procurement authorizations by CPUC:

On June 20, 2019, the Assigned Commissioner and Administrative Law Judge in the CPUC IRP proceeding (R.16-02-007) issued a ruling that identified a potential system capacity shortfall of between 2,300 and 4,400 MW in the ISO Balancing Authority Area beginning in the summer of 2021.[30]

The analysis attributed the shortfall to several factors, including shifts in peak electric demand to later in the year and later in the day, which reduces the ability of solar generation to meet peak capacity requirements; changes in the method for calculating the qualifying capacity of wind and solar resources resulting in lower qualifying capacity for these resources than previously determined; uncertainty regarding the level of imports on which California can depend in the future as other states also shift towards using more renewable energy resources; and some unanticipated non-OTC generator retirements[31].

In November 2019, the CPUC issued Decision (D.)19-11-016, resulting in ordering 3,300 MW of new capacity procurement by 2023, with 50% of this procurement due to come online by August 1, 2021, 75% by August 1, 2022, and 100% by August 1, 2023 to address the system capacity shortfall.[32] The decision limited the amount of new natural gas that could be used to meet the procurement requirements. The decision also recommended phased extensions to the OTC Policy compliance dates for specific generating units to support the procurement schedule: an extension of Alamitos Units 3, 4, and 5 for up to three years, an extension of Huntington Beach Unit 2 for up to three years, an extension of Redondo Beach Units 5, 6, and 8 for up to two years, and an extension of Ormond Beach Units 1 and 2 for up to one year). These OTC Policy compliance date extensions would provide a "bridge" of roughly 3,740 MW in 2021, roughly 2,230 MW in 2022, and roughly 1,380 MW in 2023 as the 3,300 MW of new procurement comes online by 2023. Ultimately, the State Water Resources Control Board (SWRCB) approved the extensions for all of the units identified above to the end of 2023.[33]

August 2020 Events:

On August 14 and 15, 2020, the ISO was forced to institute rotating electricity outages in California in the midst of a West-wide extreme heat wave. Following these emergency events, Governor Gavin Newsom requested that, after taking actions to minimize further outages, the ISO, the CPUC, and the CEC report on the root causes of the events leading to the August outages. The Final Root Cause Analysis[34] confirmed that the three major causal factors contributing to the August outages were related to extreme weather conditions, resource

[30] See "Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues," June 20, 2019. (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M302/K942/302942332.PDF)

[31] SACCWIS information item presentation to the State Water Board, November 19, 2019 Board meeting, Agenda Item 6

[32] Decision D.19-11-016, Conclusion of Law 27 and Ordering Paragraph 3, November 7, 2019. (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF)

[33] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.html

[34] Final Root Cause Analysis, Mid-August 2020 Extreme Heat Wave, January 13, 2021. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

adequacy and planning processes, and market practices. Focusing on the resource-related issues in particular that relate to infrastructure concerns:

- The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.
- In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.

Although August 14 and 15 were the primary focus of the analysis because the rotating outages occurred during those days, August 17 through 19 were projected to have much higher supply shortfalls. If not for the leadership of the Governor's office to mobilize a statewide mitigation effort, California was also at risk of further rotating outages on those days. As a result of the resource supply concerns evidenced by these events, the CPUC has launched additional procurement activities and emergency supply activities focusing on the summer of 2021 and 2022.

ISO System Reliability Must Run Designations for 2021:

Based on the ISO's own analysis of loads and resources expected for the summer of 2021, the ISO Board of Governors approved reliability must run designations to retain generation that would otherwise not be available for summer conditions:

- Midway Sunset Cogen (248 MW) - December 2020 Board of Governor meeting
- Kingsburg Cogen (34.5 MW) - March 2021 Board of Governor meeting

These designations were subsequently extended for 2022 at the September ISO Board of Governors meeting. Further, one generating unit, the 27.5 MW Channel Island resource that was previously designated as a local reliability must run resource but no longer required for local needs, was extended into 2022 but re-designated as meeting a system need.

Portfolios provided for 2021-2022 Transmission Planning Cycle

Based on the information and analysis available at the time, the CPUC provided to the ISO via Decision 21-02-008[35] released on February 11, 2021 base case and sensitivity portfolios for use in this 2021-2022 transmission planning cycle. The base case portfolio calls for approximately 27.7 GW of new resources to be added to the ISO grid over the 10-year planning horizon. (Please refer to section 1.4.2.1 below)

Since that time, additional resource planning activities have led to the identification of further resource requirements beyond those provided to the ISO for 2021-2022 transmission planning studies.

[35] Decision 21-02-008 released on February 11, 2021 for the purposes of the ISO 2021-22 transmission planning cycle. Page 41 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

Mid-Term Procurement Decision 21-06-035 dated June 24, 2021

Responding to emerging mid-term supply adequacy concerns in the face of, among other concerns, anticipated retirement of the gas-fired generation that had received extensions to once through cooling policy compliance dates and the Diablo Canyon Power Plant, mid-term procurement of additional resources was authorized by the CPUC in this Decision dated June 24, 2021. The CPUC found that the electric grid within the ISO's balancing authority area requires that at least 11,500 MW of incremental September net qualifying capacity be ordered for procurement compared to resources online, or contracted and approved to come online, as of June 30, 2020, to maintain grid reliability and help achieve GHG emissions reduction targets.[36]

The CPUC also found that the procurement of the 11,500 MW of incremental net qualifying capacity should be conducted by all load-serving entities under the Commission's integrated resource planning purview over the course of four years, with 2,000 MW online by August 1, 2023, an additional 6,000 MW online by June 1, 2024, an additional 1,500 MW online by June 1, 2025, and an additional 2,000 MW online by June 1, 2026.[37]

August 2021 Ruling regarding the 2021 Preferred System Plan:

On August 17, 2021, the CPUC released a ruling[38] seeking comment on a proposed preferred system plan that would also form the basis for the preferred resource portfolio for the ISO's 2022-2023 transmission planning cycle. This proposed resource portfolio set out the need for 42.7 GW of new resources over the next 10 years, a material increase over the levels being studied in this year's transmission plan, and a fourfold increase over last year's transmission plan. In commenting[39] on the ruling, the ISO studied the 38 MMT Core Portfolio that would be the basis of the preferred system plan using both stochastic and deterministic production cost modeling. Based on this analysis, the ISO found that 38 MMT Core Portfolio meets the 0.1 loss-of-load expectation (LOLE) standard in both the mid-term and the long term. However, the ISO's assessment determined the 38 MMT Core Portfolio provides only about 500 MW of effective capacity above the level necessary to meet the 0.1 LOLE in 2026, after the retirement of the Diablo Canyon Power Plant. The ISO cautioned that, consequently, any delays in meeting the procurement targets, reductions to the baseline generation resources, or other system changes beyond the 500 MW margin could increase the LOLE above the standard.

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[36] Decision 21-06-035 in proceeding R20-05-003: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K547/434547053.PDF, Page 87

[37] id. Page 94

[38] ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN, Rulemaking 20-05-003, August 17, 2021 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M399/K450/399450008.PDF

[39] OPENING COMMENTS ON ADMINSTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS ON PROPOSED PREFERRED SYSTEM PLAN OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, Rulemaking 20-05-003, Dated September 27, 2021. http://www.caisoISO.com/Documents/Sep27-2021-OpeningComments-ProposedPreferredSystemPlan-IntegratedResourcePlanning-R20-05-003.pdf

The CPUC subsequently issued a proposed decision[40] on December 22, 2021 and the ISO is now reviewing the details of the proposed decision and its impact on the earlier findings.

The above sequence of planning activities demonstrates the rapid escalation of resource requirements over a few short years, particularly storage, responding to the pressures described earlier.

1.4.2.1 Resource Portfolios provided via the Integrated Resource Planning Process

As noted above, the CPUC provided to the ISO via Decision 21-02-008[41] released on February 11, 2021 base case and sensitivity portfolios for use in this planning cycle.

The Decision transmitted to the ISO for its 2021-2022 Transmission Planning Process the reliability and policy-driven base case portfolio that meets the 46 million metric ton (MMT) greenhouse gas (GHG) emissions target by 2031. The Decision also transferred two policy-driven sensitivity portfolios for study purposes:

1) A portfolio that meets a 38 MMT GHG emissions target by 2031; and,
2) A portfolio to test transmission needs associated with 8 GW of offshore wind, which was accommodated by further lowering the greenhouse gas emissions target to a 30 MMT range. The CPUC stressed that the purpose of the study of this portfolio was to obtain key inputs for capacity expansion modeling to inform future portfolio development, not to suggest that the portfolio used for this study was seen as part of an optimal portfolio overall. Rather, this study is designed to test the transmission implications if barriers were to be removed to large-scale development of offshore wind.

These portfolios also took into account the announced retirements of approximately 3700 MW of gas-fired generation to comply with state requirements for thermal generation relying on coastal water for once-through cooling, and the announced retirement of the Diablo Canyon Power Plant.

Unlike the portfolios provided to the ISO for the 2020-2021 transmission plan, the CPUC acknowledged that utilizing the electric resource portfolio that meets the 46 MMT GHG emissions target as a reliability and policy-driven base case in the transmission planning process would likely result in the need for new transmission investment to make the portfolio deliverable.[42]

The portfolios provided to the ISO also provided specific direction regarding the treatment of out-of-state wind resources, particularly for the base case. The ISO was requested to study the

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40 Proposed Decision, DECISION ADOPTING 2021 PREFERRED SYSTEM PLAN, Rulemaking 20-05-003, December 22,2021: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K547/434547053.PDF

41 Decision 21-02-008 released on February 11, 2021 for the purposes of the CAISOISO 2021-22 transmission planning cycle. Page 41 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

42 id. Page 39

potential requirements and implications of 1062 MW being injected into the ISO system from each of Idaho/Wyoming or New Mexico in the base case, but not both simultaneously. The ISO recognized that the approval of any identified needs to accommodate either injection would hinge on the analysis and subsequent stakeholder comments[43]. Further, the CPUC acknowledged that out-of-state transmission would be needed to deliver these volumes to the existing ISO boundary, but those were outside the scope of the policy-driven transmission study request. Accordingly, the policy-driven analysis (see chapter 3) was conducted on this basis. In subsequent comments in the ISO's stakeholder process, CPUC staff comments later requested the ISO consider, time permitting, possible out-of-state requirements for information purposes only[44]. The ISO undertook additional analysis of out-of-state issues in its economic study process that also considered a related economic study request (see chapter 4).

1.4.2.2 Additional considerations supplementing Resource Portfolios

Other relevant information and input augmented the portfolios provided by the CPUC. These considerations support more extensive system upgrades in several areas beyond what the resource portfolios provided by the CPUC support.

This will allow several low-risk projects to proceed and enable the ISO to focus its 2022-2023 planning efforts on the expected growth in requirements.

1.4.2.3 Consideration of the reliance on the gas-fired generation fleet

In developing the base portfolio for the 2021-2022 transmission planning cycle, the CPUC's modeling showed that while no new natural gas-fired power plants are identified in the 2031 new resource mix, existing gas-fired plants – other than those relying on once-through-cooling and scheduled for retirement - are needed in 2031 as operable and operating resources, providing a renewable integration service. Accordingly, to align with the CPUC's assumptions, the ISO has not assumed retirement regardless of age. This is a change from the 2020-2021 transmission plan, where generation was assumed to retire at 40 years for study purposes, but the resources were added back in if a reliability issue was triggered.

Notwithstanding the strong indications that the existing gas-fired generation fleet will be needed into the foreseeable future for system-wide supply adequacy, the ISO has over a number of years 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. 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

[43] Page 34, D.21-02-008 that transferred the portfolios to the ISO. "The CAISO, in reply comments, suggested that they could study separately the injection of the full amount of energy at both the El Dorado substation representing resources from Wyoming, Idaho, or potentially other locations, and the Palo Verde substation, presentation resources from New Mexico or other Southwest locations, delivering results for further consideration at the end of this TPP cycle. We understand this to be a unique situation where the CAISO may be able to offer optionality within the base case analysis, and therefore we will take the CAISO up on this offer and work with them to understand better the transmission buildout requirements associated with generation siting in both locations." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

[44] CPUC Staff Comments dated March 11, 2021 re ISO February 25, 2021 stakeholder meeting: "We encourage the CAISO's review of possible opportunities for such an informational study of transmission needs outside the CAISO system, whether it might be conducted solely by the CAISO or jointly with another agency." http://www.caiso.com/InitiativeDocuments/CPUCComments-2021-2022TransmissionPlanningProcess-Feb252021StakeholderCall.pdf

account the renewable integration benefits the generation may provide and the system needs to retain that generation in prioritizing study efforts and in committing to alternatives to reduce local capacity needs.

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 and to understand the risk of a material amount of similarly situated generation retiring more or less simultaneously, ostensibly for economic reasons. 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.

In the 2018-2019, 2019-2020, and 2020-2021 planning cycles, the ISO undertook more in-depth analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs.

In the ISO's annual local capacity technical study processes conducted in early 2020 and 2021, the ISO also examined charging capabilities in local capacity areas, to explore the possibility of using energy storage to reduce reliance on gas-fired generation to meet local capacity requirements.

No additional analysis of gas-fired generation retirement was undertaken in this transmission planning cycle, other than considering specific economic study requests. (Please refer to section 4.10.)

1.4.2.4 Offshore Wind Generation

The portfolios provided for study in earlier transmission planning cycles considered California and modest levels of out-of-state wind generation, but did not include the exploration of offshore wind potential.

The ISO, however, had studied transmission system capabilities within the generator interconnection and deliverability allocation process in recent years, based on interconnection applications totaling up to 10 GW of generation. The bulk of the interest has been in the central coast area. In response to stakeholder inquiries, the ISO has reviewed the interconnection studies prepared in those processes and identified that the transmission system in the central coast area can accommodate approximately 5 to 6 GW of offshore wind generation interconnecting in the area of the Diablo Canyon Power Plant that will be retiring by the end of 2025, and the Morro Bay area where gas-fired generation has retired. It should be noted that the owners of the Diablo Canyon Power Plant retain certain deliverability retention options for repowering that can remain in effect for up to three years following the retirement of the nuclear plant. The north coast area, however, would require transmission development to incorporate a material amount of new offshore wind development.

As noted in section 1.4.2.1, scenarios considering different levels of offshore wind development have been developed as a sensitivity portfolio for the 2021-2022 transmission planning cycle.

1.4.2.5 Storage in meeting system capacity needs

As noted earlier, the role of battery storage is expected to continue to grow as a complement to renewable generation and a key source of capacity to meeting both system capacity needs and local needs. Ultimately, storage resources will be available to meet energy needs during most periods when renewable resources are not available to generate. Today, there are just over 2,200 MW of installed storage capacity on the market and the ISO observes these resources primarily charging during the lowest priced periods of the day (when solar is abundant) and discharging during the highest priced periods of the day. Today the ISO relies on storage resources for the critical operation of one local capacity area. The ISO anticipates that storage resources will also be necessary for the reliable operations in many other local capacity areas in the future. Accordingly, the ISO market models are evolving to address storage requirements through ISO stakeholder processes. The ISO's Energy Storage Enhancements[45] stakeholder initiative is exploring and developing enhancements to existing market rules, bidding parameters, optimization algorithm, and post market processes applied to energy storage resources. A key component of this initiative is to enable the ISO to procure and compensate resources for holding energy (state of charge) and ensuring the ISO can maintain reliability during critical periods.

1.5 Other Influences

In addition to the key study plan inputs described in section 1.4 above, the ISO must address a growing range of considerations in its planning process to ensure overall safe, reliable, and efficient operation and develop effective solutions to emerging challenges.

These considerations include a growing range of strategies, policy priority areas, emerging technologies, and risks and opportunities. Accordingly, many of the challenges are no longer served by stand-alone solutions – they can achieve great outcomes if properly planned and implemented in concert with other mitigations, or fail to provide the expected benefits if implemented in isolation or without coordination.

This section discusses a number of the emerging issues and other actions being taken to advance the understanding or implementation of those issues in the future — whether special study activities, ISO policy initiatives or regulatory proceedings.

1.5.1.1 Non-Transmission Alternatives and Storage

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

Since implementing the current transmission planning process in 2010, the ISO has considered and placed a great deal of emphasis on assessing non-transmission alternatives, including conventional generation, preferred resources (*e.g.*, energy efficiency, demand response, renewable generating resources), and energy storage solutions that are not transmission. Although the ISO cannot specifically approve non-transmission alternatives as projects or

[45] Details regarding the Energy Storage Enhancements stakeholder initiative can be found on the ISO website at: [California ISO - Stakeholder Initiatives (caiso.com)]

elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades. Further, load modifying preferred resource assumptions incorporated into the load forecasts adopted through state energy agency activities provides an additional opportunity for preferred resources to address transmission needs. This is progressively becoming more complex, as reliance on preferred resources including energy storage is taking a larger role in the CPUC's resource planning to successfully integrate higher volumes of renewable generation. As a result, the ISO is having to consider a growing number of scenarios both in assessing potential reliability concerns and in assessing the effectiveness of potential mitigations.

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

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

This approach is set out conceptually 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,[46] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[47] — energy efficiency, demand response, renewable generating resources, and energy storage — by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. In addition to developing a methodology the ISO could apply annually in each transmission planning cycle, the paper also described how the ISO would apply the proposed methodology in future transmission planning cycles. That methodology for assessing the necessary characteristics and effectiveness of preferred resources to meeting local needs was further advanced and refined through the development of the Moorpark Sub-area Local Capacity Alternative Study released on August 16, 2017.[48] In addition, the ISO has developed a methodology as discussed in section 6.6 of the 2017-2018 Transmission Plan for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources – which both builds and expands on the analysis framework of preferred resources. These efforts, with the additional detail discussed below, help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential

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

[47] 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.

[48] *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.

alternatives to meeting identified needs. The ISO must also consider the cost effectiveness and other benefits these alternatives provide.

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

Energy storage to meet identified local needs:

As discussed earlier, the rapidly increasing forecasts of energy storage requirements – to support renewable integration – is creating new challenges in mapping those resources for transmission planning purposes. However, the mapping of generic storage resources for system requirements, even if mapped to an area that would address transmission system needs, does not ensure that the resources will in fact be procured in those areas. This requires more deliberate analysis and need determination, as is conducted for other preferred resources, and coordination with the CPUC – or other local regulatory authorities as the case may be – to effectuate the procurement.

Storage played a major role in the assessment of the viability of preferred resource alternatives in the LA Basin studies and Moorpark Sub-area Local Capacity Alternative Study, as well as the Oakland Clean Energy Initiative approved in the 2017-2018 Transmission Plan and modified in the 2018-2019 Transmission Plan. The dispersion of procurement responsibility across a steadily increasing number of load serving entities has increased the complexity and concerns regarding the efficacy of relying on market based resources procured for system needs to be targeted in specific areas to also meet local needs. However, recent direction in a proposed decision[49] issued by the CPUC on December 22, 2021 has placed responsibility on the role of the central procurement entity to shape the location of specific storage to meet local transmission needs, and the ISO sees this as a positive outcome in setting the direction for other needs in the future. Accordingly, the ISO is continuing to consider this approach to meet local needs with storage where possible.

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

At the same time, the market and regulatory framework for storage that is meeting energy market and transmission system needs is also evolving. Utilization of electric storage resources

49 Proposed Decision, DECISION ADOPTING 2021 PREFERRED SYSTEM PLAN, Rulemaking 20-05-003, December 22,2021 : https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K547/434547053.PDF

is a significant issue to the ISO given the industry development underway and the growing role storage will play in supporting renewable integration. As the dependence on energy storage is expected to grow considerably in the future, the ISO is examining the means by which it can ensure these resources participating in the market are appropriately positioned to meet reliability needs without unduly limiting market participation opportunities. The ISO is exploring these issues in the ISO's on-going energy storage initiative and in its resource adequacy enhancements initiative.[50]

Energy storage solutions can be a transmission resource or a non-transmission alternative (*e.g.*, market-based). The ISO has considered storage in both contexts in the transmission planning process, although market-based approaches have generally prevailed and their implementation is more advanced.

Energy storage as a transmission asset:

The ISO has also studied in past planning cycles several potential applications of energy storage proposed as transmission assets, including the Dinuba storage project[51] approved in the 2017-2018 Transmission Plan. An important consideration in evaluating storage projects as an option to meeting transmission needs is whether the storage facility is operating as transmission to provide a transmission service and meet transmission needs. In other words, the ISO assesses whether the resource is functioning as a transmission facility. In making this assessment, considering prior FERC direction and the ISO tariff, storage as a transmission asset must:

- Provide a transmission function (*e.g.*, voltage support, mitigate thermal overloads)[52];
- Meet an ISO-determined transmission need under the tariff (reliability, economic, public policy)[53]; and,
- "Be the more efficient or cost-effective solution to meet the identified need"[54] and "[i] f 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"*[55] (emphasis added).

[50] Details on the ISO's energy storage initiative and the resource adequacy enhancements initiative can be found here: http://www.caiso.com/StakeholderProcesses/

[51] Note that the economic evaluation of the Dinuba storage project did not consider the potential for market-based revenue due the operational requirements placed on the storage project and it was nonetheless found to be the most cost-effective solution. The project is not expected to participate in the market and receive market revenues.

[52] *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.

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

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

[55] ISO Tariff Section 24.4.6.7, re economic needs

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

This direction provides that the determination of eligibility for transmission asset – and regulated rate recovery through the ISO tariff – is not only based on if a transmission need is being met, but how the storage project meets the need (*i.e.*, is it performing a transmission function?). As a result, it is necessary to consider this question individually for each storage project.

In evaluating the efficacy of storage as a solution to meet identified needs, it is also important to consider if the resource can also earn market-based revenues for providing market services when not required for specific transmission services. Although the historical assumption had been that transmission assets could not also provide other market services or access other market-based revenue streams, FERC issued a policy statement[56] in 2017 clarifying the potential for electric storage resources to receive cost-based rate recovery for transmission services while also receiving market-based revenues for providing market services. In 2018, the ISO launched its storage as a transmission asset (SATA) initiative to investigate the possibility of allowing storage to serve as a transmission asset, while also providing opportunities to participate in the wholesale electricity market.

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

FERC also provided further insights in 2020 regarding storage as a transmission asset -- and receiving cost-based revenue – in meeting transmission needs. In an order on the Midcontinent Independent System Operator's (MISO) proposal to allow storage resources to be selected as a "storage facility as a transmission-only asset (SATOA)," FERC noted:

> "In addition, the proposed Tariff language states that the proposed SATOA must demonstrate "[a] need to resolve the Transmission Issue(s) through the storage facility's functioning as a SATOA instead of as a Resource that participates in [MISO]'s markets."[38] MISO asserts that demonstrating that the need cannot be met through the market is fundamental to providing the opportunity for a storage facility to earn cost-based revenue as transmission-only.[39]" [57]

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[56] *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.

[57] FEDERAL ENERGY REGULATORY COMMISSION, Docket No. ER20-588-000, ORDER ACCEPTING TARIFF REVISIONS SUBJECT TO CONDITION, Issued August 10, 2020, Page 9, paragraph 20.

This insight provides further incentive for the ISO to consider and explore use of market-based storage to meet transmission needs before shifting consideration to transmission asset treatment.

The ISO in this transmission planning cycle has continued its assumption from recent planning cycles that, unless the transmission services very specifically conflict with providing potential market services, market-based resources would be the primary path for utilizing storage for meeting transmission needs and market revenues could be accessed through an appropriately structured power purchase agreement.

High potential areas:

In addition to providing opportunities for preferred resources including storage to be proposed in meeting needs that are being addressed within the year's transmission plan, each year's transmission plan also identifies areas where reinforcement may be necessary in the future, but immediate action is not required. The ISO expects developers interested in developing and proposing preferred resources as mitigations in the transmission planning process to take advantage of the additional opportunity to review those areas and highlight the potential benefits of preferred resource proposals in their submissions into utilities' procurement processes. To assist interested parties, each of the planning area discussions in chapter 2 contains a section describing the preferred resources that are providing reliability benefits, and the ISO has summarized areas where preferred resources are being targeted as a solution or part of a solution to address reliability issues in section 8.3. Further, as noted earlier, the ISO has expanded the scope of the biennial 10-year local capacity technical requirements study to provide additional information on the characteristics defining the need in the areas and sub-areas to further facilitate consideration of preferred resources. (Please refer to chapter 6.)

Other Use-limited resources, including demand response:

The ISO continues to support integrating demand response, which includes bifurcating and clarifying the various programs and resources as either supply side or load-modifying. Activities such as participating in the CPUC's demand response-related proceedings support identifying the necessary operating characteristics that demand response should have to fulfill a role in meeting transmission system and local capacity needs.

Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC.[58] In 2019, the ISO vetted the market processes it will use to dispatch slow demand response resources on a pre-contingency basis.[59]

[58] 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.

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

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.

1.5.1.2 Coordination with CPUC Resource Adequacy Activities

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

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

> *"[g]given 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."*[60]

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 low- to zero-carbon 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 is not a prudent long-term resource adequacy practice given the system's growing reliance on intermittent and availability limited resources.

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[60] *Order Instituting Rulemaking 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.

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

The events of August, 2020 also led to the ISO's participation in the CPUC's proceeding launched on November 20, 2020 via its Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021. The ISO's participation in that process includes recommendations for (interim) changes to certain resource adequacy requirements that include in particular an increase to the existing planning reserve margin and application of the planning reserve margin to both peak load periods as well as hours of critical need in the post-solar window period.

1.5.1.3 Potential Future Transmission Service Offerings

Other issues have been identified that are being explored through other stakeholder processes and may have significant impacts on transmission planning – and coordination with generation interconnection processes – in the future. These include:

1. Interest in developing a mechanism for load-serving entities to fund upgrades for increasing import capability and obtaining import capability rights for resource adequacy purposes. Enhancements[61] to the processes supporting establishing and allocating import capability for resource adequacy were made through the course of 2021, but did not address the issue of increases necessitating network upgrades. Note that while the ISO does have a general framework for participant-funded transmission, referred to as merchant transmission in the ISO tariff, the benefits provided to the participant are in the form of congestion revenue rights.
2. Firm service offerings for parties seeking wheeling rights through the ISO system, which may entail funding network upgrades to provide the requested capacity. This was identified as a potential future issue in the course of the ISO's Transmission Services and Market Scheduling Priorities[62] stakeholder process.

These issues have not had a direct impact on this transmission planning cycle, but depending on how they evolve, they may affect transmission planning in future cycles.

[61] Details regarding the Maximum Import Capability Enhancements stakeholder initiative can be found on the ISO website at: California ISO - Stakeholder Initiatives (caiso.com)

[62] Details regarding the Transmission Services and Market Scheduling Priorities stakeholder initiative can be found on the ISO website at: California ISO - Stakeholder Initiatives (caiso.com)

1.5.1.4 Other Renewable Integration Issues and Initiatives

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

The ISO currently conducts a range of studies to support the integration of renewable generation. These include planning for reliable deliverability of renewable generation portfolios (chapter 3), generation interconnection process studies conducted outside of the transmission planning process but closely coordinated with the transmission planning process, and renewable integration operational studies that the ISO has conducted outside of the transmission planning process – but which are now being incorporated into the transmission planning processes as supplemental information. These latter studies form the basis of determinations of system capacity and related flexibility needs discussed earlier.

The genesis of the ISO's analysis of flexibility needs was the CPUC 2010-2011 Long-term Procurement Plan (LTPP) proceeding (in docket R.10-05-006), wherein the ISO completed an initial study of renewable integration flexible generation requirements under a range of future scenarios, and the ISO has continued to analyze those issues. The ISO's efforts have led to a number of changes in market dispatch and annual resource adequacy program requirements, including considering uncertainty in the market optimization solution and developing flexible resource adequacy capacity requirements in the state's resource adequacy program. In addition to those promising enhancements, the ISO launched a stakeholder process to address several 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."[63]

This effort also led to the ISO's development of a methodology to assess the adequacy of the transmission system to access flexible capacity — the "flexible capacity" equivalent of deliverability assessed for local and system capacity. The ISO initially considered that this could be addressed through the generation interconnection process, with alignment in the annual transmission planning process, much like system resource adequacy capacity and deliverability issues are currently addressed. Through more detailed consideration of the generation resource fleet and the grid, this issue was instead incorporated into a separate study expected to be performed in each year's transmission planning studies. If in the future issues emerge that need to be addressed through the generation interconnection process, it will be revisited at that time. The study was conducted for the first time in the 2019-2020 transmission planning cycle, and has been repeated in this planning cycle. (Please refer to chapter 6.)

[63] 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-FlexibleResource AdequacyCriteria-MustOfferObligationPhase2.pdf.

Past special study efforts and other initiatives have, in addition to the above, also led to the need to review and upgrade generation models used in frequency response studies discussed in more detail below. This builds on the frequency response analysis the ISO conducted in the 2015-2016 planning cycle, where the ISO observed that simulated results varied from real-time actual performance – necessitating a review of the generator models employed in ISO studies. This has in turn led to the development of a rigorous multi-year program to ensure generation owners are providing valid and tested models, as discussed below, and the ISO appreciates the efforts made to date by market participants to address these issues. The frequency response studies themselves were then elevated from the "special study" category to an annual study expected to be conducted each year for the foreseeable future. (Please refer to chapter 6.)

1.5.2 System Modeling, Performance, and Assessments

1.5.2.1 System modeling requirements and emerging mandatory standards

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

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

The efforts undertaken in subsequent planning cycles reaffirmed the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. (Refer to section 6.3.) However, the effort also identified underlying challenges with obtaining validated models for a large – and growing – number of generators that are outside of the bounds of existing NERC mandatory standards and for which the ISO is dependent on tariff authority. The ISO has made significant progress in establishing and implementing a more comprehensive framework for the collection of this data, and will be continuing with its efforts, in coordination with the Participating Transmission Owners, to collect this important information and ensuring validated models are provided by generation owners.

1.6 Interregional Transmission Coordination per FERC Order No. 1000

Beginning in January 2020, a new biennial Interregional Transmission coordination cycle was initiated. It spans two ISO annual transmission planning cycles: the 2020-2021 transmission planning cycle and the current 2021-2022 transmission planning cycle. Following guiding principles largely developed through coordination activities, the ISO along with the other Western Planning Regions[64] continued to participate and advance interregional transmission coordination within the broader landscape of the Western Interconnection. These guiding

[64] Western planning regions are the California ISO, NorthernGrid, and WestConnect.

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 2020-2021 biennial interregional coordination cycle was initiated, the Western Planning Regions have held one Annual Interregional Coordination Meeting on February 27, 2020 to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[65]

The ISO hosted its submission period in the first quarter of 2020 in which proponents were able to request evaluation of an interregional transmission project. .The submission period began on January 1 and closed March 31 with four interregional transmission projects being submitted to the ISO. Of the four projects submitted, three were submitted into the 2018-2019 cycle. Following the submission and successful screening of the ITP submittals, the ISO coordinated its ITP evaluation with the other relevant planning regions; NorthernGrid and WestConnect.

The ISO considered all ITP proposals in its 2020-2021 transmission planning process and did not identify an ISO need for the proposed ITPs. Consistent with the Order No. 1000 Common Interregional Tariff, the ISO was not required to consider the proposed ITPs beyond the ISO's 2020-2021 transmission planning process. Commensurate with this outcome, no further consideration of the submitted ITPs were required in the 2021-2022 transmission planning process. (Please refer to chapter 5.)

1.7 ISO Processes coordinated with the Transmission Plan

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

1.7.1 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.

Currently, the most significant implication for the transmission planning process 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

[65] Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=76EEDF6D-5C04-4245-BA62-01D832E1E5E4

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% RPS has assumed deliverability for new renewable energy projects.[66] More recently, the portfolios provided to the ISO via the CPUC's integrated resource planning proceeding for consideration in the 2018-2019 transmission planning cycle and later cycles 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 13.

Interconnection customers proposing generating facilities that are not allocated transmission plan deliverability, but who still want to build their projects and obtain deliverability status, are responsible for funding needed delivery network upgrades at their own expense without being eligible for cash reimbursement from ratepayers.

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

1.7.2 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

[66] 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.

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. This is done 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. It also precludes the possibility of apportioning more DG deliverability in each cycle than was assumed in the base case resource portfolio used in the transmission planning process. As the amounts of distributed generation forecast in the recent renewable generation portfolios have declined from previous years, this creates less opportunity for this process to identify and allocate deliverability status to new resources. (Please refer to chapter 3.)

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

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

1.7.3 Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[67] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

1.7.4 Planning Coordinator Footprint

The ISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area in 2014,[68] 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. The ISO did this to determine whether these adjacent systems needed to have a planning coordinator and, if they did not have one, to offer to provide planning coordinator services to them through a fee-based planning coordinator services agreement. Unlike the requirements for the ISO's participating transmission owners who have placed their facilities under the ISO's operational control, the ISO is not responsible for planning and approving mitigations to identified reliability issues under the planning coordinator services agreement – but only for verifying that mitigations have been identified and that they address the identified reliability concerns. In essence, these services are provided to address mandatory standards via the planning coordinator services agreement, separate from and not part of the ISO's FERC-approved tariff governing transmission planning activities for facilities placed under ISO operational control. As such, the results are documented separately, and do not form part of this transmission plan.

The ISO has executed planning coordinator services agreements with Hetch Hetchy Water and Power, the Metropolitan Water District, the City of Santa Clara, and most recently with the California Department of Water Resources. Since the execution of these agreements, the ISO has conducted the relevant study efforts to meet the mandatory standards requirements for these entities within the framework of the annual transmission planning process. The ISO has met all requirements to fulfill its planning coordinator responsibilities for these entities in accordance with the implementation schedules agreed upon with each entity.

In addition to the entities discussed above, the ISO is also providing planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities that are not under ISO operational control but which were found to be Bulk Electric System as

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[67] 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.

[68] Technical Bulletin – "California ISO Planning Coordinator Area Definition" (created August 4, 2014, last revised July 28, 2016 to update URL for Appendix 2), .

defined by NERC. Considering the entirety of the ISO-controlled grid, the ISO is not anticipating a need to offer these services to other parties, as the ISO is not aware of other systems inside the boundaries of the ISO's planning coordinator footprint requiring these services.

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Chapter 2

2 Reliability Assessment – Study Assumptions, Methodology and Results

2.1 Overview of the ISO Reliability Assessment

The ISO conducts its annual reliability assessment to identify facilities that demonstrate a potential of not meeting the applicable reliability performance requirements and 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. These requirements are set out in section 2.2. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2021-2022 planning cycle, the ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable reliability standards. The ISO performed this analysis across a 10-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions.

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

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

The Western Electricity Coordinating Council (WECC) full-loop power flow base cases provide the foundation for the study. The detailed reliability assessment results are provided in Appendix B and Appendix C.

In addition, the ISO has also incorporated into this study process a review of short circuit studies conducted by the transmission owners, to identify and address proactively potential fault level issues affecting future resource additions.

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 of 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 2021 was 43,982 MW and occurred on September 8 at 5:50 p.m. The following were the peak demand for the four load-serving participating transmission owners' service areas:

- PG&E peak demand occurred on September 8, 2021 at 5:51 p.m. with 20,118 MW
- SCE peak demand occurred on September 9, 2021 at 3:58 p.m. with 21,849 MW
- SDG&E peak demand occurred on August 26, 2021 at 5:43 p.m. with 3,923 MW, and
- VEA peak demand occurred on July 11, 2021 at 5:21 p.m. with 152 MW.

Most of the ISO-controlled grid experiences summer peaking conditions and thus those summer conditions were 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 2021-2022 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, WECC regional criteria, and ISO planning standards across the 2022-2031 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2021-2022 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 set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the ISO as a registered NERC planning authority and are the primary driver of the need for reliability upgrades:[69]

TPL-001-5[70]:	Transmission System Planning Performance Requirements[71]; and
NUC-001-3	Nuclear Plant Interface Coordination.[7]

[69] http://www.nerc.com/page.php?cid=2%7C20

70 TPL-001-5 modified Category P5 single point of failure & R2.4.5 requirements will be implemented based on the TPL-001-5 Implementation plan dates.

71 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.

2.2.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-3.2[72] Regional Criteria are applicable to the ISO as a Planning Coordinator and set forth planning criterion for near-term and long-term transmission planning within the WECC Interconnection.

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.[73] 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.

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-001-5 were conducted for both the near-term[74] (2023-2026) and longer-term[75] (2027-2031) per the requirements of the reliability standards.

Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2023, 2026 and 2031.

2.3.2 Transmission Assumptions

2.3.2.1 Transmission Projects

The transmission projects that the ISO has previously approved were modeled in the study. This includes existing transmission projects that have been in service and future transmission projects that have received ISO approval in the 2020-2021 or earlier ISO transmission plans. Currently, the ISO anticipates the 2021-2022 Transmission Plan will be presented to the ISO Board of Governors for approval in March 2022. Projects that were approved but subsequently put on hold were not modeled in the starting base case.

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[72] https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf

73 http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

[74] 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.

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

2.3.2.2 Reactive Resources

The study modeled the existing and new reactive power resources in the base cases to ensure that realistic reactive support capability were included in the study. These include generators, capacitors, static var compensators (SVCs), synchronous condensers and other devices. For the complete list of these resources, please refer to the base cases which are available through the ISO-secured website.

2.3.2.3 Protection Systems

To help ensure reliable operations, many Remedial Action Schemes (RAS), Protection Systems, safety nets, Under-voltage Load Shedding (UVLS) and Under-frequency Load Shedding (UFLS) schemes have been installed in some areas. Typically, these systems shed load, trip generation, and/or re-configure system by strategically operating circuit breakers under select contingencies or system conditions after detecting overloads, low voltages or low frequency. The major new and existing RAS, safety nets, and UVLS that were included in the study are listed in section A5 of Appendix A. Per WECC's RAS modeling initiative, the ISO has been modeling RAS in power flow studies for some areas in previous planning cycles as they were made available by the PTOs.

2.3.2.4 Control Devices

Expected automatic operation of existing and planned devices were modeled in the studies. These control devices include:

- All shunt capacitors
- Dynamic reactive supports such as static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, Santiago, Suncrest, Miguel, San Luis Rey, San Onofre, and Talega substations
- Load tap changing transformers
- DC transmission lines such as PDCI, IPPDC, and Trans Bay Cable Projects
- Imperial Valley phase shifting transformers

2.3.3 Load Forecast Assumptions

2.3.3.1 Energy and Demand Forecast

The assessment used the California Energy Demand Updated Forecast, 2020-2030 adopted by California Energy Commission (CEC) on January 25, 2021[76].

During 2020, the CEC, CPUC and ISO reviewed the issue of how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end and consistent with past transmission plans, the 2020 IEPR final report, also adopted on January 25, 2021, recommended using the Mid Additional Achievable Energy Efficiency

[76] https://efiling.energy.ca.gov/getdocument.aspx?tn=237269

(AAEE) scenario for system-wide and flexibility studies for the CPUC LTPP and ISO transmission planning 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 2021-2022 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.

2.3.3.2 Self-Generation

Baseline peak demand in the CEC demand forecast is reduced by projected impacts of self-generation serving on-site customer load. Most of the increase in self-generation over the forecast period comes from PV. The ISO wide self-generation PV capacity is projected to reach 22,655 MW in the mid demand case by 2031. In 2021-2022 transmission planning process base cases, baseline PV generation production was modeled explicitly. The CEDU 2020-2030 forecast also includes behind-the-meter storage as a separate line item. The combined ISO-wide, residential and non-residential behind-the-meter storage is projected to reach about 2,820 MW in the mid demand case by 2031. Behind-the-meter storage was not modeled explicitly in 2021-2022 transmission planning base cases due to lack of locational information and limitation within the GE PSLF tool to model more than one distributed resources behind each load.

PV Self-generation installed capacity for mid-demand scenario by PTO and forecast climate zones are shown in Table 2.3-1. Output of the self-generation was selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Table 2.3-1: Mid-demand baseline PV self-generation installed capacity by PTO[77]

PTO	Forecast Climate Zone	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
PGE	Central Coast	557	646	739	832	925	1018	1109	1199	1289	1378	1468
	Central Valley	1425	1569	1720	1869	2015	2156	2290	2418	2542	2663	2781
	Greater Bay Area	1538	1692	1860	2032	2202	2351	2486	2612	2731	2847	2959
	North Coast	403	443	485	526	565	602	634	663	690	715	738
	North Valley	316	339	365	390	413	435	455	475	494	512	530
	Southern Valley	1660	1815	1975	2132	2282	2424	2562	2696	2829	2961	3092
	PG&E Total	**5899**	**6504**	**7144**	**7781**	**8402**	**8986**	**9536**	**10063**	**10575**	**11076**	**11568**
SCE	Big Creek East	415	453	492	529	563	594	621	646	671	694	717
	Big Creek West	256	286	319	353	386	418	447	475	500	525	548
	Eastern	980	1099	1214	1322	1425	1522	1613	1701	1788	1873	1959
	LA Metro	1528	1718	1918	2120	2323	2517	2699	2867	3023	3170	3310
	Northeast	766	869	986	1106	1224	1339	1452	1563	1671	1779	1886
	SCE Total	**3945**	**4425**	**4929**	**5430**	**5921**	**6390**	**6832**	**7252**	**7653**	**8041**	**8420**
SDGE	SDGE	**1641**	**1784**	**1924**	**2050**	**2164**	**2266**	**2359**	**2444**	**2522**	**2597**	**2667**
ISO Total		**11485**	**12713**	**13997**	**15261**	**16487**	**17642**	**18727**	**19759**	**20750**	**21714**	**22655**

Behind-the-meter storage installed capacity for mid demand scenario by PTO and forecast climate zones is shown in Table 2.3-2. These resources were netted to load in the 2021-2022 transmission planning process base cases,

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

Table 2.3-2 Mid demand baseline behind-the-meter storage installed capacity by PTO

Year	BTM-Storage-Type	PGE-Zones						PG&E Total	SCE-Zones					SCE Total	SDGE Total	ISO Total
		C. Coast	C. Valley	Bay Area	North Coast	North Valley	Southern Valley		Big Creek East	Big Creek West	Eastern	LA Metro	North East			
2021	Res	15	25	75	24	5	10	**154**	3	13	20	48	14	**98**	**62**	**314**
	Non-Res	11	32	37	11	2	20	**113**	10	7	15	122	37	**191**	**51**	**355**
2022	Res	19	31	94	30	6	12	**192**	4	17	25	62	18	**126**	**80**	**398**
	Non-Res	15	43	50	16	3	32	**159**	15	9	20	148	46	**238**	**63**	**460**
2023	Res	24	37	114	36	7	14	**232**	5	20	31	78	22	**156**	**98**	**486**
	Non-Res	20	54	63	21	4	44	**206**	20	10	26	173	56	**285**	**76**	**567**
2024	Res	30	44	136	42	9	17	**278**	5	24	38	94	27	**188**	**118**	**584**
	Non-Res	25	65	76	25	6	56	**253**	25	12	31	199	65	**332**	**88**	**673**
2025	Res	35	51	159	49	10	20	**324**	6	29	44	112	32	**223**	**138**	**685**
	Non-Res	30	76	89	30	7	68	**300**	30	14	36	224	75	**379**	**100**	**779**
2026	Res	42	59	183	56	11	23	**374**	7	33	51	132	37	**260**	**160**	**794**
	Non-Res	35	87	102	35	8	80	**347**	35	16	41	250	84	**426**	**112**	**885**
2027	Res	49	67	208	63	13	26	**426**	8	38	59	152	43	**300**	**182**	**908**
	Non-Res	40	99	115	40	9	92	**395**	40	17	47	276	94	**474**	**124**	**993**
2028	Res	56	75	235	71	14	29	**480**	9	43	67	173	49	**341**	**204**	**1025**
	Non-Res	45	110	128	45	11	104	**443**	45	19	52	301	103	**520**	**136**	**1099**
2029	Res	63	83	262	79	16	32	**535**	10	48	75	195	55	**383**	**228**	**1146**
	Non-Res	50	121	141	49	12	116	**489**	50	21	57	327	113	**568**	**148**	**1205**
2030	Res	71	92	290	87	18	36	**594**	11	54	83	218	62	**428**	**252**	**1274**
	Non-Res	55	132	154	54	13	128	**536**	55	23	63	352	123	**616**	**160**	**1312**
2031	Res	80	101	319	95	19	39	**653**	11	60	92	242	69	**474**	**276**	**1403**
	Non-Res	59	143	167	59	15	140	**583**	60	24	68	378	132	**662**	**172**	**1417**

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

2.3.4 Generation Assumptions

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

2.3.4.1 Generation Projects

In addition to generators that are already in-service, new generators were modeled in the studies depending on the status of each project.

2.3.4.2 IRP Portfolio Resources

The integrated resource planning (IRP) process is designed to ensure that the electric sector is on track to achieve the State's greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals. The IRP process develops resource portfolios annually as a key input to the ISO's transmission planning process. The resources portfolios include a base portfolio, which was used in reliability, policy-driven, and economic assessments, and sensitivity portfolios, which were used in the policy-driven assessment that is covered in section 3. The generic base portfolio resources were modeled in the 2031 base cases. The reliability analysis focuses specifically on the transmission grid's ability to be operated reliability and within all relevant technical standards recognizing that reliable operation can include re-dispatch of resources in ways that are not necessarily aligned with policy objectives; subsequent analysis in studying policy driven needs or providing additional economic benefits may therefore result in mitigations initially identified in the reliability analysis being upgraded or replaced by larger solutions in the subsequent levels of analysis.

The CPUC issued a Decision[78] recommending transmittal of a base portfolio along with two sensitivity portfolios for use in the 2021-2022 transmission planning process. The base portfolio was designed to meet the 46 million metric ton GHG target by 2031. The portfolios were developed using the RESOLVE resource optimization model assuming resources under development with CPUC-approved contracts to be part of the baseline assumptions. The ISO modeled the baseline resources in the study cases based on their in service dates in accordance with the data provided by the CPUC. The ISO supplemented the data with information regarding contracted resources and resources that were under construction as of March 2021.

The base portfolio comprised of generic wind, solar, geothermal, pumped hydro and battery storage resources. Generic non-battery resources selected as portfolio resources were at a geographic scale that is too broad for transmission planning purpose which requires specific interconnection locations. Generic battery storage resources selected by the model were not

[78] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

tied to a location. CPUC staff, in collaboration with CEC and ISO staff, mapped both the battery and non-battery resources in the portfolios to the substation busbar level for use in the ISO's 2021-2022 transmission planning process.

2.3.4.3 Thermal generation

For the latest updates on new generation projects, please refer to the CEC website under the licensing section[79]. 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.

2.3.4.4 Hydroelectric Generation

During drought years, the availability of hydroelectric generation production can be severely limited. In particular, during a drought year the Big Creek area of the SCE system has experienced a reduction of generation production that is 80% below average production. It is well known that the Big Creek/Ventura area is a local capacity requirement area that relies on Big Creek generation to meet NERC Planning Standards. The Sierra, Stockton and Greater Fresno local capacity areas in the PG&E system also rely on hydroelectric generation. For these areas, the ISO considered drought conditions when establishing the hydroelectric generation production levels in the base case assumptions.

2.3.4.5 Generation Retirements

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

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

- Nuclear Retirements – Diablo Canyon was modeled offline based on the OTC compliance dates
- Once Through Cooling (OTC) Retirements – As identified in Appendix A
- Renewable and Hydro Retirements – Assumed these resource types stay online unless there is an announced retirement date.

2.3.4.6 OTC Generation

Modeling of the once-through cooling (OTC) generating units followed the compliance schedule from the SWRCB's Policy on OTC plants with the following exception:

Generating units that were repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table A2 in Appendix A. This table also includes retirements of some OTC generating units to accommodate repowering projects, which received the CPUC

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

approval for the Power Purchase and Tolling Agreements (PPTAs) and as well as the certificate to construct and operate from the CEC.

All other OTC generating units were modeled off-line beyond their compliance dates or planned retirement dates provided by the generating owners except for the units that have been approved for compliance schedule extension by the State Water Resources Control Board[80] for helping to meet ISO's system capacity need for the 2021-2023 timeframe;

Generating units with acceptable Track 2[81] mitigation plan that was approved by the State Water Resources Control Board.

2.3.4.7 2012 LTPP Authorization Procurement for Local Capacity

OTC replacement local capacity amounts in Southern California that were authorized by the CPUC under the LTPP Tracks 1 and 4 were considered along with the procurement activities to date from the utilities. Table 2.3-5 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 2.3-3: Summary of SCE area 2012 LTPP Track 1 & 4 Procurement and Implementation Activities to date

	LTPP EE (MW)	Behind the Meter Solar PV (NQC MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE's procurement for the Western LA Basin[82]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark sub-area	6.00	5.66	195[83]	0	0	206.66

2.3.5 Preferred Resources and Energy Storage

In complying with tariff Section 24.3.3(a), the ISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. The ISO received a submission from the Public Advocates Office related to offshore wind. The ISO conducted an

[80] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/otc2020.pdf

[81] Track 2 requires reductions in impingement mortality and entrainment to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both (https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/rs2015_0018.pdf).

[82] 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.

[83] SCE procured 95 MW of the 195 MW energy storage under the ACES program.

offshore wind study as defined in the sensitivity study provided by the CPUC for the Policy Assessment, in section 3.

Methodology

The ISO issued a paper[84] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO's transmission plan as an alternative to the conventional transmission or generation solution.

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

As in the 2019-2020 planning cycle, reliability assessments in the current planning cycle considered a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies also incorporated the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the CPUC Default RPS Portfolio and a mix of preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization. These incremental preferred resource amounts were 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

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

Moorpark area[85]. The ISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

As part of the 2020-2021 IRP, 9,368 MW of storage was provided in the base portfolio as listed in Table 2.7-2 and was modeled in the year 2031 base cases. These resources can be considered as potential mitigation options, including in earlier years if needed, to address specific transmission reliability concerns identified in the reliability assessment. If a storage option is considered, it could be for informational purposes only and would be clearly documented, as a potential option to be pursued through a resource procurement process.

Demand Response

For long term transmission expansion studies, the methodology described above was utilized for considering fast-response DR and slow-response PDR resources. In 2017, the ISO performed a study to assess the availability requirements of slow-response resources, such as DR, to count for local resource adequacy.[86] The study found that at current levels, most existing slow-response DR resources appear to have the required availability characteristics needed for local RA if dispatched pre-contingency as a last resort, with the exception of minimum run time duration limitations. The ISO will address duration limitations through the annual Local Capacity Requirements stakeholder process through hourly load and resource analysis.

The ISO has developed a methodology that will allow it to dispatch slow-response demand response resources after the completion of the ISO's day-ahead market run as a preventive measure to maintain local capacity area requirements in the event of a potential contingency. Specifically, the methodology allows the ISO to assess whether there are sufficient resources and import capability in a local capacity area to meet forecasted load without using slow response demand response. If the assessment shows insufficient generation and import capability in the local area, the ISO used the new methodology to determine which and how much of the available slow-response demand response it should commit after the completion of the day-ahead market via exceptional dispatch to reduce load for some period during the next operating day to meet the anticipated insufficiency.

The IOUs submitted information of their existing DR programs and allocation to substations, in response to the ISO's solicitation for input on DR assumptions, that will serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects continued to be accounted for when considering the load impacts that supply-side DR has on the system.

A description of the total supply-side DR capacity assumptions[87] is shown in Table 2.3-6.

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

[86] ISO-CPUC Joint Workshop, Slow Response Local Capacity Resource Assessment:

https://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf

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

Table 2.3-4: 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		236	543	0.89	780	RDRR	Yes
AP-I		0.0	31	0.0	31	RDRR	Yes
PDP		4.2	0.0	0.0	4.2	Day-Ahead	No
SmartRate		5.5	0.0	0.0	5.5	Day Ahead	No
SmartAC		34	0.0	0.0	34	PDR	None required
Summer Discount Plan Residential SDP-R		0.0	150	0.0	150	PDR	Yes
Summer Discount Plan Commercial SDP-C		0.0	18	0.0	18	PDR	Yes
Smart energy Program		0.0	38	0.0	38	PDR	Yes
CPP[29]		0.0	0.0	7.18	7.18	PDR	No
AC Saver – Day Ahead		0.0	0.0	7.82	7.82	PDR	No
AC Saver- Day Of		0.0	0.0	2.42	2.42	PDR	No
CBP		36	8	3.43	47.43	PDR	No
Other procurement program DR							
SCE LCR RFO,[88] post 2018			5.0		5	RDRR	Yes
DRAM[89]	2017	56.4	56.2	12	125	PDR[90]	No
	2018	79.5	88.5	13.9	182		
	2019	90.1	99.2	15.7	205		
	2020	NA	100	12.77	112.77	PDR	

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

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

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

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

90 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.

Table 2.3-5: Factors to Account for Avoided Distribution Losses

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

Energy Storage

The ISO modeled the existing, under construction and/or approved procurement status energy storage projects in the reliability base cases. For the purpose of this table, co-located resources have their own respective market IDs as compared to hybrid resources that have a single market ID. The ISO relied on multiple sources, including but not limited to PTO inputs, CEC forecast and generation interconnection queue to update the numbers in the table 2.8-3.

Table 2.3-6: IOU Existing and Proposed Energy Storage Procurement[91]

PTO	Category	In-service	Under Construction / Approved Procurement			Total
			2023	2026	2031	
PG&E	Transmission(Stand alone and co-located)	0	892.5	0	0	892.5
	Front of the meter Distribution including co-located	6.5	20	0	0	26.5
	Behind the meter Customer (Residential and Non-Residential)	359	439	721	1236	2755
	Hybrid Generation	0	0	0	0	0
SCE	Transmission(Stand alone and co-located)	100	100	100	0	300
	Front of the meter Distribution including co-located	65	235	0	0	300
	Behind the meter Customer (Residential and Non-Residential)	475	441	687	1136	2739
	Hybrid Generation	0	0	0	0	0
SDG&E	Transmission(Stand alone and co-located)	104	816.1	0	0	920.1
	Front of the meter Distribution including co-located	50.08	0	0	0	50.08
	Behind the meter Customer (Residential and Non-Residential)	59.3	0	0	448	507.3
	Hybrid Generation	0	0	0	0	0
Total		**1219**	**2944**	**1508**	**2820**	**8490**

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

In November 2019, the CPUC adopted D.19-11-016, which ordered the procurement of 3,300 MW of resource adequacy capacity by 2023 and recommended the extension of several once-through-cooling (OTC) thermal generators for system reliability. Neither the 3,300 MW of procurement nor the OTC extensions were modeled as part of the baseline of the reference system plan (RSP) adopted in this decision. This RSP identified a need consistent with the near-term procurement order in D.19-11-016, and vice versa. Many of these new resources that comprise the 3,300 MW were anticipated to be battery energy storage system based on the proposed bi-lateral contracts submitted by the Load-Serving Entities.

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 four major interties with the outside system and Southern California. The capability and power flows modeled in each scenario on these paths in the northern area assessment[92] are listed in Table 2.3-7.

Table 2.3-7: Major paths and power transfer ranges in the Northern California assessment[93]

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4,000[94]	Summer Peak
PDCI (N-S)	3,220[95]	
Path 66 (N-S)	4,800[96]	
Path 15 (N-S)	-5,400[97]	Spring Off Peak
Path 26 (N-S)	-3000	
PDCI (N-S)	-1,000[98]	
Path 66 (N-S)	-3675	Winter Peak

92 These path flows were modeled in all base cases.

93 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)

94 May not be achievable under certain system loading conditions.

95 Current operational limit is 3210 MW.

96 The Path 66 flows will be modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch.

97 May not be achievable under certain system loading conditions

98 Current operational limit in the south to north direction is 1000 MW.

For the spring off-peak cases in the Northern California study, Path 15 flow was adjusted to a level to bring it as close to its rating limit of 5,400 MW (S-N) as possible. This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. However, the cases may not have enough resources due to retirements and may have other limitations, so it was not always possible to model high Path 15 flow in south-to-north direction. 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 2.3-8 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.

Table 2.3-8: Major Path flow ranges in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (N-S)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3,220	3220	Summer Peak
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 10,100	Summer Peak
San Diego Import	2,765~3,565	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	600	0 to 408	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring 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.

Generation:

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

Demand Level:

Since most of the ISO footprint is a summer peaking area, summer peak conditions were evaluated in all study areas. With hourly demand forecast being available from the 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 was consistent with the hour identified in the CEC demand forecast report. For the non-coincident local peaks scenarios, the net-peak hour may represent hour of the highest net load for the local area. Winter peak, spring off-peak or winter off-peak were also studied for areas in where such scenarios may result in more stress on system conditions. Examples of these areas are the coastal sub-transmission systems in the PG&E service area (e.g. Humboldt, North Coast/North Bay, San Francisco, Peninsula and Central Coast), which were studied for both the summer and winter peak conditions. Table 2.3-11 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 2.3-9: Summary of study areas, horizon and peak scenarios for the reliability assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2023	2026	2031
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak Winter Off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak
SCE Metro Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak

2.3.8.2 Sensitivity study cases

In addition to the base scenario studies that the ISO assessed in the reliability analysis for the 2021-2022 transmission planning process, the ISO also conducted sensitivity studies identified in Table 2.3-10. 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 2.3-10: Summary of Study Sensitivity Scenarios in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-term Planning Horizon
	2023	2026	2031
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	
Off peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	
Summer Peak with high San Jose and SVP load			PG&E Greater Bay Area
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off peak with heavy renewable output	-	VEA Area	

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)[99]
- 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)[100]
- 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)

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

[100] 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[101] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme Event contingencies (TPL-001-4)

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

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

2.3.10 Known Outages

Requirements R2.1.4 and R2.4.4 of TPL-001-5 require the planning assessment for the near-term transmission planning horizon portion of the steady state analysis [R2.1.4] and stability analysis [R2.4.4] to include assessment of the impact of selected known outages on system performance.

The ISO Planning Standard also recognizes that scheduled outages are necessary to support reliable grid operations. The ISO Planning Standard requires the P0 and P1 performance requirements in NERC TPL-001-5 for either BES or non-BES facilities must be maintained during scheduled outages. The standard stipulates Corrective Action Plans must be implemented when it is established through a combination of real-time data and technical studies that there is no window to accommodate necessary scheduled outages.

Any issues or conflicts identified with planned outages in the assessment described above will be documented in the IRO-017 Requirement R4[102] Planned Outage Mitigation Plan in addition to the transmission plan.

The following provides the known scheduled outages involving multiple facilities satisfying the criteria's mentioned above that are selected for assessment in the current transmission planning cycle based on information obtained from the PTOs and TOPs for the ISO footprint.

Table 2.3-11: Known outages involving multiple facilities selected for assessment

PTO Area	Scheduled Outage Involving Multiple Facilities	Facilities Affected	Additional Description, If Needed
PG&E	None	None	
SCE	SONGS 220 kV Bus Section	The 220 kV facilities that the bus connects to	
SCE	Sylmar Bank outage	The 220 kV buses that the bank directly connects to	
SCE	Victor 220 kV Bus Outage	North or South 220 kV Bus	
SCE	Lugo 220 kV Bus Outage	East or West 220 kV Bus	
SCE	Lugo 500 kV Bus Outage	East or West 500 kV Bus	

[102] IRO-017-1 Requirement R4 - Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.

PTO Area	Scheduled Outage Involving Multiple Facilities	Facilities Affected	Additional Description, If Needed
SCE	Devers 220 kV Bus Outage	North or South 220 kV Bus	
SCE	Magunden 220 kV Bus Outage	North or South 220 kV Bus	
SDG&E	San Onofre 230kV Bus Sections Scheduled Maintenance Outage	230kV Bus Sections	The ISO will review applicable operating criteria to determine whether the scheduled maintenance outage for San Onofre 230kV bus sections still causes operational concerns.
SDG&E	TL666 and TL662 Reliability Project	TL662 and TL666 lines	Outage timeframe: June 2026

2.3.11 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.

2.3.11.1 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.

2.3.11.2 Technical Studies

The section explains the methodology that were used in the study:

Steady State Contingency Analysis

The ISO performed power flow contingency analyses based on the ISO Planning Standards[103] 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)[104]. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

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

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

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

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

Post Transient Voltage Stability Analyses

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

Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies were selected for further analysis using WECC standards of 8% voltage deviation for P1 events.

Voltage Stability and Reactive Power Margin Analyses

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

Transient Stability Analyses

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

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

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

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

The 500 kV bulk transmission system in Northern California consists of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue past Bakersfield in the south. This system transfers power between California and other states in the northwestern part of the United States and western Canada. The transmission system is also a gateway for accessing resources located in the sparsely populated portions of northern California, and the system typically delivers these resources to population centers in the Greater Bay Area and Central Valley. In addition, a large number of generation resources in the central California area are delivered over the 500 kV systems into southern California. The typical direction of power flow through Path 26 (three 500 kV lines between the Midway and Vincent substations) is from north-to-south during on-peak load periods and in the reverse direction during off-peak load periods. However, depending on the generation dispatch and the load value in northern and southern California, Path 26 may have north-to-south flow direction during off-peak periods also. The typical direction of power flow through Path 15 (Los Banos-Gates #1 and #3 500 kV lines and Los Banos-Midway #2 500 kV line) is from south-to-north during off-peak load periods and the flows can be either south-to-north or north-to-south under peak conditions. The typical direction of power flow through California-Oregon Intertie (COI, Path 66) and through the Pacific DC Intertie (bi-pole DC transmission line connecting the Celilo Substation in Washington State with the Sylmar Substation in southern California) is from north-to-south during summer on-peak load periods and in the reverse direction during off-peak load periods in California, which are the winter peak periods in Pacific Northwest.

Because of this bi-directional power flow pattern on the 500 kV Path 26 lines and on COI, both the summer peak (N-S) and spring off-peak (S-N) flow scenarios were analyzed, as well as peak and off-peak sensitivity scenarios with high renewable generation output and low gas generation output. Post transient contingency analysis was also performed for all flow patterns and scenarios (seven base cases and three sensitivity cases) described in section 2.4.2 below. Transient stability studies were performed for the selected six cases: four base cases – 2026 and 2031 Summer Peak and 2026 and 2031 Spring off-Peak and two sensitivity cases: 2026 Summer Peak with high CEC forecast and 2023 spring off-Peak with high renewable and low gas generation output.

2.4.2 Study Assumptions and System Conditions

The northern area bulk transmission system study was performed consistent with the general study methodology and assumptions described in section 2.3. The ISO-secured website lists the contingencies that were performed as a part of this assessment. In addition, specific methodology and assumptions that are applicable to the northern area bulk transmission system study are provided in the next sections. The studies for the PG&E bulk transmission system analyzed the most critical conditions: summer peak and spring off-peak cases for the years 2023, 2026 and 2031; and winter off-peak peak case for 2031. In addition, three sensitivity cases were studied: the 2023 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 2026 Summer Peak with high CEC forecasted load. All single and common mode 500 kV system outages were studied, as well as outages of large generators and contingencies involving stuck circuit breakers and delayed clearing of single-phase-to-ground faults. Also, extreme events such as contingencies that involve a loss of major substations and all transmission lines in the same corridors were studied.

Generation and Path Flows

The bulk transmission system studies use the same set of generation plants that are modeled in the local area studies. The total generation in each of the local planning areas within the PG&E system are provided in Section 2.5.

Since the studies analyzed the most critical conditions, the flows on the interfaces connecting northern California with the rest of the WECC system were modeled at or close to the paths' flow limits, or as high as the generation resource assumptions allowed. Due to retirement of several large OTC power plants in Northern California, flow on Path 26 between northern and southern California was modeled in some summer peak cases below its 4000 MW north-to-south rating. For the same reason and due to new renewable generation projects in the area, flow on Path 15 in some off-peak cases was modeled significantly below its 5,400 MW south to north 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

Scenario Type	Description	COI	Path 15	Path 26	PDCI	N.Cal Hydro, %
		MW	MW	MW	MW	
Base Line	2023 Summer peak load conditions. Peak load time -hour ending 18:00	4800 N-S	1350 N-S	4000 N-S	3220 N-S	80%
Base Line	2023 Spring off-peak load conditions. Off-peak load time - hour ending 20:00	4800 N-S	300 S-N	2200 N-S	3220 N-S	57%
Base Line	2026 Summer peak load conditions. Peak load time - hour ending 19:00	4800 N-S	2050 N-S	2200 N-S	2700 N-S	80%
Base Line	2026 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	3470 S-N	1080 S-N	570 N-S	1050 S-N	60%
Base Line	2031 Summer peak load conditions. Peak load time - hour ending 19:00	4720 N-S	1730 N-S	2120 N-S	3200 N-S	80%
Base Line	2031 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	3600 S-N	1260 N-S	3470 N-S	1000 S-N	55%
Base Line	2031 Winter off-peak load conditions. Off-peak load time - hour ending 5:00	700 S-N	600 S-N	1400 S-N	900 S-N	57%
Sensitivity	2023 Summer peak load conditions with high renewables and minimum gas	4800 N-S	100 S-N	3920 N-S	3220 N-S	80%
Sensitivity	2026 Summer peak load conditions with high CEC forecasted load	4800 N-S	1700 N-S	1800 N-S	3200 N-S	80%
Sensitivity	2023 spring off-peak load conditions with high renewables and minimum gas	2300 S-N	400 S-N	4000 N-S	0	57%

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

S. No.	Study Case	Scenario Type	Description	Solar, incl.hybrid		Wind		Hydro, incl.pump-storage		Thermal		Battery Storage (MW)	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	2023 Summer peak load conditions.	Base Line	2023 Summer peak load conditions. Peak load time -hour ending 18:00	5,693	707	1,828	1,085	9,996	7,871	21,497	19,218	1,531	0
2	2023 Spring off-peak load conditions.	Base Line	2023 Spring off-peak load conditions. Off-peak load time - hour ending 20:00	5,693	122	1,828	346	9,996	5,607	21,497	12,747	1,531	465
3	2026 Summer peak load conditions.	Base Line	2026 Summer peak load conditions. Peak load time - hour ending 19:00	5,735	328	1,791	729	9,996	7,852	19,148	16,064	1,687	1,289
4	2026 Spring off-peak load conditions.	Base Line	2026 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	5,735	5,026	1,791	347	9,996	6,715	19,148	3,586	1,687	-1,426
5	2031 Summer peak load conditions.	Base Line	2031 Summer peak load conditions. Peak load time - hour ending 19:00	7,862	178	3,964	1,649	9,996	7,743	19,175	16,875	2,566	1,073
6	2031 Spring off-peak load conditions.	Base Line	2031 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	7,862	6,067	3,964	819	9,996	5,445	19,175	3,926	2,566	-2,084
7	2031 Winter off-peak load conditions.	Base Line	2031 Winter off-peak load conditions. Off-peak load time - hour ending 5:00	7,862	163	3,964	501	9,996	5,194	19,175	11,700	2,566	-2,558
8	2023 Summer peak load conditions with high renewables and minimum gas	Sensitivity	2023 Summer peak load conditions with high renewables and minimum gas	5,693	4,967	1,828	1,085	9,996	7,771	21,497	9,395	1,531	0
9	2026 Summer peak load conditions with high CEC forecasted load	Sensitivity	2026 Summer peak load conditions with high CEC forecasted load	5,735	328	1,791	737	9,996	7,814	19,148	16,077	1,687	1,287
10	2023 spring off-peak load conditions with high renewables and minimum gas	Sensitivity	2023 spring off-peak load conditions with high renewables and minimum gas	5,693	5,188	1,828	1,133	9,996	5,657	21,497	8,840	1,531	466

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 % of the 1-in-5 summer peak load level. Table 2.4-3 shows the assumed load levels for selected areas under summer peak and non-peak conditions. The table shows gross PG&E load in all the cases studied and the load modifiers: Additional Achievable Energy Efficiency, output of the Behind the Meter solar PV generation, and it also shows the load for irrigational pumps and hydro pump storage plants if they are operating in the pumping mode. In the base cases, pumping load is modeled as negative generation. Net load is the gross load with the Additional Achievable Energy Efficiency and the output of the Behind the Meter solar PV generation subtracted and the pumping load added.

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

BASE CASE	Scenario Type	Description	Gross PG&E Load	AAEE	Behind the Meter PV		Net Load	Demand Response		Pumps (Irrigation and pump-storage)
					Installed	Output		Total	D2	
			MW	MW	MW	MW	MW	MW	MW	MW
2023 Summer peak load conditions.	Base Line	2023 Summer peak load conditions. Peak load time -hour ending 18:00	29,693	247	7,169	1,506	**27,940**	307	235	657
2023 Spring off-peak load conditions.	Base Line	2023 Spring off-peak load conditions. Off-peak load time - hour ending 20:00	20,014	211	7,169	0	**19,803**	307	235	1,587
2026 Summer peak load conditions.	Base Line	2026 Summer peak load conditions. Peak load time - hour ending 19:00	28,020	334	9,016	540	**27,146**	307	235	666
2026 Spring off-peak load conditions.	Base Line	2026 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	14,240	201	9,016	7,114	**6,925**	307	235	1,596
2031 Summer peak load conditions.	Base Line	2031 Summer peak load conditions. Peak load time - hour ending 19:00	29,559	544	11,589	695	**28,320**	307	235	676
2031 Spring off-peak load conditions.	Base Line	2031 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	14,047	272	11,589	9,146	**4,629**	307	235	1,576
2031 Winter off-peak load conditions.	Base Line	2031 Winter off-peak load conditions. Off-peak load time - hour ending 5:00	14,005	458	11,589	0	**13,547**	307	235	1,606
2023 Summer peak load conditions with high renewables and minimum gas	Sensitivity	2023 Summer peak load conditions with high renewables and minimum gas	29,578	247	7,169	7,098	**22,233**	307	235	657
2026 Summer peak load conditions with high CEC forecasted load	Sensitivity	2026 Summer peak load conditions with high CEC forecasted load	28,065	0	9,016	540	**27,525**	307	235	666
2023 spring off-peak load conditions with high renewables and minimum gas	Sensitivity	2023 spring off-peak load conditions with high renewables and minimum gas	20,057	211	7,169	7,098	**12,748**	307	235	1,587

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:

- Two Category P1 overloads were identified under summer peak conditions in the base cases on the 500 kV transmission lines prior to the installation of the Round Mountain Statcom. 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. After the installation of the Round Mountain Statcom that will be connected to these transmission lines at the new Fern Road Substation, both northern and southern circuits on both Round Mountain-Table Mountain 500 kV lines may overload with an outage of the parallel circuit. The overloaded lines will be Round Mountain-Fern Road # 1 and # 2 and Fern Road-Table Mountain # 1 and # 2.

- Four Category P1 overloads were identified on PG&E 500/230 kV transformers. Round Mountain and Table Mountain transformers may overload with single contingencies of 500/230 kV transformers or 500 kV lines in the Northern part of PG&E. These overloads were identified under off-peak load conditions with high output of hydro generation in Northern California connected to the 230 kV sides of these transformers. Also, Gates 500/230 kV transformers # 11 or # 12 were found to overload for outages of parallel Gates transformers and Gates 500/230 kV bank # 12 also with an outage of the Los Banos 500/230 kV transformer. The cause of these overloads is high generation output in the Gates area.

- Under P2 contingencies, overloads were identified on the Table Mountain 500/230 kV transformer under spring off-peak conditions with contingencies that involve outages of 500/230 kV transformers or 500 kV lines in the area. These overloads were identified only in the 2026 Spring off-peak case.

  The Eight Mile-Tesla 230 kV line was found to be the only 230 kV facility at risk of overload for P2 contingencies; that line may overload with an outage of the Table Mountain 500/230 kV transformer and Table Mountain-Fern Road 500 kV line under 2026 and 2031 Spring off-peak load conditions.

- Category P3 contingencies studied included an outage of one of the Diablo Canyon generation units and another transmission facility. Since both Diablo Canyon nuclear units are scheduled to retire in 2024 and 2025, contingencies involving an outage of Diablo Canyon generator were studied only for the year 2023. There are no other generation units that are connected to the Northern California 500 kV Bulk electric system, thus no other P3 contingencies were simulated in the PG&E Bulk system studies. Other P3 contingencies were studied in local area studies.

  In addition to the facilities that were overloaded under Categories P0 and P1, the Malin-Round Mountain 500 kV line #2 was also identified as overloaded with P3 contingencies in all 2023 cases, except for the Spring off-peak sensitivity case with high renewable and low gas generation. It may overload with an outage of the Diablo Canyon generation unit and the parallel Malin-Round Mountain # 1 500 kV circuit.

  It was assumed that there were no system adjustments between the contingencies. If the system is adjusted after the first contingency such as COI flow is reduced, then overload on the Malin-Round Mountain 500 kV line will not be expected.

- Thirty-nine P6 overloaded facilities were identified in the studies in the base cases. Out of these, four overloads were on 500 kV transmission lines, including two pairs of the 500 kV transmission lines in the same corridors: Round Mountain-Table Mountain and Midway-Vincent. Overloads on the Round Mountain-Table Mountain lines were under peak load conditions with high COI flow, on the Midway-Vincent lines both under peak and off-peak load conditions with high north to south flow on Path 26.

  Eleven Category P6 overloads were identified on 500/230 kV transformers, including three parallel transformers on the Metcalf and Midway 500/230 kV Substations, two parallel transformers on the Gates 500/230 kV Substation and also transformers on the

Round Mountain, Table Mountain and Los Banos Substations. Out of these overloads, Round Mountain, Table Mountain, Los Banos, Midway and Gates transformer overloads are expected under spring off-peak load conditions. Metcalf 500/230 kV transformer overload is expected both under peak and off-peak load conditions. Under these system conditions, the flow on Metcalf 500/230 kV transformers was from 500 kV to 230 kV. In addition to the off-peak cases, Gates 500/230 kV transformers were also identified as overloaded in the 2023 Summer Peak sensitivity case with high renewable and low gas generation output, which is explained by high output of renewable generation connected to the 230 kV system from the Gates 500/230 kV substation.

Seventeen Category P6 overloads were observed on 230 kV transmission lines in the base cases, and another six Category P6 overloads were observed on 230 kV lines in sensitivity cases only. Out of these 23 overloaded transmission lines, eight were overloaded only under peak load conditions, 12 only under off-peak conditions and three under both peak and off-peak load conditions. Overloads were observed in the San Jose area, Stockton-Tesla area, and in Fresno. Some of these overloads were due to high output of renewable generation. Overload on the Table Mountain-Rio Oso 230 kV line was due to the limiting terminal equipment that will be replaced as a PG&E maintenance project, which is currently being delayed.

There were nine 115 kV transmission lines that were identified as overloaded for Category P6 contingencies. Five of them were in the San Jose area and overloaded under summer peak-load conditions with an outage of the Metcalf-Tesla 500 kV line and another 500 kV or 230 kV transmission line in the area. Another four were in Fresno area and the overloads were under off-peak load conditions due to high output from renewable generation.

There were more transmission facilities that overloaded with Category P6 contingencies under off-peak load conditions than under peak load conditions. This is mainly explained by relatively high generation output in the off-peak cases while the load was low. However, there were overloads caused by generators being off-line due to the off-peak conditions while local loads still were high.

- Nine overloaded facilities were identified with the 500 kV double contingencies in the same corridors, five under peak conditions, three under off-peak conditions and one under both peak and off-peak conditions. One of these facilities (Round Mountain – Cottonwood # 2 230 kV line) was overloaded only in the sensitivity case, all others either in the base cases, or both in the base and sensitivity cases.
- There were no high or low voltages observed in the 500 kV system under the normal system conditions or contingencies. Installation of dynamic reactive support on the Gates 500 kV Substation and in the Round Mountain area was modeled starting from the 2026 cases. This reactive support mitigated both high and low voltages. With an outage of both Statcom units on 500 kV on the Gates Substation, voltages in this area may become high, but this is acceptable for Category P6 contingencies, because the system may be adjusted between outages. No system adjustments between contingencies were assumed for the Category P3 and P6 contingencies.

Low voltages were observed on the San Jose 115 and 60 kV systems, but their mitigation is discussed in the local Bay Area studies.

- No voltage deviation or reactive margin concerns were identified in the studies, except for the Category P6 contingency of an outage of the Moss Landing-Los Banos and Tesla Metcalf 500 kV lines in the 2023 Summer Peak sensitivity case with high renewable and low gas generation output. The loss of Moss Landing – Los Banos 500 kV line together with the Tesla – Metcalf 500 kV line is a severe contingency, because with this contingency, 500 kV source of power serving Bay Area is lost. If there is not enough reactive support, reactive margin may appear to be insufficient, as it was in the 2023 Summer Peak sensitivity case, because in this case, thermal generation in the area was assumed to be off-line. To avoid voltage collapse in this case, some generation units in San Jose or around Moss Landing need to be dispatched after the first contingency. Turning on peaking generation at Los Esteros appeared to be sufficient to avoid voltage collapse in this case. 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 load model parameters were updated. 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 composite load model used the new modular option where composite load parameters were defined by climate zones and types of feeders.
- 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, except for under-voltage or under-frequency load tripping with Category P1 contingencies. This tripping may be due to inadequate relay settings, or modeling errors.

2.4.4 Request Window Proposals

There were no projects proposed on the PG&E Bulk system submitted in the 2021-2022 transmission planning process Request Window.

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-Fern Road-Table Mountain 500 kV lines # 1 and # 2 if any of these lines overloads.

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

- Moss Landing-Las Aguilas 230 kV transmission line
- Table Mountain 500/230 kV transformer
- Round Mountain 500/230 kV transformer
- Delevan-Cortina 230 kV line
- 230 kV lines between Gold Hill and Tesla. Overload on these transmission lines may also be mitigated by installation of second Table Mountain 500/230 kV transformer.

Other proposed mitigation solutions for thermal overloads:

- Implement congestion management after first contingency for Category P6 overloads
- High voltages were observed on 500 kV system in Central California after Diablo Canyon Nuclear Power Plant retires. To mitigate the voltage issues, in the 2018-2019 transmission planning process, it was proposed to install dynamic reactive support on the Round Mountain and Gates 500 kV Substations. These projects were approved and planned to be implemented in 2024.

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

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process.

The ISO's 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 Humboldt Area study are provided in Table 2.5-1 and Table 2.5-2.

Table 2.5-1: Humboldt load and load modifier assumption

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	HUMB-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	124	1	15	0	124	4	3
2	HUMB-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	128	1	18	0	126	4	3
3	HUMB-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	128	1	18	0	126	4	3
4	HUMB-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	110	1	15	0	110	4	3
5	HUMB-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	86	0	18	14	72	4	3
6	HUMB-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	137	1	15	0	136	4	3
7	HUMB-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	140	2	18	0	139	4	3
8	HUMB-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	146	3	23	0	144	4	3
9	HUMB-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	128	0	18	0	128	4	3
10	HUMB-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	86	0	18	17	69	4	3
11	HUMB-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	124	1	15	15	109	4	3
12	HUMB-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	144	9	46	0	135	3	3

Table 2.5-2: Humboldt generation assumption

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	HUMB-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	0	0	0	0	0	5	0	259	172
2	HUMB-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	0	0	0	0	0	5	0	259	187
3	HUMB-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	187
4	HUMB-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	0	0	0	0	0	5	0	259	187
5	HUMB-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	0	0	0	0	0	5	0	259	187
6	HUMB-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	229
7	HUMB-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	15
8	HUMB-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	15
9	HUMB-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	0	0	5	0	259	187
10	HUMB-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	5	0	259	187
11	HUMB-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	0	0	0	0	0	5	0	259	15
12	HUMB-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	0	0	0	0	0	5	0	259	187

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

2.5.1.3 Assessment Summary

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process.

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

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process. As such, the consideration of preferred resources and energy storage in Humboldt area is same as presented in the 2019-2020 Transmission Plan.

2.5.1.6 Recommendation

Since this area relied on the use of the 2019-2020 transmission planning process reliability assessment and no further issues have been identified, no mitigation is recommended for 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 Areas power flow study were 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. With regards to transient stability studies and in accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process in which no transient stability issues were identified in North Coast and North Bay Areas. 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 Areas study are shown in Table 2.5-5 and Table 2.5-6.

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Table 2.5-3: North Coast and North Bay load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	NCNB-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	1,474	24	658	0	1,451	6	3
2	NCNB-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	1,473	15	528	0	1,459	6	3
3	NCNB-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	1,537	57	847	0	1,479	6	3
4	NCNB-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	1,021	20	493	0	1,002	16	10
5	NCNB-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	702	21	658	520	161	0	0
6	NCNB-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 19:00.	1,369	20	528	0	1,349	0	0
7	NCNB-2026-WP	Baseline	2026 winter peak load conditions. Peak load time - hours ending 19:00.	1,442	32	658	0	1,410	6	3
8	NCNB-2031-WP	Baseline	2031 winter peak load conditions. Peak load time - hours ending 19:00.	1,557	58	847	0	1,499	6	3
9	NCNB-2026-SP-HiCEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	1,474	0	658	0	1,474	6	3
10	NCNB-2023-SPOP-HiReMinGas	Sensitivity	2026 spring off-peak load conditions with hi renewable dispatch sensitivity	1,021	20	493	488	513	16	10
11	NCNB-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	1,473	15	528	523	936	6	3

Table 2.5-4: North Coast and North Bay generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	NCNB-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	11	1,535	54
2	NCNB-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	11	1,535	54
3	NCNB-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	11	1,535	105
4	NCNB-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	0	0	0	0	0	25	3	1,535	732
5	NCNB-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	0	0	0	0	0	25	5	1,535	704
6	NCNB-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	5	1,535	727
7	NCNB-2026-WP	Baseline	2026 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	5	1,535	730
8	NCNB-2031-WP	Baseline	2031 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	5	1,535	781
9	NCNB-2026-SP-HiCEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	0	0	25	11	1,535	54
10	NCNB-2023-SPOP-HiReMinGas	Sensitivity	2026 spring off-peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	25	3	1,535	732
11	NCNB-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	0	0	0	0	0	25	0	1,535	54

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 2021-2022 reliability assessment of the PG&E North Coast and North Bay area identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P2 to P7 contingencies most of which are addressed by previously approved projects. Details of the reliability assessment are presented in Appendix B.

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

Corona - Lakeville 115kV Line Overload

An overload under P2-4, P6 & P7 conditions was identified. Among options such as RAS, reconductoring and battery storage, the ISO is exploring battery storage as an economically viable option and is working with PG&E to study for the possibility and logistics of implementation. In the interim, the area will rely on operating action plans.

Fulton- Santa Rosa No.1&2 115kV Line Overload

An overload under a P6 condition was identified. Among a few options such as RAS, reconductoring and battery storage, the ISO is exploring battery storage as an economically viable option and is working with PG&E to study for the possibility and logistics of implementation. In the interim the area will rely on operating action plans.

Santa Rosa- Corona 115 kV Line Overload

An overload under P2-4, P6 & P7 condition was identified. Among a few options such as RAS, reconductoring and battery storage, the ISO is exploring battery storage as an economically viable option and is working with PG&E to study for the possibility and logistics of implementation. In the interim the area will rely on operating action plans.

2.5.2.4 Request Window Submissions

There was no project submission in the North Coast North Bay area in the 2021 request window.

2.5.2.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.2.2, about 15 MW of AAEE and 528 MW of installed behind-the-meter PV reduced the North Coast and North Bay Area load in 2026 by about 1%. This year's reliability assessment for North Coast and North Bay Area included the "high CEC forecast" sensitivity case for year 2026 which modeled no AAEE. Comparisons between the reliability issues identified in the 2026 summer peak baseline case and the "high CEC forecast" sensitivity case show that the facility overloads shown in Table 2.5-5 are potentially avoided due to reductions in net load.

Table 2.5-6: Reliability Issues Avoided due to AAEE

Facility	Category
Hopland 115/60 kV Bank #.2	P2
Tulucay - Vaca 230 kV Line	P6
Vaca-Lakeville #1 230 kV Line	P6

Furthermore, more than 6 MW of demand response is modeled in the North Coast and 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.

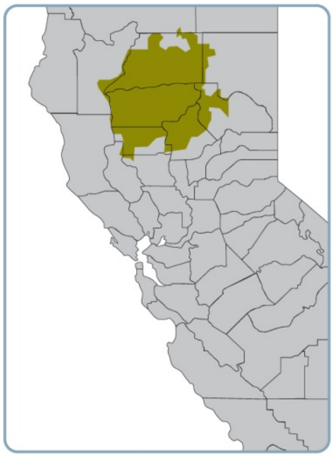
2.5.2.6 Recommendation

Based on the studies performed for the 2021-2022 Transmission Plan, several reliability concerns were identified for the PG&E North Coast North Bay Area. These concerns consisted of thermal overloads concerns under Categories P2 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Coast North Bay area. To address new reliability issues identified in this cycle, the ISO is exploring the option of battery storage as a potentially economically viable option and is working with PG&E to study for the possibility and logistics of implementation. In the interim, the area will rely on operating action plan. The remaining issues are only observed under the sensitivity scenario or in the long term. The ISO will continue to monitor those issues and will mitigate them if the issues are identified in future assessments.

2.5.3 North Valley Area

2.5.3.1 Area Description

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

Historically, North Valley experiences its highest demand during the summer season; however, a few small areas in the mountains experience highest demand during the winter season. Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions.

2.5.3.2 Area-Specific Assumptions and System Conditions

The North Valley Area power flow 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. With regards to transient stability studies and in accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process in which no transient stability issues were identified in the North Valley area. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Valley Area study are shown in Table 2.5-8 and Table 2.5-9.

Table 2.5-7: North Valley load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	NVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:20.	893	10	355	7	876	15	13
2	NVLY-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:20.	903	17	423	8	878	15	13
3	NVLY-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:20.	935	42	503	10	883	14	13
4	NVLY-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	593	11	381	0	581	36	28
5	NVLY-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	309	15	423	334	-40	0	0
6	NVLY-2026-SP-HiCEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	903	0	423	8	895	15	13
7	NVLY-2023-SPOP-HiReMinGas	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	593	11	381	377	205	36	28
8	NVLY-2023-SP-HighREMinGas	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	879	10	355	352	517	15	13

Table 2.5-8: North Valley generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	NVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:20.	0	8	0	103	62	1,792	1,417	1,067	476
2	NVLY-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:20.	0	8	0	103	62	1,792	1,511	1,067	585
3	NVLY-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:20.	0	8	0	457	274	1,792	1,395	1,067	507
4	NVLY-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	0	8	0	103	21	1,792	941	1,067	431
5	NVLY-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	0	8	8	103	21	1,792	1,273	1,067	0
6	NVLY-2026-SP-HiCEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	0	8	0	103	62	1,792	1,511	1,067	470
7	NVLY-2023-SPOP-HiReMinGas	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	0	8	0	103	66	1,792	943	1,067	416
8	NVLY-2023-SP-HighREMinGas	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	0	8	8	103	86	1,792	1,388	1,067	397

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 2021-2022 reliability assessment of the PG&E North 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. Details of the reliability assessment are presented in Appendix B.

The following new overloads issues were observed in the North Valley area:

Caribou - Table Mountain 230kV Line Section Overload

The Caribou - Table Mountain 230 kV Line was found to overload under the peak-load scenario in the near term for the following contingencies:

- P2-1 Line Section w/o Fault of the Caribou-Table Mountain 230 kV line
- P2-2 Bus Fault at Table Mountain 230 KV Section 1D
- P2-4 Bus Tie Breaker Fault Table Mountain 230KV - Section 1D & 2D
- P2-4 Bus Tie Breaker Fault Table Mountain Section 1D & Table Mountain Section 1E 230 kV.

The ISO is recommending the protection upgrades and/or expansion of the existing Caribou RAS. In the interim the area will rely on operating action plans.

Caribou-Plumas Jct 60 kV Line Overload

The Caribou-Plumas Jct 60 kV Line was found to overload under the peak load scenario in the near term for the following contingencies:

P2-1 Line Section w/o Fault Caribou-Table Mountain 230 kV

P2-2 Bus Fault at Table Mountain 230 kV Section 1D

P2-4 Bus Tie Breaker Fault Table Mountain 230 kV - Section 1D & 2D

P2-4 Bus Tie Breaker Fault Table Mountain Section 1D & Table Mountain Section 1E 230 kV.

The ISO is recommending the protection upgrade and/or expansion of the existing Caribou RAS. In the interim, the area will rely on operating action plans.

2.5.3.4 Request Window Submissions

There were no request window submissions for North Valley Area.

2.5.3.5 Consideration of Preferred Resources and Energy Storage

As presented in section 2.5.2, about 17 MW of AAEE and around 423 MW of installed behind-the-meter PV reduced the North Valley Area load in 2025 by about 3%. This year's reliability assessment for the North Valley Area included "high CEC forecast" sensitivity case for year 2026 which modeled no AAEE. A comparison of the reliability issues identified in the 2026 summer peak baseline case and the "high CEC forecast" sensitivity case shows that facility overloads shown in Table 2.5-10 are potentially avoided due to reductions in net load:

Table 2.5-9: Reliability Issues in Sensitivity Studies

Facility	Category
Keswick-Cascade 60 kV Line	P5
Benton-Deschutes 60 kV Line	P5
Trinity-Keswick 60 kV Line	P5

Furthermore, more than 15 MW of demand response is modeled in the North Valley Area. These resources are modeled offline in the base case and are used as potential mitigations as needed. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

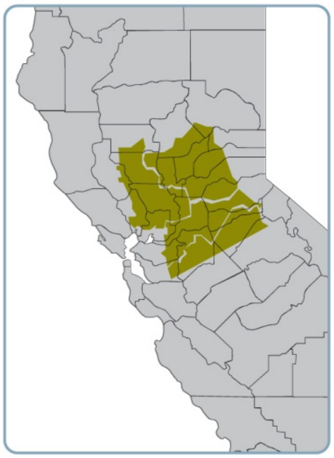
2.5.3.6 Recommendation

Based on the studies performed in the 2021-2022 transmission planning cycle, several reliability concerns were identified for the PG&E North Valley Area. These concerns consisted of thermal overloads under Category P2 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Valley area. To address new reliability P2 issues identified in this cycle, the ISO is working with the PTO on the protection upgrade and/or expansion of the existing Caribou RAS. The remaining issues are only under sensitivity scenario or in the long term. The ISO continues to monitor those issues in future planning cycles.

2.5.4 Central Valley Area

2.5.4.1 Area Description

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



Sacramento Division

The Sacramento division covers approximately 4,000 square miles of the Sacramento Valley, but excludes the service territory of the Sacramento Municipal Utility District and Roseville Electric. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system is comprised 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 cities located within this area. Sierra's electric transmission system is comprised 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 comprised of 60 kV, 115 kV and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. Lodi is a member of the Northern California Power Agency (NCPA), and it is the largest city that is currently served by the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus Division

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

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

2.5.4.2 Area-Specific Assumptions and System Conditions

The Central Valley Area power flow 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. With regards to transient stability studies and in accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process in which no transient stability issues were identified in the Central Valley area. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Valley Area study are shown in Table 2.5-11 and Table 2.5-12.

Table 2.5-10: Central Valley load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	CVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:50.	4,062	31	1,667	17	4,014	103	88
2	CVLY-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	4,138	49	2,100	21	4,068	101	88
3	CVLY-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	4,269	122	2,688	27	4,121	99	88
4	CVLY-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	2,869	54	1,696	0	2,815	101	59
5	CVLY-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,425	44	2,100	1659	(278)	0	0
6	CVLY-2026-SP-Hi-CEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	4,138	0	2,100	21	4,117	101	88
7	CVLY-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	2,869	54	1,696	1679	1,136	101	59
8	CVLY-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	4,062	31	1,667	1650	2,381	103	88

Table 2.5-11: Central Valley generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	CVLY-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:50.	15	34	0	1021	552	1409	1342	1324	758
2	CVLY-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	65	34	0	1021	552	1409	1371	1324	780
3	CVLY-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	123	34	0	1245	745	1409	1222	1324	912
4	CVLY-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	15	34	1	1254	251	1409	1123	1324	599
5	CVLY-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	65	34	31	1256	244	1409	850	1324	223
6	CVLY-2026-SP-Hi-CEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	65	34	0	1021	552	1409	1371	1324	762
7	CVLY-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	15	34	34	1254	803	1409	1124	1324	605
8	CVLY-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	15	34	20	1021	612	1409	842	1324	51

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

2.5.4.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2021-2022 reliability assessment of the PG&E Central Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P0 to P7 contingencies, most of which are addressed by previously approved projects. The areas where additional mitigation requirement were identified are discussed below.

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

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

Cortina 230/115/60 kV TB #1 Transformer Overload

An overload on Cortina 230/115/60 kV TB #1 Transformer was identified under P1 contingency of the Cortina 230/115 kV TB #4 starting 2023. The ISO is recommending the approval of the Cortina 230/115/60 kV Bank #1 Replacement Project to address this issue. The proposed project replaces the existing Cortina 230/115/60 kV TB #1 with one 230/115 kV and one 115/60 kV transformer banks. The project cost estimate is $21M - $42M, with an estimated in-service date of May 2027. In the interim, the area will rely on operating action plans.

Weber - Mormon Jct 60 kV Line Overload

P0 overload was identified on the Weber – Mormon Jct. 60 kV line starting 2023. This issue is also identified in the real time operation. The ISO is recommending the approval of the Weber -

Mormon Jct 60 kV Line Section Reconductoring Project to address P0 overload issues on the line. The project includes reconductoring 6.2 miles of the Weber - Mormon Jct 60 kV Line with larger conductor with a cost estimate of $9.3M - $18.6M and an estimated in-service date of May 2027. In the interim, the area will rely on operating action plans.

Manteca – Ripon and Melones – Valley Home 115 kV Line Overload

P1 overloads were identified on the Manteca – Rippon and Melones – Valley Home 115 kV lines starting 2023. The ISO is recommending the approval of the Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project to address P1 overload issues in the area. The proposed project scope includes reconductoring a total of 4.2 miles of 115 kV line between Manteca and Ripon, and between Riverbank and Valley Home, with a cost estimate of $6.8M - $13.6M and an estimated in-service date of May 2028. In the interim, the area will rely on operating action plans.

Vaca – Plainfield 60 kV Line Overload and Plainfield 60 kV bus low voltage

The total load at Plainfield and Winters substations that are radially supplied by the Vaca – Plainfield 60 kV Line is higher than the rating of the line and causes P0 overload on the line starting in 2023. In addition to overload, there are P0 low-voltage issues at Plainfield 60 kV bus which will be addressed by the capacitor bank addition. In the 2018-2019 transmission planning process, the ISO recommended PG&E reconfigure the Plainfield substation and connect load bank #1 to the E. Nicolaus substation. The ISO recommends PG&E continue that practice in the near term while the ISO continues to monitor the load forecast in this area in future planning cycles.

Placerville and Eldorado Area

P2-1 contingencies resulted in overload on the Gold Hill – Eldorado 115 kV lines in 2031. The ISO will continue to monitor the forecast load in the Placerville and Eldorado area in future cycles to address the forecast P2-1 overloads.

Tesla 115 kV Bus

P2-4 contingency at Tesla 115 kV substation resulted in overloads and voltage issues in the underlying 115 kV network in the area starting in the near term. The ISO is considering either an SPS or the upgrade of the Tesla 115 kV substation to address this issue. In the interim, the ISO will continue to rely on the PG&E-developed feasible and compliant operating measures.

Brighton – Davis 115 kV Line Overload

An overload under P1 condition was identified on the Brighton – Davis 115 kV line for the contingency of the Brighton – West Sacramento 115 kV line only in 2023. The implementation of the Rio Oso 230/115 kV Transformer upgrade and Rio Oso SVC projects in 2024 will address the issue. In the interim the area will rely on operating action plans.

Kasson – Louise 60 kV and Manteca – Louise 60 kV Lines Overload

The P1 contingency of the Kasson 115/60 kV transformer overloads the Kasson – Louise 60 kV and Manteca – Louise 60 kV lines. This issue is currently managed by Kasson SPS which trips the Kasson – Louise 60 kV line following the P1 contingency of Kasson 115/60 kV transformer.

The ISO is working with PG&E to assess different alternatives to address the issue and recommends to continue to rely on the SPS while other mitigation measures are being evaluated.

Drum – Higgins 115 kV Line Overload

An overload on Drum – Higgins 115 kV line was identified under P7 contingency of Placer – Gold Hill #1 and #2 115 kV lines in the year 2030. The ISO will continue to monitor the load forecast in the area and will address the issues with a line upgrade or an SPS as potential mitigation measures.

Drum – Grass Valley – Weimar 60 kV Line Overload

An overload on Drum – Grass Valley – Weimar 60 kV line was identified under P3 contingency of Rollins Unit 1 and Colgate – Grass Valley 60 kV line starting 2023. The ISO recommendation is to disable load transfer automatics to address the issue.

Rio Oso – Lincoln 115 kV Line Overload

P6 contingency of Rio Oso – Atlantic and Atlantic – Gold Hill 230 kV lines overload Rio Oso – Lincoln 115 kV line starting 2023. In addition, the P7 contingency of Rio Oso – Atlantic and Rio Oso – Gold Hill 230 kV lines causes overload on the Rio Oso – Lincoln 115 kV line in the long term as well. The ISO recommendation is to use operating measure in the near term and SPS in the long term to address the issue.

2.5.4.4 Request Window Submissions

There were three projects submitted into the 2021 Request Window.

Cortina 230/115/60 kV Bank #1 Replacement Project

PG&E proposed the Cortina 230/115/60 kV Bank #1 Replacement Project to address P1 overload issue on the Cortina 230/115/60 kV Bank #1. The proposed project scope includes replacing the existing Cortina 230/115/60 kV Bank #1 with one 230/115 kV and one 115/60 kV transformer banks. The project cost estimate is $21 million to $42 million with an estimated in-service date of May 2027. The ISO's recommendation is to approve the project.

Weber - Mormon Jct 60 kV Line Section Reconductoring Project

PG&E proposed the Weber - Mormon Jct 60 kV Line Section Reconductoring Project to address P0 overload issues on the line. The proposed project scope includes reconductoring 6.2 circuit miles of the Weber - Mormon Jct 60 kV Line with a larger conductor. The project cost estimate is $9.3 million to $18.6 million, with an estimated in-service date of May 2027. The ISO's recommendation is to approve the project.

Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project

PG&E proposed the Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project to address P1 overload issues in the area. The proposed project scope includes re-conductoring a total of 4.2 miles of the 115 kV line between Manteca and Ripon, and between

Riverbank and Valley Home. The project cost estimate is $6.8 million to $13.6 million, with an estimated in-service date of May 2028. The ISO's recommendation is to approve the project.

2.5.4.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1, about 49 MW of AAEE and more than 2,100 MW of installed behind-the-meter PV reduced the Central Valley Area load in 2026 by about 1.2%. This year's reliability assessment for the Central Valley Area included the "high CEC forecast" sensitivity case for year 2026 which modeled no AAEE. Comparisons between the reliability issues identified in the 2026 summer peak baseline case and the "high CEC forecast" sensitivity case show that the facility overloads shown in Table 2.5-13 are potentially avoided due to reduction in net load:

Table 2.5-12: Reliability Issues in Sensitivity Studies

Facility	Category
Vaca - Suisun - Jameson 115 kV Line	P6
Eldorado - Missouri Flat 115 kV No. 2 Line	P2
Stanislaus - Melones Sw 115 kV Line	P7
Tesla - Salado - Manteca 115 kV Line	P7

Furthermore, more than 88 MW of demand response are modeled in the Central Valley Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.4.6 Recommendation

Based on the studies performed for the 2021-2022 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. To address new reliability issues identified in this cycle, the ISO is recommending approval of:

- The Cortina 230/115/60 kV Bank #1 Replacement Project
- The Weber - Mormon Jct 60 kV Line Section Reconductoring Project, and
- The Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project.

The ISO is working with PG&E to address P2-4 issue at Tesla 115 kV substation through either an SPS or substation upgrade, and P1 overload on Kasson – Louise 60 kV and Manteca – Louise 60 kV lines. The remaining issues are only observed under the sensitivity scenario or in the long term. The ISO will continue to monitor those issues and will mitigate them if the issues are identified in future assessments.

2.5.5 Greater Bay Area

2.5.5.1 Area Description

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

The East Bay sub-area includes cities in Alameda and Contra Costa counties. Some of the 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 of the cities are San Jose, Mountain View, Morgan Hill and Gilroy. Los Esteros, Metcalf, Monta Vista and Newark are the key substations that deliver power to this sub-area. The South Bay sub-area encompasses the De Anza and San Jose divisions and the City of Santa Clara. Generation units within this sub-area include Calpine's Metcalf Energy Center, Los Esteros Energy Center, Calpine Gilroy Power Units, and SVP's Donald Von Raesfeld Power Plant. In addition, this sub-area has key 500 kV and 230 kV interconnections to the Moss Landing and Tesla substations. Lastly, the San Francisco-Peninsula sub-area encompasses San Francisco and San Mateo counties, which include the cities of San Francisco, San Bruno, San Mateo, Redwood City and Palo Alto. The San Francisco-Peninsula area presently relies on transmission line import capabilities that include the Trans Bay Cable to serve its electricity demand. Electric power is imported from Pittsburg, East Shore, Tesla, Newark and Monta Vista substations to support the sub-area loads.

Trans Bay Cable became operational in 2011. It is a unidirectional, controllable, 400 MW HVDC land and submarine-based electric transmission system. The line employs voltage source converter technology, which will transmit power from the Pittsburg 230 kV substation in the city of Pittsburg to the Potrero 115 kV substation in the city and county of San Francisco.

The ISO Planning Standards were enhanced in 2014 to recognize that the unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages for extreme events that are beyond the level that is applied to the rest of the ISO- controlled grid.

2.5.5.2 Area-Specific Assumptions and System Conditions

The Greater Bay Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Greater Bay Area study are provided in Table 2.5-14 and Table 2.5-15. The transmission modeling assumptions are consistent with the general assumptions described in section 2.3.

Table 2.5-13 Greater Bay Area load and load modifier 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 Total (MW)	Demand D2 (MW)
1	2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	9,081	40	1,931	155	8,886	61	30
2	2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 19:00.	7,351	51	1,931	12	7,288	61	30
3	2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	6,245	104	1,931	0	6,141	61	30
4	2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	9,081	40	1,931	1,912	7,129	61	30
5	2023-OP-HiRenew	Baseline	2023 spring off-peak load conditions with hi-renewable dispatch sensitivity	6,245	104	1,931	1,944	4,197	61	30
6	2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	9,177	60	2,423	24	9,093	59	30
7	2026-WP	Baseline	2026 winter peak load conditions. Peak load time - hours ending 19:00.	7,874	81	2,423	0	7,793	59	30
8	2026-SpOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	5,118	52	2,423	1,914	3,152	59	30
9	2026-SP-Hi-CEC	Sensitivity	2026 summer peak load conditions with high CEC load forecast sensitivity	9,177	0	2,423	24	9,153	59	30
10	2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	9,486	142	3,098	31	9,313	57	30
11	2031-WP	Baseline	2031 winter peak load conditions. Peak load time - hours ending 19:00.	8,389	142	3,098	0	8,247	57	30
12	2031-Hi-SouthBay	Sensitivity	2031 summer peak load conditions with high South Bay load sensitivity	9,937	142	3,098	31	9,764	57	30

Note: Includes PG&E load only. DR and storage are modeled offline in starting base cases.

Includes PG&E load only.

DR and storage are modeled offline in starting base cases.

Table 2.5-14 Greater Bay Area generation assumptions

S. No.	Study Case	Scenario Type	Description	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	2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 18:00.	45	48	25	227	98	0	0	5710	5150
2	2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 19:00.	45	25	0	227	30	0	0	5710	3227
3	2023-SpOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	45	25	0	227	53	0	0	5910	3091
4	2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	45	48	39	227	141	0	0	5710	3095
5	2023-OP-HiRenew	Baseline	2023 spring off-peak load conditions with hi-renewable dispatch sensitivity	45	25	25	227	167	0	0	5910	879
6	2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	401	48	24	227	81	0	0	5710	4947
7	2026-WP	Baseline	2026 winter peak load conditions. Peak load time - hours ending 19:00.	401	48	13	227	30	0	0	5710	4893
8	2026-SpOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	401	48	45	227	44	0	0	5710	684
9	2026-SP-Hi-CEC	Sensitivity	2026 summer peak load conditions with high CEC load forecast sensitivity	401	48	24	227	81	0	0	5710	4903
10	2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	656	48	24	257	74	0	0	5710	4574
11	2031-WP	Baseline	2031 winter peak load conditions. Peak load time - hours ending 19:00.	656	48	0	257	32	0	0	5710	5126
12	2031-Hi-SouthBay	Sensitivity	2031 summer peak load conditions with high South Bay load sensitivity	656	48	0	257	80	0	0	5710	5032

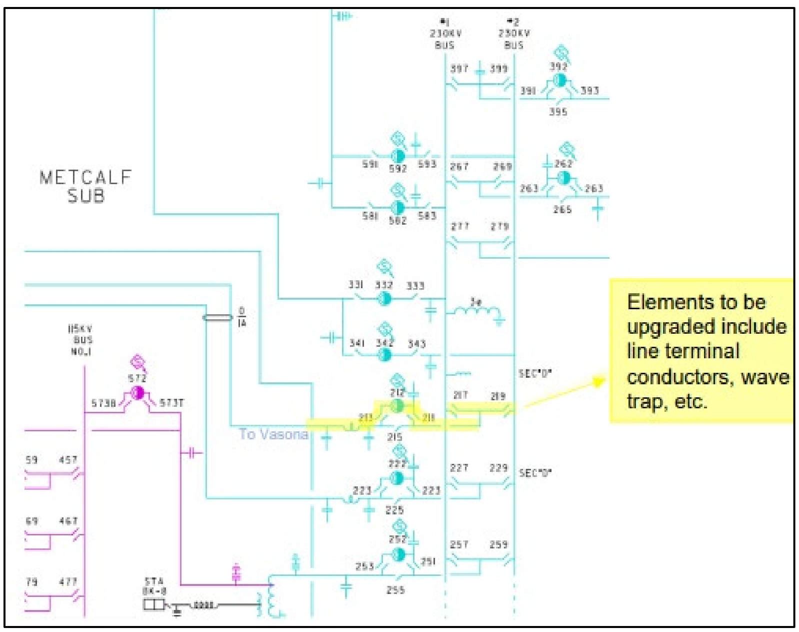
2.5.5.3 Assessment Summary

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 2021-2022 reliability assessment identified several reliability concerns consisting of thermal overloads under Category P1 to P7 contingencies, most of which are addressed by previously approved projects. The areas where additional mitigation requirements were identified are discussed below.

Vasona-Metcalf 230 kV Line Limiting Elements Removal

Multiple Category P2 and P7 short-term and P1 long-term overloads were identified on the Vasona-Metcalf 230 kV line. The ISO is recommending approval of the "Vasona-Metcalf 230 kV Line Limiting Elements Removal" project which includes upgrading terminal conductors and wave traps. Estimated cost of this project is $0.6M to $1.2M and the in-service date is May 2025. In the interim, the area will rely on operating action plans.

Figure - Vasona-Metcalf 230 kV Line Limiting Elements Removal project one-line diagram.



Contra Costa 230 kV Line Terminals Reconfiguration

Multiple Category P2 contingency driven overloads were identified in the Contra Costa-Newark 230 kV corridor in both the short and long term in the area. The Contra Costa 230 kV bus and breakers were also found to be overloaded in the recent generation interconnection studies. The overloads are primarily due to several bus and breaker contingencies at the 230 kV Contra Costa substation which results in both the line and generation loss at the substation. The ISO is recommending approval of the "Contra Costa 230 kV Line Terminals Reconfiguration" project which includes swapping of the Lone Tree – Contra Costa PP 230 kV line and Birds Landing – Contra Costa PP 230 kV line terminal positions at Contra Costa PP 230 kV Substation. The project scope also includes relocating the terminal of one additional element from bus section F to an available spare position at bus section E. The estimated cost of this project is $5M to

$10M and the in-service date is May 2025. In the interim, the area will rely on operating action plans.

Figure - Contra Costa 230 kV Line Terminals Reconfiguration project one-line diagram

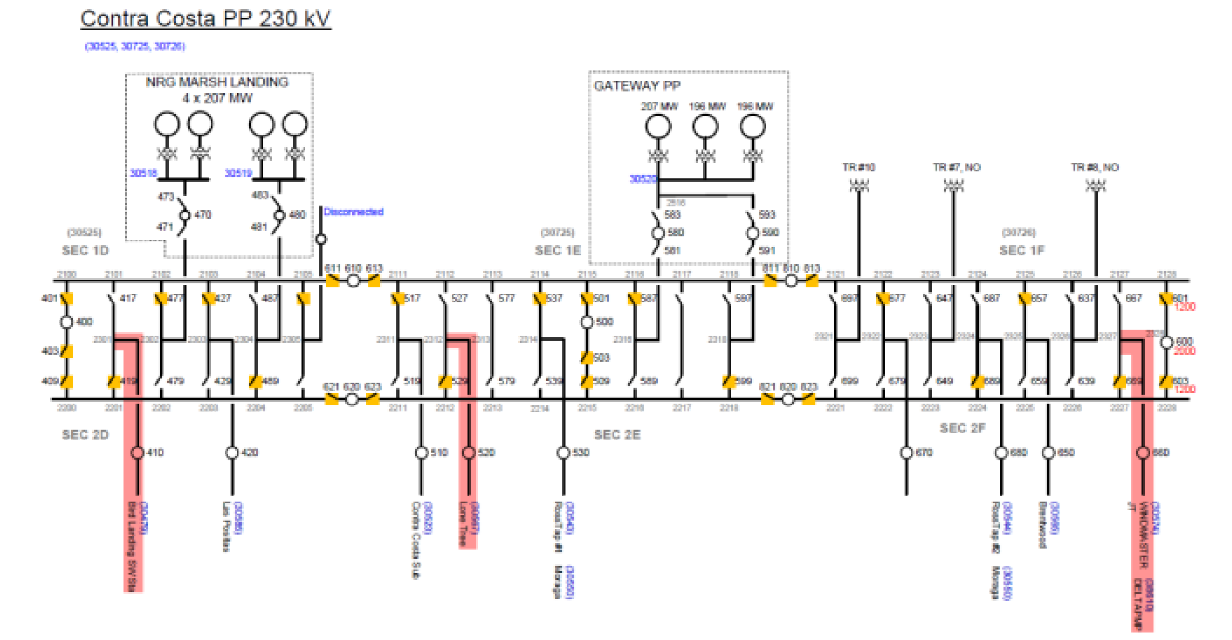
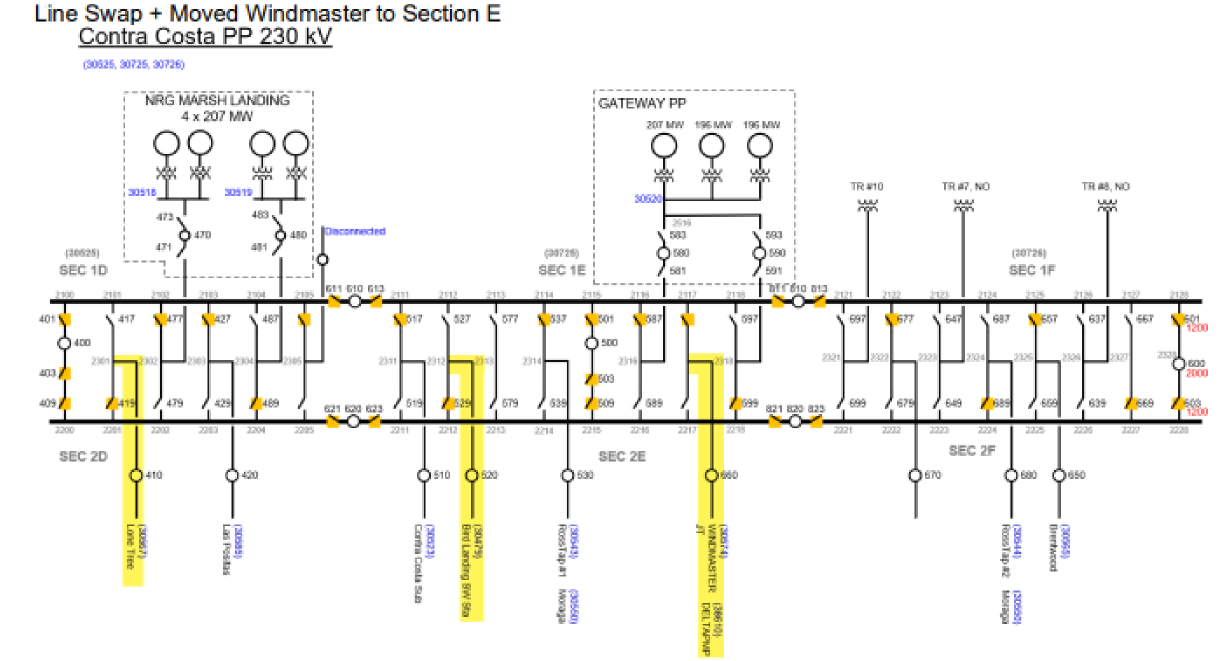


Figure 3: Existing System Diagram

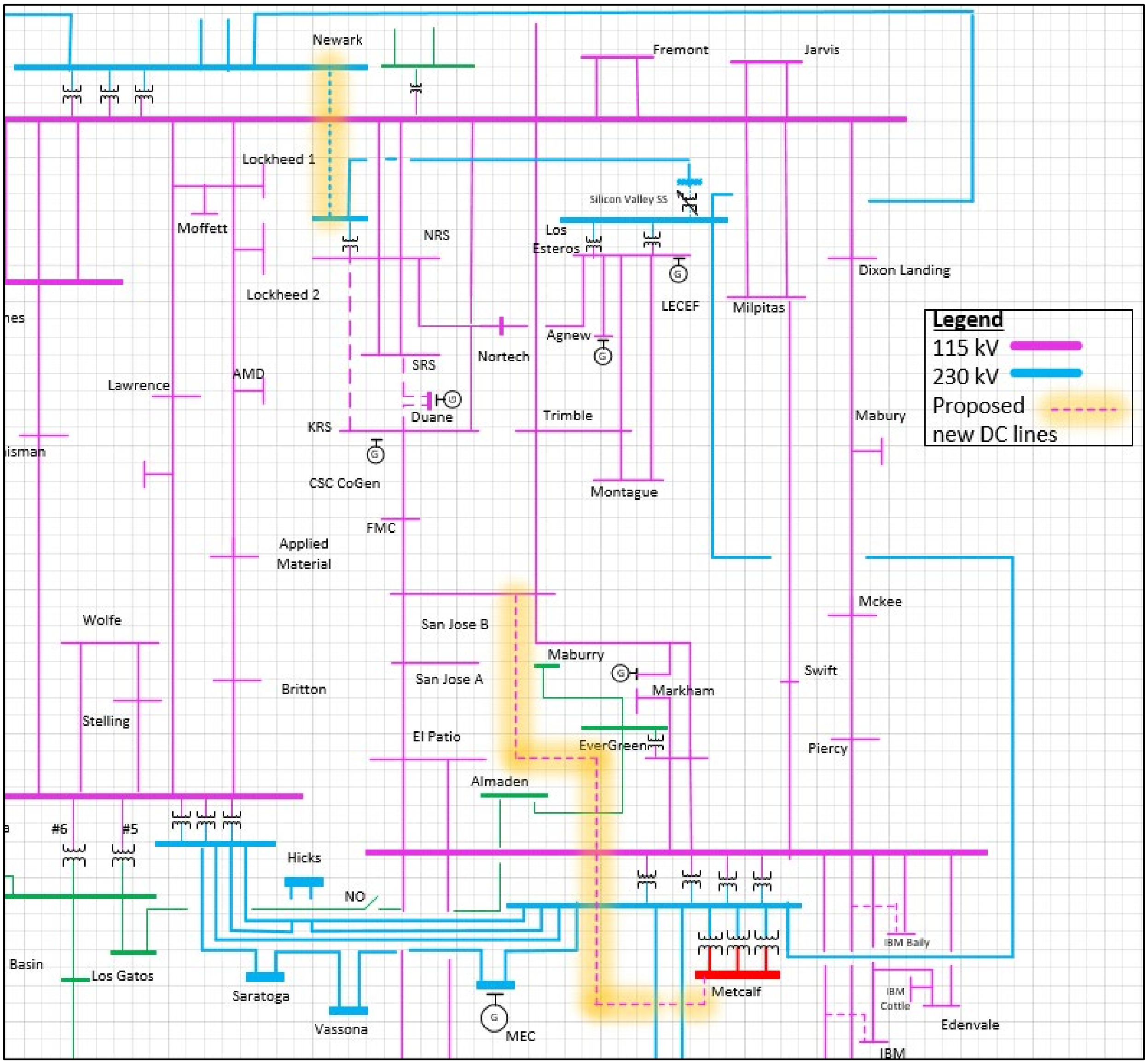
Line Swap + Moved Windmaster to Section E



South Bay Overloads

This year's load forecast included significant load increase of about 500 MW (~75%) in the Silicon Valley Power (SVP) area. As a result, multiple near-term and much more long-term overloads were identified in the San Jose 115 kV system. The near-term issues include overloads driven by P2, P6 and P7 category contingencies. However, the mid and long-term issues include overloads driven by P1 contingencies as well as multiple overloads driven by other category contingencies. Several mitigation alternatives were studied, including reconductoring of existing 115 kV lines, converting 115 kV lines to higher capacity 230 kV line and building new 230 kV lines into the San Jose and SVP areas. Different technologies, including series compensation devices and HVDC lines were also evaluated as part of the alternative analysis. The San Jose/SVP area is essentially served from Newark 230 kV substation in the north and Metcalf 500/230 kV substation in the south. However, due to the electrical proximity of bulk of the area load to the Newark substation, specifically the SVP area load where most of the load increase is, the bulk of the power flows from the Newark side. Accordingly, the near-term and P1 contingency driven issues were identified on the lines emanating from Newark and Los Esteros substations. However, overloads were also identified in the rest of the San Jose 115 kV system in the mid and long-term under P2, P6 and P7 category contingencies. Due to this imbalance between two sources in the AC connected network, the HVDC alternatives resulted in better performance from the power flow perspective as a result of controllability of the HVDC source. The HVDC alternative also provides benefits in reducing local capacity requirements in the San Jose subarea and overall Greater Bay Area that reduces reliance on the local gas generation. Based on analysis of the alternatives, the ISO is recommending approval of the two HVDC lines in the area. The project scope includes one 500 MW HVDC line from Newark 230 kV to near the Los Estero 230 kV substation and connected to the SVP's NRS 230 kV with 230 kV AC lines or cables and another 500 MW HVDC line from Metcalf 500 kV to San Jose B 115 kV stations. The estimated cost of the Newark-NRS HVDC line project is $325M to $510M and the Metcalf-San Jose B HVDC line project is $425M to $615M. The target in-service date for both lines is 2027.

Figure – South Bay new HVDC lines project one-line diagram.



Alternatives considered:

- 115 kV lines reconductoring: This alternative is not recommended as the forecasted overall San Jose area load is beyond capacity of 115 kV lines.
- New 230 kV AC lines from Newark and Metcalf: This alternative is not recommended because of the imbalance in natural flows from the Newark and Metcalf sources.
- Energy Storage: This alternative is not recommended as previous studies have shown that the San Jose system has far less charging capacity compared to the size of energy storage needed to address all reliability issues identified in the area.

Furthermore, in the interim, to address the near-term critical, category P1 contingency driven issues, the ISO is also recommending approval of adding series compensation devices on the Los Esteros-Nortech 115 kV line. Current studies show that adding about 2 ohms reactor on the Los Esteros-Northech 115 kV line would be an optimal solution along with running the Silicon Valley Power (SVP) phase-shifting transformer at its limit and energy storage addition in the SVP system. The estimated cost of this project is $10M to $15M and the target in-service date is 2023.

Moraga- Sobrante (on-hold project)

A Category P5 contingency driven overload was identified on the Moraga-Sobrante 115 kV line in the high load sensitivity scenario. The ISO had recommended the project to be put on hold in the last cycle and recommends to continue the project on hold for this cycle as well.

C*ooley Landing Substation Circuit Breaker #62 Upgrade*

Based on the short circuit study performed by PG&E, the circuit breaker #62 at Cooley Landing is expected to be overstressed to 100% by 2023. The ISO, in 2021-2022 transmission planning process, is recommending approval of breaker #62 upgrade at Cooley Landing. The estimated cost of this project is $750k - $1.13M and the expected in-service date is Q4 2026.

Metcalf Substation Circuit Breaker #292 Upgrade

Based on the short circuit study performed by PG&E, the circuit breaker #292 at Metcalf is expected to be overstressed to 103% by 2023. The ISO, in 2021-2022 transmission planning process, is recommending approval of breaker #292 upgrade at Metcalf. The estimated cost of this project is $900k-$1.35M and the expected in-service date is Q4 2025.

2.5.5.4 Request Window Submissions

The ISO received five submissions in the 2021 Request Window in the Greater Bay Area.

Request Window Submission – Contra Costa 230 kV Line Terminals Reconfiguration

Pacific Gas & Electric (PG&E) proposed a project, Contra Costa 230 kV Line Terminals Reconfiguration, targeting thermal overloads on the Contra Costa-Newark 230 kV corridor, Contra Costa 230 kV bus and circuit breaker #820 and associated switches caused by various P2 contingencies at Contra Costa 230 kV. The project includes swapping of the Lone Tree – Contra Costa PP 230 kV line and Birds Landing – Contra Costa PP 230 kV line terminal positions at Contra Costa PP 230 kV. The project also includes relocating of the terminal of one additional element from bus section F to an available spare position at bus section E. The ISO review found that the project addresses the reliability issue. Hence, the ISO determined that the Contra Costa 230 kV Line Terminals Reconfiguration project is needed. The estimated cost of this project is $5M to $10M and the in-service date is May 2025.

Request Window Submission – Vasona-Metcalf 230 kV Line Limiting Elements Removal

Pacific Gas & Electric (PG&E) proposed a project, Vasona-Metcalf 230 kV Line Limiting Elements Removal, targeting thermal overloads on the Vasona-Metcalf 230 kV line. The project includes upgrading Vasona-Metcalf line terminal conductors from single 1113 conductor into bundled 1113 conductors at Metcalf substation. The project also would replace the wave traps and any other terminal conductors that limit the line summer rating to 1600 Amps at both Metcalf and Vasona substations. The ISO review found that the project addresses the reliability issue. Hence, the ISO determined that the Vasona-Metcalf 230 kV Line Limiting Elements Removal project is needed. The estimated cost of this project is $0.6M to $1.2M and the in-service date is May 2025.

Request Window Submission - South Bay 115 kV Reinforcement Conceptual Project

PG&E proposed the South Bay 115 kV Reinforcement Conceptual Project, targeting various thermal overloads on the South Bay 115 kV system. The submission included three alternatives: 1) Reconductor the two Newark-NRS 115 kV lines, 2) Rebuild the two Newark-NRS 115 kV lines as two 230 kV higher capacity lines and 3) Build a new 230 kV line from Newark to NRS. The ISO used these alternatives in the South Bay alternative evaluation study.

Request Window Submission - Ames – Palo Alto 115 kV Line Project

The City of Palo Alto proposed the Ames-Palo Alto 115 kV Line Project, targeting thermal overloads on the Ravenswood-Cooley Landing 115 kV line and potential reliability concern for loss of three 115 kV line feeding Palo Alto substation. The project includes building a new Ames-Palo Alto 115 kV line. The ISO's reliability assessment identified overloads on the Ravenswood-Cooley Landing 115 kV line under categories P2 and P5 contingencies. Category P2 overload was identified in the 2031 scenario only. For the P5 contingency driven overload, the ISO recommended PG&E to upgrade bus protection at Ravenswood 115 kV. The contingency of three 115 kV lines is an extreme event, which doesn't result in an uncontrolled wide-area cascading. Hence, the ISO determined that the Ames – Palo Alto 115 kV Line Project is not an appropriate solution for reliability issues identified in Peninsula 115 kV system.

Request Window Submission - Santa Clara Area Series Compensation Project

Smart Wires proposed the Santa Clara Area Series Compensation Project, targeting various thermal overloads on the South Bay 115 kV system. The project includes adding series compensation on the Los Esteros – Nortech and Newark – NRS 115 kV lines. The ISO used this alternative in the South Bay alternative evaluation study using the models provided in the submission and found that this alternative would alleviate some overloads. However, the alternative also created new overloads. Hence, the ISO determined that Santa Clara Area Series Compensation Project is not an appropriate solution for reliability issues identified in the South Bay 115 kV system.

2.5.5.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.5.2, about 60 MW of AAEE and more than 2,400 MW of installed behind-the-meter PV reduced the Greater Bay Area load in 2026 by about 1%.This year's reliability assessment for the Greater Bay Area included the “high CEC forecast” sensitivity case for year 2026 which modeled no AAEE. Comparisons between the reliability issues identified in the 2026 summer peak baseline case and the “high CEC forecast” sensitivity case show that the facility overloads shown in Table 2.5-16 are potentially avoided due to reduction in net load.

Table 2.5-15: Reliability Issues Avoided due to AAEE

Facility	Category
Los Esteros-Nortech 115 kV Line	P0, P1
Newark 230/115kV Transformer #11	P5
San Mateo-Bair 60kV Line	P2
Sobrante-El Cerrito STA G #1 115kV Lin	P2
Sobrante-El Cerrito STA G #2 115kV Lin	P2

Furthermore, about 59 MW of demand response and 400 MW of battery energy storage are modeled in the Greater Bay Area in the year 2026. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources mitigated overloads in Oakland and San Jose areas under some contingency conditions.

2.5.5.6 Recommendation

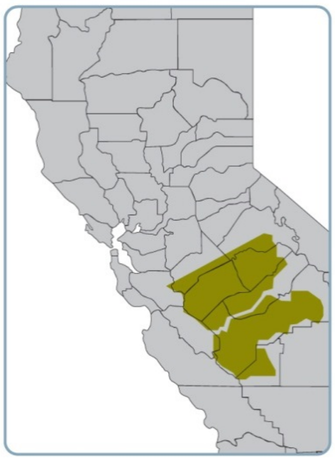
Based on the studies performed in the 2021-2022 transmission planning cycle, several reliability concerns were identified for the PG&E Greater Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Bay area.

Stakeholders submitted five projects through the Request Window in the Greater Bay Area in this cycle. Out of the five projects submitted, the ISO found two needed for reliability and are recommended for approval; the Contra Costa 230 kV Line Terminals Reconfiguration and the Vasona-Metcalf 230 kV Line Limiting Elements Removal projects. The remaining three projects were found to be not appropriate solutions for reliability issues identified. Furthermore, the ISO is also recommending approval of two new HVDC lines in the San Jose area; the 500 MW HVDC line from Newark 230 kV station to SVP’s NRS 230 kV station and the 500 MW HVDC line from Metcalf 500 kV station to San Jose B 115 kV station. The ISO is also recommending approval of an interim mitigation, the series compensation devices on the Los Esteros-Nortech 115 kV line.

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 comprised of 70 kV, 115 kV and 230 kV transmission facilities. Electric supply to the Greater Fresno area is provided primarily by area hydro generation (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 comprised of two primary load pockets including the Yosemite area in the northwest portion of the shaded region in the adjacent figure. The rest of the shaded region represents the Fresno area.

The Greater Fresno area interconnects to the bulk PG&E transmission system by 12 transmission circuits. These consist of nine 230 kV lines; three 500/230 kV banks; and one 70 kV line, which are served from the Gates substation in the south, Moss Landing in the west, Los Banos in the northwest, Bellota in the northeast, and Templeton in the southwest. Historically, the Greater Fresno area experiences its highest demand during the summer season, but it also experiences high loading because of the potential of 900 MW of pump load at Helms Pump Storage Power Plant during off-peak conditions. The largest generation facility within the area is the Helms plant, with 1212 MW of generation capability. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and off-peak conditions that reflect different operating conditions of Helms. Significant transmission upgrades have been approved in the Fresno area in past transmission plans, which are set out in chapter 8.

2.5.6.2 Area-Specific Assumptions and System Conditions

The Greater Fresno Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are shown in Table 2.5-17 and Table 2.5-18.

Table 2.5-16 Greater Fresno Area load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	GFA-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	3,208	22	1,610	16	3,170	33	19
2	GFA-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	3,266	36	2,076	21	3,209	32	19
3	GFA-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	3,369	84	2,744	27	3,257	31	19
4	GFA-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	2,312	41	1,811	0	2,271	51	22
5	GFA-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,001	27	2,076	1640	(666)	0	0
6	GFA-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	3,208	22	1,610	1594	1,592	33	19
7	GFA-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi-renewable dispatch sensitivity	2,312	41	1,811	1793	478	51	22
8	GFA-2026-SP-Hi-CEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	3,266	0	2,076	21	3,245	32	19

Table 2.5-17: Greater Fresno Area generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	GFA-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:00.	309	2758	329	13	9	1870	1784	1269	1165
2	GFA-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:00.	421	2440	763	13	9	1870	1807	1269	1192
3	GFA-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:00.	852	3484	48	186	126	1870	1768	1269	1181
4	GFA-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	309	2336	0	13	3	685	-302	1386	1176
5	GFA-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	421	2529	2172	13	3	685	-330	1405	84
6	GFA-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	309	2758	2495	13	8	1870	1817	1269	526
7	GFA-2023-SpOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi-renewable dispatch sensitivity	309	2758	2473	13	8	668	-354	1234	811
8	GFA-2026-SP-Hi-CEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	421	2440	763	13	9	1870	1808	1269	1192

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 2021-2022 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.

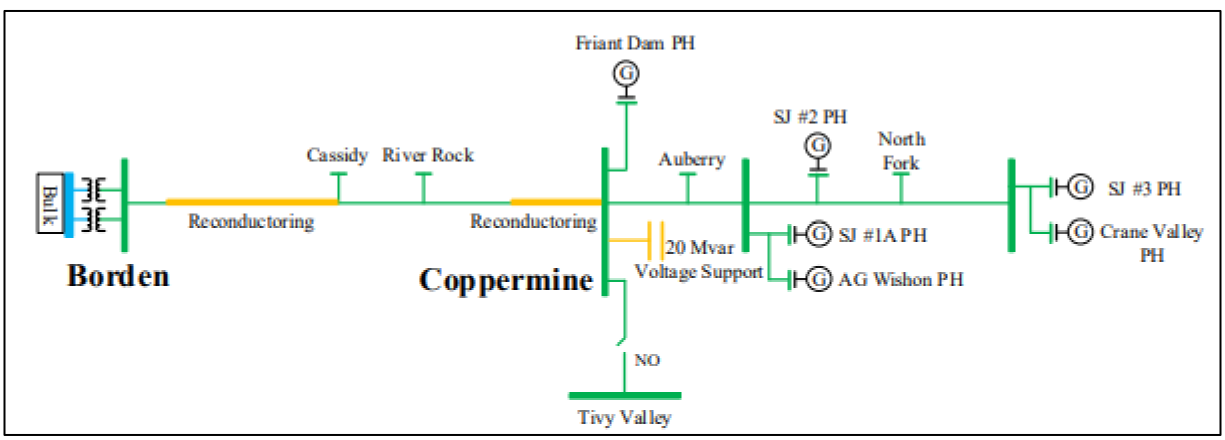
Coppermine 70kV

Recent recorded data showed overload on the Coppermine-Tivy Valley 70 kV line and low voltage under normal system conditions. These normal overload and low-voltage issues are expected to occur even more frequently in the summer peak scenario as California's water crisis evolves further. As such, the ISO is recommending approval of the "Coppermine 70 kV Reinforcement Project" project which includes the following:

- Reconductor ~9.45 circuit miles between Borden and Cassidy Substations (from 19/10A to Cassidy Sub section) on the Borden-Coppermine 70kV Line with a larger conductor to achieve at least 700 Amps of summer normal rating
- Reconductor ~3.57 circuit miles between Cassidy and Coppermine Substations (from 3/7 to Coppermine Sub section) on the Borden-Coppermine 70kV Line with a larger conductor to achieve at least 500 Amps of summer normal rating
- Remove any limiting components to achieve the full conductor capacity
- Install 20 MVAR voltage support at Coppermine Substation distribution.

The total estimated cost of this project is \$21.8M to \$43.6M, which includes \$6M to \$12M of distribution cost. The expected in-service date of this project is May 2027. In the interim, the area will rely on operating action plans.

Figure - Coppermine 70 kV Reinforcement Project one-line diagram.



P5 overloads

There were P5 contingencies (failure of non-redundant relay) affecting the Gates section D & E 230 kV #1 bus that result in overloads on several 70 kV and 230 kV lines in the baseline and sensitivity cases. The ISO is recommending adding redundant rely protection to mitigate this contingency.

Long-term overload issues

There were several P1-P5 contingency-driven overloads identified in the 2031 summer peak baseline scenario. These overloads include the Chowchilla-Kerchkoff #2 115 kV line, the Henrietta 230/115 kV bank 3, and the Wilson-Oro Loma (Oro Loma-El Nido section) 115 kV line. The ISO's recommendation is to continue to monitor future load forecast for these issues.

Spring off-peak only overloads

There were some P2, P6, P7 contingency-driven overloads identified in the spring off-peak cases including the Oroloma-Medota 115 kV line, Melones-Wilson 230 kV line, GWF-Kingsburg 115 kV line, Wilson-Storey #1 or #2 230 kV lines, Mendota-San Joaquin-Helm 70 kV lines, Mccall- Sanger #2 or #3 115 kV lines, McCall 230/115 kV banks, Gates-Gregg 230 kV lines, Gregg-Ashlan line, Herdon-Ashlan 230 kV lines, Warnerville-Wilson 230 kV line, Los Banos-Dos Amigos 230 kV line, Los Banos-Panoche 230 kV line, Chowchilla-Kerckhoff 115 kV line, Herndon-Barton line, Herndon-Manchester 115 kV line, and Herndon-Woodward 115 kV line. The recommended mitigation is to utilize Warnerville-Wilson series reactors for Warnerville-Wilson and Melones-Wilson overloads and generation re-dispatch.

Fresno 115 kV and 70 kV area voltage concerns

In the 2031 summer peak baseline scenario, for contingency categories P1, P3, P5 and P6, some low voltages were identified in the Chowchilla, Yosemite, Firebaugh, Oro Loma area 115 kV and 70 kV systems. The ISO will continue to monitor future load forecast for these issues.

Bellota-Warnerville 230 kV line reconductoring

Bellota-Warnerville 230 kV line reconductoring project is one of the previously approved transmission planning process policy driven projects. Recently, it has been identified that the rating of the line following reconductoring will be limited by equipment at the Warnerville end, which is owned and operated by City and County of San Francisco (CCSF). The ISO is coordinating with CCSF and PG&E for scope and timing of necessary upgrade at the Warnerville station. Based on the information received from CCSF, CCSF has existing plans to upgrade the remaining portion of the Warnerville 230 kV switch yard by 2026.

2.5.6.4 Request Window Submissions

One request window submission, the Coppermine 70kV reinforcement project, was submitted in this area.

Coppermine 70 kV Reinforcement Project

The Coppermine 70 kV Reinforcement Project consists of the following scope:

- Reconductor ~9.45 circuit miles between Borden and Cassidy Substations (from 19/10A to Cassidy Sub section) on the Borden-Coppermine 70kV Line with a larger conductor to achieve at least 700 Amps of summer normal rating
- Reconductor ~3.57 circuit miles between Cassidy and Coppermine Substations (from 3/7 to Coppermine Sub section) on the Borden-Coppermine 70kV Line with a larger conductor to achieve at least 500 Amps of summer normal rating
- Remove any limiting components to achieve the full conductor capacity
- Install 20 MVAR voltage support at Coppermine Substation.

This will address P0 overload on the Coppermine-Tivy valley 70kV line, low voltages in surrounding areas and prevent radialization in summer. This project would establish the Borden-Coppermine 70 kV Line as a stronger power source to the local 70 kV system and will provide enough transmission capacity to meet future local demand. This project will also increase operating flexibility, load serving capability, customer reliability and reduce losses. Hence, The ISO determined that the Coppermine 70kV reinforcement project is needed

2.5.6.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.6.2, about 36 MW of AAEE reduced the Greater Fresno Area load in 2026 by about 1%. This year's reliability assessment for the Greater Fresno Area included the "high CEC forecast" sensitivity case for the year 2026, which modeled no AAEE. Comparisons between the reliability issues identified in the 2026 summer peak baseline case and the "high CEC forecast" sensitivity case are shown in Table 2.5-19 and indicate these facility overloads are potentially avoided due to reductions in net load.

Table 2.5-18: Reliability Issues in Sensitivity Studies

Facility	Category
Wilson-Atwater #2 115 kV Line	P6
Wilson-Oro Loma 115KV Line	P6
Kingsriver-Sanger-Reedley 115 kV Line	P6
McCall-Reedley 115 kV Line (Reedley-Wahtoke)	P6

Furthermore, about 31 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

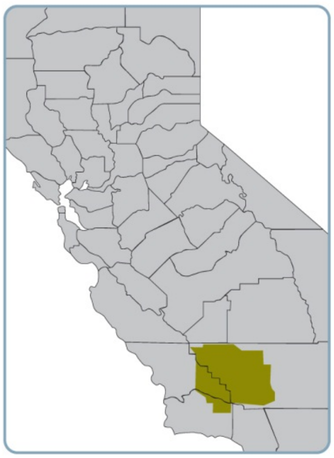
Based on the studies performed for the 2021-2022 Transmission Plan, several reliability concerns were identified for the PG&E Greater Fresno Area. These concerns consisted of thermal overloads and voltage concerns under categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Fresno Area. Sensitivity scenarios do show worsening overloads for most elements.

Stakeholders submitted one project through the Request Window process in the Greater Fresno Area in this cycle. The ISO found the project, the Coppermine 70 kV Reinforcement Project, is needed for reliability and is recommended for approval. The ISO also recommends installing redundant protection at the Gates 230 kV Bus.

2.5.7 Kern Area

2.5.7.1 Area Description

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



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

2.5.7.2 Area-Specific Assumptions and System Conditions

The Kern Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are shown in Table 2.5-20 and Table 2.5-21.

Table 2.5-19 Kern Area load and load modifier assumptions

	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	KERN-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:40.	1,910	12	565	0	1,897	66	60
2	KERN-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:40.	1,931	20	671	0	1,911	66	60
3	KERN-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:40.	1,977	46	825	0	1,931	65	60
4	KERN-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	1,315	21	565	0	1,294	66	57
5	KERN-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	1,073	15	671	530	529	0	0
6	KERN-2026-SP-HiCEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	1,931	0	671	0	1,930	66	60
7	KERN-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	1,910	12	565	560	1,338	66	60
8	KERN-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	1,922	18	565	560	1,345	66	60

Table 2.5-20 Kern Area generation assumptions

	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	KERN-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours ending 19:40.	0	510	38	0	0	18	11	2,348	2,175
2	KERN-2026-SP	Baseline	2026 summer peak load conditions. Peak load time - hours ending 19:40.	182	510	0	0	0	18	11	2,348	2,348
3	KERN-2031-SP	Baseline	2031 summer peak load conditions. Peak load time - hours ending 19:40.	277	1,316	860	0	0	18	18	2,348	2,156
4	KERN-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	0	510	0	0	0	18	18	2,348	2,227
5	KERN-2026-SOP	Baseline	2026 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	182	510	524	0	0	18	17	2,348	527
6	KERN-2026-SP-HiCEC	Sensitivity	2026 summer peak load conditions with hi-CEC load forecast sensitivity	182	510	0	0	0	18	11	2,348	2,348
7	KERN-2023-SOP-HiRenew	Sensitivity	2023 spring off-peak load conditions with hi renewable dispatch sensitivity	0	510	515	0	0	18	18	2,348	549
8	KERN-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	0	510	438	0	0	18	11	2,348	0

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. The details of the planning assessment results are presented in Appendix B. The reliability assessment identified several reliability concerns consisting of thermal overloads, low voltage and voltage deviation under various Category P1 to P7 contingencies in both the baselines and sensitivity cases. The majority of reliability issues are addressed by previously approved projects and/or continued reliance on existing summer setups for the area.

There were near and mid-term categories P1, P2, P6 and P7 reliability issues identified on the Live Oak – Kern Oil 115 kV line. This overload can be mitigated by the previously approved Kern PP 115 kV Area Reinforcement project. There are some near-term category P2, P6 and P7 overloads seen in the Midway 230 kV area that can be mitigated by the previously approved project Midway – Kern PP 230 kV #2 Line.

There were several category P2 overloads identified for the near-term in the greater Kern and Midway areas. These overloads will be mitigated by a PGE Bus conversion maintenance project. In the Kern 115 kV and 70 kV systems there are several category P2, P3, P6 and P7 overloads that will be mitigated using existing summer setups.

Under category P1 and P2 contingencies, there were overloads identified on the Kern PP – Tevis 115 kV lines based on the historical load data in the Kern PP-Lamont 115 kV system. These overloads can be mitigated by the previously recommended 95 MW battery energy storage project at Lamont 115 kV.

Summary of review of previously approved projects

There is one previously approved on-hold project in the Kern area not modeled in the study cases. The final recommendation for the project not modeled in the study cases is shown in Table 2.5-26.

Table 2.5-21: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
Wheeler Ridge Junction Project	On Hold

Wheeler Ridge Junction Project

The Wheeler Ridge Junction project was put on hold in the 2019-2020 transmission planning process. In the 2020-2021 transmission planning process, the ISO recommended procurement of a 95 MW 4 hour energy storage option to mitigate the 115 kV issues on the Kern-Lamont 115 kV system and recommended keeping the Wheeler Ridge Junction Station project on hold pending procurement of the battery in the 115 kV system and until the evaluation of 230 kV options are completed.

This year's assessment identified no reliability issue in the Wheeler Ridge 230 kV system mainly due to PG&E's bus upgrade maintenance project at Midway and new resource interconnection in the Wheeler Ridge 70 kV system. The ISO recommends to keep the Wheeler Ridge Junction Project on hold in this transmission planning cycle as well pending procurement of the battery storage.

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 20 MW and 46 MW of AAEE reduced the Kern Area net load by 2% and 3% in 2026 and 2031 respectively. Similar to last year, this year's reliability assessment for the Kern Area included the "high CEC forecast" sensitivity case for year 2026, which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2026 summer peak baseline case and the "high CEC forecast" sensitivity case show that following facility overloads shown in Table 2.5-22 are diminished or eliminated due to reduction in net load.

Table 2.5-22: Reliability Issues in Sensitivity Studies

Facility	Category
Fellows-Taft 115 kV Line	P2
Midsun-Midway 115 kV Line	P1, P2
Smyrna-Semitropic-Midway 115 kV Line	P1
Taft-Cuyama #1 70 kV Line	P0

Furthermore, about 66 MW of demand response and 277 MW of battery energy storage are modeled in the 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. In addition, The ISO also confirmed the battery energy storage solutions to mitigate the 115 kV reliability issues identified with the on hold Wheeler ridge Junction project.

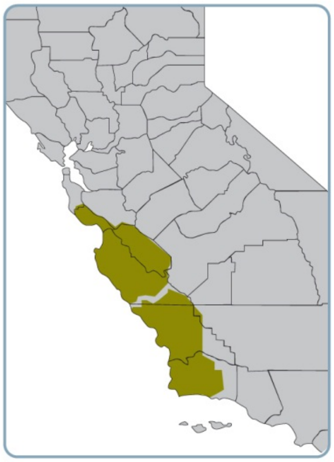
2.5.7.6 Recommendation

Based on the studies performed for the 2021-2022 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. These reliability concerns are addressed by previously approved projects within the Kern 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 2,400 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 2,400 MW DCPP output as it does not serve the load in PG&E's Los Padres division.

2.5.8.2 Area-Specific Assumptions and System Conditions

The Central Coast and Los Padres areas study was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Coast and Los Padres areas study are shown in Table 2.5-23 and Table 2.5-24. For this planning cycle the Central Coast and Los Padres area relied on the use of past studies from the 2019-2020 transmission planning process for the years 2026 and 2031 in both baseline and sensitivity.

Table 2.5-23: Central Cost and Los Padres Area load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	CCLP-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	1,269	13	488	5	1,252	23	21
2	CCLP-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	1,243	15	504	0	1,228	27	15
3	CCLP-2030-SP	Baseline	2030 summer peak load conditions. Peak load time -hours between 19:00 and 20:00.	1,324	26	631	0	1,297	27	15
4	CCLP-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	829	14	488	0	815	27	25
5	CCLP-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	710	0	504	403	307	27	15
6	CCLP-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 19:00.	1,053	15	488	2	1,036	0	0
7	CCLP-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	1,054	16	504	0	1,038	27	15
8	CCLP-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	1,122	28	631	0	1,094	27	15
9	CCLP-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	1,243	0	504	0	1,243	27	15
10	CCLP-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	710	0	504	499	211	27	15
11	CCLP-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	1,189	9	488	429	751	27	15

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

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	CCLP-2023-SP	Baseline	2023 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	0	812	18	0	0	0	0	2,676	1,161
2	CCLP-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	600	816	0	101	44	0	0	2,718	1,143
3	CCLP-2030-SP	Baseline	2030 summer peak load conditions. Peak load time -hours between 19:00 and 20:00.	650	816	0	101	44	0	0	2,718	1,143
4	CCLP-2023-SOP	Baseline	2023 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	0	841	0	0	0	0	0	2,676	1,098
5	CCLP-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	600	816	773	101	20	0	0	2,718	163
6	CCLP-2023-WP	Baseline	2023 winter peak load conditions. Peak load time - hours ending 19:00.	0	826	0	0	0	0	0	2,676	681
7	CCLP-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	600	816	0	101	13	0	0	2,718	1,098
8	CCLP-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	650	816	0	101	13	0	0	2,718	1,098
9	CCLP-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	600	816	0	101	44	0	0	2,718	1,143
10	CCLP-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	600	816	766	101	65	0	0	2,718	451
11	CCLP-2023-SP-HiRenew	Sensitivity	2023 summer peak load conditions with hi-renewable dispatch sensitivity	0	812	972	0	0	0	0	2,676	0

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with the exception of approved projects shown in Table 2.5-25, which were not modeled in the base cases.

Table 2.5-25: Central Coast / Los Padres approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
None		

2.5.8.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2021-2022 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.

There was a near-term category P1, P3 and P6 reliability issue identified on the Salinas- Firestone #1 60 kV line and near-term category P1 overloads seen in the Salinas- Firestone #2 60 kV line. These overloads can be mitigated by the previously approved Salinas- Firestone #1 and #2 reconductor project.

There were P2 overloads identified for the near-term in the San Luis Obispo and Sisquoc areas. These overloads will be mitigated by South of Mesa upgrades. There are near-term P7 overloads on the Crazy Horse-Soledad 115 kV line and Crazy Horse-Natividad #1 115 kV line. RAS was recommended for these overloads in the 2018-2019 transmission planning process.

In the Green Valley-Watsonville 60 kV line and Watsonville-Salinas 60 kV line, there were several P5 overloads that will be mitigated by installing redundant bus protection relay. Under categories P6 and P7 contingencies, there were several overloads on the Green Valley-Watsonville 60 kV line and Watsonville-Salinas 60 kV line that can be mitigated by previously approved Morgan Hill Area reinforcement project.

Summary of review of previously approved projects

There is one previously approved active project in the Central Coast/Los Padres area not modeled in the study cases, as it was placed on hold in a previous planning cycle; the ISO can put projects on hold when necessary to consider emerging constructability issues, cost increases or potential misalignment of scope of the project and nature of the current need. The final recommendation for the project not modeled in the study cases is shown in Table 2.5-26.

Table 2.5-26: Recommendation for previously approved projects not modeled in the study cases

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

North of Mesa Upgrades (Previously Midway-Andrew) Project

The previously approved Midway-Andrew 230 kV project was approved in the 2012-2013 transmission planning process. The Midway-Andrew 230 kV project was not modelled in the base case due to the fact that it was split into two separate projects in the 2018-2019 transmission planning process; the North of Mesa Upgrades and the South of Mesa Upgrades. The South of Mesa Upgrades were approved in the 2018-2019 transmission planning process; it was recommended that the North of Mesa upgrades remain on hold so further study assessments could be performed. In the 2020-2021 transmission planning process, the ISO recommended procuring 50 MW 4-hour battery storage at the Mesa 115 kV substation to address maintenance window and utilizing existing Mesa, Divide and Santa Maria UVLS for peak load conditions, instead of proceeding with the North of Mesa upgrade. The ISO also recommended for the North of Mesa upgrade project to remain on hold pending procurement of the battery storage. The ISO recommends to keep the North of Mesa upgrade on hold in this transmission planning cycle as well pending procurement of the battery storage.

2.5.8.4 Request Window Submissions

There were no request window submissions for the Central Coast and Los Padres Area.

2.5.8.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.8.2, about 13 MW of AAEE reduced the Central Coast and Los Padres Area net load by 1% in 2023. Furthermore, about 23 MW of demand response and 488 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, they did not completely alleviate the overloads.

2.5.8.6 Recommendation

Based on the studies performed for the 2021-2022 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 and P7 contingency conditions. These reliability concerns are addressed by previously approved projects within the Central Coast and Los Padres Area.

2.5.9 PG&E System High Voltage Assessment

2.5.9.1 Background and Objective

The objective of the high-voltage assessment in PG&E system in this planning cycle is to identify the high-voltage issues that are not addressed by the already approved projects or by adjusting the existing system. System upgrades are then recommended to address the high-voltage issues.

2.5.9.2 Study Scenarios

Most of the high-voltage issues across the PG&E system occur in the middle of the day in the spring, when the gross load is relatively low and a significant portion of the load is served by the behind-the-meter PV and other solar generation. As a result, the transmission and distribution lines are lightly loaded, which results in high voltage across the system. Four spring off-peak cases were considered in the 2021-2022 transmission planning process and were used for the PG&E high voltage assessment. Table 2.5-28 provides details of the four base cases.

Table 2.5-27: Study Scenarios for High Voltage Assessment

Study Scenario in 2021-2022 TPP	Date/time	Load Power Factor
2023 Spring off Peak	4/26 HE 20	Historical
2026 Spring off Peak	4/7 HE 13	Historical
2031 Spring off Peak	4/6 HE 13	Tariff limits
2026 Spring off Peak with High Renewables	This is a sensitivity to 2026 spring off peak case with higher BTM-PV, solar, and wind generation.	

2.5.9.3 Assessment Summary

The details of the high-voltage issues across PG&E system that were identified in each of the four study scenarios are provided in Appendix C. The first step in mitigating the high voltage issues in this study was to adjust the existing system by changing the settings of the transformer taps, switching the existing shunts on or off, and changing the scheduled voltage of the generators. The feasibility of the system adjustments as well as historical data of high-voltage issues across PG&E system were discussed with real time operations team. Further assessments indicated that the high-voltage issues at Table Mountain/Palermo 230 kV, Atlantic 60 kV, and Exchequer 115 kV areas would have higher priority to be mitigated and require system enhancements as they cannot be addressed by adjustments to the existing system:

- Table Mountain/Palermo 230 kV Area

In real-time operations, there are currently high-voltage issues at the Table Mountain/Palermo 230 kV area at the time that the existing Table Mountain 500/230 kV transformer is taken out of service for maintenance, which is around the October/November timeframe. With Rio Oso SVC going into service, the high-voltage issue goes from P0 under maintenance to P1 under maintenance. The ISO recommendation is to add a second 500/230 kV transformer at Table Mountain. PG&E has provided a cost estimate of $38.4M - $76.8M for the project, with an expected in service date of 2027.

- Atlantic 60 kV Area

The Atlantic 230/60 kV transformer that supplies the area does not have LTC and there is no voltage regulator to control the 60 kV voltage. As a result, there are high-voltage issues under light load conditions. The ISO recommendation is to add a voltage regulator at the substation to control the voltage on the 60 kV system. PG&E has provided cost estimate of $5M - $10M for the project, with an expected in service date of 2026.

- Exchequer 115 kV Area

The Exchequer 115 kV substation is radially connected to the rest of the system through a long 115 kV line. As a result, high voltages have been observed in real time under light load conditions. The ISO recommendation is to add 2 x 20 Mvar shunt reactors at the Exchequer 115 kV substation. PG&E is in the process of finalizing the implementation plan for a maintenance project on Exchequer 115 kV substation. A project to add 2 x 20 Mvar shunt reactor will be recommended for approval after PG&E’s plan for the maintenance project is finalized.

2.5.9.4 Recommendations and Next Steps

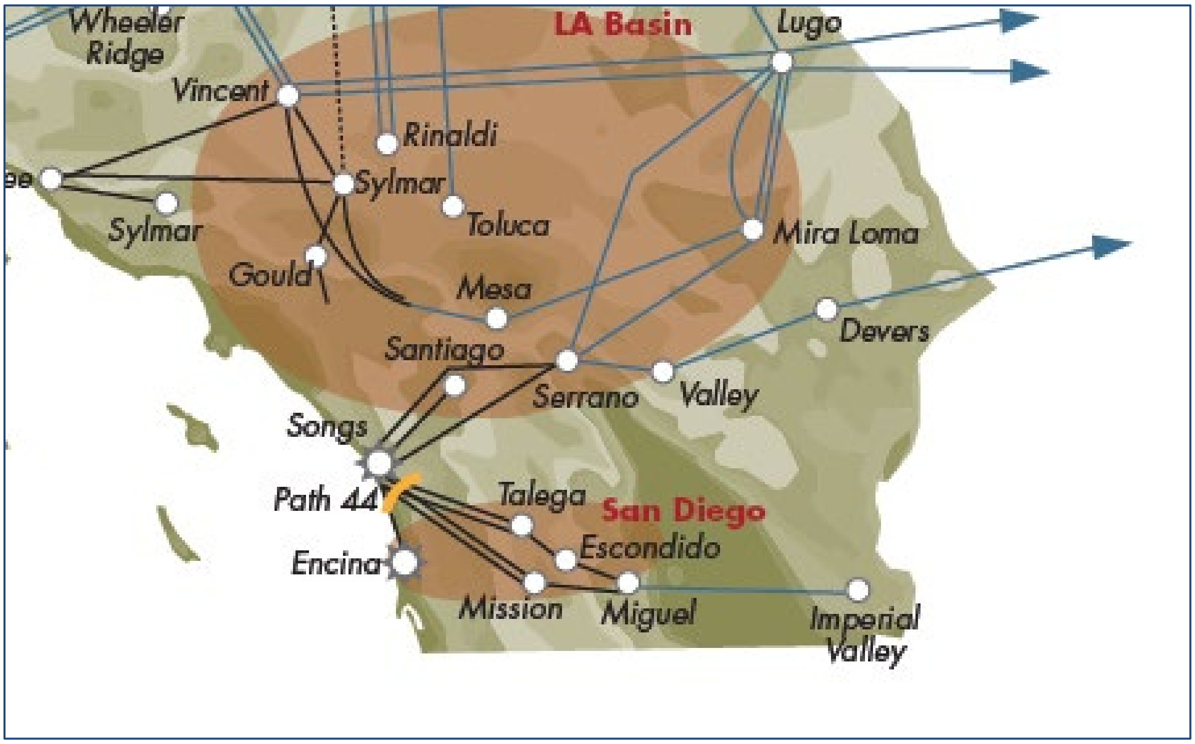
The ISO recommendation is to approve the projects to add the second 500/230 kV transformer at Table Mountain substation, and a voltage regulator at Atlantic 60 kV substation. With these additions to the system, some of the voltage issues with higher priority from real-time operations standpoint will be addressed. Further required system enhancements to address remaining high voltage issues will be recommended for approval in future transmission planning cycles.

2.6 Southern California Bulk Transmission System Assessment

2.6.1 Area Description

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

Figure 2.6-1: Southern California Bulk Transmission System



SCE serves about 15 million people in a 50,000 square mile area of central, coastal and southern California, excluding the City of Los Angeles[105] and certain other cities[106]. 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 56 MW[107] on the average per year with considering the projection for mid additional achievable energy efficiency (AAEE) and additional achievable PV (AAPV). 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

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

[106] 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.

[107] Based on the CEC-adopted California Energy Demand Forecast 2023-2031 (Form 1.5c) – Mid Demand Baseline Case, No AAEE or AAPV Savings, January 2020 version

Water Resources and Metropolitan Water District of southern California pump loads. The 2031 summer peak 1-in-5 forecast sales load, including system losses, is 24,635 MW[108]. 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 3.6 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[109] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2031 summer peak 1-in-5 forecast load for the SDG&E area including Mid-AAEE and system losses is 4,601 MW. Most of the SDG&E area load is served by generation that includes a diverse mix of renewables, qualifying facilities, pumped storage, and gas-fired power plants. The remaining demand is served by power transfers into San Diego via points of imports discussed above.

Electric grid reliability in southern California has been challenged by the retirement of the San Onofre Nuclear Generating Station and the expected retirement of power plants using ocean or estuarine water for cooling due to OTC regulations. In total, approximately 10,760 MW of generation (8,514 MW gas-fired generation and 2,246 MW San Onofre nuclear generation) in the region has been affected. A total of 5,931 MW of OTC-related electric generation has been retired since 2010. The remaining 4,829 MW of OTC-related gas-fired generation is scheduled to retire in the near term, to comply with the State Water Resources Control Board's Policy on OTC Plants. Some are scheduled to be replaced, such as Alamitos and Huntington Beach, albeit with lower capacity, through the CPUC long-term procurement plan for the local capacity requirement areas in the LA Basin and San Diego. Additionally, consistent with 2020-2021 Transmission Plan, the ISO has also taken into account the potential retirement of 1,328 MW of aging non-OTC and mothballed generation in the area[110].

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.[111] In May 2015, the CPUC issued Decision D.15-05-

108 Based on the CEC-adopted California Energy Demand Forecast 2020-2031 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE and AAPV Savings, January 2020 version

109 The SONGS was officially retired on June 7, 2013.

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

111 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).

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[112]. The Decision also required the residual 100 MW of requested capacity to consist of preferred resources or energy storage. In November 2015, the CPUC issued Decision D.15-11-041 to approve, in part, results of SCE's Local Capacity Requirements Request for Offers for the Western LA Basin. The Decision permitted SCE to enter into a PPTA for a total of 1812.6 MW of local capacity that includes 124.04 MW of energy efficiency, 5 MW of demand response, 37.92 MW of behind-the-meter solar photovoltaic generation, 263.64 MW of energy storage, and 1382 MW of conventional (gas-fired) generation. In this analysis, the ISO considered the authorized levels of procurement and then focused on the results thus far in the utility procurement process – which, in certain cases, is less than the authorized procurement levels.

As set out below, preferred resources and storage are expected to play an important role in addressing the area's needs. As the term "preferred resources" encompasses a range of measures with different characteristics, they have been considered differently. Demand side resources such as energy efficiency programs are accounted for as adjustments to loads, and supply side resources such as demand response are considered as separate mitigations. Further, there is a higher degree of uncertainty as to the quantity, location and characteristics of these preferred resources, given the unprecedented levels being sought and the expectation that increased funding over time will result in somewhat diminishing returns. While the ISO's analysis focused primarily on the basic assumptions set out below in section 2.6.2, the ISO has conducted and will continue to conduct additional studies as needed on different resource mixes submitted by the utilities in the course of their procurement processes.

The ISO has approved the following major transmission projects in the bulk system in prior planning cycles:

- Harry Allen - Eldorado 500 kV Line (completed August 2021)
- Mesa 500 kV Substation (March 2022)
- Delaney-Colorado River 500 kV Line (June 2023)
- Lugo – Victorville 500 kV Upgrade (June 2023)
- Alberhill 500 kV Substation (October 2025)

2.6.2 Area-Specific Assumptions and System Conditions

The Southern California bulk transmission system steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers and generation dispatch assumptions for the various scenarios used for the Southern California bulk transmission system assessment are provided in Table 2.6-1 and Table 2.6-2.

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

Table 2.6-1: Southern California Bulk System Demand Side Assumptions

Study Case	Description	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Pump Load (MW)	Demand Response (MW)	
				Installed Capacity	Output			D1 (fast)	D2 (slow)
B1-2023-SP	2023 summer peak load condition at HE16 PST, 9/5	30159	338	6853	2493	27666	493	411	407
B2-2026-SP	2026 summer peak load condition at HE16 PST, 9/1	28039	836	8656	0	28039	493	411	407
B3-2031-SP	2031 summer peak load condition at HE19 PST, 9/3	28604	886	11087	0	28604	544	411	407
B4-2023-OP	2023 spring off-peak load condition at HE20 PST, 4/26	18799	220	6853	0	18799	1111	NA	NA
B5-2026-LL	2026 spring off-peak/minimal load condition at HE13 PST, 4/5	13194	192	8656	6997	6196	1079	NA	NA
B6-2026-LL	2031 spring off-peak/minimal load condition at HE13:00 PST, 4/6	13575	151	11087	9002	4573	0	NA	NA
S1-2026-SP-HLOAD	2026 summer peak load condition with high CEC load forecast	30309	836	8656	0	30309	493	411	407
S2-2023-SP-HRPS	2023 summer peak load condition with heavy renewable output	30159	338	6853	2493	27666	493	411	407
S3-2023-OP-HRPS	2023 spring off-peak load condition with heavy renewable output	18799	220	6853	0	18799	1111	NA	NA

Table 2.6-2: Southern California Bulk System Supply Side Assumptions

Study Case	Description	Thermal (MW)		Hydro (MW)		Solar (MW)		Wind (MW)		Energy Storage (MW)	
		Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch
B1-2023-SP	2023 summer peak load condition at HE16 PST, 9/5	26100	8615	1596	1068	14572	7435	5212	1002	5987	0
B2-2026-SP	2026 summer peak load condition at HE16 PST, 9/1	26105	12813	1600	1059	14650	0	5195	1969	6181	3219
B3-2031-SP	2031 summer peak load condition at HE19 PST, 9/3	26108	11576	1614	1283	21166	0	7027	2707	13710	2143
B4-2023-OP	2023 spring off-peak load condition at HE20 PST, 4/26	26130	9562	1596	1068	14570	106	5107	2457	6004	40
B5-2026-LL	2026 spring off-peak/minimal load condition at HE13 PST, 4/5	26110	157	1596	112	14628	13664	4935	1610	6065	-5516
B6-2031-LL	2031 spring off-peak/minimal load condition at HE13:00 PST, 4/6	26385	488	1600	14	21060	19034	6875	2072	13588	-11457
S1-2026-SP-HLOAD	2026 summer peak load condition with high CEC load forecast	26105	13033	1600	1059	14650	0	5195	1951	6181	3820
S2-2023-SP-HRPS	2023 summer peak load condition with heavy renewable output	26100	4413	1596	1068	14586	13811	5212	3185	5987	104
S3-2023-OP-HRPS	2023 spring off-peak load condition with heavy renewable output	26100	426	1596	1068	14584	14148	5107	3185	6004	-3850

Transmission Assumptions

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

2.6.2.1 Path Flow Assumptions

The transfers modeled on major paths in the southern California assessment are shown in Table 2.6-3.

Table 2.6-3: Path Flow Assumptions

Path	SOL/Transfer Capability (MW)	B1-2023 SP (MW)	B2-2026 SP (MW)	B3-2031 SP (MW)	B4-2023 OP MW)	B5-2026 OP (MW)	B6-2031 OP (MW)	S1-2026 SP w/High CEC Load (MW)	S2-2023 SP Heavy Ren. (MW)	S3-2023 OP Heavy Ren. (MW)
Path 26 (N-S)	4,000	3,848	2,210	2,128	887	567	3,392	2,200	2,375	291
PDCI (N-S)	3,220	3,220	2,712	3,200	2,712	-1,048	-997	2,712	3,220	2,712
SCIT	17,870	13,523	9,803	12,266	10,512	1,123	3,258	10,166	11,288	10,002
Path 46 (WOR)(E-W)	11,200	4,560	4,698	3,863	4823	14	-1,557	5,060	3,695	5405
Path 49 (EOR)(E-W)	10,100	1,299	1,772	1,447	979	-3199	-5,722	2,027	469	2,163

2.6.3 Assessment Summary

The ISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 and identified the following steady state issues in the base and/or sensitivity cases under the contingency conditions indicated. Details of the planning assessment results are presented in Appendix C.

- The Midway – Vincent #1 and #2, and Midway – Whirlwind #3 500 kV lines overloaded for P6 contingencies. Operational mitigation and congestion management mitigate the overloads
- The Antelope – Whirlwind and Antelope – Vincent 500 kV lines overloaded for Category P1, P2, P4, and P6 contingencies. The planned Tehachapi cRAS and operational mitigation action curtailing generation in the Tehachapi area mitigated the overloads.
- The Lugo – Vincent 500 kV lines overloaded following a Category P6 contingency. Operational action curtailing generation in the Tehachapi area addresses the overload concerns
- The Devers – Red Bluff 500 kV line #1 or #2 overloaded following Category P3 and P6 contingencies. The Colorado River Corridor RAS was adequate to eliminate the overload.

The overload concerns identified above can be mitigated in the operations horizon without relying on non-consequential load loss by using operational mitigations along with RAS, as further discussed in Appendix B.

2.6.4 Request Window Project Submissions

There is no request window submittal received in the current planning cycle for the southern California bulk system.

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 886 MW of additional energy efficiency (AAEE), and up to 11,087 MW of distributed generation were used to avoid potential reliability issues by reducing area load
- The existing and planned fast-response demand response amounting to 411 MW and energy storage amounting to 13,710 MW were used to mitigate any Category P1, P3, P6, or P7 related thermal overloads
- Since no reliability issues that require mitigation were identified, additional 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. Planned resources and operating solutions, such as re-dispatching resources or reconfiguring the system before or after the contingency conditions as described in more detail in Appendix B, address the identified reliability concerns.

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:

500/230 kV transformers at Windhub and Whirlwind substations that deliver renewable generation onto the 500 kV lines between PG&E's Midway substation and SCE's Vincent substation;

230 kV transmission system between Vincent and Big Creek Hydroelectric project that serves customers in Tulare county; and

Antelope-Bailey 66 kV system which serves the Antelope Valley, Gorman, and Tehachapi Pass areas.

The Tehachapi and Big Creek Corridor area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 2,213 MW in 2031 including the impact of 686 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 32 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 (completed).

2.7.1.2 Area-Specific Assumptions and System Conditions

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

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

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 below 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.

Table 2.7-1 Tehachapi and Big Creek Areas demand-side assumptions

Scenario No.	Base Case	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response (installed)	
				Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)
B1	2023 Summer Peak	2559	16	469	216	2328	59	13
B2	2026 Summer Peak	1102	32	185	98	972	59	13
B3	2031 Summer Peak	2245	32	686	0	2213	59	13
B4	2023 Off Peak	2120	16	469	0	2104	59	13
B5	2026 Off Peak	1650	32	469	448	1170	59	13
S1	2026 Peak High CEC Load	2802	32	469	261	2509	59	13
S2	2023 Peak Heavy Renewable Output & Min. Gas Gen.	2559	16	469	216	2328	59	13
S3	2023 Off Peak Heavy Renewable Output & Min. Gas Gen.	2120	16	469	0	2104	59	13

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

Supply-Side Assumptions

The table below 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.

Table 2.7-2 Tehachapi and Big Creek Areas supply-side assumptions

Scenario No.	Base Case	Battery Storage (Installed) (MW)	Solar (Grid Connected)		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2023 Summer Peak	901	1247	636	0	0	962	773	1607	1452
B2	2026 Summer Peak	1021	1680	858	0	0	980	780	1614	1564
B3	2031 Summer Peak	1021	1668	0	0	0	980	913	1614	1564
B4	2023 Off Peak	901	1247	0	0	0	962	773	1607	1564
B5	2026 Off Peak	1021	1257	1177	0	0	962	773	1614	1534
S1	2026 Peak High CEC Load	1021	1680	858	0	0	980	780	1614	1564
S2	2023 Peak Heavy Renewable Output & Min. Gas Gen.	901	1682	1235	0	0	980	773	1607	1452
S3	2023 Off Peak Heavy Renewable Output & Min. Gas Gen.	901	1682	1666	0	0	980	782	1607	1564
Note: DR and storage are modeled offline in starting base cases.										

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 Tehachapi and Big Creek Areas assessment identified the following steady state and transient stability issues in the base and/or sensitivity cases under the contingency conditions indicated.

- The Whirlwind 500/230 kV transformers were overloaded following an overlapping outage of two of the three transformers in the 2026 spring off-peak and 2023 and 2026 summer peak cases. The existing Whirlwind RAS mitigates the overloads by tripping generation connected to the substation

- The Neenach-Bailey/Westpack Tap 66 kV line was overloaded with all transmission facilities in-service (P0 event)
- The Big Creek 2–Big Creek 3 230 kV line was overloaded following an overlapping outage of Big Creek 1–Rector & Big Creek 8–Big Creek 3 or Big Creek 8–Big Creek 2 230 kV lines in all three summer peak cases and the 2023 spring off-peak case
- The Antelope 230/66 kV transformers were overloaded following an overlapping outage of two of the three transformers in all three summer peak cases and the 2023 spring off-peak case
- Voltage collapse in the Antelope–Bailey 66 kV system in the 2031 summer peak and the 2023 spring off-peak cases under P6 conditions
- Loss of synchronism of Big Creek Hydro generators in the 2026 summer peak and 2023 spring Off-Peak cases under P6 conditions
- Local instability in the Antelope–Bailey 66 kV system in the 2031 summer peak case under P6 conditions
- Based on SCE information submitted in response to the September 28, 2021 stakeholder meeting, the Antelope 66 kV breakers are currently operating at 96% of their 40 kA short circuit duty rating, and with the resource assumptions in this 2021-2022 transmission planning process analysis these breakers would be overstressed.

The steady state and transient stability issues identified above can be mitigated in the operations horizon without relying on non-consequential load loss by using existing RAS or such operational measures as re-dispatching resources, reconfiguring the system or utilizing available spares as further discussed in Appendix B. As a result, no further corrective action was considered.

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. However, SCE's comments submitted in response to the September 28, 2021 stakeholder meeting included a project to upgrade the Antelope 66 kV breakers to address their overstressed condition described above.

This project proposes to upgrade the existing Antelope 66 kV switchrack to a 50 kA short circuit duty rating by replacing (41) 66 kV circuit breakers, (101) 66 kV ground disconnect switches, (45) 66 kV potential transformers, performing a ground grid study, and removing (15) steel lattice structures and installing (15) new dead-end structures. The existing circuit breakers are currently operating at 96% of their 40 kA short circuit duty rating and our preliminary analyses show that adding the CPUC portfolio generation at the Antelope Substation 230 kV bus alone will trigger the need for circuit breaker replacement. The large number of circuit breakers and resultant need for outage coordination result in this upgrade being estimated at 45 months, which is longer than the time for interconnection facilities in many cases and would therefore represent the critical path upgrade to installation of new generation in the Tehachapi area. The estimated cost for this project is $55M, and the proposed in-service date is 1/1/2026.

The ISO has found that this project is needed.

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 32 MW of additional energy efficiency (AAEE), and up to 686 MW of distributed generation were used to avoid potential reliability issues by reducing area load
- The Tehachapi and Big Creek Corridor Area reliability assessment did not identify need for additional preferred resources and storage resources in the area

2.7.1.6 Recommendation

The SCE Tehachapi and Big Creek Corridor area assessment identified several steady state and transient stability related issues. Existing RAS and operating solutions such as re-dispatching resources, reconfiguring the system or utilizing available spares as described in more detail in Appendix B can be utilized to address the issues identified. As a result, no further corrective action was considered.

The ISO recommends approval of the Antelope 66 kV switchrack upgrade.

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 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 North of Lugo area study are provided in Table 2.7-3 and Table 2.7-4.

Table 2.7-3 North of Lugo Area Demand Side Assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV MW)		Net Load (MW)	Demand Response (Installed)	
				Installed	Output		Fast (MW)	Slow (MW)
B1	2023 Summer Peak	1206	12	985	453	741	76	4
B2	2026 Summer Peak	1385	27	1337	615	743	76	4
B3	2031 Summer Peak	796	30	1883	0	766	76	33
B4	2023 Spring Light Load	478	8	985	0	470	N/A	N/A
B5	2026 Spring Off-peak	1233	6	1337	1056	171	N/A	N/A
B6	2031 Spring Off-peak	1651	5	1883	1506	140	N/A	N/A
S1	2026SP High CEC Load	1382	27	1337	615	740	76	4
S2	2023 SP Heavy Renewable Output & Min. Gas Gen	1206	12	985	453	741	N/A	N/A
S3	2023 SOP Heavy Renewable Output & Min. Gas Gen.	478	8	985	0	470	N/A	N/A

Table 2.7-4 North of Lugo Area Supply Side Assumptions

Scenario No.	Case	Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2023 Summer Peak	467	1441	735	0	0	74	23	1206	1107
B2	2026 Summer Peak	467	1441	735	0	0	74	23	1361	1255
B3	2031 Summer Peak	594	1741	0	0	0	74	54	1361	1022
B4	2023 Spring Light Load	467	1441	0	0	0	74	23	1206	1115
B5	2026 Spring Off-peak	467	1441	1355	0	0	74	23	1361	615
B6	2031 Spring Off-peak	594	1741	1637	0	0	74	2.3	1361	556
S1	2026SP High CEC Load	467	1441	735	0	0	74	0	1361	1109
S2	2023 SP Heavy Renewable Output & Min. Gas Gen	467	1441	1427	0	0	74	23	1206	470
S3	2023 SOP Heavy Renewable Output & Min. Gas Gen.	467	1441	1427	0	0	74	23	1206	500

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.

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 2021-2022 reliability assessment of the North of Lugo area has identified thermal overload and high/low voltages issues under Category P6 contingencies. There was one Category P6 overload observed in the 2031 summer peak scenario only. For that overload, we would monitor the load growth in the area and rely on the spare equipment when needed. The rest of those issues can be mitigated in the operation horizon by relying upon the existing operating procedure. Appendix B has a detailed discussion.

The transient stability assessment identified a voltage recovery and voltage dip incident following a Category P6 contingency. The ISO recommends relying on existing RAS, and re-dispatching generation after the first contingency.

2.7.2.4 Request Window Project Submissions

The ISO received one project submittal through the 2021 request window submission for the SCE North of Lugo Area. Below is a description of the proposal followed by ISO comments and findings.

Victor 230 kV Switchrack Reconfiguration

The project was submitted by SCE as a reliability transmission project. The project scope includes converting two double breaker double bus (DBDB) positions at the Victor 230 kV switchrack to breaker-and-a-half (BAAH) configuration by adding a tie breaker and relocating 2 lines. The project would mitigate voltage instability risk during planned/unplanned Victor 230 kV bus outage and associated constraints. It would provide operational flexibility and enhance reliability. The preliminary cost estimate is $5 million. The proposed in-service date of the project is 12/31/2023. The ISO has identified the proposed reliability project as needed.

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 additional achievable energy efficiency (AAEE), and distributed generation were used to avoid potential reliability issues by reducing area load
- The existing and planned fast-response demand response amounting to 76 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 overload and high-voltage issues. Operating solutions, including relying upon existing operating procedures, existing RAS, and congestion management are recommended to address those.

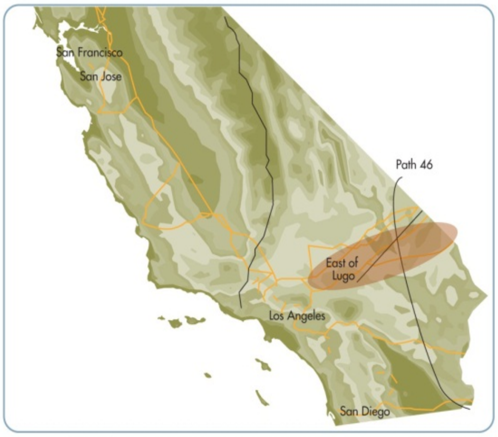
The assessment also identified one WECC transient criteria incident for a category P6 contingency with existing HDPP and Mohave Desert RAS schemes. The ISO recommends relying on generation re-dispatch after the first contingency along with the RAS.

The ISO recommends approval of the Victor 230 kV Switchrack Reconfiguration.

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 Harry Allen-Eldorado 500 kV line went in-service in July 2020 and is now 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, including the new Harry Allen-Eldorado line.

2.7.3.2 Area-Specific Assumptions and System Conditions

The East of Lugo area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the East of Lugo area study are provided in Table 2.7-5 and Table 2.7-6.

Table 2.7-5 East of Lugo Area Demand Side Assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV MW)		Net Load (MW)	Demand Response (Installed)	
				Installed	Output		Fast (MW)	Slow (MW)
B1	2023 Summer Peak	38	0	0	0	38	0	0
B2	2026 Summer Peak	27	0	2	1	26	0	0
B3	2031 Summer Peak	31	0	4	0	31	0	0
B4	2023 Spring Light Load	26	0	0	0	26	0	0
B5	2026 Spring Off-peak	2	0	2	1	1	0	0
B6	2031 Spring Off-peak	16	0	4	3	13	0	0
S1	2026SP High CEC Load	27	0	2	1	26	0	0
S2	2023 SP Heavy Renewable Output & Min. Gas Gen	38	0	0	0	38	0	0
S3	2023 SOP Heavy Renewable Output & Min. Gas Gen.	26	0	0	0	26	0	0

Table 2.7-6 East of Lugo Area Supply Side Assumptions

Scenario No.	Case	Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2023 Summer Peak	0	1261	643	0	0	0	0	525	419
B2	2026 Summer Peak	0	1461	745	0	0	0	0	525	419
B3	2031 Summer Peak	501	2434	0	1062	425	0	0	525	419
B4	2023 Spring Light Load	0	1261	0	0	0	0	0	525	419
B5	2026 Spring Off-peak	0	1461	1373	0	0	0	0	525	0
B6	2031 Spring Off-peak	501	2434	2288	1062	361	0	0	525	0
S1	2026SP High CEC Load	0	1461	745	0	0	0	0	525	419
S2	2023 SP Heavy Renewable Output & Min. Gas Gen	0	1261	1248	0	0	0	0	525	0
S3	2023 SOP Heavy Renewable Output & Min. Gas Gen.	0	1261	1248	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 2022 study cases are:

- Harry Allen-Eldorado 500 kV transmission line (in-service)
- Eldorado-Lugo 500 kV series capacitor and terminal equipment upgrade
- Lugo-Mohave 500 kV series capacitor and terminal equipment upgrade
- New Calcite 230 kV Substation and loop into Lugo-Pisgah #1 230 kV line
- Lugo-Victorville 500 kV terminal equipment upgrade and remove ground clearance limitations

2.7.3.3 Assessment Summary

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

The SCE East of Lugo area steady state assessment identified one Category P3 overload issue in 2031 spring off-peak case. Generation re-dispatch after the first contingency would mitigate the overload. The stability analysis performed in the EOL Area assessment did not identify transient issues that require mitigation.

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

2.7.3.4 Request Window Project Submissions

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

2.7.3.5 Consideration of Preferred Resources and Energy Storage

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

2.7.3.6 Recommendation

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

2.7.4 SCE Eastern Area

2.7.4.1 Area Description

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

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

- West of Devers Upgrade Project (in-service 2021)
- Ten West Link 500 kV line Project (2023).
- Riverside Transmission Reliability Project (2026)
  - Alberhill 500 kV Substation Project (2026)

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. Specific assumptions related to study scenarios, load, resources and transmission that were applied to the Eastern area study are shown in Table 2.7-7 and Table 2.7-8.

Table 2.7-7 Eastern Area load and load modifier assumptions

S. No.	Base Case	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
				Installed (MW)	Output (MW)		Fast	Slow
B1	2023 Summer Peak	5507	58	1058	487	4962	57	18
B2	2026 Summer Peak	5700	117	1058	612	4971	57	18
B3	2031 Summer Peak	5197	114	1718	0	5083	57	18
B4	2023 Off Peak	3114	58	1058	0	3057	57	18
B5	2026 Off Peak	2218	117	1058	1051	1050	57	18
S1	2026 Peak High CEC Load	6136	117	1058	612	5407	57	18
S2	2023 Peak Heavy Renewable Output & Min. Gas Gen.	5494	58	1058	487	4949	57	18
S3	2023 Off Peak Heavy Renewable Output & Min. Gas Gen.	3408	58	1058	0	3351	57	18

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

Table 2.7-8 Eastern Area generation assumptions

S. No.	Base Case	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2023 Summer Peak	1161	3488	1779	880	176	311	201	3032	2801
B2	2026 Summer Peak	1161	3488	1779	880	176	311	201	3032	2871
B3	2031 Summer Peak	1262	3488	0	880	352	311	311	3032	2871
B4	2023 Off Peak	1161	3488	0	880	422	311	201	3032	2871
B5	2026 Off Peak	1161	3488	3278	880	299	311	201	3032	2871
S1	2026 Peak High CEC Load	1161	3488	1779	880	176	311	201	3032	2871
S2	2023 Peak Heavy Renewable Output & Min. Gas Gen.	1161	3488	3453	860	577	311	201	3032	2815
S3	2023 Off Peak Heavy Renewable Output & Min. Gas Gen.	1161	3488	3453	880	590	311	201	3032	2871

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

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 a few contingencies that caused thermal overloads, overvoltage and under-voltage issues, but those can be mitigated with existing Remedial Action Schemes, system adjustments, and reactive device switching.

Also, the SCE Eastern area stability analysis identified a few contingencies that caused transient issues, but those can be mitigated with existing Remedial Action Schemes.

2.7.4.4 Request Window Project Submissions

The ISO received a request for a project at the SCE Eastern Area in this planning cycle.

Devers 230 kV Reconfiguration Project

This project would be located at the Devers substation, and the proposed scope involves the following milestones:

- Create positions 1XS and 7S at the 230 kV Bus (breaker-and-a-half configuration)
- Moving the *Devers - Mirage No. 2* line from position 1S to position 1XS
- Moving the *Devers - Vista No. 2* line from position 8S to position 7S

The estimated cost is $6M and the proposed in-service date is December 31st 2023. Upon completion, this project will increase reliability and operational flexibility.

More specifically, with one of the two 230 kV buses at the Devers substation de-energized for maintenance purposes; a fault on the second bus would result in a system voltage collapse. During this event, with the current bus configuration, the *Devers - Mirage No. 2* and *Devers - Vista No. 2* lines would be disconnected, from the Devers substation. This would result in voltage collapse for that area; and isolation of the IID and MWD systems from the SCE system. With the proposed bus configuration, during the same event described above, the *Devers - Mirage No. 2* line would stay connected to the system through the Devers 1AA Bank; while the *Devers - Vista No. 2* line would serve the 4A Bank, and a system voltage collapse would be avoided. As a result, the ISO finds that this minor system reconfiguration is needed to increase reliability and operational flexibility.

2.7.4.5 Consideration of Preferred Resources and Energy Storage

No additional grid-connected preferred resources or storage were 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 some thermal overload, voltage, and stability issues. Remedial Action Schemes, reactive device switching, and operating solutions; including curtailing generation after the first contingency are recommended to address the issues.

A minor system reconfiguration was found to be needed to avoid a system voltage collapse following loss of the remaining Devers 230 kV bus during a planned outage of the other Devers 230 kV bus.

2.7.5 SCE Metro Area

2.7.5.1 Area Description

The SCE main system consists of the SCE Metro area and its 500 kV bulk system that serve major metropolitan areas in the Los Angeles, Orange, Ventura counties and surrounding areas. 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 SCE main transmission system to serve electricity customers. The SCE main system has a forecasted 1-in-10 net load of 25,586 MW in 2031 including the 544 MW of pumping load and the impact of 459 MW of additional achievable energy efficiency (AAEE).

The SCE main system will have approximately 62,376 MW of grid-connected generation resources in 2031 after the retirement of 4,153 MW of generation in total to comply with the state's policy regarding once-through-cooling (OTC) generation. The California Public Utilities Commission (CPUC) has approved a total of 2,019 MW of conventional generation, preferred resources and energy storage 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 the area in prior planning cycles:

- Mesa 500 kV Substation (March 2022)
- Laguna Bell Corridor Upgrade (December 2020)
- Moorpark-Pardee No. 4 230 kV Circuit Project (June 2021)
- Pardee-Sylmar No. 1 and No. 2 230 kV Lines Rating Increase Project (June 2023).

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 SCE main and the Southern California bulk base cases, stability model data, and contingencies that were used in this assessment. In addition, specific demand and supply-side assumptions for the various scenarios used for the SCE Main system assessment are provided in Table 2.7-9 and Table 2.7-10, respectively.

Table 2.7-9: SCE main system demand side assumptions

Study Case	Scenario	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Pump Load (MW)	Demand Response*	
				Installed Capacity	Output			D1 (fast)	D2 (slow)
B1-2023-SP	Baseline	26607	207	4929	2267	24340	493	410	373
B2-2026-SP	Baseline	27380	502	6390	2939	24441	493	410	373
B3-2031-SP	Baseline	25042	459	8420	0	25042	544	410	373
B4-2023-OP	Baseline	15821	134	4929	0	15821	1111	NA	NA
B5-2026-LL	Baseline	10670	115	6390	5048	5621	1079	NA	NA
S1-2026-SP-HLOAD	Sensitivity	29288	502	6390	2939	26349	493	410	373
S2-2023-SP-HRPS	Sensitivity	28825	207	4929	4485	24340	493	410	373
S3-2023-OP-HRPS	Sensitivity	20306	134	4929	4485	15821	1111	NA	NA

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

Table 2.7-10: SCE main system supply-side assumptions

Study Case	Scenario	Thermal (MW)		Hydro (MW)		Solar (MW)		Wind (MW)		Energy Storage (MW)	
		Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch
B1-2023-SP	Baseline	22388	8401	1596	1068	12946	6605	4484	856	5603	104
B2-2026-SP	Baseline	22437	8326	1596	1071	13175	6712	4420	843	5787	0
B3-2031-SP	Baseline	22437	9832	1596	1327	19142	14	5757	2247	12151	2659
B4-2023-OP	Baseline	22388	6878	1596	1068	12946	0	4484	2054	5603	0
B5-2026-LL	Baseline	22437	143	1596	112	13159	12365	4420	1455	5667	-5516
S1-2026-SP-HLOAD	Sensitivity	22437	9384	1596	1071	13175	6702	4420	843	5787	0
S2-2023-SP-HRPS	Sensitivity	22388	4966	1596	1068	12950	12014	4484	2868	5603	104
S3-2023-OP-HRPS	Sensitivity	22388	124	1596	1068	12959	12627	4484	2839	5603	-3373

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 assessment identified the following thermal overloads in the base and/or sensitivity cases under the contingency conditions indicated:

- The Mesa–Laguna Bell #1 230 kV line overloaded for a common-mode outage (P7) and P3/P6 contingencies. The Mesa–Laguna Bell #1 230 kV line overload mitigation identified in the policy-driven need assessment eliminated the overloads

- The Pardee – Warne Tap 230 kV line overloaded for P6 contingency. Operation mitigation reducing generation output from Pastoria Energy Facility after the initial event eliminated the overload
- The Ellis - Santiago 230 kV line overloaded for a couple of P6 contingencies. Operation mitigation dispatching available resources in the San Diego and Imperial Valley area after the initial P1 contingency eliminated the overload
- The Serrano 500/230 kV transformers overloaded following an overlapping outage involving any two of the three transformer banks. Operation mitigation actions including re-dispatching available resources along with energizing the spare single phase transformers after the initial contingency are adequate to mitigate the P6 overload
- Santa Clara – Moorpark 230 kV line #1 or #2 overloaded for the loss of Pardee – Santa Clara and remaining Santa Clara – Moorpark 230 kV line (P6). The overload can be eliminated by dispatching available resources in the Ventura/Santa Barbara area after the first contingency
- The Goleta 230 kV bus voltage dropped as low as 0.86 pu. for a couple of P6 contingencies. The previously approved energy storage projects in the area are adequate to eliminate the low-voltage concern
- SCE and LADWP joint-owned Sylmar banks E and F overloaded in the SCE Main 2031 summer peak and the southern California bulk 2031 spring off-peak cases following Category P2, P4, and P6 contingencies.

The overload concerns identified above, except the Sylmar banks E and F overloads, can be mitigated in the operations horizon, without relying on non-consequential load loss, by operational measures such as re-dispatching resources including preferred resources and energy storage or reconfiguring the system before or after the contingency as further discussed in Appendix B. The ISO will continue to work with SCE and LADWP to develop a corrective action plan addressing the Sylmar banks overloads to meet TPL 001-4 requirements.

2.7.5.4 Request Window Project Submissions

The ISO received three projects submittal through the 2021 request window submission for the SCE Metro area. Below is a description of the proposal followed by ISO comments and findings.

Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project

The project was submitted by SCE and proposes to reconductor the existing Laguna Bell-Mesa No. 1 230 kV line with Aluminum Conductor Composite Core (ACCC) conductor to increase the line rating. Upon completion, the project could address the portfolio resource deliverability issue identified in the policy-driven transmission analysis and also provide reliability and economic benefits. The length of the line to be rewired is approximately five miles. The conceptual estimated cost for the project is $15 million, with a targeted in-service date Q4 2023. After further evaluation, SCE has adjusted the cost to $17.3 million to include necessary upgrades of the Laguna Bell Substation terminal equipment, which were not included in the original estimate. Please see Chapter 3 for the policy-driven transmission need analysis of this project.

Laguna Bell – Mesa Series Compensation Project

The project was submitted by Smart Wires as an alternative to the Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project, which proposes to install a total of 9 SmartValve 10-3600 units at SCE's Mesa Cal 230 kV substation in series with the Laguna Bell – Mesa Cal No. 1 230 kV. The conceptual cost estimated by Smart Wires for the project is $7 ~ 8 million with a targeted in-service date of Q2 2023.

The ISO requested SCE to conduct a feasibility assessment for the Smart Wires' proposal. In response, SCE worked with Smart Wires on the technical requirements/scope, performed the feasibility assessment and estimated the total cost for the series compensation project. Please see Chapter 3 for additional information from this feasibility assessment and the policy-driven transmission need analysis of this project.

New Serrano 4AA 500/230 kV Transformer Bank

The project was submitted by SCE to address the Serrano banks overload for the loss of any two of the three Serrano 500/230 kV banks (P6). The project proposes to install a 4th 500/230 kV 1120 MVA transformer bank at Serrano Substation. The 4th transformer bank would cause the 230 kV switching facility to exceed its short circuit duty rating of 63 kA. As a result, the switching facilities would have to be rebuilt to 80 kA capability. The conceptual estimated cost for this project is $120 million with a targeted in-service date of Q4 2026.

2.7.5.5 Consideration of Preferred Resources and Energy Storage

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

- As indicated earlier, projected amounts of up to 459 MW of additional energy efficiency (AAEE), and up to 8,420 MW of distributed generation were used to avoid potential reliability issues by reducing area load
- Up to 410 MW of the existing and planned fast-response demand response and up to 12,151 MW of existing energy storage were used in the base or sensitivity cases to mitigate thermal overloads and low voltage concerns.

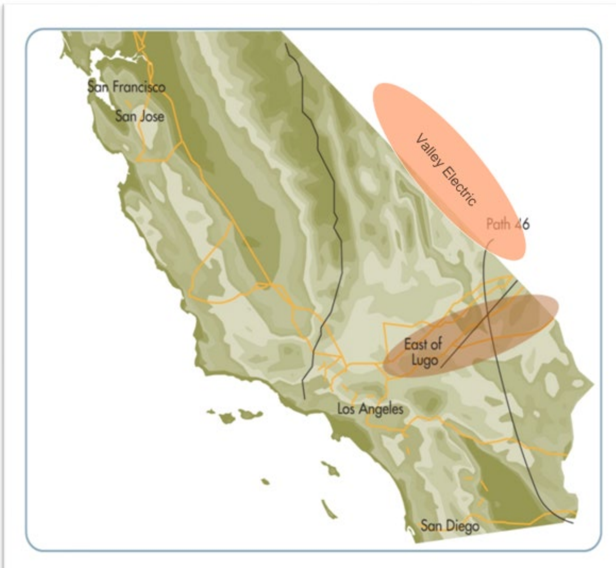
2.7.5.6 Recommendation

The SCE Metro area assessment identified several thermal overloads and low-voltage concerns under contingency conditions. Planned resources and operating solutions, such as re-dispatching resources or reconfiguring the system before or after the contingency condition as described in more detail in Appendix B would address the issues identified. The ISO will continue to work with SCE and LADWP to develop a corrective action plan addressing the Sylmar banks overloads.

2.8 Valley Electric Association Area

2.8.1 Area Description

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



The VEA system is electrically connected to neighboring systems through the following lines:

- Sloan Canyon – Eldorado 230kV tie line with SCE
- Mead – Sloan Canyon 230 kV tie line with WAPA
- Amargosa – Sandy 138 kV tie line with WAPA
- Jackass Flats – Lathrop Switch 138 kV tie line with NV Energy (NVE), and
- Northwest – Desert View 230 kV tie line with NV Energy.

2.8.2 Area-Specific Assumptions and System Conditions

The VEA area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The ISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the VEA area study are provided in Table 2.8-1 and Table 2.8-2.

Table 2.8-1: VEA Area Demand Side Assumptions

Case	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Demand Response (MW)	
			Installed	Output		Fast	Slow
2023 Summer Peak	171	0	0	0	171	0	0
2026 Summer Peak	176	0	0	0	176	0	0
2031 Summer Peak	192	0	0	0	192	0	0
2023 Spring Light Load	112	0	0	0	112	0	0
2026 Spring Off-peak	32	0	0	0	32	0	0
2031 Spring Off-peak	46	0	0	0	46	0	0
2023SP Load Addition	182	0	0	0	182	0	0
2026SP Load Addition	188	0	0	0	188	0	0
2023OP High Renewable	112	0	0	0	112	0	0

Table 2.8-2: VEA Area Supply Side Assumptions

Scenario No.	Case	Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2023 Summer Peak	0	375	60	0	0	0	0	0	0
B2	2026 Summer Peak	0	375	60	0	0	0	0	0	0
B3	2031 Summer Peak	0	2,647	0	0	0	0	0	0	0
B4	2023 Spring Light Load	0	375	0	0	0	0	0	0	0
B5	2026 Spring Off-peak	0	375	111	0	0	0	0	0	0
B6	2031 Spring Off-peak	0	2,647	1,195	0	0	0	0	0	0
S1	2023SP Load Addition	0	375	60	0	0	0	0	0	0
S2	2026SP Load Addition	0	375	60	0	0	0	0	0	0
S3	2023OP High Renewable	0	375	360	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 2023, 2026, and 2031 study cases are:

- New Sloan Canyon (previously named Bob) 230 kV switching station that loops into the existing Pahrump-Mead 230kV Line (in-service)
- New Eldorado-Sloan Canyon 230kV transmission line (in-service)
- Sloan Canyon-Mead 230kV line upgrade (in-service)
- New Gamebird 230/130kV transformer project

2.8.3 Assessment Summary

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

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

The VEA area steady state assessment identified thermal overloads on the WAPA's Amargosa 230/138 kV transformer following Category P6 contingency of loss of Gamebird 230/138 kV transformer and Gamebird – Pahrump 138 kV line. The transformer was overloaded under various base and forecasted load addition sensitivity scenarios. The same contingency also caused low voltages at Charleston, Thousandaire and Sandy 138 kV buses. The existing UVLS would drop load at Charleston and Thousandaire substations and mitigate the low voltages and thermal overload issues.

Amargosa – Sandy 138 kV Overload

The assessment identified thermal overload and potential system divergence on Amargosa – Sandy 138kV line following multiple Category P6 outages involving loss of one of the Pahrump – Innovation – Desert View – Northwest 230 kV lines and one of the Gamebird – Trout Canyon – Sloan Canyon 230 kV lines under 2031 summer peak scenario. The mitigation includes relying on the existing UVLS scheme or installing a second Pahrump – Trout Canyon – Sloan Canyon 230 kV line.

Pahrump Transformer Overloads

The assessment identified thermal overloads on each of the Pahrump 230/138 kV transformer banks following a Category P6 contingency of the other Pahrump transformer and the new Gamebird 230/138 kV transformer under the 2031 summer peak scenario. The mitigation includes relying on the short-term emergency rating of the transformer and performing manual load shedding after the second contingency.

Jackass Flats – Mercury Switch Overloads

The assessment identified thermal overloads on Jackass Flats – Mercury Switch 138 kV line following multiple Category P6 contingencies under the 2031 summer peak and 2026 spring off-peak scenarios. The overload identified under 2031 summer peak scenario was driven by the load growth in the area. The recommendation is to monitor the load growth and reconfigure certain 138 kV transmission lines if needed.

Multiple Normal and Contingency Overloads in 2031 Spring Off-peak Case

Over 2,000 MW RPS base portfolio generation was modeled in the GLW system in the 2031 spring off-peak case and was dispatched to over 1,000 MW. The large amount of RPS base portfolio generation caused normal and contingency overload on multiple 138 kV and 230 kV facilities in the VEA and GLW system. Generation re-dispatch pre-contingency could be utilized to eliminate the normal overloads and some of the contingency overloads. RAS proposed in the GIDAP process would mitigate the remaining contingency overloads. However, to allow for the delivery of the renewable generation in the area to ISO load without excessive curtailment, transmission upgrades are necessary. Please see Chapters 3 and 4 for a detailed analysis of the policy and economic driven transmission upgrade needs in the VEA/GLW area.

In addition to the overloads discussed above, the assessment identified several Category P6 thermal overloads under the 2023 off-peak with heavy renewable sensitivity scenario which could be mitigated by previously identified generation-tripping Sloan Canyon RAS or congestion management.

The stability analysis performed in the VEA area assessment did not identify any WECC voltage criteria violation.

2.8.4 Request Window Project Submissions

The ISO received one project submittal through the 2021 request window submission for the VEA/GLW Area. Below is a description of the proposal followed by ISO comments and findings.

GLW Upgrade

The project was submitted by GLW as a Reliability Transmission Project. The project scope includes:

- Rebuild to 230kV double circuit from Desert View to Northwest substations
- Add a second 230kV circuit from Innovation to Desert View substations
- Rebuild to 230kV double circuit from Pahrump to Gamebird to Trout Canyon substations
- Rebuild to 230kV double circuit from Trout Canyon to Sloan Canyon 230kV substations
- Add a 500/230kV transformer at Sloan Canyon and loop-in the Harry Allen – Eldorado 500kV line at Sloan Canyon
- Upgrade WAPA Amargosa 230/138kV transformer to alleviate known constraints
- Additional planned upgrades on the NVE system were included to alleviate known constraints. NVE will move the Mercury Switch 138 kV termination from IS TAP to Innovation and upgrade the 138 kV from Innovation to Northwest to 210MVA.

Rebuilding the Pahrump – Gamebird – Trout Canyon – Sloan Canyon line to 230 kV double circuit would mitigate the multiple Category P6 overloads on Amargosa – Sandy 138 kV line identified in reliability assessment. For an additional detailed assessment of the project, please refer to Chapter 3.

2.8.5 Consideration of Preferred Resources and Energy Storage

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

2.8.6 Recommendation

The VEA area assessment identified several Category P6 thermal overloads under the base and sensitivity scenarios as described in Appendix B. The mitigations include utilizing the existing UVLS scheme; installing or a second 230 kV circuit an operating procedure; utilizing the facility short-term emergency rating and performing manual load shedding; and congestion management.

The VEA area assessment identified several Category P6 thermal overloads under the 2023 off-peak with heavy renewable sensitivity scenario. The RAS schemes developed in the GIDAP process and congestion management would be able to mitigate all the violations.

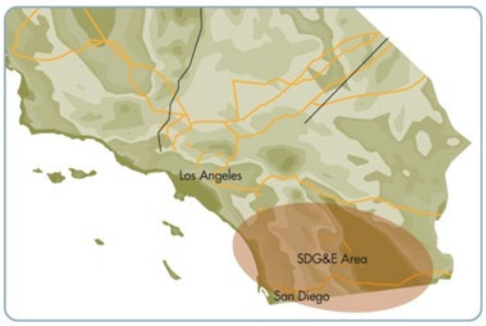
Multiple normal and contingency overloads were identified under the 2031 spring off-peak base scenario. The overloads were caused by the large RPS base portfolio modeled in GLW system. Generation re-dispatch pre-contingency would eliminate the normal overloads and potentially some of the contingency overloads. RAS proposed in the GIDAP process would mitigate the remaining contingency overloads. However, to allow for the delivery of the renewable generation in the area to ISO load without excessive curtailment, transmission upgrades are necessary. Please see Chapters 3 and 4 for a detailed analysis of the Policy and Economic driven transmission upgrade needs in the VEA/GLW area.

The VEA area assessment did not identify any transient stability WECC voltage concerns.

2.9 SDG&E Area

2.9.1 San Diego Local Area Description

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



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

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

The interface of San Diego import transmission (SDIT) consists of SWPL, SRPL, the south of San Onofre (SONGS) transmission path, and the Otay Mesa-Tijuana 230 kV transmission tie with CENACE. The San Diego area relies on internal generation and import through SDIT to serve electricity customers. The area has a forecasted 1-in-10 peak sales load of 4847 MW in 2031 after incorporating a load reduction of 176 MW of additional achievable energy efficiency (AAEE) and 0 MW of forecast behind-the-meter photovoltaic (BTM PV) generation production as the San Diego peak hour continues to be HE19:00.

The area is forecast to have approximately 8897 MW of grid-connected generation by the year 2031, including a total of 3357 MW renewable generation and 1515 MW energy storage resources.

2.9.2 Area-Specific Assumptions and System Conditions

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

Demand-Side Assumptions

The summer peak cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table below provides the load forecast assumptions including load reduction impact of BTM PV and AAEE on demand side. The load forecast provided by CEC are net demand values including load reduction and system losses. The 2023 and 2026 spring off-peak cases assume approximately 75% and 13% of the net-peak load, respectively.

Supply-Side Assumptions

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

Transmission Assumptions

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

Table 2.9-1: SDG&E Load and Load Modifier Assumptions

Study Case	Scenario	Description	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Demand Response (MW)	
					Installed Capacity	Output		Fast	Slow
B1-2023SP	Baseline	2023 summer peak load condition (9/6 HE 19)	4600	43	492	0	4600	0	0
B2-2026SP		2026 summer peak load condition (9/2 HE 19)	4711	96	1949	0	4711	0	0
B3-2031SP		2031 summer peak load condition (9/4 HE 19)	4847	176	2667	0	4847	0	0
B4-2023OP		2023 spring off-peak load condition (5/23 HE 20)	3450	32	492	0	3450	0	0
B5-2026OP		2026 spring off-peak load condition (4/5 HE 13)	2561	52	2266	1949	612	0	0
S1-2023SP	Sensitivity	2023 summer peak load condition with heavy renewable output and minimum gas generation commitment	4600	43	492	473	4127	0	0
S2-2023OP		2023 spring off-peak load condition with heavy renewable output and minimum gas generation commitment	3450	32	492	473	2977	0	0
S3-2026SP		2026 summer peak load condition with high CEC forecasted load	4711	96	1949	0	4711	0	0

Table 2.9-2: SDG&E Generation Resources Assumptions

Study Case	Scenario	Description	Energy Storage (MW)		Solar (MW)		Wind (MW)		Thermal (MW)		Pumped Storage Hydro (MW)		Biomass (MW)	
			Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch
B1-2023SP	Baseline	2023 summer peak load condition (9/6 HE 19)	341	0	1479	0	778	257	3713	3343	40	40	0	0
B2-2026SP	Baseline	2026 summer peak load condition (9/2 HE 19)	341	181	1483	0	778	257	3671	3453	40	40	0	0
B3-2031SP	Baseline	2031 summer peak load condition (9/4 HE 19)	1515	0	2084	0	1273	425	3671	2449	354	40	0	0
B4-2023OP	Baseline	2023 spring off-peak load condition (5/23 HE 20)	341	40	1624	105	623	424	3743	2664	40	0	0	0
B5-2026OP	Baseline	2026 spring off-peak load condition (4/5 HE 13)	398	0	1469	814	515	155	3673	219	40	0	0	0
S1-2023SP	Sensitivity	2023 summer peak load condition with heavy renewable output and minimum gas generation commitment	384	0	1479	1561	778	371	3713	1306	40	40	0	0
S2-2023OP	Sensitivity	2023 spring off-peak load condition with heavy renewable output and minimum gas generation commitment	341	50	1624	1559	623	318	3743	1058	40	0	0	0
S3-2026SP	Sensitivity	2026 summer peak load condition with high CEC forecasted load	341	181	1483	0	778	257	3671	3453	40	40	0	0

Assessment Summary

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

The steady state assessment of the baseline scenarios identified a number of thermal overload concerns under Category P1 to P7 contingencies in the SDG&E main and sub-transmission systems. The sensitivity scenarios assessment identified similar concerns compared to the baseline scenarios. The assessments confirmed that most of these concerns can be mitigated by previously approved projects and operational mitigations including operational procedures, congestion management, and remedial action schemes (RAS). The short-term emergency ratings of transmission lines along with demand response and energy storage resources in the area can be relied upon under contingency to allow time needed for operational actions to re-dispatch conventional generation and preferred resources, reduce ISO imports, adjust the phase shifting transformers at Imperial Valley substation, and bypass series capacitors. Furthermore, non-convergence issues were observed in the sensitivity scenarios with heavy renewable output and minimum gas generation commitment due to the amount of generation in the Imperial Valley area being dropped as part of RAS actions exceeding the ISO RAS guidelines. The stability analysis performed did not identify any transient issues requiring mitigation. Please refer to Appendix B for details on these concerns and associated mitigations.

2.9.3 Request Window Project Submissions

The ISO received a total of two valid project submittals through the 2021 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.

Friars – Doublet Tap Reconductor Project

This project was proposed by SDG&E as a reliability transmission solution to address an overload on TL13810A (Friars – Doublet Tap) driven by a P7 (N-2) contingency observed under certain system conditions. The scope of the project involves upgrading TL13810A to its full line capacity from 150 MVA to 204 MVA by reconductoring 9620 feet of 400 CU wire with 636 ACSR. The project can optimize the TL13810A circuit capacity and minimize the RAS action tripping generation in Otay Mesa area, as well as improve operational flexibility. The estimated cost of the project is $5.5 million, and the proposed in-service date is 2022. This project was not found to be needed in the reliability assessment.

New ML-SCR 500kV Line Project

This project was proposed by SDG&E as a reliability transmission solution to address overloads on TL 23054 and TL 23055, currently the most limiting elements on the Sunrise path for P6 contingencies. The scope of the project involves constructing a new 33 mile 500 kV line between the existing Miguel and Suncrest substations. Potential benefits of the new line includes providing a second 500 kV connection to Miguel and Suncrest, improving system reliability, increasing operational flexibility, as well as reducing the complexity of the TL 23054 / 23055 RAS. The estimated cost of the project is $335 - $600 million, and the proposed in-service date is 2032.

Current operational actions, including the use of RAS, are sufficient to meet the identified need within the 10-year planning horizon. This will be further assessed in future transmission plans.

2.9.4 Consideration of Preferred Resources and Energy Storage

Projected amounts of energy efficiency (AAEE) and distributed BTM-PV self-generation were used in the study scenarios for the San Diego area. The load reductions due to the preferred resources 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 contingencies
- Voltage instability in the San Diego and LA Basin for Category P6 contingencies
- The south of San Onofre Safety Net taking action for Category P6 contingency
- Bay Boulevard–Silvergate-Old Town 230 kV path overloads for Category P6/P7 contingencies
- Friars-Doublett 138 kV line for Category P6/P7 contingencies
- SCE's Ellis 220 kV south corridor for Category P6 contingencies
- Otay Mesa-Tijuana 230 kV tie line for Category P6 contingency

- Cross-tripping the 230 kV tie lines with CENACE for Category P6 contingencies.

The operational and planned battery energy storage and demand response were used as potential mitigations in the base and sensitivity scenarios as needed. Utilization of these resources helps to reduce some of the thermal overloads identified in the area.

In this planning cycle, no need for additional preferred resource and battery energy storage systems were identified as a cost-effective mitigation to meet reliability needs in the San Diego area.

2.9.5 Recommendation

The assessments identified a number of thermal overload concerns under Categories P1 to P7 contingencies in the SDG&E main and sub-transmission systems. In response to the ISO reliability assessment results and proposed alternative mitigations, a total of two valid project submissions was received through the 2021 request window. The ISO evaluated the alternatives and found that the proposed projects are not needed at this time. Below is a summary of recommendations for the San Diego area:

- The amount of generation being dropped in the Imperial Valley area as part of RAS actions currently exceeds the ISO RAS guidelines and should be further investigated.

Chapter 3

3 Policy-Driven Need Assessment

3.1 Background

The overarching public policy objective for the California ISO's Policy-Driven Need Assessment is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets. For the purposes of the transmission planning process, this high-level objective is comprised of two sub-objectives: first, to support Resource Adequacy (RA) deliverability status for the renewable generation and energy storage resources identified in the portfolio as requiring that status, and second, to support the economic delivery of renewable energy over the course of all hours of the year.

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

The CPUC issued a Decision[113] 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 GHG reduction target, at least cost, while maintaining electric service reliability and meeting other state goals. In subsequent years, the CPUC has been developing integrated resource plans and transmitting them to the ISO for use in the annual transmission planning process. The CPUC issued Decision 21-02-008[114] on February 17, 2021 to transfer the following reliability and policy-driven base portfolio and two sensitivity portfolios with updated assumptions from the CEC's 2019 Integrated Energy Policy Report as detailed in Attachment A[115] of the order for study in the ISO 2021-2022 transmission planning process:

(a) A reliability and policy-driven base-case portfolio that meets the 46 million metric ton GHG target by 2031 (Base Portfolio);

(b) A portfolio that meets a 38 million metric ton GHG target by 2031 as a policy-driven sensitivity (Sensitivity 1 Portfolio);

(c) A portfolio to test transmission needs associated with offshore wind (OSW) and a 30 million metric ton GHG emissions target by 2031 (Sensitivity 2 Portfolio).

The CPUC used the RESOLVE resource optimization model to develop the portfolios studied as part of the 2020-2021 transmission planning process. The model assumed existing resources

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

[114] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

[115] ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2021_22_TPP_Final.pdf

and resources under development with CPUC-approved contracts to be part of the baseline resource assumptions.

3.2 Objectives of policy-driven assessment

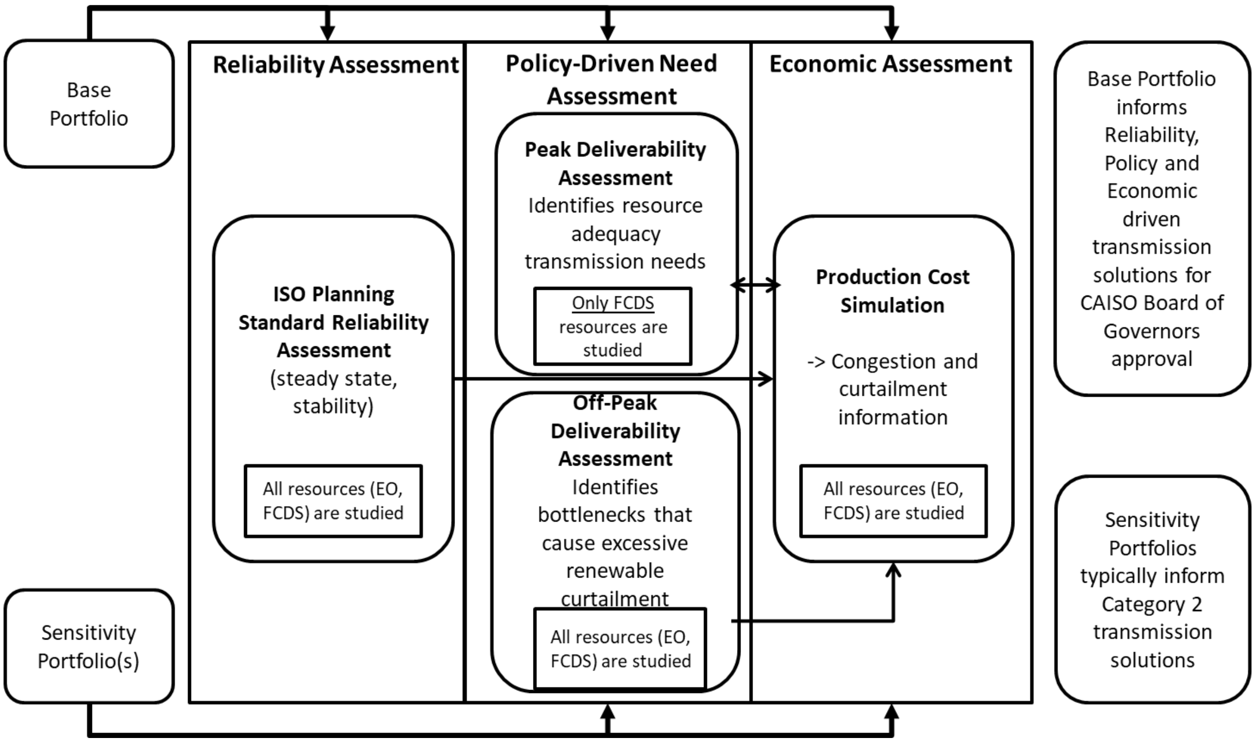
Key objectives of the policy-driven assessment are to:

- Assess the transmission impacts of portfolio resources using:
    - Reliability assessment
    - Peak and Off-peak deliverability assessment; and
    - Production cost simulation
- Identify transmission upgrades or other solutions needed to ensure reliability deliverability or alleviate excessive curtailment, and
- Gain further insights to inform future portfolio development.

3.3 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies as illustrated in Figure 3.3-1. These studies are geared towards capturing the impact of resource build-out on transmission infrastructure, identifying any required upgrades and generating transmission input for use by the CPUC in the next cycle of portfolio development.

Figure 3.3-1: Policy assessment methodology and study components



Reliability assessment

The policy-driven reliability assessment is used to identify constraints that need to be modeled in production cost simulations to capture the impact of the constraints on renewable curtailment caused by transmission congestion. The reliability assessment component of the policy-driven assessment is covered by the year-10 reliability assessment presented in chapter 2 and the off-peak deliverability assessment that is performed in accordance with the off-peak deliverability methodology and is presented in this section.

On-peak deliverability assessment

The on-peak deliverability assessment is designed to ensure portfolio resources selected with full capacity deliverability status (FCDS) are deliverable and can count towards meeting resource adequacy needs. The assessment examines whether sufficient transmission capability exists to transfer resource output from a given sub-area to the aggregate of the ISO control-area load when the generation is needed most. The ISO performs the assessment in accordance with the On-peak Deliverability Assessment Methodology[116].

[116] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

Off-peak deliverability assessment

The off-peak deliverability assessment is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The ISO performed the assessment following the Off-Peak Deliverability Assessment Methodology[117].

Production cost model (PCM) simulation

Production cost models for the base and sensitivity portfolios are developed and simulated to identify renewable curtailment and transmission congestion in the ISO Balancing Authority Area. The PCM for the base portfolio is used in the policy-driven assessment that is covered in this section as well as the economic assessment covered in chapter 4. The PCM with the sensitivity portfolios is used in the policy-driven assessment only. The PCM cases are developed based on study assumptions for the ISO-controlled grid outlined in the 2021-2022 transmission planning process study plan. Details of PCM modeling assumptions and approaches are provided in chapter 4.

3.4 Resource Portfolios

As mentioned in Section 3.1, a base portfolio and two sensitivity portfolios were transmitted by the CPUC for study in the ISO 2021-2022 transmission planning process policy-driven assessment. The three portfolios complete with the final busbar mapping results for non-battery and battery resources as well as a retirement list for the sensitivity portfolios are available at the CPUC website.

Final busbar mapping results for non-battery resources for the base and sensitivity portfolios – https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/mappingsummary_bysubstation_allportfolios_2021_22tpp_ver2.xlsx

Final busbar mapping results for battery storage for the base and sensitivity portfolios – ftp://ftp.cpuc.ca.gov/energy/modeling/Battery_Mapping_Dashboard_All_Portfolios_Final.xlsx

Retirement list for the policy-driven sensitivity portfolios – ftp://ftp.cpuc.ca.gov/energy/modeling/Retirement_List_for_Sensitivity_Portfolios.xlsx

The composition of each of the portfolios by resource type is provided in Table 3.4-1. The table includes resources selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO). The portfolios are comprised of solar, wind, pumped hydro, geothermal and battery storage resources. While the base portfolio assumes all of the existing gas-fired generation is retained, the sensitivity portfolios assume some of the existing gas-fired generation fleet will be retired by 2031. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment, where only FCDS resources are modeled.

117 http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

Table 3.4-1: Portfolio composition – FCDS+EO resources (MW)

	Base	Sensitivity-1	Sensitivity-2
Solar	13,044	13,817	9,807
Wind	4,005	7,955	16,039
Pumped Hydro	627	1,843	1,495
Geothermal	651	105	0
Battery storage	9,368	9,447	7,604
Gas Retirements	0	(1,319)	(1,718)
Total (FC+EO)	**27,695**	**31,848**	**33,227**

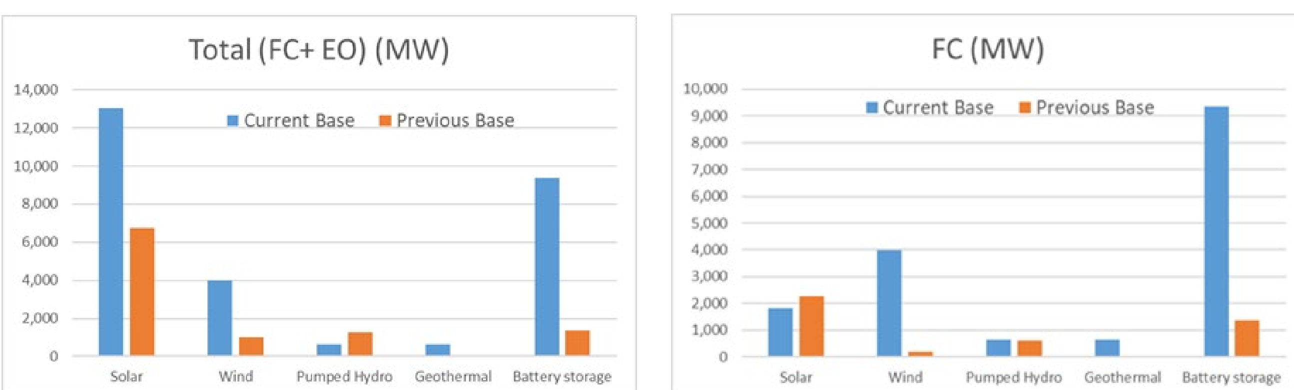
Table 3.4-2 below provides the composition of the portfolio resources selected with Full Capacity Deliverability Status (FCDS).

Table 3.4-2: Portfolio composition – FCDS resources (MW)

	Base	Sensitivity-1	Sensitivity-2
Solar	1,832	2,422	1,332
Wind	3,971	6,451	13,250
Pumped Hydro	627	1,843	1,495
Geothermal	651	57	0
Battery storage	9,368	9,447	7,604
Gas Retirements	0	1,319	1,718
Total FC	**16,448**	**18,901**	**21,963**

Compared to the base portfolio studied in the 2020-2021 transmission planning process, the current base portfolio includes significantly more resources, both in total amount and FCDS amount as shown in Figure 3.4-1

Figure 3.4-1: Comparison of current and 2020-21 TPP base portfolios



As discussed in Chapter 1, the portfolios provided to the ISO also provided specific direction regarding the treatment of out-of-state wind resources, particularly for the base case. The ISO was requested to study the potential requirements and implications of 1062 MW being injected into the ISO system from Idaho/Wyoming or New Mexico in the base case, but not both simultaneously. The ISO recognized that the approval of any identified needs to accommodate either injection would hinge on the analysis and subsequent stakeholder comments[118]. Further, the CPUC acknowledged that out-of-state transmission would be needed to deliver these volumes to the existing ISO boundary, but those were outside of the scope of the policy-driven transmission study request. In subsequent comments in the ISO's stakeholder process, CPUC staff later requested the ISO to consider, time permitting, possible out-of-state requirements for information purposes only[119]. Accordingly, the ISO in this chapter focused on policy-driven analysis aligned with the CPUC decision regarding transmission implications inside the ISO footprint, and conducted additional analysis including consideration of out-of-state transmission issues as part of broader economic studies documented in chapter 4. In addition, out-of-state wind resources were also included in the two sensitivity portfolios provided by the CPUC as indicated in Table 3.4-3 to be assessed for information only. The assessment of the out-of-state wind in the sensitivity portfolios has also been aligned with the CPUC decision regarding transmission implications inside the ISO footprint.

3.4.1 Mapping of portfolio resources to transmission substations

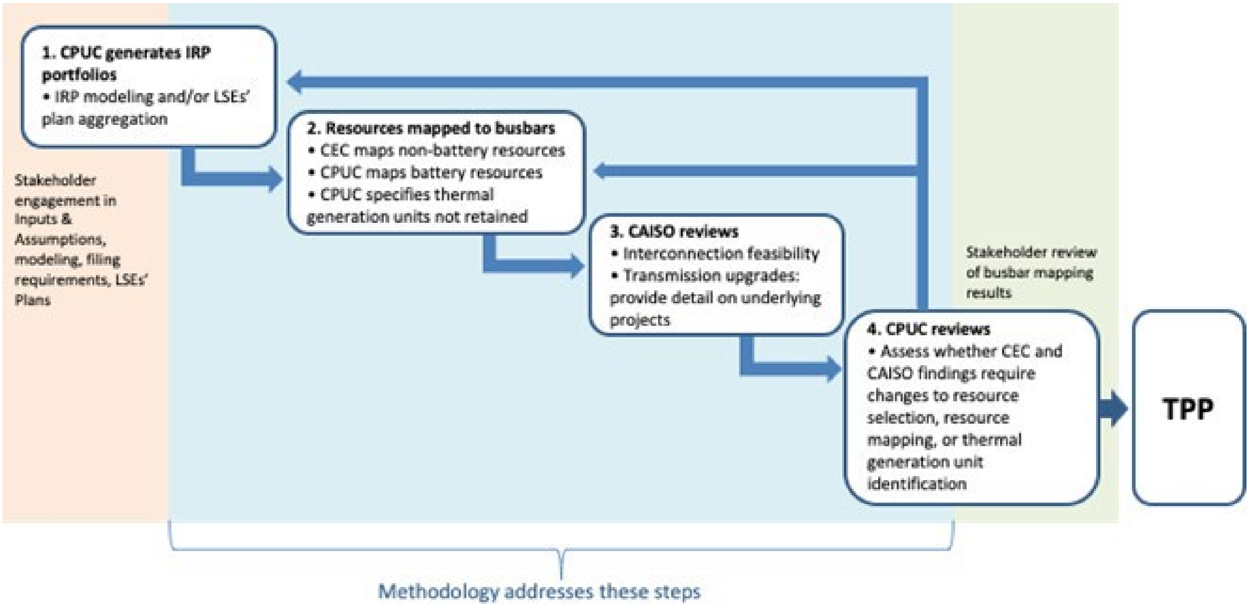
The portfolios that RESOLVE generates are at the renewable transmission zone level as shown in the previous section in the case of renewable resources and location non-specific in the case of battery storage. As a result, the portfolios have to be mapped to the busbar level for use in the ISO transmission planning process. The resource-to-busbar mapping process is documented in the CPUC report entitled Methodology for Resource-to-Busbar Mapping & Assumptions for the 2021-2022 transmission planning process[120] with further refinements as described in the CPUC report entitled Modeling Assumptions for the 2021-2022 Transmission Planning Process. Figure 3.4-2 shows a flowchart of the CPUC 2021-2022 transmission planning process busbar mapping process. Portfolio non-battery and battery resources were modeled in the ISO studies in accordance with the results of the mapping process.

[118] Page 34, D.21-02-008 that transferred the portfolios to the ISO. "The CAISO, in reply comments, suggested that they could study separately the injection of the full amount of energy at both the El Dorado substation representing resources from Wyoming, Idaho, or potentially other locations, and the Palo Verde substation, presentation resources from New Mexico or other Southwest locations, delivering results for further consideration at the end of this TPP cycle. We understand this to be a unique situation where the CAISO may be able to offer optionality within the base case analysis, and therefore we will take the CAISO up on this offer and work with them to understand better the transmission buildout requirements associated with generation siting in both locations." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

[119] CPUC Staff Comments dated March 11, 2021 re CAISO February 25, 2021 stakeholder meeting: "We encourage the CAISO's review of possible opportunities for such an informational study of transmission needs outside the CAISO system, whether it might be conducted solely by the CAISO or jointly with another agency." http://www.caiso.com/InitiativeDocuments/CPUCComments-2021-2022TransmissionPlanningProcess-Feb252021StakeholderCall.pdf

[120] ftp://ftp.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%202021-2022%20TPP_V.2021-01-07.pdf

Figure 3.4-2: Flowchart of the CPUC 2021-2022 TPP busbar mapping process



Portfolio non-battery and battery resources were modeled in the ISO studies in accordance with the results of the mapping process. Table 3.4-3 provides the total and FC non-battery resources in the three portfolios complete with busbar mapping. Table 3.4-4 lists battery storage resources in the three portfolios, all of which are considered to have FC deliverability status.

Table 3.4-3: Total generic non-battery resources in the base and sensitivity portfolios, MW (2031)

			Base Portfolio		Sensitivity-1		Sensitivity-2	
RESOLVE Resource	**Tx Deliv. Zone**	**Substation**	**Total**	**FCDS**	**Total**	**FCDS**	**Total**	**FCDS**
Arizona_Solar	SCADSNV-Riverside_Palm_Springs	Hassayampa 500kV	871		600		707	
		Delaney-Colorado 500kV	1,482		981		1,203	
Carrizo_Wind	SPGE-Kern_Greater_Carrizo-Carrizo	Templeton 230kV	187	187	287	287	287	287
Carrizo_Solar	SPGE-Kern_Greater_Carrizo-Carrizo	Mesa 115 kV(1)	55		55		55	
Central_Valley_N._Los_Banos_Wind	Central_Valley_North_Los_Banos-SPGE	Los Banos 230kV	173	173	173	173	173	173
Greater_Imperial_Solar	Greater_Imperial-SCADSNV	Imperial Valley 230kV	333		697	365	697	365
		Ocotillo Express 230kV	215		451	235	451	235
Humboldt_Wind	Sacramento_River-Humboldt	Bridgeville 115kV	34		34		34	
Kern_Greater_Carrizo_Solar	SPGE-Kern_Greater_Carrizo	Arco 230kV	144		165			
		Midway 230kV	140		160			
		Renfro 115kV	143		164	21		
		Stockdale 230kV	144		165	21		
		Wheeler Ridge 230kV	129		147			
		Lamont 115 kV(1)	106		106		106	
Kern_Greater_Carrizo_Wind	SPGE-Kern_Greater_Carrizo	Cholame 70 kV	20	20	20	20	20	20
Mountain_Pass_El_Dorado_Solar	Mountain_Pass_El_Dorado	El Dorado 230kV	83		83		83	
		EL Dorado 500kV	165		165		165	
North_Victor_Solar	North_Victor-Greater_Kramer	Victor 230kV	215	159	215	159	215	159
		Coolwater 230kV	85	85	85	85	85	85
Northern_California_Ex_Wind	Sacramento_River	Glenn 230kV	354	354	354	354	354	354
		Delevan 230kV	83	83	83	83	83	83
		Thermalito 230kV	178	178	178	178	178	178
		Rio Oso 230kV	152	152	152	152	152	152
Pisgah_Solar	Pisgah	Calcite	140		140		140	
		Lugo	47	47	47	47	47	47
		Pisgah 230kV	14	14	14	14	14	14
Sacramento_River_Solar	Sacramento_River	Delevan 230kV			43			
		Glenn 230kV			47			
		Palmero 230kV			46			
		Rio Oso 230kV			49			
		Thermalito 230kV			46			
SCADSNV_Solar	SCADSNV	Mohave 500kV	568		740		410	
Solano_Geothermal	Solano-Sacramento_River	Sonoma 3 230kV	51	51	105	57		
Solano_Solar	Solano-Sacramento_River	Fulton 230kV			159			
		Contra Costa 230kV			156			
		Tulucay 230kV			137			
		Vaca-Dixon & GC Yard			170			
Solano_Wind	Solano-Sacramento_River	Lakeville 230kV	194	194	194	194	194	194
		Tulucay 230kV	20	20	20	20	20	20
		Vaca-Dixon & GC Yard	146	146	146	146	146	146
		Shilo III 230kV	72	72	72	72	72	72
		Lone Tree 230kV	30	30	30	30	30	30
Southern_Nevada_Solar	SCADSNV-GLW_VEA	Innovation 230kV	445		40		40	
		Desert View 230kV	344	106	31	31	31	31
		Crazy Eyes 230kV	1,234	242	111		111	
Southern_Nevada_Wind	SCADSNV-GLW_VEA	Innovation 230kV			97	97	97	97
		Desert View 230kV			75	75	75	75
		Crazy Eyes 230kV			270	270	270	270
Tehachapi_Solar	Tehachapi	WindHub 230kV	1,153		1,398		1,153	
		Whirlwind 500kV	1,277		1,549		1,277	
		Antelope 230kV	1,247	395	1,512	660	1,247	395
		Vincent 230kV	1,003		1,217		1,003	
Tehachapi_Wind	Tehachapi	WindHub 230kV	275	275	275	275	275	275
Westlands_Solar	Central_Valley_North_Los_Banos-SPGE	Gates 230kV	151		151			
		Helm 230kV	176	176	176	176		
		Henrietta 230kV	163	163	163	163		
		Mc Call 230kV	204	204	204	204		
		Mc Mullin 230kV	190	190	190	190		
		Panoche 230kV	160	50	160	50		
		Gates 500kV(1)	218		883		567	
Pumped Hydro Storage	Pumped Hydro Storage	Lee Lake 500kV	313	313	500	500	500	500
		Sycamore Canyon 230kV	314	314	500	500	500	500
		Red Bluff 500kV			843	843	495	495
Baja_California_Wind	Greater_Imperial-SCADSNV	East County 500kV	495	495	495	495	495	495
Greater_Imperial_Geothermal	Greater_Imperial-SCADSNV	Bannister	600	600				
New_Mexico_Wind(2)	SCADSNV-Riverside_Palm_Springs	Palo Verde 500kV	Note(1)		1,500	1,500	1,500	1,392
Wyoming_Wind(3)	SCADSNV-Mountain_Pass_El_Dorado	El Dorado 500kV	1,062	1,062	1,500	1,500	1,500	
NW_Ext_Tx_Wind(4)	Sacramento_River	Round Mountain 500kV	530	530	1,500	530	1,500	587
SW_Ext_Tx_Wind(5)	SCADSNV-Riverside_Palm_Springs	Palo Verde 500kV			500		234	
Diablo_Canyon_Offshore_Wind		Diablo Canyon 500kV					4,419	4,419
Humboldt_Bay_Offshore_Wind(6)		Humboldt 115kV					1,607	1,607
Morro_Bay_Offshore_Wind(6)		Morro Bay 230kV					2,324	2,324
		Portfolio Total (non-battery)	**18,327**	**7,080**	**23,720**	**10,773**	**27,341**	**16,077**

(1) In coordination with the CPUC, adjustments were made to the final mapping of co-located solar-battery resources to accommodate the need for 155 MW of battery storage at Mesa, Lamont and Kettleman identified in the 2020-2021 transmission plan. Accordingly, 161 MW of co-located solar, along with 155 MW of storage, was moved from Gates 500 kV to Mesa and Lamont substations.
(2) New_Mexico_Wind on new transmission is modeled at Paloverde 500 kV on top of MIC
(3) Wyoming_Wind on new transmission is modeled at Eldorado 500 kV on top of MIC
(4) NW_Ext_Tx_Wind on existing transmission is modeled in Washington without MIC expansion
(5) SW_Ext_Tx_Wind on existing transmission is modeled in New Mexico without MIC expansion
(6) See discussion later in this section regarding offshore wind interconnection options considered in the study

Table 3.4-4: Generic battery resources in the base and sensitivity portfolios, MW (2031)

Substation Name	Tx Deliv. Zone	Base Portfolio	Sensitivity 1	Sensitivity 2
Antelope 230kV	Tehachapi	575	575	575
Panoche	SPGE_Z1_Westlands	99	99	0
Wheeler Ridge	SPGE_Z2_KernAndGreaterCarrizo	0	16	0
Arco	SPGE_Z2_KernAndGreaterCarrizo	0	19	0
Midway 230kV	SPGE_Z2_KernAndGreaterCarrizo	0	18	0
Birds Landing	Norcal_Z4_Solano	5	0	0
Gates 230kV	SPGE_Z1_Westlands	136	136	0
Delaney	SCADSNV_Z4_RiversideAndPalmSprings	426	331	0
Vincent	Tehachapi	809	941	748
Windhub	Tehachapi	1,008	1,081	860
Whirlwind 230kV	Tehachapi	1,645	1,198	953
Gates 500kV(1)	SPGE_Z1_Westlands	186	186	500
Victor	GK_Z3_NorthOfVictor	50	50	50
Hassayampa	SCADSNV_Z4_RiversideAndPalmSprings	269	53	0
Mohave 500kV	SCADSNV_Z5_SCADSNV	228	369	98
Calcite	GK_Z4_Pisgah	126	126	126
Innovation	SCADSNV_Z2_GLW_VEA	123	36	36
Eldorado 230kV	SCADSNV_Z1_EldoradoAndMtnPass	75	75	75
Eldorado 500kV	SCADSNV_Z5_SCADSNV	149	149	149
Red Bluff	SCADSNV_Z4_RiversideAndPalmSprings	0	278	0
Colorado River	SCADSNV_Z4_RiversideAndPalmSprings	0	278	0
Crazy Eyes	SCADSNV_Z2_GLW_VEA	125	100	100
Mesa 115 kV(1)	SPGE-Carrizo	50	50	50
Lamont 115(1)	SPGE-Kern	95	95	95
Kettleman(1)	SPGE_Z1_Westlands	10	10	10
Gold Hill	NorCalOutsideTxConstraintZones	59	59	59
Martin	NorCalOutsideTxConstraintZones	250	250	250
Walnut	TehachapiOutsideTxConstraintZones	200	200	200
Hinson	TehachapiOutsideTxConstraintZones	200	200	200
Etiwanda	KramerInyoOutsideTxConstraintZones	101	101	101
Laguna Bell	TehachapiOutsideTxConstraintZones	500	500	500
Walnut	TehachapiOutsideTxConstraintZones	200	200	200
Silvergate	GreaterImpOutsideTxConstraintZones	200	200	200
Moorpark	TehachapiOutsideTxConstraintZones	500	500	500
Escondido	GreaterImpOutsideTxConstraintZones	50	50	50
Sycamore Canyon	GreaterImpOutsideTxConstraintZones	300	300	300
Talega 138kV	GreaterImpOutsideTxConstraintZones	200	200	200
Trabuco 138kV	GreaterImpOutsideTxConstraintZones	250	250	250
Encina 138kV	GreaterImpOutsideTxConstraintZones	160	160	160
Kearny	GreaterImpOutsideTxConstraintZones	10	10	10
	Total	**9,368**	**9,447**	**7,604**

(1) In coordination with the CPUC, adjustments were made to the final mapping of co-located solar-battery resources to accommodate the need for 155 MW of battery storage at Mesa, Lamont and Kettleman identified in the 2020-2021 transmission plan. Accordingly, 161 MW of co-located solar, along with 155 MW of storage, was moved from Gates 500 kV to Mesa and Lamont substations.

3.4.2 Transmission capability estimates and utilization by portfolios

One of the key inputs to the co-optimization performed by the RESOLVE model used by the CPUC in portfolio development is the transmission capability estimates provided by the ISO for transmission constraints identified in the system that limit the amount of FCDS and EODS resources that can be selected in the part of the system that is affected by the constraint. The CPUC used the transmission capability estimates the ISO published in a white paper on May 20, 2019[121] in the development and busbar mapping of the portfolios used in the current transmission planning process. The transmission capability estimates provided in that white paper were developed based on the ISO's previous deliverability assessment methodology. The ISO has since overhauled the transmission capability estimate information based on the current deliverability assessment methodology, which is published in a new white paper.[122]

The utilization of estimated available FCDS and EODS transmission capability by IRP resource portfolios is monitored by the CPUC in the portfolio development and busbar mapping process using spreadsheet calculations. Since the new transmission capability estimates were not available when the CPUC developed the portfolios for the 2021-2022 transmission planning process, CPUC staff have conducted the evaluation for 2021-2022 transmission planning process portfolios retroactively. The results of the evaluation are posted on the CPUC website.[123] It is important to note that, while the transmission capability estimates and the results of the spreadsheet evaluation provide useful information by indicating where transmission limits are likely or unlikely to be exceeded, it should not be viewed as a substitute for the analysis the ISO performs as part of this policy-driven assessment using detailed power system models.

As indicated in the white paper, the transmission capability estimates are over and above the baseline future resource amounts the CPUC transmitted as part of its resource portfolios for the ISO 2020-2021 transmission planning process. It is to be noted that the transmission capability exceedance calculation does not take into account the incremental amount of new baseline resources the CPUC transmitted for the 2021-2022 transmission planning process and, as a result, it overestimates available transmission capability in some areas. Also, consistent with the modeling approach used in the ongoing 2021-2022 transmission planning process analysis work, portfolio resources identified as NW_wind_Ext_Tx and SW_wind_Ext_Tx, which are out-of-state portfolio resources that are assumed to be delivered to the ISO BAA on existing out-of-state transmission, were presumed to not require additional transmission capacity.

Table 3.4-5 and Table 3.4-6 show the transmission constraints where FCDS or EODS capability estimates are exceeded in one or more portfolios. The transmission capability estimates as well as the exceedance amounts provided in the tables are expressed in terms of the applicable resource-type specific output assumptions used in deliverability assessments as described in

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[121] https://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf

[122] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=79BEBAD0-E696-4E04-A958-1AAF53A12248

[123] ftp://ftp.cpuc.ca.gov/energy/modeling/TxCalculator-for2021-22TPP-Portfolios.xlsx

the deliverability assessment methodology, which are summarized in the following sections, rather than on the basis of installed capacity.

Table 3.4-5: FCDS transmission capability estimates exceedances

Transmission Constraint	Existing System FCDS Capability Estimate Based on HSN/SSN Resource Output Assumptions (MW)	FCDS Capability Exceedance (Higher of HSN or SSN Study Amount) (MW)		
		Base	Sensitivity-1	Sensitivity-2
Mesa – Laguna Bell Constraint	0	1309	1441	1248
GLW/VEA Constraint	300	97	82	85
Internal San Diego Constraint	968	63	284	284
Cortina–Vaca Dixon 230 kV Constraint	454	478	479	2029
Rio Oso-SPI — Lincoln 115 kV Constraint	42	59	59	59
Woodland-Davis 115 kV Line Constraint	64	38	38	38
Warnerville — Wilson 230 kV Line	272*	149	149	--
Moss Landing — Las Aguillas 230 kV Constraint	316*	14	14	--
Mohave/Eldorado 500 kV "Default" Constraint	1560*	--	203	--
Humboldt–Trinity 115 kV Line Constraint	21	--	--	1586
Midway – Gates 230 kV Line Constraint	1431	--	--	1181
Morro Bay —Templeton 230 kV Constraint	1708	--	--	1591
Los Banos — Gates 500 kV Line Constraint	1265*	--	--	1263
Moss Landing–Los Banos 230 kV Constraint	1611*	--	--	1032

* Capability estimates marked with an asterisk (*) reflect the amount of resources studied in the latest GIP cluster deliverability studies as a "default" limit because binding constraints were not identified.

Table 3.4-6: EODS transmission capability estimate exceedances

Transmission Constraint	Existing System EODS Capability Estimate Based on Off-peak Resource Output Assumptions (MW)	EODS Capability Exceedance ((MW)		
		Base	Sensitivity-1	Sensitivity-2
GLW/VEA Constraint	269	1041	--	--
East of Miguel Area Constraint	950	120	596	733
Woodland – Davis 115 kV Line Constraint	64*	32	65	32
Moss Landing – Aguillas 230 kV Constraint	0	317	317	--
Cortina–Vaca Dixon 230 kV Constraint	795*	--	595	1549
Rio Oso – SPI–Lincoln 115 kV Constraint	124*	--	5	--
Humboldt – Trinity 115 kV Line Constraint	63*	--	--	1565
Morro Bay – Templeton 230 kV Constraint	1903*	--	--	552

* Capability estimates marked with an asterisk (*) reflect the amount of resources studied in the latest GIP cluster deliverability studies as a “default” limit because binding constraints were not identified.

3.5 On-Peak Deliverability assessment

The primary objective of the policy-driven on-peak deliverability assessment is to support deliverability of the renewable generation and energy storage resources that are identified in the portfolios as requiring FCDS status so they can count towards meeting resource adequacy needs. The assessment evaluates whether the net resource output from a given area can be simultaneously transferred to the remainder of the ISO Control Area during periods of peak system load. The on-peak deliverability assessment of the base and sensitivity portfolios is used to:

- Assess deliverability of FCDS portfolio resources in accordance with the on-peak deliverability assessment methodology[124]
- Identify transmission upgrades or other solutions needed to ensure deliverability of FCDS renewable portfolio resources
- Gain further insights regarding transmission capability, transmission upgrade requirements, etc. to inform future portfolio development.

[124] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

3.5.1 On-peak deliverability assessment assumptions and base case

The deliverability assessment is performed under two distinct system conditions – the highest system need (HSN) scenario and the secondary system need (SSN) scenario. The HSN scenario represents the period when the capacity shortage is most likely to occur. In this scenario, the system reaches peak sale with low solar output. The highest system need hours represent the hours ending 18 to 22 in the summer months.

The secondary system need scenario represents the period when capacity shortage risk increases if variable resources are not deliverable during periods when the system depends on their high output for resource adequacy. In this scenario, the system load is modeled to represent the peak consumption level and solar output is modeled at a significantly higher output. The secondary system need hours are hours ending 15 to 17 in the summer months.

The ISO performed the on-peak deliverability assessment for both HSN and SSN scenarios. For each scenario and each portfolio, the ISO developed a master on-peak deliverability assessment base case that modeled all FCDS portfolio resources. Key assumptions of the deliverability assessment are described below.

Transmission

The ISO modeled the same transmission system as in the 2031 peak load base case that is used in the reliability assessment performed as part of the current transmission planning process.

System load

The ISO modeled a coincident 1-in-5 year peak for the ISO balancing authority area load in the HSN base case. Pump load was dispatched within the expected range for summer peak load hours. The load in the SSN base case was adjusted from HSN to represent the net customer load at the time of forecasted peak consumption.

Maximum resource output (Pmax) assumptions

Pmax in the on-peak deliverability assessment represents the resource-type specific maximum resource output assumed in the deliverability assessment. For non-intermittent resources, the same Pmax is used in the HSN and SSN scenarios. The most recent summer peak NQC is used as Pmax for existing non-intermittent generating units. For proposed new non-intermittent generators that do not have NQC, the Pmax is set according to the interconnection request. For non-intermittent generic portfolio resources, the FCDS capacity provided in the portfolio is used as the Pmax. For energy storage resources, the Pmax is set to the 4-hour discharging capacity, limited by the requested maximum output from the resource, if applicable. For hybrid projects, the study amount for each technology is first calculated separately. Then the total study amount among all technologies is based on the sum of each technology, but limited by the requested maximum output of the generation project.

Intermittent resources are modeled in the HSN scenario based on the output profiles during the highest system need hours. A 20% exceedance production level for wind and solar resources during these hours sets the Pmax tested in the HSN deliverability assessment. In the SSN scenario, intermittent resources are modeled based on the output profiles during the secondary system need hours. 50% exceedance production level for wind and solar resources during the hours sets the Pmax tested in the SSN deliverability assessment.

The maximum resource output (Pmax) assumptions used in the HSN and SSN deliverability assessment are shown in Table 3.5-1

Table 3.5-1: Maximum resource output tested in the deliverability assessment

Area	HSN			SSN		
	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	3.0%	10.6%	10.0%	40.2%	42.7%	55.6%
Wind	33.7%	55.7%	66.5%	11.2%	20.8%	16.3%
New Mexico Wind	67%			35%		
Wyoming Wind	67%			35%		
Diablo OSW	100%			37%		
Morro Bay OSW	100%			49%		
Humboldt Bay OSW	100%			53%		
Energy Storage	100% or 4-hour equivalent if duration is < 4-hour					
Non-Intermittent resources	NQC or 100%					

Import Levels

For the HSN scenario, the net scheduled imports at all branch groups as determined in the 2021 annual Maximum Import Capability (MIC) assessment set the imports in the study. Approved MIC expansions were added to the import levels. Historically unused Existing Transmission Contracts (ETC's) crossing control area boundaries were modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts for screening analysis

For the SSN scenario, the hour with the highest total net imports among all secondary system need hours from the 2021 MIC assessment data is selected. Net scheduled imports for the hour set the imports in the study. Approved MIC expansions are added to the import levels.

Portfolio resources in the IID area and out-of-state portfolio resources delivered to the ISO BAA boundary on new transmission were dispatched once imports levels in the base cases are set as described above.

3.5.2 General On-peak deliverability assessment procedure

The main steps of the California ISO on-peak deliverability assessment procedure are described below.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool is used to identify potential deliverability problems. For each analyzed facility, an electrical circle is drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% or greater:

Distribution factor (DFAX) = (Δ flow on the analyzed facility / Δ output of the generating unit) *100%

or

Flow impact = (DFAX * Full Study Amount / Applicable rating of the analyzed facility) *100%.

Load flow simulations are performed, which study the worst-case combination of generator output within each 5% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5% Circle are increased starting with units with the largest impact on the transmission facility. No more than 20 units are increased to their maximum output. In addition, no more than 1,500 MW of generation is increased. All remaining generation within the Control Area is proportionally displaced, to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased more than 1,500 MW, the impact of the remaining amount of generation to be increased is considered using a Facility Loading Adder. The Facility Loading Adder is calculated by taking the remaining MW amount available from the 20 units with the highest impact multiplied by the DFAX of each unit. An equivalent MW amount of generation with negative DFAX is also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders is negative, the impact is set to zero and the flow on the analyzed facility without applying Facility Loading Adders is reported.

The ISO has its on-peak deliverability assessment simulation procedure implemented in PowerGem's Transmission Adequacy & Reliability Assessment (TARA) software. The ISO Deliverability Assessment module in TARA was used to perform the policy-driven on-peak deliverability assessment.

3.5.3 On-Peak deliverability assessment results

The Base Portfolio and the two sensitivity portfolios were studied as part of the 2021-2022 transmission planning process policy-driven, on-peak deliverability assessment. Two variations were assessed for the Base Portfolio. One variation includes 1062 MW of Wyoming Wind injected at Eldorado 500 kV (Base Portfolio A) while the other variation (Base Portfolio B) includes the same amount of New Mexico Wind injected at Paloverde 500 kV instead. These variations are mainly relevant for East of Pisgah, Eastern and SDG&E study areas in southern California. Resources designated as FCDS in each portfolio were modeled and dispatched as described in the previous section. EODS generation was not dispatched in this assessment.

Potential mitigation options considered to address on-peak deliverability constraints include Remedial Action Schemes (RAS), reduction of energy storage behind the constraints and transmission upgrades.

3.5.4 SCE and DCRT area on-peak deliverability results

Table 3.5-2 shows all portfolio resources inside and outside SCE/DCRT area that are likely to impact deliverability constraints in the SCE/DCRT area.

Table 3.5-2: Portfolio resources likely to impact deliverability constraints in SCE/DCRT area

Transmission Zone/Location	Full Capacity Only (MW)			
	Base Portfolio		Sensitivity 1 (S1)	Sensitivity 2 (S2)
	Base A	Base B		
Wyoming	1062 Wind	--	1,500 Wind	--
New_Mexico	--	1062 Wind	1,500 Wind	1,392 Wind
Tehachapi	4706 (395 Solar, 275 Wind, 4036 BESS)		4729 (660 Solar, 275 Wind, 3794 BESS)	3806 (395 Solar, 275 Wind, 3136 BESS)
Ventura	500 BESS		500 BESS	500 BESS
Greater_LA	1514 (313 PSH, 1201 BESS)		1701 (500 PSH, 1201 BESS)	1701 (500 PSH, 1201 BESS)
North of Lugo	341 (291 Solar, 50 BESS)		341 (291 Solar, 50 BESS)	341 (291 Solar, 50 BESS)
Pisgah	140 (14 Solar, 126 BESS)		140 (14 Solar, 126 BESS)	140 (14 Solar, 126 BESS)
Mohave_Eldorado	452 BESS		593 BESS	321 BESS
GLW/VEA	596 (348 Solar, 248 BESS)		609 (31 Solar, 442 Wind, 136 BESS)	609 (31 Solar, 442 Wind, 136 BESS)
Riverside_Palm_Springs	--		1399 (843 PSH, 556 BESS)	495 PSH
Greater Imperial (IID)	600 Geothermal		--	--
Arizona (ISO BA)	695 BESS		383 BESS	--

Metro Area: Mesa–Laguna Bell No.1 230 kV constraint

The deliverability of FC resources in parts of the Northern LA Basin, Tehachapi (Vincent 230 kV) and Ventura is limited by thermal overloading of the Mesa–Laguna Bell No.1 230 kV line under Category P7 conditions as shown in Table 3.5-3. The constraint was identified in the base and sensitivity portfolios under both HSN and SSN conditions. In the case of the Base Portfolio, a total 3,098 MW of capacity resources including 500 MW of portfolio battery storage will be undeliverable without mitigation, as shown in Table 3.5-4.

Mitigation alternatives considered to address the deliverability constraint include RAS, relocating portfolio storage, and transmission upgrades. RAS is not a viable alternative because the amount of generation tripping needed would exceed the 1,400 MW limit for a category P7 contingency and require a large number of geographically dispersed resources with small contribution factors (DFAX) to participate. Given the amount of undeliverable capacity resources due to the constraint, relocating the 500 MW portfolio battery storage at Moorpark is also not adequate to mitigate the constraint.

Table 3.5-3: Mesa–Laguna Bell 230 kV deliverability constraint

Overloaded Facility	Contingency	Condition	Loading (%)		
			Base Portfolio	S1	S2
Mesa–Laguna Bell No.1 230 kV	Mesa–Lighthipe & Mesa - Laguna Bell No.2 230 kV (P7)	HSN	114.1%	111.8%	109.0%
		SSN	104.6%	101.1%	99.3%

Table 3.5-4: Mesa–Laguna Bell 230 kV constraint summary

Affected transmission zones		Northern LA Basin, Tehachapi (Vincent 230 kV), Ventura		
		Base Portfolio	**S1**	**S2**
Renewable portfolio MW behind the constraint (installed FCDS capacity)		0 MW	0 MW	0 MW
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		500 MW	500 MW	500 MW
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0 MW	0 MW	0 MW
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		3,098 MW	3,048 MW	2,329 MW
Mitigation Options	RAS	Not applicable		
	Re-locate portfolio battery storage (MW)	Not adequate		
	Transmission upgrade including cost	1. Reconductor Laguna Bell–Mesa No. 1 230 kV line or 2. Smart Wires' Laguna Bell–Mesa Series Compensation Project		
Recommended Mitigation		Reconductor Laguna Bell—Mesa No. 1 230 kV line		

The two request window proposals for the transmission upgrade described below were evaluated to mitigate the Mesa–Laguna Bell 230 kV deliverability constraint.

1. <u>Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project</u>

   The Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project was submitted by SCE and involves reconductoring the line with High Temperature Low Sag (HTLS) conductor such as ACCC. The project results in a 31% and 42% increase in the normal and emergency ratings of the line, respectively. SCE's original cost estimate for the project was $15 million. After further evaluation, SCE has adjusted the cost to $17.3 million to include necessary upgrades of the Laguna Bell Substation terminal equipment, which were not included in the original estimate.

2. <u>Laguna Bell – Mesa Series Compensation Project</u>

   The Laguna Bell – Mesa Series Compensation Project was submitted by Smart Wires and would involve SCE installing 9 SmartValve 10-3600 units (3 units/Phase) at SCE's Mesa Substation or an alternate location in series with the Laguna Bell – Mesa No. 1 line to provide 2.31 ohm reactive injection (i.e., 7.72 kV of voltage injection) into the line. Smart Wires' is the vendor of the SmartValve technology and their conceptual estimate for the cost of the project is $6.7–$8 million.

Considering the nature of the project, the ISO requested SCE to perform a feasibility assessment of the Smart Wires' proposal. In response, SCE indicated that it has worked with Smart Wires through several meetings on the technical requirements/scope assumptions and also completed its own analysis on the site feasibility, ability to mitigate reliability issues, and cost using the same methodology as for the reconductor project.

Based on its evaluation, SCE concluded that locating the Smart Valves at Laguna Bell Substation was the only feasible location, though some transmission and substation work would be required to accommodate the installation of the SmartWires SmartValves. SCE estimated the total cost for the series compensation project located at Laguna Bell at $18.1 M. SCE's estimates do not include increased O&M costs or the projected need for a fourth valve per phase in 2031.

The ISO assessment of the Mesa–Laguna Bell 230 kV constraint mitigation alternatives

The deliverability assessment the ISO performed with each alternative modeled indicates that both alternatives mitigate the deliverability constraint. The reconductor alternative mitigates the constraint by adding new capacity to the south of Mesa 230 kV corridor while the series compensation project works by redistributing power flow on the lines. It is the ISO's assessment that the reconductoring alternative is more aligned with long-term needs because increased transmission capacity into the LA Metro load center would likely be needed to support reliability and deliverability as more and more local gas-fired generation is replaced with remotely-located renewable generation. Considering the cost of the two alternatives, which is similar, and the long-term needs of the system, the ISO recommends the Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project to mitigate the deliverability constraint.

Tehachapi Area: Windhub 500/230 kV Transformer Constraint

The deliverability of FC resources interconnecting at Windhub 230 kV bus is limited by thermal overloading of the 500/230 kV transformers under Category P1 conditions as shown in Table 3.5-5. The constraint is identified in the base and sensitivity portfolios under both HSN and SSN conditions. In the case of the Base Portfolio, 717 MW of capacity resources will be undeliverable without mitigation as shown in Table 3.5-6. The constraint can be mitigated by the planned Windhub CRAS, which can be expanded to include the new resources.

Table 3.5-5: Windhub 500/230 kV transformer deliverability constraint

Overloaded Facility	Contingency	Condition	Loading (%)		
			Base Portfolio	S1	S2
Windhub #3 or #4 500/230 kV transformer	Windhub #3 or #4 500/230 kV transformer	HSN	154.0%	160.0%	142.3%
		SSN	127.0%	132.8%	116.4%
Windhub #1 or #2 500/230 kV transformer	Windhub #1 or #2 500/230 kV transformer	HSN	115.6%	122.1%	115.6%
		SSN	<100%	<100%	<100%

Table 3.5-6: Windhub 500/230 kV transformer constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="3">Tehachapi (Windhub 230 kV)</td></tr>
<tr><td colspan="2"></td><td>Base Portfolio</td><td>S1</td><td>S2</td></tr>
<tr><td colspan="2">Renewable portfolio MW behind the constraint (installed FCDS capacity)</td><td>275</td><td>275</td><td>275</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>1,008</td><td>1,081</td><td>860</td></tr>
<tr><td colspan="2">Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>568</td><td>569</td><td>566</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW (Installed FCDS capacity)</td><td>715</td><td>787</td><td>569</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td colspan="3">Planned Windhub CRAS</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td colspan="3">Not needed</td></tr>
<tr><td>Transmission upgrade including cost</td><td colspan="3">Not needed</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="3">Planned Windhub CRAS</td></tr>
</table>

Eastern Area: Red Bluff - Devers 500 kV constraint

The deliverability of FC resources interconnecting in the Eastern area is limited by thermal overloading of the Red Bluff – Devers 500 kV line under Category P1 conditions as shown in Table 3.5-7. The constraint is identified in the sensitivity portfolios under both HSN and SSN conditions. The constraint can be mitigated by the planned West of Colorado River CRAS, which can be expanded to include the new resources as shown in Table 3.5-8.

Table 3.5-7: Red Bluff – Devers 500 kV Deliverability Constraint

<table>
<tr><th rowspan="2">Overloaded Facility</th><th rowspan="2">Contingency</th><th rowspan="2">Condition</th><th colspan="3">Loading (%)</th></tr>
<tr><th>Base Portfolio (A and B)</th><th>S1</th><th>S2</th></tr>
<tr><td rowspan="2">Red Bluff - Devers 500 kV No.1 line</td><td rowspan="2">Red Bluff – Devers 500kV No.2 line</td><td>HSN</td><td><100%</td><td>101%</td><td><100%</td></tr>
<tr><td>SSN</td><td><100%</td><td>111%</td><td><100%</td></tr>
<tr><td rowspan="2">Red Bluff – Devers 500kV No.2 line</td><td rowspan="2">Red Bluff – Devers 500kV No.1 line</td><td>HSN</td><td><100%</td><td>101%</td><td><100%</td></tr>
<tr><td>SSN</td><td><100%</td><td>108%</td><td><100%</td></tr>
</table>

Table 3.5-8: Red Bluff – Devers 500 kV Constraint Summary

Affected transmission zones		Riverside and Palm Springs			
		Base		**S1**	**S2**
		A	**B**		
Renewable portfolio MW behind the constraint		0	1,062	2,343	1,887
Energy storage (ES) portfolio MW behind the constraint		695	695	940	0
Deliverable portfolio MW without mitigation		695	1,757	2,635	1,887
Total undeliverable baseline and portfolio MW		0	0	648	0
Mitigation Options	RAS	Not needed		West of Colorado River CRAS	Not needed
	Re-locate portfolio battery storage (MW)			Not needed	
	Transmission upgrade including cost				
Recommended Mitigation		Not needed		West of Colorado River CRAS	Not needed

3.5.5 VEA and GLW area on-peak deliverability results

All portfolio resources inside and outside the GLW/VEA area that are likely to be impacted by deliverability constraints in the GLW/VEA area are shown in Table 3.5-9.

Table 3.5-9: Portfolio resources likely to be impacted by deliverability constraints in VEA/GLW area

TX Zone / Location	**Full Capacity Only (MW)**		
	Base Portfolio (A and B)	**Sensitivity-1 (S1)**	**Sensitivity 2 (S2)**
Southern_Nevada_Solar	348	31	31
Southern_Nevada_Wind	-	442	442
SCADSNV_Z2_GLW_VEA (BESS)	248.3	136	136

There were no on-peak deliverability constraints identified in VEA and GLW study area in the Base, Sensitivity 1 and Sensitivity 2 portfolios[125].

125 See discussion in the Off-Peak Deliverability assessment section on the VEA and GLW area regarding the ISO system capability to deliver the portfolio resources without relying on the neighboring systems.

3.5.6 SDG&E area deliverability results

All portfolio resources inside and outside the SDG&E area that are likely to be impacted by deliverability constraints in the SDG&E area are shown in Table 3.5-10.

Table 3.5-10: Portfolio resources likely to be impacted by deliverability constraints in SDG&E area

TX Zone / Location	Full Capacity Only (MW)			
	Base Portfolio		Sensitivity-1 (S1)	Sensitivity 2 (S2)
	Base A	Base B		
New Mexico Wind	-	1062	-	-
Arizona Solar	-		-	-
Arizona BESS	695		383	-
Greater Imperial Solar	-		600	600
Greater Imperial Geothermal (Bannister)	600		-	-
Baja California Wind	495		495	495
Pumped Hydro Storage (Sycamore Canyon)	314		500	500
SDGE BESS	1,170		1,170	1,170

Doublet Tap-Friars 138 kV constraint

The deliverability of portfolio resources in the Doublet Tap-Friars 138 kV area is limited by thermal overloading of the Doublet Tap-Friars 138 kV line as shown in Table 3.5-11. This constraint was identified for the base portfolio and both of the sensitivity portfolios in the HSN and/or SSN scenarios. As shown in Table 3.5-12, approximately 713 MW of base portfolio generation would be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation at Otay Mesa. Another mitigation option is to reconductor the overloaded line (i.e. Options 1 or 2). Option 1 was submitted as a Request Window project but was determined to not meet the potential long-term needs of the area. Option 2 would potentially meet the long-term needs of the area but needs more analysis. The P7 contingency overload would also be eliminated by rearranging the Old Town-Penasquitos 230 kV line and Penasquitos-Mira Sorrento 69 kV line, so that the P7 outage would be eliminated.

Table 3.5-11: Doublet Tap-Friars 138 kV constraint

Overloaded Facility	Contingency	Condition	Loading (%)		
			Base Portfolio (A and B)	S1	S2
Doublet Tap-Friars 138 kV	Old Town-Penasquitos and Sycamore Penasquitos 230 kV	HSN	<100	108	101
		SSN	103	115	113

Table 3.5-12: Doublet Tap-Friars 138 kV deliverability constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="3">Greater Imperial Solar, SDGE BESS</td></tr>
<tr><td colspan="2"></td><td>Base Portfolio (A and B)</td><td>S1</td><td>S2</td></tr>
<tr><td colspan="2">Renewable portfolio MW behind the constraint (installed FCDS capacity)</td><td>314</td><td>500</td><td>500</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>500</td><td>500</td><td>500</td></tr>
<tr><td colspan="2">Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>713</td><td>370</td><td>425</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW (Installed FCDS capacity)</td><td>101</td><td>630</td><td>575</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td colspan="3">Planned RAS to trip Otay Mesa area generation</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td>Re-locate 100 MW</td><td colspan="2">Not Adequate</td></tr>
<tr><td>Transmission upgrade</td><td colspan="3">Option 1: Reconductor TL13810A Friars - Doublet Tap 138 kV line to 204 MVA ($5.5M)
Option 2: Reconductor TL13810A Friars - Doublet Tap 138 kV line to 325 MVA ($48M)
Option 3: Rearrange TL23013 and TL6959 ($19M)</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="3">Planned RAS to trip Otay Mesa area generation</td></tr>
</table>

San Marcos-Melrose Tap 69 kV constraint

The deliverability of portfolio resources in the San Marcos-Melrose Tap 69 kV area is limited by thermal overloading of the San Marcos-Melrose Tap 69 kV line as shown in Table 3.5-13. This constraint was identified for the base portfolio and both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-14, there is an existing RAS that can be modified to mitigate this overload. No base portfolio generation would be deliverable without this RAS or some other transmission upgrade. The overload can also be mitigated by reconductoring the overloaded line.

Table 3.5-13: San Marcos-Melrose Tap 69 kV constraint

Overloaded Facility	Contingency	Condition	Loading (%)		
			Base Portfolio (A and B)	S1	S2
San Marcos-Melrose Tap 69 kV	Encina-San Luis Rey 230 kV and Encina-San Luis Rey-Palomar 230 kV	HSN	117	134	126
		SSN	151	170	168
	Encina-San Luis Rey-Palomar 230 kV and Palomar-Artesian 230 kV	HSN	<100	<100	<100
		SSN	<100	101	101

Table 3.5-14: San Marcos-Melrose Tap 69 kV deliverability constraint summary

Affected transmission zones		Greater Imperial Solar, SDGE BESS		
		Base Portfolio (A and B)	**S1**	**S2**
Renewable portfolio MW behind the constraint (installed FCDS capacity)		314	500	500
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		710	710	710
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		1124	1403	1382
Mitigation Options	RAS	Existing/modified TL684 RAS to open Melrose Tap-San Marcos 69 kV line. Existing RAS monitors flow on TL684 Escondido-San Marcos and opens TL680C Melrose Tap-San Marcos. RAS needs to be modified to monitor flow on TL680C	Existing/modified TL684 RAS to open Melrose Tap-San Marcos 60 kV line. Opening line results in overloads on Mission-San Luis Rey 230 kV #1 and #2 lines, need to trip Encina gen to mitigate. Existing RAS monitors flow on TL684 Escondido-San Marcos and opens TL680C Melrose Tap-San Marcos. RAS needs to be modified to monitor flow on TL680C	
	Re-locate portfolio battery storage (MW)	Not Adequate		
	Transmission upgrade	Reconductor TL680C San Marcos - Melrose Tap 69 kV line ($28M)		
Recommended Mitigation		Existing/modified TL684 RAS to open Melrose Tap-San Marcos 69 kV line	Existing/modified TL684 RAS to open Melrose Tap-San Marcos 69 kV line and planned RAS to trip Encina generation	

Encina-San Luis Rey 230 kV constraint

The deliverability of portfolio resources in the SDG&E area is limited by thermal overloading of 230 kV lines in the Encina/San Luis Rey area as shown in Table 3.5-15. This constraint was identified for the base portfolio and both of the sensitivity portfolios in the HSN and/or SSN scenarios. As shown in Table 3.5-16, no portfolio generation in the base portfolio would be deliverable without any transmission upgrades. In the base portfolio, the constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-15: Encina-San Luis Rey 230 kV constraint

Overloaded Facility	Contingency	Condition	Loading (%)		
			Base Portfolio (A and B)	S1	S2
Encina-Encina Tap 230 kV	Encina-San Luis Rey 230 kV	HSN	<100	<100	<100
		SSN	107	119	118
Encina Tap-San Luis Rey 230 kV		HSN	112	126	118
		SSN	139	154	152
Encina-San Luis Rey 230 kV	San Luis Rey-Encina-Palomar 230 kV	HSN	100	112	105
		SSN	124	137	135
Encina-San Luis Rey 230 kV	San Luis Rey-Encina-Palomar 230 kV and - Palomar-Batiquitos 138 kV or - Encina-Palomar 138 kV or - Batiquitos-Shadowridge 138 kV	HSN	100	112	105
		SSN	124	137	135
	San Luis Rey-Encina-Palomar 230 kV and Palomar-Artesian 230 kV	HSN	101	114	106
		SSN	124	139	138
Encina-San Luis Rey 230 kV	San Luis Rey-Mission 230 kV #1 and #2	SSN	<100	<100	<100
		SSN	<100	103	102
Encina Tap-San Luis Rey 230 kV		HSN	<100	<100	<100
		SSN	100	111	110
Mission-San Luis Rey 230 kV #1	Encina-San Luis Rey 230 kV and Encina-San Luis Rey-Palomar 230 kV	HSN	<100	<100	<100
		SSN	<100	108	107
Mission-San Luis Rey 230 kV #2		HSN	<100	<100	<100
		SSN	<100	110	108

Table 3.5-16: Encina-San Luis Rey 230 kV deliverability constraint summary

Affected transmission zones		Baja California Wind, Greater Imperial Solar, SDGE BESS		
		Base Portfolio (A and B)	**S1**	**S2**
Renewable portfolio MW behind the constraint (installed FCDS capacity)		809	1595	1595
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		720	720	720
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		1609	2496	2431
Mitigation Options	RAS	Planned RAS to trip Encina generation	Planned RAS to trip Encina not sufficient in SSN scenario	
	Re-locate portfolio battery storage (MW)	Not Adequate		
	Transmission upgrade	New Encina-San Luis Rey 230 kV line ($102M)		
Recommended Mitigation		Planned RAS to trip Encina generation	New Encina-San Luis Rey 230 kV line ($102M)	

San Luis Rey-San Onofre 230 kV constraint

The deliverability of portfolio resources in the SDG&E area is limited by thermal overloading of the San Luis Rey-San Onofre 230 kV line as shown in Table 3.5-17. This constraint was identified for the base portfolio and both of the sensitivity portfolios in the HSN and/or SSN scenarios. As shown in Table 3.5-18, approximately 265 MW of base portfolio generation would be deliverable without any transmission upgrades. For the base portfolio, the constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-17: San Luis Rey-San Onofre 230 kV constraint

Overloaded Facility	**Contingency**	**Condition**	**Loading (%)**		
			Base Portfolio (A and B)	**S1**	**S2**
San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	HSN	<100	108	100
		SSN	129	145	142

Table 3.5-18: San Luis Rey-San Onofre 230 kV deliverability constraint summary

Affected transmission zones		Baja California Wind, Greater Imperial Solar, SDGE BESS		
		Base Portfolio (A and B)	**S1**	**S2**
Renewable portfolio MW behind the constraint (installed FCDS capacity)		809	1595	1595
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		720	720	720
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		265	233	311
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		1264	2082	2004
Mitigation Options	RAS	Planned RAS to trip Encina generation	Planned RAS to trip Encina not sufficient in SSN scenario	
	Re-locate portfolio battery storage (MW)	Not adequate		
	Transmission upgrade	New San Luis Rey-San Onofre 230 kV line ($237M)		
Recommended Mitigation		Planned RAS to trip Encina generation	New San Luis Rey-San Onofre 230 kV line ($237M)	

3.5.7 PG&E area on-peak deliverability results

Table 3.5-19 shows all portfolio resources in Northern California and outside Northern California that are likely to be impacted by deliverability constraints in the PG&E area.

The offshore wind detailed study in the Sensitivity 2 Portfolio is provided in section 3.7. For the interconnection of the 1,607 MW Humboldt offshore wind in Sensitivity 2 Portfolio the following three alternatives were assessed:

- Option 1: Humboldt offshore wind injected into Fern Road 500 kV substation via radial 500 kV AC lines
    - Fern Road 500 kV substation is planned to be in service by 2024 as part of Round Mountain DRS project and is located 11 miles south of Round Mountain substation.
- Option 2: Humboldt offshore wind injected into a new a HVDC converter station in the Bay Area via HVDC subsea cables
    - The converter station will have 230 kV connections to the existing substations in San Francisco Peninsula, South Bay and East Bay areas.
- Option 3: LCC HVDC Bipole to Collinsville 500/230 kV substation
    - Collinsville 500 kV substation would loop into the Vaca Dixon – Tesla 500 kV line and have two 230 kV connections to the Pittsburg 230 kV substation.

Table 3.5-19: Portfolio resources likely to be impacted by constraints in PG&E area

Transmission Delivery Zone	Full Capacity Only (MW)				
	Base	SENS-01	SENS-02		
			Option 1	Option 2	Option 3
Northern California	589 Wind	589 Wind	589 Wind	589 Wind	589 Wind
Solano	107.4 (102 Wind + 5.4 BESS)	102 Wind	102 Wind	102 Wind	102 Wind
Westlands	733 Solar	733 Solar	-	-	-
Humboldt OSW	-	-	1,607	1,607	1,607
Diablo Canyon OSW	-	-	4,419	4,419	4,419
Morro Bay OSW	-	-	2,324	2,324	2,324

With the resource mix specified in Table 3.5-19 modeled in the base cases, the On-Peak deliverability assessment identified the following constraints in PG&E study areas:

<u>Round Mountain-Fern Road #1 and #2 500 kV lines on-peak deliverability constraint</u>

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Round Mountain-Fern Road 500 kV line under N-1 conditions as shown in Table 3.5-20. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table 3.5-21, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by a previously recommended RAS to bypass the series compensation on the remaining line. For Sensitivity 2 the base case overload will be mitigated below in the Fern Road-Table Mountain constraint.

Table 3.5-20: Round Mountain-Fern Road-Table Mountain #1 and #2 500 kV lines on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Round Mountain-Fern Road #1 and #2 500 kV lines	Round Mountain-Fern Road #2 or #1 500 kV lines	HSN	113%	116%	104%	111%	111%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.5-21: Round Mountain-Fern Road-Table Mountain #1 and #2 500 kV lines on-peak deliverability constraint summary

Affected transmission zones		Northern California				
		Base Portfolio	**S1 Portfolio**	**S2 Portfolio**		
				Option 1	**Option 2**	**Option 3**
Renewable portfolio MW behind the constraint (installed FCDS capacity)		437 Wind	437 Wind	437 Wind	437 Wind	437 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		0	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		1,393	1,957	579	1,155	1,232
Mitigation Options	RAS	Yes, previously identified in TPP				
	Re-locate portfolio battery storage (MW)	Not needed				
	Transmission upgrade including cost	Not needed				
Recommended Mitigation		RAS to bypass the series capacitor on the remaining line (split into columns and have note to refer to below table for base case situations)				

Delevan-Cortina 230 kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in Northern California area is limited by thermal overloading of the Delevan-Cortina 230 kV line under N-2 as well as N-0 conditions as shown in Table 3.5-22. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table 3.5-23, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. There is a base case overload, therefore RAS is not a viable option. The constraint can be mitigated by reconductoring the line.

Table 3.5-22: Delevan-Cortina 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Delevan-Cortina 230 kV line	Base Case	HSN	101%	102%	107%	100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
	Olinda-Tracy 500 kV Line	HSN	114%	116%	122%	112%	109%
		SSN	<100%	<100%	<100%	<100%	<100%
	Delevan-Vaca Dixon #2 and #3 230 kV lines	HSN	118%	120%	126%	118%	114%
		SSN	<100%	<100%	101%	<100%	<100%

Table 3.5-23: Delevan-Cortina 230 kV line on-peak deliverability constraint summary

Affected transmission zones		Northern California				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		437 Wind	437 Wind	437 Wind	437 Wind	437 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		0	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		564	588	713	538	479
Mitigation Options	RAS	No applicable, N-0 overload				
	Re-locate portfolio battery storage (MW)	Not applicable				
	Transmission upgrade including cost	Reconductor the Delevan-Cortina 230 kV line ($17.7M - $35.4M)				
Recommended Mitigation		Reconductor the Delevan-Cortina 230 kV line ($17.7M - $35.4M)				

Cayetano-North Dublin 230 kV line on-peak deliverability constraint

The deliverability of renewable and energy storage portfolio resources in the Solano area is limited by thermal overloading of the Cayetano-North Dublin 230 kV line under N-2 conditions as shown in Table 3.5-24. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table 3.5-25, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was ruled out due to the complexity. The RAS would need to encompass the larger area and requires remote monitoring. The new Collinsville 500 kV substation has been identified as the mitigation.

Table 3.5-24: Cayetano-North Dublin 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Cayetano-North Dublin 230 kV line	Contra Costa-Morago #1 and #2 230 kV lines	HSN	106%	107%	110%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%

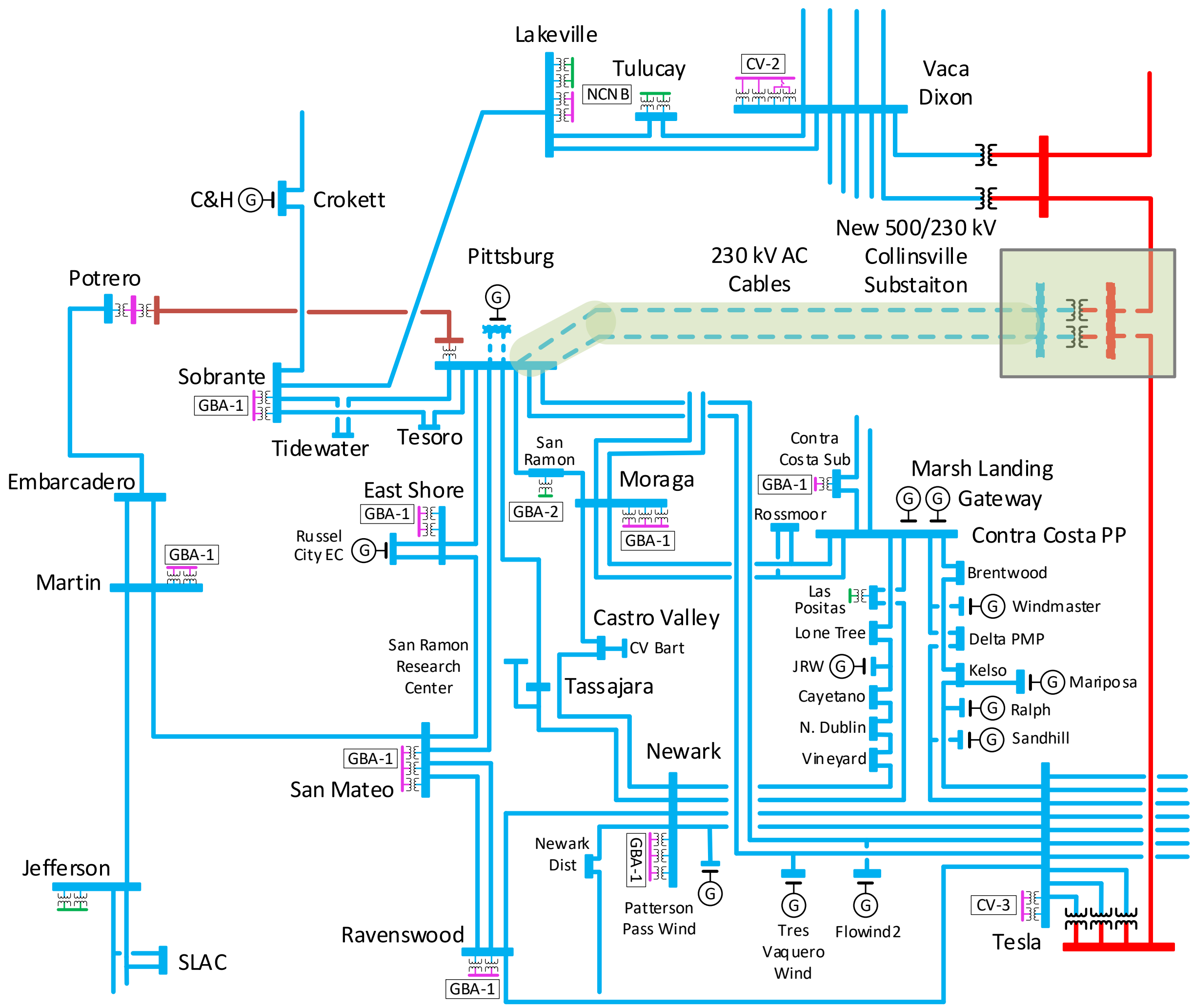
Table 3.5-25: Cayetano-North Dublin 230 kV line on-peak deliverability constraint summary

Affected transmission zones		Solano				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		102 Wind	102 Wind	102 Wind	102 Wind	102 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		5.4	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	102	102
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		260	299	422	0	0
Mitigation Options	RAS	No, remote monitoring (RAS Guideline violation)				
	Re-locate portfolio battery storage (MW)	Not applicable				
	Transmission upgrade including cost	Reconductor the line ($42.4M – $55.1M) or New Collinsville 500 kV substation ($475M – $675M)				
Recommended Mitigation		New Collinsville 500 kV substation ($475M – $675M)				

Collinsville 500/230 kV substation project

The Collinsville 500/230 kV substation project will address a number of identified transmission constrains within the base portfolio (Cayetano-North Dublin 230 kV line, Lone Tree-USWP-JRW-Cayetano 230 kV line, and Las Positas-Newark 230 kV line) and provide an additional supply from the 500 kV system into the northern Greater Bay Area to increase reliability to the area and advance additional renewable generation in the northern area.

Figure 3.5-1: Collinsville 500/230 kV substation project interconnection



The scope of the Collinsville 500/230 kV substation project is as follows:

- A new Collinsville 500/230 kV substation looping in Vaca Dixon – Tesla 500 kV line
- Two 500/230 kV transformers with 1,500 MVA ratings
- Two 230 kV cables between Collinsville and Pittsburg 230 kV.

- The series capacitor on the Vaca Dixon – Tesla 500 kV line is currently all at Vaca Dixon substation. As part of the project, the series capacitor at Vaca Dixon will be reduced and new series caps will be installed on the Collinsville – Tesla 500 kV line at Collinsville substation to keep the compensation level on each line section the same as what is currently between Vaca Dixon and Tesla (~%75)

The estimated cost of the Collinsville 500/230 kV substation project is $475-675 million with an expected in-service date of 2028.

<u>Lone Tree-USWP-JRW-Cayetano 230 kV line on-peak deliverability constraint</u>

The deliverability of renewable and energy storage portfolio resources in the Solano-Sacramento River area is limited by thermal overloading of the Lone Tree-USWP-JRW-Cayetano 230 kV line under N-0 conditions as shown in Table 3.5-26. This constraint was identified in the baseline portfolio under HSN conditions. As shown in Table 3.5-27, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was ruled out due to N-0 overloads. The new Collinsville 500 kV substation has been identified as the mitigation.

Table 3.5-26: Lone Tree-USWP-JRW-Cayetano 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Lone Tree-USWP-JRW-Cayetano 230 kV line (Lonetree-USWP JRW)	Contra Costa-Morago #1 and #2 230 kV lines (also Base Case overload)	HSN	100%	101%	105%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Lone Tree-USWP-JRW-Cayetano 230 kV line (USWP JRW-Cayetano)	Base Case	HSN	101%	101%	103%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Lone Tree-USWP-JRW-Cayetano 230 kV line (USWP JRW-Cayetano)	Contra Costa-Las Positas 230 kV Line	HSN	104%	104%	106%	<100%	100%
		SSN	<100%	<100%	<100%	<100%	<100%
Lone Tree-USWP-JRW-Cayetano 230 kV line (USWP JRW-Cayetano)	Contra Costa-Morago #1 and #2 230 kV lines	HSN	111%	112%	115%	105%	104%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.5-27: Lone Tree-USWP-JRW-Cayetano 230 kV line on-peak deliverability constraint summary

Affected transmission zones		Solano				
		Base Portfolio	**S1 Portfolio**	**S2 Portfolio**		
				Option 1	**Option 2**	**Option 3**
Renewable portfolio MW behind the constraint (installed FCDS capacity)		102 Wind	102 Wind	102 Wind	102 Wind	102 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		5.4	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		500	533	642	218	201
Mitigation Options	RAS	No, N-0 overloads				
	Re-locate portfolio battery storage (MW)	Not applicable				
	Transmission upgrade including cost	Reconductor the line ($55.1M – $71.6M) New Collinsville 500 kV substation ($475M – $675M)				
Recommended Mitigation		New Collinsville 500 kV substation ($475M – $675M)				

Las Positas-Newark 230 kV line on-peak deliverability constraint

The deliverability of renewable and energy storage portfolio resources in the Solano-Sacramento River area is limited by thermal overloading of the Las Positas-Newark 230 kV line under N-2 conditions as shown in Table 3.5-28. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table 3.5-29, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was ruled out due to the complexity. The RAS would need to encompass the larger area and requires remote monitoring. The new Collinsville 500 kV substation has been identified as the mitigation.

Table 3.5-28: Las Positas-Newark 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading BASE	Loading SENS-01	Loading SENS-02 Option 1	Loading SENS-02 Option 2	Loading SENS-02 Option 3
Las Positas-Newark 230kV line	Contra Costa-Delta Switchyard 230kV Line	HSN	103%	101%	106%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Las Positas-Newark 230kV line	Contra Costa-Morago #1 and #2 230kV lines	HSN	116%	115%	121%	102%	107%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.5-29: Las Positas-Newark 230kV line on-peak deliverability constraint summary

Affected transmission zones		Solano				
		Base Portfolio	S1 Portfolio	S2 Portfolio Option 1	S2 Portfolio Option 2	S2 Portfolio Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		102 Wind	102 Wind	102 Wind	102 Wind	102 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		5.4	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		510	476	638	116	253
Mitigation Options	RAS	No, remote monitoring (RAS Guideline violation)				
	Re-locate portfolio battery storage (MW)	Not applicable				
	Transmission upgrade including cost	Reconductor the line ($47.65M – $62M) New Collinsville 500 kV substation ($475M – $675M)				
Recommended Mitigation		New Collinsville 500 kV substation ($475M – $675M)				

Rio Oso-SPI Jct-Lincoln 115 kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Sacramento River area is limited by thermal overloading of the Rio Oso-SPI Jct-Lincoln 115kV line under N-2 conditions as shown in Table 3.5-30. This constraint was identified in the baseline portfolio under HSN conditions. As shown in Table 3.5-31, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was considered but due to remote monitoring criteria, it has been rejected. The same constraint has been previously identified in GIDAP and reconductoring the Rio Oso-SPI Jct-Lincoln 115kV line has been identified as the mitigation.

Table 3.5-30: Rio Oso-SPI Jct-Lincoln 115 kV line on-peak deliverability constraint

<table>
<tr><th rowspan="3">Overloaded Facility</th><th rowspan="3">Contingency</th><th rowspan="3"></th><th colspan="5">Loading</th></tr>
<tr><th rowspan="2">BASE</th><th rowspan="2">SENS-01</th><th colspan="3">SENS-02</th></tr>
<tr><th>Option 1</th><th>Option 2</th><th>Option 3</th></tr>
<tr><td rowspan="2">Rio Oso-SPI Jct-Lincoln 115kV line</td><td rowspan="2">Rio Oso-Atlantic and Rio Oso-Gold Hill 230kV lines</td><td>HSN</td><td>115%</td><td>115%</td><td>122%</td><td>114%</td><td>115%</td></tr>
<tr><td>SSN</td><td><100%</td><td><100%</td><td><100%</td><td><100%</td><td><100%</td></tr>
</table>

Table 3.5-31: Rio Oso-SPI Jct-Lincoln 115kV line on-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="5">Northern California</td></tr>
<tr><td colspan="2" rowspan="2"></td><th rowspan="2">Base Portfolio</th><th rowspan="2">S1 Portfolio</th><th colspan="3">S2 Portfolio</th></tr>
<tr><th>Option 1</th><th>Option 2</th><th>Option 3</th></tr>
<tr><td colspan="2">Renewable portfolio MW behind the constraint (installed FCDS capacity)</td><td>152 Wind</td><td>152 Wind</td><td>152 Wind</td><td>152 Wind</td><td>152 Wind</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)</td><td>396</td><td>403</td><td>615</td><td>368</td><td>395</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td colspan="5">No, remote monitoring (RAS Guideline violation)</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td colspan="5">Not applicable</td></tr>
<tr><td>Transmission upgrade including cost</td><td colspan="5">Reconductor the line ($10.6M - $21.2M)</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="5">Transmission Upgrade</td></tr>
</table>

Borden-Storey #2 230kV line on-peak deliverability constraint

The deliverability of renewable and energy storage portfolio resources in the Solano-Sacramento River area is limited by thermal overloading of the Borden-Storey #2 230kV line under N-1 conditions as shown in Table 3.5-32. This constraint was identified in the baseline portfolio under SSN conditions. RAS was considered but due to remote monitoring it has been rejected. As shown in Table 3.5-33, 659 MW of renewable and energy storage would be deliverable without any transmission upgrades. The new Manning 500 kV substation has been identified as the mitigation.

Table 3.5-32: Borden-Storey #2 230kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Borden-Storey #2 230kV line	Borden-Storey #1 230kV line	HSN	<100%	<100%	<100%	<100%	<100%
		SSN	104%	105%	<100%	<100%	<100%

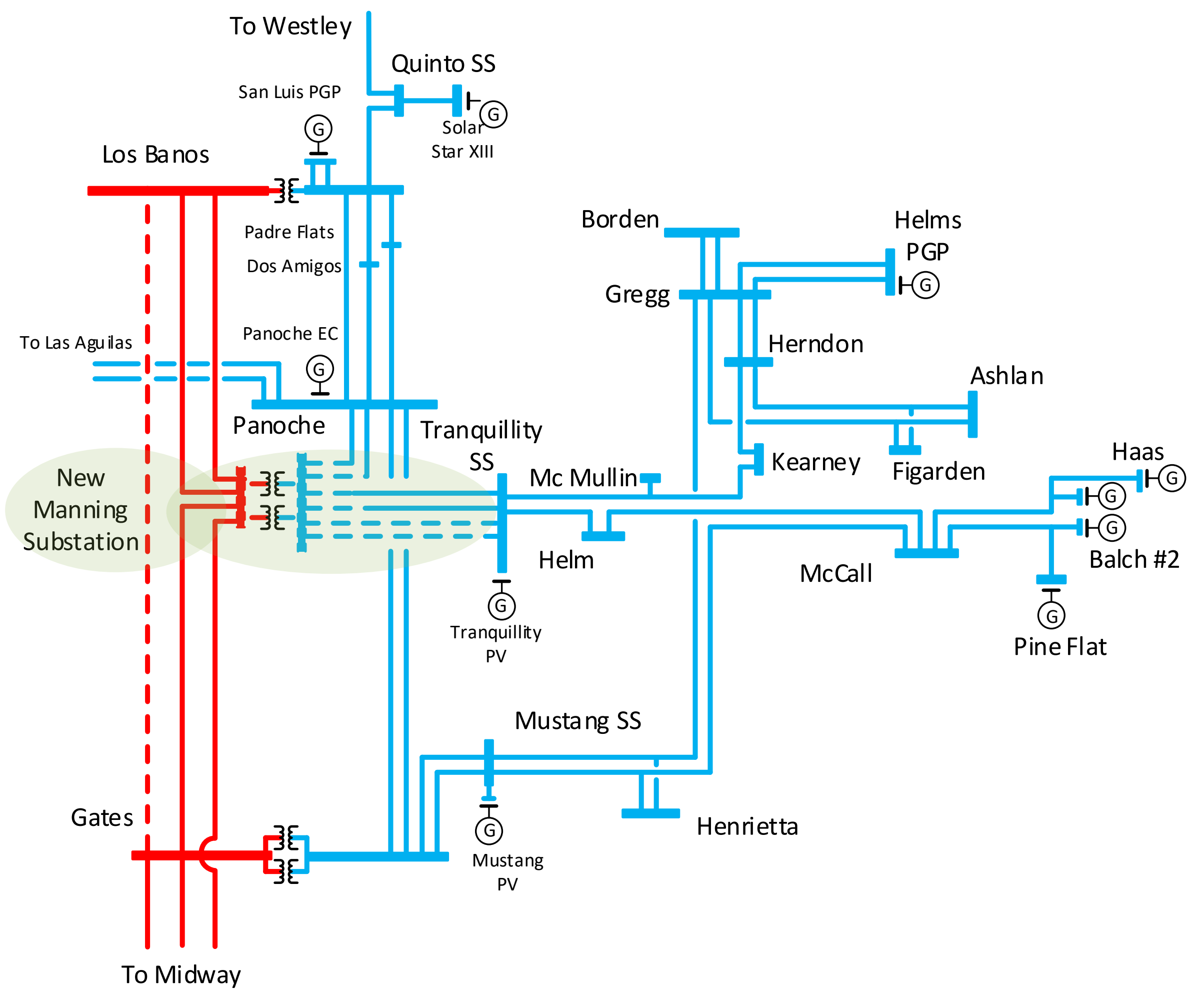
Table 3.5-33: Borden-Storey #2 230kV line on-peak deliverability constraint summary

Affected transmission zones		Westlands				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		733 Solar	733 Solar	0	0	0
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		0	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		659	552	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		44	181	0	0	0
Mitigation Options	RAS	No, remote monitoring (RAS Guideline violation)		Not Needed		
	Re-locate portfolio battery storage (MW)	Not applicable		Not Needed		
	Transmission upgrade including cost	Reconductor the line ($24.24M – $31.5M) New Manning 500/230 kV substation ($325M – $485M)		Not Needed		
Recommended Mitigation		New Manning 500/230 kV substation		Not Needed		

Manning 500 kV Substation

The addition of the Manning 500 kV substation will allow for the advancement of renewable generation within the Westlands or San Joaquin area that has been identified with significant least-conflict lands for potential solar development[126]. In addition, within the SB100 analysis, the California Energy Commission has identified this area as having significant potential for solar development for the state to meet its long-term GHG goals. The ISO is recommending the Manning Station in advance of the needs within the current portfolios to advance the development of solar generation within the San Joaquin area and defer the need for upgrades to transmission lines in the area, such as reconductoring the Borden-Storey 230 kV lines.

Figure 3.5-2: Manning 500/230 kV substation interconnection



126 https://sjvp.databasin.org/pages/least-conflict/

The scope of the Manning 500/230 kV substation project is as follows:

- A new Manning 500/230 kV substation looping in Los Banos – Midway #2 and Los Banos – Gates #1 500 kV lines
- Two 500/230 kV transformers at Manning substation with 1,122 MVA ratings
- Loop in existing Panoche – Tranquility 230 kV lines into the new Manning substation
- Reconductor Manning – Tranquility 230 kV lines to have 1,195 MVA SN/SE ratings
- Build a new double circuit 230 kV line between Manning and Tranquility with 1,195 MVA SN/SE ratings
- The series capacitor on the Los Banos – Midway #2 and Los Banos – Gates #1 lines are currently all at or close to the Gates substation. As part of the Manning 500/230 kV project, the existing series capacitor at the Gates substation will be reduced and new series caps will be installed on the Manning – Los Banos 500 kV lines at Manning substation to keep the compensation level on each line section the same as what is currently between Los Banos and Gates (~%55)

The estimated cost of the Manning 500/230 kV project is $325-485 million with an expected in-service date of 2028.

Fulton 60kV lines on-peak deliverability constraint

The deliverability of renewable and energy storage portfolio resources in the area is limited by thermal overloading of the Fulton 60kV lines under N-2 conditions as shown in Table 3.5-34. This constraint was identified in the baseline portfolio under HSN and SSN conditions. As shown in Table 3.5-35, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades.

RAS, which requires infrastructure and new equipment for the Fulton Substation, was considered with a total cost estimate of $20M. Due to high cost, it was rejected.

Possible mitigation has been evaluated with the option of reconductoring different sections of the Fulton-Hopland 60 kV line. High level estimate indicates that reconductoring the overloaded sections could cost between $69 and $138M.

Due to the high cost of alternatives considered, the ISO is exploring other economically viable options with PG&E, which includes voltage conversion of a parallel 60kV path from the Fulton substation to the Mendocino substation, or to build a new 60kV line, which could bring numerous additional benefit such as increasing the transfer capability and reducing the LCR in the local areas.

Table 3.5-34: Fulton 60kV lines on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Fulton 60kV Lines	Geysers #9-Lakeville and Eagle Rock-Fulton-Silverado 115kV lines	HSN	112%	115%	117%	105%	<100%
		SSN	110%	108%	112%	105%	<100%

Table 3.5-35: Fulton 60kV lines on-peak deliverability constraint summary

Affected transmission zones		N/A				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		0	0	0	0	0
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		0	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		40	40	38	13	0
Mitigation Options	RAS	Rejected due to high cost				Not Needed
	Re-locate portfolio battery storage (MW)	Not applicable				Not Needed
	Transmission upgrade including cost	Reconductoring the existing two 60 kV Line sections was rejected due to high cost				Not Needed
Recommended Mitigation		ISO is exploring other cost-effective alternatives				Not Needed

Humboldt 60kV lines on-peak deliverability constraint

The deliverability of renewable storage portfolio resources in the area is limited by thermal overloading of the Humboldt 60kV lines under N-0, N-1 and N-2 conditions as shown in Table

3.5-36. This constraint was identified in the baseline portfolio under HSN and SSN conditions. As shown in Table 3.5-37, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was considered, which requires infrastructure and new equipment for both Humboldt substation and Humboldt Bay. The total cost estimate is $16 - $23M. Due to high cost, it was rejected.

Other possible mitigation has been evaluated with the option of reconductoring the entire Bridgeville-Garberville 60kV line, the entire Rio Dell Jct.-Bridgeville 60kV line and the line section from Humboldt Jct.-Humboldt of Humboldt Bay-Humboldt #1 60 kV Line. Due to the high cost of alternatives considered, the ISO is exploring other economically viable options with PG&E, which could include building a new 60 or 115kV line, which could bring numerous additional benefit such as increasing the transfer capability and reducing the LCR in the local areas.

Table 3.5-36: Humboldt 60kV lines on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Humboldt 60kV Lines	Base Case	HSN	117%	110%	108%	104%	102%
		SSN	110%	<100%	<100%	<100%	<100%
	Eagle Rock-Cortina and Cortina-Mendocino 115k'V lines	HSN	117%	122%	124%	118%	114%
	Bridgeville-Cottonwood 115 kV Line	SSN	110%	110%	105%	104%	103%

Table 3.5-37: Humboldt 60kV lines on-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="5">N/A</td></tr>
<tr><td colspan="2" rowspan="2"></td><td rowspan="2">Base Portfolio</td><td rowspan="2">S1 Portfolio</td><td colspan="3">S2 Portfolio</td></tr>
<tr><td>Option 1</td><td>Option 2</td><td>Option 3</td></tr>
<tr><td colspan="2">Renewable portfolio MW behind the constraint (installed FCDS capacity)</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)</td><td>80</td><td>106</td><td>110</td><td>87</td><td>68</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td colspan="5">Rejected due to high cost</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td colspan="5">Not applicable</td></tr>
<tr><td>Transmission upgrade including cost</td><td colspan="5">Reconductoring the existing three 60 kV Lines was rejected due to high cost</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="5">ISO is exploring other cost-effective alternatives</td></tr>
</table>

3.6 Off-Peak Deliverability assessment

The ISO modified its on-peak deliverability assessment to reflect the changing contribution of solar to meeting resource adequacy needs. Additional solar resources provide a much lower incremental resource adequacy benefit to the system than the initial solar resources, because their output profile ceases to align with the peak hour of demand on the transmission system which has shifted to later in the day due to the proliferation of behind-the-meter solar. As a result, there is a reduced need for transmission upgrades to support deliverability of additional solar resources for resource adequacy purposes. Generation developers have been relying on transmission upgrades required under the previous on-peak deliverability assessment methodology to ensure that generation would not be exposed to excessive curtailment due to transmission limitations. Therefore, the off-peak deliverability assessment methodology[127] was developed to address renewable energy delivery during hours outside of the summer peak load period to ensure some minimal level of protection from otherwise potentially unlimited curtailment.

Accordingly, the key objectives of the policy-driven off-peak deliverability assessment are to:

- Identify transmission constraints that would cause excessive renewable curtailment in accordance with the off-peak deliverability methodology
- Identify potential transmission upgrades and other solutions needed to relieve excessive renewable curtailment
- Provide the constraints and the identified transmission upgrades as candidates for a more thorough evaluation using production cost simulation

3.6.1 Off-peak deliverability assessment methodology

The general system study conditions are intended to capture a reasonable scenario for the load, generation, and imports that stress the transmission system, but not coinciding with an oversupply situation. By examining the renewable curtailment data from 2018, a load level of about 55% to 60% of the summer peak load and an import level of about 6000 MW was selected for the off-peak deliverability assessment.

The production of wind and solar resources under the selected load and import conditions varies widely. The production duration curves for solar and wind were examined. The production level under which 90% of the annual energy was selected to set the outputs to be tested in the off-peak deliverability assessment. The dispatch of the remaining generation fleet is set by examining historical production associated with the selected renewable production levels. The hydro dispatch is about 30% of the installed capacity and the thermal dispatch is about 15%. All energy storage facilities are assumed offline.

The dispatch assumptions discussed above apply to both full capacity and energy-only resources. However, depending on the amount of generation in the portfolio, it may be impossible to balance load and resources under such conditions with all portfolio generation dispatched. The dispatch assumptions are applied to all existing, under-construction and

[127] http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

contracted generators first, then some portfolio generators if needed to balance load and resources. This establishes a system-wide dispatch base case or master base case that is the starting case for developing each of the study area base cases to be used in the off-peak deliverability assessments. Table 3.6-1 summarizes the generation dispatch assumptions in the master base case.

Table 3.6-1: ISO System-Wide Generator Dispatch Assumptions

	Dispatch Level
wind	44%
solar	68%
battery storage	0
hydro	30%
thermal	15%

The off-peak deliverability assessment is performed for each study area separately. The study areas in general are the same as the reliability assessment areas in the generation interconnection studies. Below is the typical list of the study areas, which may be adjusted depending the portfolio. The study areas may be adjusted and may vary among portfolios depending on the amount of generation.

- PG&E north
- PG&E Fresno
- PG&E Kern
- SCE Northern
- SCE North of Lugo
- SCE/VEA/GWL East of Pisgah
- SCE/DCRT Eastern
- SDGE Inland
- SDGE East

Study area base cases are created from the system-wide dispatch base case. All generators in the study area, existing or future, are dispatched to a consistent output level. In order to capture local curtailment, the renewable dispatch is increased to the 90% energy level for the study area, which is higher than the system-wide 90% energy level. The study area 90% energy level was determined from representing individual plants in different areas. For out-of-state and off-shore wind, the dispatch values are based on data obtained from NREL for the PCM model.

If the renewables inside the study area are predominantly wind resources (more than 70% of total study area capacity), wind resource dispatch is increased as shown in Table 3.6-2. All the solar resources in the wind pocket are dispatched at the system-wide level of 68%. If the renewables inside the study area are not predominantly wind resources, then the dispatch assumptions in Table 3.6-3 are used. The dispatch assumptions for out-of-state and off-shore wind used in the current study are provided in Table 3.6-4.

Table 3.6-2: Local Area Solar and Wind Dispatch Assumptions in Wind Area

	Wind Dispatch Level	Solar Dispatch Level
SDG&E	69%	68%
SCE	64%	
PG&E	63%	

Table 3.6-3: Local Area Solar and Wind Dispatch Assumptions in Solar Area

	Solar Dispatch Level	Wind Dispatch Level
SDG&E	79%	44%
SCE	77%	
PG&E	79%	

Table 3.6-4: Additional Local Area Dispatch Assumptions

Resource	Dispatch Level
Offshore Wind	100%
New Mexico Wind	67%
Wyoming Wind	67%

As the generation dispatch increases inside the study area, the following resource adjustment can be performed to balance the loads and resources:

- Reduce new generation outside the study area (staying within the Path 26, 4000 MW north to south, and 3000 MW south to north limits)
- Reduce thermal generation inside the study area
- Reduce imports
- Reduce thermal generation outside the study area.

Once each study area case has been developed, a contingency analysis is performed for normal conditions and selected contingencies:

- Normal conditions (P0)
- Single contingency of transmission circuit (P1.2), transformer (P1.3), single pole of DC lines (P1.5) and two poles of PDCI if impacting the study area
- Multiple contingency of two adjacent circuits on common structures (P7.1) and loss of a bipolar DC line (P7.2).

For overloads identified under such dispatch, resources that can be re-dispatched to relieve the overloads are adjusted to determine if the overload can be mitigated:

- Existing energy storage resources are dispatched to their full four-hour charging capacity to relieve the overload
- Thermal generators contributing to the overloads are turned off
- Imports contributing to the overloads are reduced to the level required to support out-of-state renewables in the RPS portfolios.

The remaining overloads after the re-dispatch will be mitigated by the identification of transmission upgrades or other solutions. Generators with 5% or higher distribution factor (DFAX) on the constraint are considered contributing generators. The distribution factor is the percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer under the applicable contingency condition when the displaced generation is spread proportionally, across all dispatched resources available to scale down output proportionally. Generation units are scaled down in proportion to the dispatch level of the unit.

3.6.2 Off-Peak deliverability assessment results

All three portfolios were studied as part of the 2021-2022 transmission planning process policy-driven off-peak deliverability assessment. Two variations were assessed for the Base Portfolio. One variation includes 1062 MW of Wyoming Wind injected at Eldorado 500 kV (Base Portfolio A) while the other variation includes the same amount of New Mexico Wind injected at Paloverde 500 kV instead (Base Portfolio B). Renewable generation in each portfolio was dispatched as shown in the previous section. Energy storage resources were modeled initially offline.

The potential solutions considered to address off-peak deliverability constraints include Remedial Action Schemes (RAS), dispatching available battery storage behind the constraints, adding energy storage behind the constraints (subject to on-peak deliverability) and transmission upgrades.

3.6.3 SCE and DCRT area off-peak deliverability results

All portfolio resources inside and outside the SCE/DCRT area that are likely to impact off-peak deliverability constraints in the area are shown in Table 3.6-5.

Table 3.6-5: Portfolio resources likely to impact constraints in the SCE/DCRT area

Transmission Zone/Location	Full Capacity and Energy Only (MW)			
	Base Portfolio		Sensitivity 1 (S1)	Sensitivity 2 (S2)
	Base A	Base B		
Wyoming	1062 Wind	--	1500 Wind	1500 Wind
New_Mexico	--	1062 Wind	1500 Wind	1500 Wind
Tehachapi	8991 (4680 Solar, 275 Wind, 4036 BESS)		9745 (5676 Solar, 275 Wind, 3794 BESS)	8091 (4680 Solar, 275 Wind, 3136 BESS)
Ventura	500 BESS		500 BESS	500 BESS
Greater_LA	1514 (313 PSH, 1201 BESS)		1701 (500 PSH, 1201 BESS)	1701 (500 PSH, 1201 BESS)
North of Lugo	397 (347 Solar, 50 BESS)		397 (347 Solar, 50 BESS)	397 (347 Solar, 50 BESS)
Pisgah	280 (154 Solar, 126 BESS)		280 (154 Solar, 126 BESS)	280 (154 Solar, 126 BESS)
Mohave_Eldorado	1268 (816 Solar, 452 BESS)		1581 (988 Solar, 593 BESS)	979 (658 Solar, 321 BESS)
GLW/VEA	2272 (2024 Solar, 248 BESS)		760 (182 Solar, 442 Wind, 136 BESS)	760 (182 Solar, 442 Wind, 136 BESS)
Riverside_Palm_Springs	--		1399 (843 PSH, 556 BESS)	495 PSH
Greater Imperial (IID)	600 Geothermal		--	--
Arizona (ISO BA)	3047 (2352 Solar, 695 BESS)		1963 (1580 Solar, 383 BESS)	1910 Solar
SW_Ext_Tx	--		500 Wind	234 Wind

Windhub transformer bank off-peak deliverability constraint

Wind and solar resources interconnecting to the Windhub 230kV buses are subject to curtailment in the base and sensitivity portfolios due to loading limitations of the Windhub 500/230kV transformers under category P1 conditions as shown in Table 3.6-6. Pre-contingency curtailment can be avoided by dispatching portfolio energy storage in charging mode during times of high renewable generation or expanding the planned Windhub CRAS to include the new resources as shown in Table 3.6-7.

Table 3.6-6: Windhub 500/230 kV transformer bank off-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)		
		Base Portfolio	S1	S2
Windhub 500/230kV No. 3 & 4 transformers	Windhub 500/230kV No. 3 or 4 transformer	140.1%	154.1%	140.5%
Windhub 500/230kV No. 1 & 2 transformers	Windhub 500/230kV No. 1 or 2 transformer	105.3%	104.4	105%

Table 3.6-7: Windhub transformer bank off-peak deliverability constraint summary

Affected renewable transmission zones		Tehachapi (Windhub 230 kV)		
		Base Portfolio	**S1**	**S2**
Renewable portfolio MW behind the constraint		1,428	1,673	1,428
Energy storage (ES) portfolio MW behind the constraint		1,008	1081	860
Renewable curtailment without mitigation (MW)		538	736	548
Mitigation Options:	Portfolio ES (in charging mode) (MW)[128]	390	520	350
	RAS	Planned Windhub RAS		
	Additional battery storage (MW)	Not needed		
	Transmission upgrades	Not needed		
Recommended Mitigation		Planned Windhub RAS/ Dispatch baseline and/or portfolio battery in charging mode		

Midway–Whirlwind 500 kV line off-peak deliverability constraint

Wind and solar resources in the Tehachapi and surrounding area are subject to curtailment in the base and sensitivity portfolios due to loading limitations of a segment of the Midway–Whirlwind 500 kV line as shown in Table 3.6-8 and Table 3.6-9. The constraint occurs under normal conditions during periods of high renewable output and heavy south to north transfers on Path 26. While it appears from the off-peak deliverability assessment results that curtailment can be avoided by dispatching energy storage in charging mode and increasing generation on the other side of the constraint to maintain supply-demand balance, production simulation studies show this line, along with Path 26[129], to be one of the most congested paths in the ISO system. Since the constraint occurs under normal system conditions, RAS is not a viable mitigation. The two no-cost transmission alternatives below are considered to mitigate the off-peak deliverability constraint:

[128] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

[129] PG&E and SCE are currently performing path rating studies to increase the South to North and North to South ratings of Path 26, respectively.

Increase the normal rating of the PG&E portion of Midway–Whirlwind 500 kV line or

PG&E'S portion of the line is rated 1503/3265 MVA based on conductor preload limits to gain the higher summer emergency 30-minute rating. According to the Transmission Register, it appears the normal rating of the segment can be increased to 2146 MVA if the 4-hour emergency rating is limited to 2567 MVA. Since the overall emergency rating of the Midway–Whirlwind 500 kV line is limited to 2078 MVA by SCE's series capacitor at Midway, the 3265 MVA 30-min rating is valid only when the series cap is by passed.

Bypass the series capacitor at Midway on the Midway–Whirlwind 500 kV line

Bypassing the series capacitor at Midway on the Midway–Whirlwind 500 kV line also mitigated the off-peak deliverability constraint. The series capacitor bypass mitigates the off-peak deliverability constraint by reducing north-bound flow and increasing south-bound from Whirlwind Substation. While assessment of the impact of the bypass under both on-peak and off-peak conditions using the portfolio cases did not indicate any new deliverability constraints in the south-bound direction, it can have some impact in the generation interconnection process. The impact on Path 26 rating will also need to be assessed.

Based on the above considerations and the results of the economic assessment in section 4.9.1, the ISO will coordinate with PG&E and SCE to further investigate the new ratings on PG&E'S portion of the Midway-Whirlwind line to mitigate the off-peak deliverability constraint and the bypassing the series capacitor at Midway on the Midway-Whirlwind 500 kV line.

Table 3.6-8: Midway–Whirlwind 500 kV off-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)		
		Base Portfolio	S1	S2
Midway–Whirlwind 500 kV line (PG&E's portion)[130]	Base Case	121.8%	129.5%	121.7%

Table 3.6-9: Midway–Whirlwind 500 kV off-peak deliverability constraint summary

Affected renewable transmission zones		Tehachapi, Big Creek Corridor		
		Base Portfolio	**S1**	**S2**
Renewable portfolio MW behind the constraint		3,952	4,734	3,952
Energy storage (ES) portfolio MW behind the constraint		3,228	2,854	2,389
Renewable curtailment without mitigation (MW)		1,593	2,029	1,623
Mitigation Options	Portfolio ES (in charging mode) (MW)	0 (There is sufficient baseline BESS)		
	RAS	Not applicable		
	Additional battery storage (MW)	Not needed		
	Transmission upgrades	• Re-rate PG&E'S segment of the Midway–Whirlwind 500 kV line • Bypass series capacitor of the Midway–Whirlwind 500 kV line		
Recommended Mitigation		Re-rate PG&E'S segment of the Midway–Whirlwind 500 kV line		

3.6.4 VEA and GLW area off-peak deliverability results

All portfolio resources inside and outside the GLW/VEA area that are likely to impact deliverability constraints in the GLW/VEA area are shown in Table 3.6-10.

Table 3.6-10: Portfolio resources likely to impact deliverability constraints in GLW/VEA area

TX Zone / Location	Full Capacity and Energy Only (MW)		
	Base Portfolio (A/B)	**Sensitivity-1 (S1)**	**Sensitivity 2 (S2)**
Southern_Nevada_Solar	2,024	182	182
Southern_Nevada_Wind	-	442	442
SCADSNV_Z2_GLW_VEA (BESS)	248.3	136	136

GLW/VEA area off-peak deliverability constraints

Solar and wind resources connecting to GLW's Sloan Canyon, Gamebird, Innovation and Desert View 230kV buses are subject to curtailment in the Base Portfolio off-peak deliverability assessment due to normal loading limitations of multiple 230 kV and 138 kV lines in the GLW/ VEA area and the tie-lines to the neighboring system as shown in Table 3.6-11. The curtailment may be avoided by upgrading the GLW/VEA system and implementing RAS as described in Table 3.6-12. Adding battery storage is not a viable mitigation due to on-peak deliverability limitations. RAS without transmission upgrades is also not considered a potential mitigation because the overloads occur under N-0 conditions.

Table 3.6-11: GLW/VEA area off-peak deliverability constraints

Overloaded Facility	Contingency	Loading (%)		
		Base	S1	S2
Trout Canyon – Sloan Canyon 230kV	Base Case	234	<100	<100
Amargosa 230/138kV transformer	Base Case	196	<100	<100
NVE 138kV Tie-line	Base Case	183	<100	<100
Innovation – Desert View 230kV	Base Case	177	<100	<100
Gamebird – Trout Canyon 230kV	Base Case	173	<100	<100
Pahrump – Gamebird 230kV	Base Case	134	<100	<100
Northwest – Desert View 230kV	Base Case	127	<100	<100
Amargosa – Sandy 138kV	Base Case	123	<100	<100
Sandy – Gamebird 138kV	Base Case	110	<100	<100
NVE 138kV Tie-line	Northwest – Desert View 230kV	Ncov	181	181
Amargosa 230/138kV transformer	Northwest – Desert View 230kV	Ncov	116	116
Trout Canyon – Sloan Canyon 230kV	Gamebird – Trout Canyon 230kV	Ncov	105	105
Gamebird – Trout Canyon 230kV	Trout Canyon – Sloan Canyon 230kV	Ncov	105	105

In the 2020-2021 transmission planning process policy assessment, the sensitivity 2 portfolio was similar to the 2021-2022 Base Portfolio, and similar transmission constraints were identified. An upgrade, the GLW Conversion Project, consisting of a new Gamebird – Arden 230kV line along and a second Innovation – Desert View and Desert View – Northwest 230 kV lines was evaluated, and mitigated the identified constraints. However, that analysis did not consider the commercial issue of whether the ISO system had enough transmission capacity without relying on neighboring transmission systems. Once that issue was taken into consideration the Conversion Project proved to be inadequate.

The VEA/GLW system is connected to the rest of the ISO grid through the Trout Canyon – Sloan Canyon – Eldorado 230 kV path, which is a single 230 kV circuit with a normal rating of only 286 MVA. While there is 2,024 MW CPUC base portfolio generation in GLW area and the VEA summer peak forecasted load is 190 MW by 2031, there is not enough ISO transmission capacity to deliver the majority of the generation to the ISO load without relying on neighboring systems. Also in the CPUC base portfolio, there is 790 MW of generation at Innovation and Desert View substations. The only ISO transmission capacity to deliver that 790 MW of generation to the ISO system without relying on the neighboring system is through the Innovation – Pahrump – Gamebird – Trout Canyon 230 kV line and the underlying 138 kV VEA system. The normal rating of the Innovation – Pahrump 230 kV line is 331 MVA and the normal rating of the Pahrump – Gamebird – Trout Canyon 230 kV line is 286 MVA. This single 230 kV line path and the underlying 138 kV system does not have enough capacity to deliver the portfolio generation at Innovation and Desert View substations to ISO load.

During the 2021-2022 transmission planning process request window submission process, the GridLiance West LLC submitted the GLW Upgrade project. The project scope includes rebuilding Desert View – Northwest 230kV, Pahrump – Gamebird 230kV, Gamebird – Trout Canyon 230kV and Trout Canyon – Sloan Canyon 230kV to double circuit lines; adding a second Innovation – Desert View 230 kV line; adding a 500/230 kV transformer at Sloan Canyon and looping in the Harry Allen – Eldorado 500kV line; an upgrade to WAPA's Amargosa 230/138 kV transformer[131] and a tentatively planned NV Energy upgrade on the Mercury SW – Northwest 138 kV tie line. The estimated cost of this project is $213M, with an in-service date of 2025.

The submitted GLW Upgrade project was able to mitigate all normal overloads and the majority of the contingency overloads under the base portfolio off-peak deliverability scenario[132]. The ISO has also learned that the tentatively planned NV Energy upgrade on the Mercury SW – Northwest 138 kV tie line, is no longer under consideration by NV Energy. Preliminary analysis has demonstrated that a phase shifter would mitigate the constraints on this 138 kV tie-line, but detailed analysis to determine the design specifications are still needed. Other flow control devices will also be considered during the detailed analysis. The estimated cost of the phase shifter option is $5 M[133]. As part of the project scope is outside of the GLW territory, coordination with NV Energy and WAPA have been ongoing, and both entities have preliminarily concurred with the proposed upgrades planned to mitigate the identified impacts on their respective systems.

In addition, the submitted GLW Upgrade did not address the Innovation – Pahrump 230 kV line capacity limit issue discussed above. The ISO recommends the addition of an upgrade to the Innovation – Pahrump 230kV line with a minimum capacity of 665 MVA. GLW provided two options to mitigate this constraint. Option 1 would be to utilize a high-temperature conductor to reconductor the line to a normal/emergency rating of 767 MVA/767 MVA at an estimated cost of $22M. Option 2 would be to upgrade the existing single circuit Innovation – Pahrump 230 kV line to a larger single circuit 230 kV line that is double circuit capable with an 1154 MVA normal rating, at an estimated cost of $60M. Because the base portfolio would already utilize 665 MW of the 767 MW of capability, Option 1 would not provide a significant amount of transmission capability for future generation development. Therefore the ISO recommends Option 2.

With the queued generation development in the Eldorado area on the GLW, SCE, NVE, and LADWP systems, the short circuit duty capability on the 230 kV and 500 kV equipment at Eldorado Substation is expected to be exceeded in the near term, and must be mitigated. The scope and schedule of this mitigation is still under development. It is expected that a mitigation will need to be in place before the GLW Upgrades discussed above can be fully utilized. SCE is

[131] The existing Amargosa 230/138 kV transformer is owned by VEA, but is located in WAPA's Amargosa Substation. It is expected that WAPA would perform the work to replace the transformer and other associated equipment to allow full utilization of the proposed 120 MVA transformer. The ISO recommends that the cost of this mitigation should be recovered through the ISO Regional Transmission Access charge pursuant to ISO Tariff Section 24.10.

[132] The ISO's preliminary analysis identified overloads on the Eldorado-McCullough 500 kV line. Subsequent analysis identified a modeling error that has since been corrected, and the Eldorado-McCullough 500 kV line loading is no longer an issue.

[133] The ISO recommends that the cost of this phase shifter should be recoverable through the ISO Regional Transmission Access charge pursuant to ISO Tariff Section 24.10.

also investigating whether an interim operational mitigation can be implemented prior to the long-term mitigation. Until the Eldorado short circuit duty mitigations are proposed and approved, there is a risk that the in-service date for the GLW Upgrade or projects relying on it may need to be delayed accordingly. SCE is working with key stakeholders such as LADWP, NVE and the ISO to develop both interim and permanent mitigations.

Table 3.6-12: GLW/VEA area off-peak deliverability constraint summary

Affected transmission zones		Southern Nevada (ISO)			
		Base		**S1**	**S2**
		A	**B**		
Renewable portfolio MW behind the constraint		2,024	2,024	624	624
Energy storage (ES) portfolio MW behind the constraint		248	248	136	136
Renewable curtailment without mitigation (MW)		1,482	1,482	130	130
Mitigation Options:	Portfolio ES (in charging mode) (MW)	Not sufficient		36	
	RAS	N/A		Innovation RAS Sloan Canyon RAS	
	Additional battery storage (MW)	Not feasible		100	
	Transmission upgrades	GLW Upgrade		N/A	
Recommended Mitigation		GLW Upgrade ($278 M)		RAS	

Based on the above evaluation, the proposed GLW Upgrade along with the additional upgrades described above have been identified as needed Policy-Driven transmission upgrades. An analysis of the economic benefits of this project is documented in Chapter 4.

3.6.5 SDGE area off-peak deliverability results

All portfolio resources inside and outside the SDG&E area that are likely impact off-deliverability constraints in the SDG&E area are shown in Table 3.6-13.

Table 3.6-13: Portfolio resources likely to impact off-deliverability constraints in SDG&E area

TX Zone / Location	Full Capacity and Energy Only (MW)			
	Base Portfolio		Sensitivity-1 (S1)	Sensitivity 2 (S2)
	Base A	Base B		
New Mexico Wind	-	1062	-	-
Arizona Solar	2,352		1,580	1,910
Arizona BESS	695		383	-
Greater Imperial Solar	548		1,148	1,148
Greater Imperial Geothermal	600		-	-
Baja California Wind	495		495	495
Pumped Hydro Storage (Sycamore Canyon)	314		500	500
SDGE BESS	1,170		1,170	1,170

There were no constraints identified in the SDG&E area off-peak deliverability assessment.

3.6.6 PG&E area off-peak deliverability results

All portfolio resources in Northern California and outside Northern California that are likely to be impacted by deliverability constraints in the PG&E area are shown in Table 3.6-14.

Table 3.6-14: Portfolio resources likely to be impacted by constraints in PG&E area

Transmission Delivery Zone	Full Capacity and Energy Only (MW)				
	Base	SENS-01	SENS-02		
			Option 1	Option 2	Option 3
Westlands	244.9 BESS	244.9 BESS	10 BESS	10 BESS	10 BESS
Greater Carrizo	379.8 (234.8 Solar + 145 BESS)	416 (253 Solar + 163 BESS)	251 (106 Solar + 145 BESS)	251 (106 Solar + 145 BESS)	251 (106 Solar + 145 BESS)
Diablo Canyon OSW	4,419 OSW	4,419 OSW	4,419 OSW	4,419 OSW	4,419 OSW
Morro Bay OSW	2,324 OSW	2,324 OSW	2,324 OSW	2,324 OSW	2,324 OSW

Kettlemen-Gates 70kV line off-peak deliverability constraint

Portfolio energy storage resources in Westlands are subject to curtailment due to overloading on Kettlemen-Gates 70kV line under P0 conditions as shown in Table 3.6-15 and Table 3.6-16. The constraint can be mitigated by turning on the battery at Kettlemen 70kV. As a result, other mitigation options were not considered.

Table 3.6-15: Kettlemen-Gates 70kV line off-peak deliverability constraint

Overloaded Facility	Contingency	Loading				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Kettlemen-Gates 70kV Line	Base Case	126%	125%	125%	125%	125%

Table 3.6-16: Kettlemen-Gates 70kV off-peak deliverability constraint summary

Affected renewable transmission zones		Westlands				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed capacity)		0	0	0	0	0
Energy storage portfolio MW behind the constraint (installed capacity)		10	10	10	10	10
Renewable MW curtailment (installed capacity)		10 Solar	10 Solar	10 Solar	10 Solar	10 Solar
Portfolio energy storage MW re-dispatched in charging mode (installed capacity)		10	10	10	10	10
Potential Options	RAS	Not Needed				
	Add battery storage					
	Transmission upgrade and cost					
Recommended Mitigation		Turn on Battery Storage				

Weedpatch 70kV area off-peak deliverability constraint

Portfolio resources in the Westlands 70kV area are subject to curtailment due overloading on Wheeler Ridge-Weedpatch area 70kV lines under P7 conditions as shown in Table 3.6-17 and Table 3.6-18. RAS was considered but failed due to too many elements being monitored. No portfolio battery storage is in the 5% circle. Adding battery storage for charging is not feasible due to the large amount of storage needed and due to issue in the on-peak deliverability. A Weedpatch 70kV area reinforcement project could mitigate the issues observed.

Table 3.6-17: Weedpatch 70kV area off-peak deliverability constraint

Overloaded Facility	Contingency	Loading				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Weedpatch 70kV Area	Midway-Wheeler Ridge #1 and #2 230kV Lines	406%	441%	145%	145%	146%

Table 3.6-18: Weedpatch 70kV area off-peak deliverability constraint summary

Affected renewable transmission zones		Greater Carrizo				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed capacity)		128.8 Solar	147 Solar	0	0	0
Energy storage portfolio MW behind the constraint (installed capacity)		0	18	0	0	0
Renewable MW curtailment (installed capacity)		178 Solar	51 Solar	0	0	0
Portfolio energy storage MW re-dispatched in charging mode (installed capacity)		0	18	0	0	0
Potential Options	RAS	No, too many elements (RAS Guideline violation)		Not needed		
	Add battery storage	Not feasible		Not needed		
	Transmission upgrade and cost	Weedpatch 70kV area reinforcement		Not needed		
Recommended Mitigation		Status Quo		Not needed		

Kern-Tevis-Stockdale 115kV lines off-peak deliverability constraint

Portfolio resources in the Greater Carrizo area are subject to curtailment due to overloading on the Kern-Tevis-Stockdale 115kV lines under P1 conditions as shown in Table 3.6-19 and Table 3.6-20. Dispatching the portfolio battery storage at Lamont 115kV to 34MW charging eliminated the overload. As a result, other mitigation options were not considered.

Table 3.6-19: Kern-Tevis-Stockdale 115kV area off-peak deliverability constraint

Overloaded Facility	Contingency	Loading				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Kern-Tevis-Stockdale 115kV Lines	Remaining Kern-Tevis-Stockdale-Lamont 115kV Line	123%	121%	121%	121%	121%

Table 3.6-20: Kern-Tevis-Stockdale 115kV area off-peak deliverability constraint summary

Affected renewable transmission zones		Greater Carrizo				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed capacity)		106 Solar	106 Solar	106 Solar	106 Solar	106 Solar
Energy storage portfolio MW behind the constraint (installed capacity)		95	95	95	95	95
Renewable MW curtailment (installed capacity)		34 Solar	32 Solar	33 Solar	31 Solar	31 Solar
Portfolio energy storage MW re-dispatched in charging mode (installed capacity)		34	32	33	31	31
Potential Options	RAS	Not needed				
	Add battery storage	Not needed				
	Transmission upgrade and cost	Not needed				
Recommended Mitigation		Turn on Portfolio Battery Storage				

Gates 500/230kV Bank 12 off-peak deliverability constraint

Portfolio resources in the Greater Carrizo and Westlands area are subject to curtailment due to overloading on the Gates 500/230kV Bank 12 under P1 conditions as shown in Table 3.6-21 and Table 3.6-22. Dispatching the portfolio battery storage at Gates 230kV to 60MW charging eliminated the overload. As a result, other mitigation options were not considered.

Table 3.6-21: Gates 500/230kV Bank 12 area off-peak deliverability constraint

Overloaded Facility	Contingency	Loading				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Gates 500/1230kV Bank 12	Gates 500/230kV Bank 11	102.1	<100%	<100%	<100%	<100%

Table 3.6-22: Gates 50/230kV Bank 12 off-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected renewable transmission zones</td><td colspan="5">Greater Carrizo, Westlands</td></tr>
<tr><td colspan="2" rowspan="2"></td><td rowspan="2">BASE</td><td rowspan="2">SENS-01</td><td colspan="3">SENS-02</td></tr>
<tr><td>Option 1</td><td>Option 2</td><td>Option 3</td></tr>
<tr><td colspan="2">Renewable portfolio MW behind the constraint (installed capacity)</td><td>1,243 Solar
207 Wind</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint (installed capacity)</td><td>294.9</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td></tr>
<tr><td colspan="2">Renewable MW curtailment (installed capacity)</td><td>60 Solar</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td></tr>
<tr><td colspan="2">Portfolio energy storage MW re-dispatched in charging mode (installed capacity)</td><td>60</td><td>NA</td><td>NA</td><td>NA</td><td>NA</td></tr>
<tr><td rowspan="3">Potential Options</td><td>RAS</td><td>NA</td><td colspan="4" rowspan="3">Not Needed</td></tr>
<tr><td>Add battery storage</td><td>NA</td></tr>
<tr><td>Transmission upgrade and cost</td><td>NA</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>Turn on Portfolio Battery Storage</td><td colspan="4">Not Needed</td></tr>
</table>

3.7 Sensitivity 2 – Offshore Wind Study

3.7.1 Introduction

The offshore wind sensitivity 2 study included the following offshore wind resources:

- Humboldt Bay: 1,607 MW
- Diablo Canyon: 4,419 MW
- Morro Bay: 2,324 MW

Other resources in the sensitivity 2 portfolio were similar to base portfolio and are discussed in section 3.4. Detailed studies were performed to identify the transmission upgrades required to address reliability and deliverability constraints. In addition, an offshore wind outlook assessment with the following resources was also included to evaluate the impact of accommodating the remaining offshore wind resource potential in California, at high level:

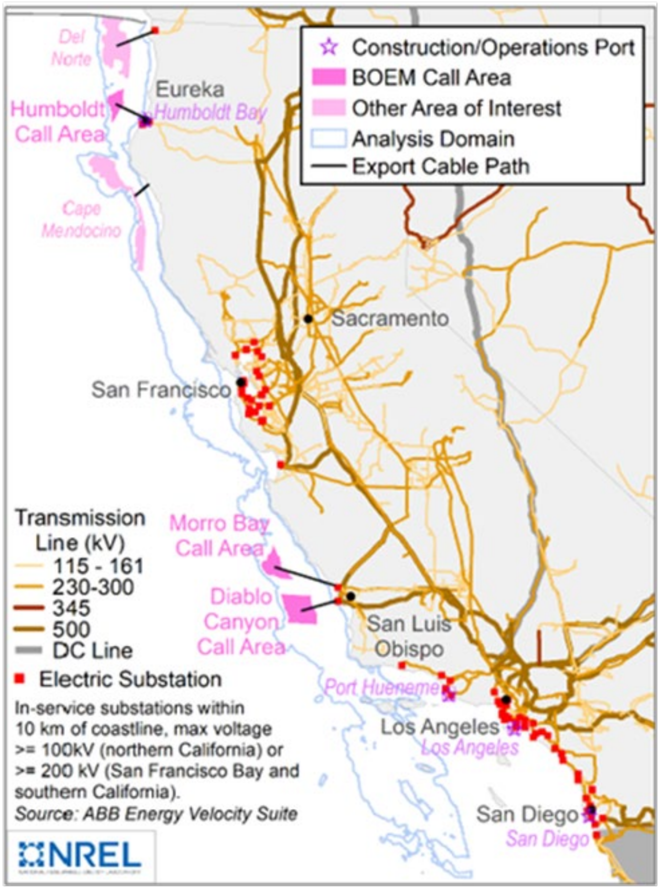
- Del Norte: 6,605 MW
- Cape Mendocino: 6,216 MW

The total offshore wind resources in the wind outlook assessment is 21,171 MW from which 14,428 MW is in the north coast and 6,743 MW is in the central coast. Figure 3.7-1 provides an approximate location of the offshore wind sites considered in this study.

The following aspects of offshore wind scenario were evaluated in this study that will be discussed in this section:

- Interconnection of the offshore wind generation to the rest of the ISO system
- On-peak deliverability assessment results
- Off-peak deliverability assessment results
- Mitigation measures to address deliverability constraints
- High level cost estimate
- High level assessment of the wind outlook with 21,171 MW of wind generation.

Figure 3.7-1: Offshore Wind Development Location Assumptions[134]



3.7.2 System Interconnection Options

Considering the CPUC offshore wind modelling assumptions[135], the offshore wind projects were assumed to be connected with export cables to a substation located approximately 3 miles inland. The objective of this study was to study interconnection options to connect the assumed inland substation to the rest of the ISO system.

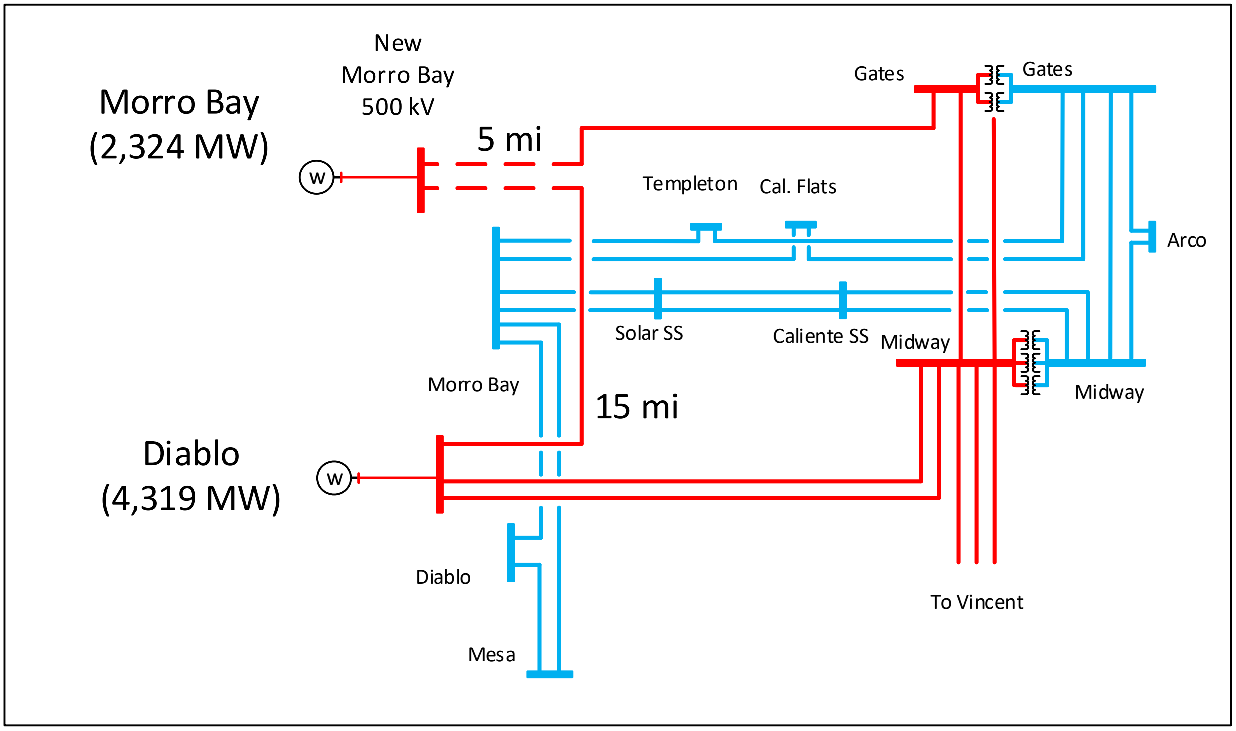
3.7.2.1 Diablo and Morro Bay Offshore Wind Interconnection

The initial mapping of resources to substations discussed in section 3.4.1, maps the 4,419 MW Diablo Canyon offshore wind to Diablo 500 kV substation. The same assumption is used in this study. The initial mapping however maps the 2,324 MW Morro Bay offshore wind to the Morro Bay 230 kV substation. A high-level evaluation indicated that the Morro Bay 230 kV substation does not have the required capacity and therefore the Morrow Bay offshore wind was connected to a new 500 kV substation at Morro Bay looping in the Diablo – Gates 500 kV line. A schematic diagram of the interconnection of the Diablo and Morro Bay offshore wind projects to the system is provided in Figure 3.1-2.

[134] The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 (nrel.gov) (Page 39)

[135] ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2021_22_TPP_Final.pdf

Figure 3.7-2: Diablo and Morro Bay Offshore Wind Interconnection



3.7.2.2 Humboldt Bay Offshore Wind Interconnection

There are no existing substation close to 1,607 MW Humboldt Bay offshore wind. In addition, the CPUC guidance in selecting transmission solutions for 1,607 MW at Humboldt Bay, is to be “least regret” if ultimate potential of 14,428 MW in outlook is developed in the north coast at the Humboldt Bay, Del Norte, and Cape Mendocino sites. Therefore a conceptual interconnection option for the 14,428 MW was needed to ensure that the interconnection option for the 1,607 MW Humboldt Bay is part of a bigger plan to interconnect the 14,428 MW offshore wind potential in the north coast of California. A high level comparison of bulk power transfer technology options is discussed in the following section.

Bulk Power Transmission Technology Options

High-voltage AC lines, conventional HVDC -- which is also called Line Commutated Converter (LCC) HVDC -- and Voltage-Sourced Converter (VSC) HVDC are the main technologies used in the power industry to transmit bulk power. While the majority of the power transmission is through AC lines, there are certain scenarios in which HVDC would be the preferred option. A high-level comparison of the benefits and challenges of these technologies is provided below.

High Voltage AC Transmission

The majority of power transmission in the world is done using AC transmission technology. The maximum nominal voltage rating in WECC is 500 kV. Higher voltages have been used in other parts of the U.S. and around the world.

The advantages of AC transmission include the following:

- It is very common. The majority of bulk power transfer is done on AC line
- It doesn't need converter stations
- It can be easily looped into a new substation.

Potential challenges of AC transmission include the following:

- It requires series compensation for high-power transfers over longer distance applications
- With the same power transfer capacity, it may require a wider right-of-way compared to other technologies
- Power flow on the line is determined by the network topology and load/generation patterns and cannot be easily controlled
- Long-distance AC cables are not feasible or practical. Cable applications of 500 kV AC lines are very limited and only for very short distances.

<u>Conventional (LCC) HVDC</u>

The HVDC transmission technology has been used under special circumstances around the world for more than 60 years. In California, PDCI and IPPDC are two ±500 kV Bipole LCC HVDC links connecting California to neighboring systems. PDCI transmits power over more than 850 miles and is rated at 3,210 MW N-S with evaluations performed to increase it to 3,800 MW N-S. Much higher ratings are in operation around the world.

The advantages of LCC HVDC include the following:

- Transmission over long distances with overhead lines or underground/subsea cables; there is no practical limit on how far power could be transmitted with HVDC lines
- Potentially requires smaller rights-of-way
- Power flow on the line is set by the operator
- Overload capability

Potential challenges of LCC HVDC transmission include the following:

- Requires a converter station at each end of the line; for high-power applications, the converter station may require a significant area
- The AC system the HVDC convertors are connected to should have short-circuit levels above a certain threshold, especially at the receiving end
- Most of the schemes in the world are point-to-point interconnections. "Looping in" the line for other interconnections (Multi-terminal HVDC applications) are rare
- HVDC converters consume reactive power which is around 50-60% of the operating real power

Voltage Source Converter Based HVDC (VSC-HVDC)

VSC-HVDC technology has been used for certain DC applications for more than 20 years. Trans Bay Cable is a 400 MW VSC-HVDC link that went into service in California in 2010.

Most high-power installations of VSC-HVDC are around 1000 MW, with new projects planned for 2,000 MW. Siemens is planning a number of 2,000 MW VSC-HVDC links that will go in service in the 2026-2028 timeframe with multi-terminal capability for some of the projects[136]. Higher capacity VSC-HVDC projects exist around the world but are not common.

The advantages of VSC-HVDC transmission over LCC HVDC include the following:

- The AC system the VSC-HVDC converters are connected to does not need specific minimum short circuit levels
- The converter stations are physically smaller compared to LCC HVDC stations and therefore more suitable to deliver power to urban centers
- Does not require reactive power support at the converter station
- Multi-terminal configuration is less complicated

Potential challenges of VSC-HVDC includes the following:

- The power rating is lower than LCC HVDC
- It is challenging to design schemes with overhead lines; the majority of existing applications are cable connections
- The converter station losses are higher

ISO Generation Trip/Drop Limits

The ISO Planning Standard sets the following limits with regards to generation tripping following contingencies:

- The generation drop following N-1 contingency should be limited to 1,150 MW
- The generation drop following N-2 (DCTL) contingency should be limited to 1,400 MW

These limits should be taken into account in designing a concept for interconnecting large generators to the ISO system.

Interconnection Concept for 14,428 MW of North Coast Offshore Wind

High-voltage AC lines are the most common technology for bulk power transfers. If only AC transmission lines are used, five to six 500 kV AC lines would be required to reliably transfer 14,428 MW power.

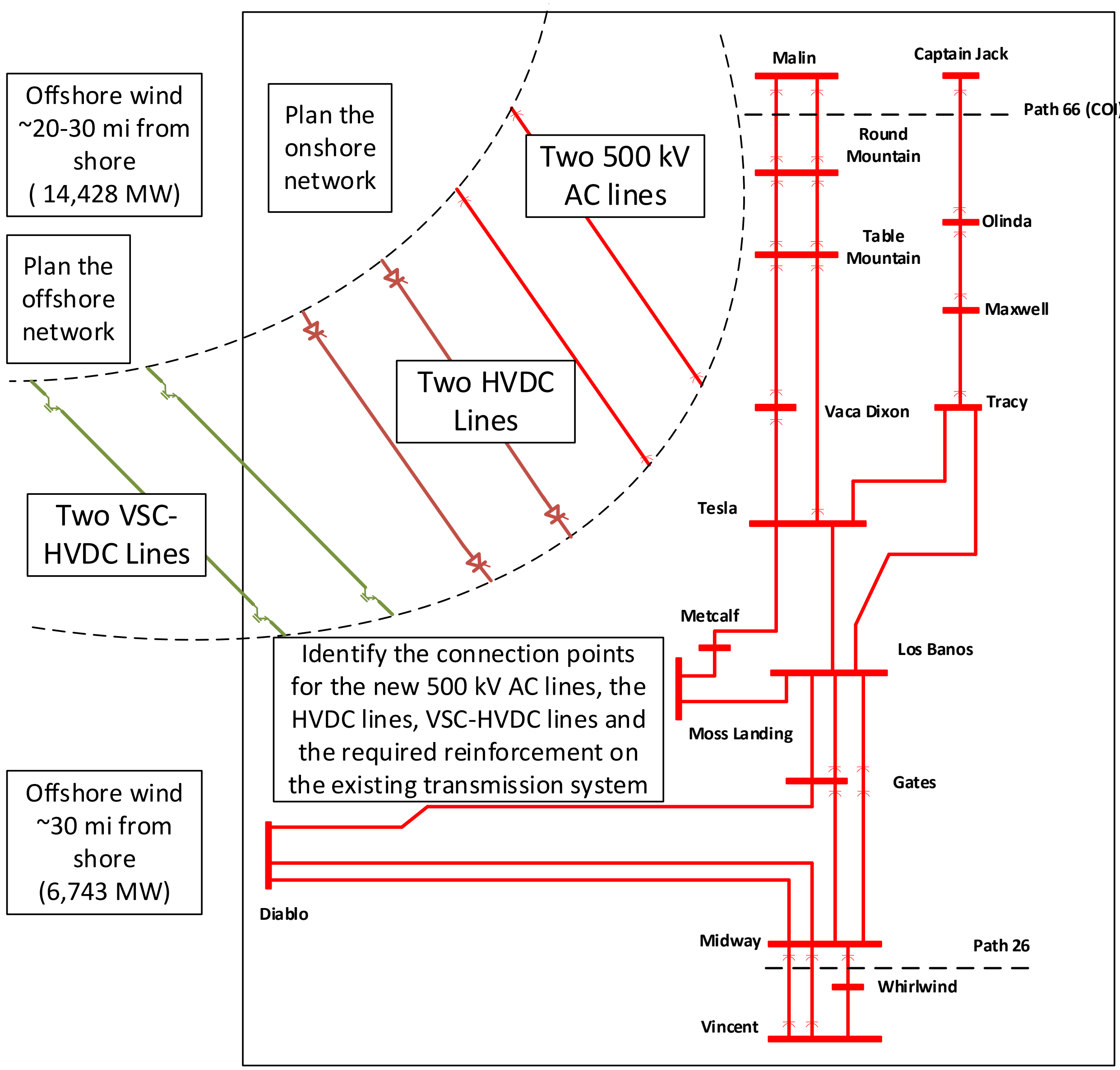
Four high-capacity LCC HVDC bipoles with short-term overload capability would have the capacity to transfer power and to meet the ISO generation drop limits.

[136] Siemens Energy · Technical document · DIN A4 landscape – Template (siemens-energy.com)

VSC-HVDC is suitable for delivering power to urban areas and systems with low short-circuit levels. Considering 2,000 MW maximum rating, seven or eight underground/subsea cable schemes would be required to reliably transfer the required power in this application.

Considering the advantages and challenges of each transmission technology, potentially a hybrid AC and HVDC solution concept could be explored as the preferred concept to connect the 14,428 MW of north coast offshore wind in the outlook assessment. A schematic diagram of such a hybrid system is provided in Figure 3.1-3. As shown in the figure, two high-capacity links from each technology would be required to reliably transfer 14,428 MW of power while meeting the ISO standard on generation trip limits following N-1 and N-2 contingencies.

Figure 3.7-3: Hybrid AC and HVDC Interconnection Option for North Coast Offshore Wind



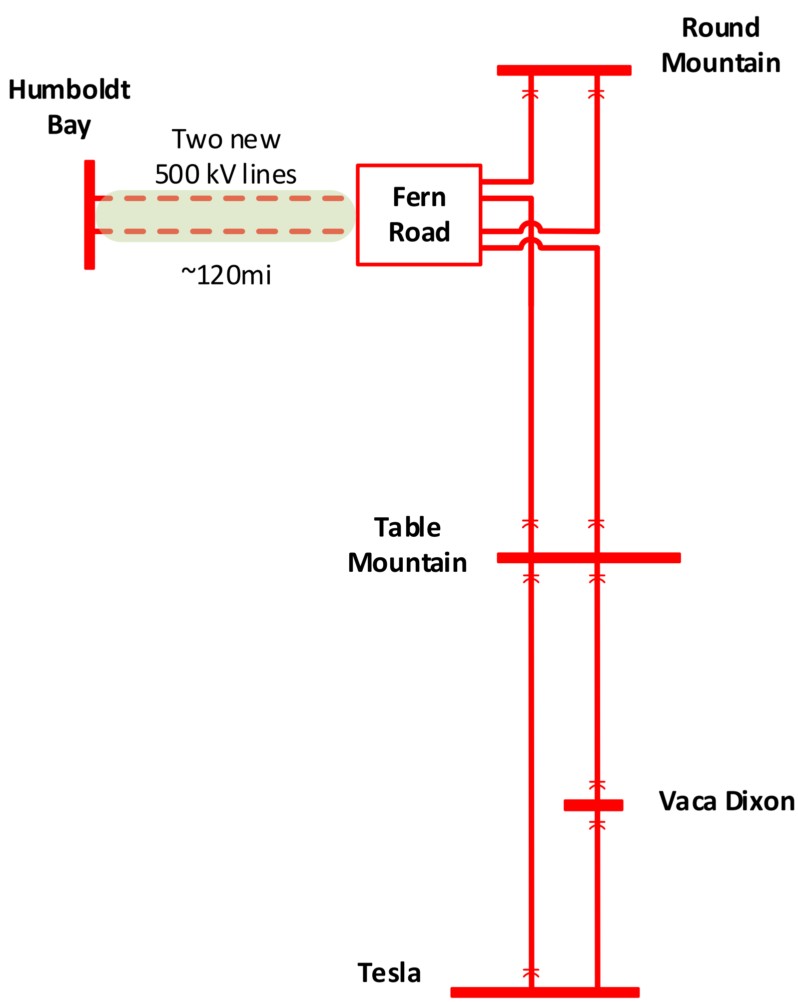
Interconnection Options for 1,607 MW Humboldt Bay Offshore Wind

Considering the overall interconnection concept for 14,428 MW of north coast offshore wind (Figure 3.7-3), three interconnection options, one for each technology, were selected for detailed deliverability studies for interconnecting just 1,607 MW of Humboldt Bay offshore wind.

<u>Option 1: 500 kV AC line to Fern Road 500 kV substation</u>

Fern Road 500 kV substation is planned to be in service in 2024 as part of the Round Mountain DRS project that is located approximately 11 miles south of the Round Mountain substation. In this option, it is assumed two approximately 120-mile, 500-kV AC lines will interconnect the project to the Fern Road substation (Figure 3.1-4). The cost estimate for option 1 is $1.2B.

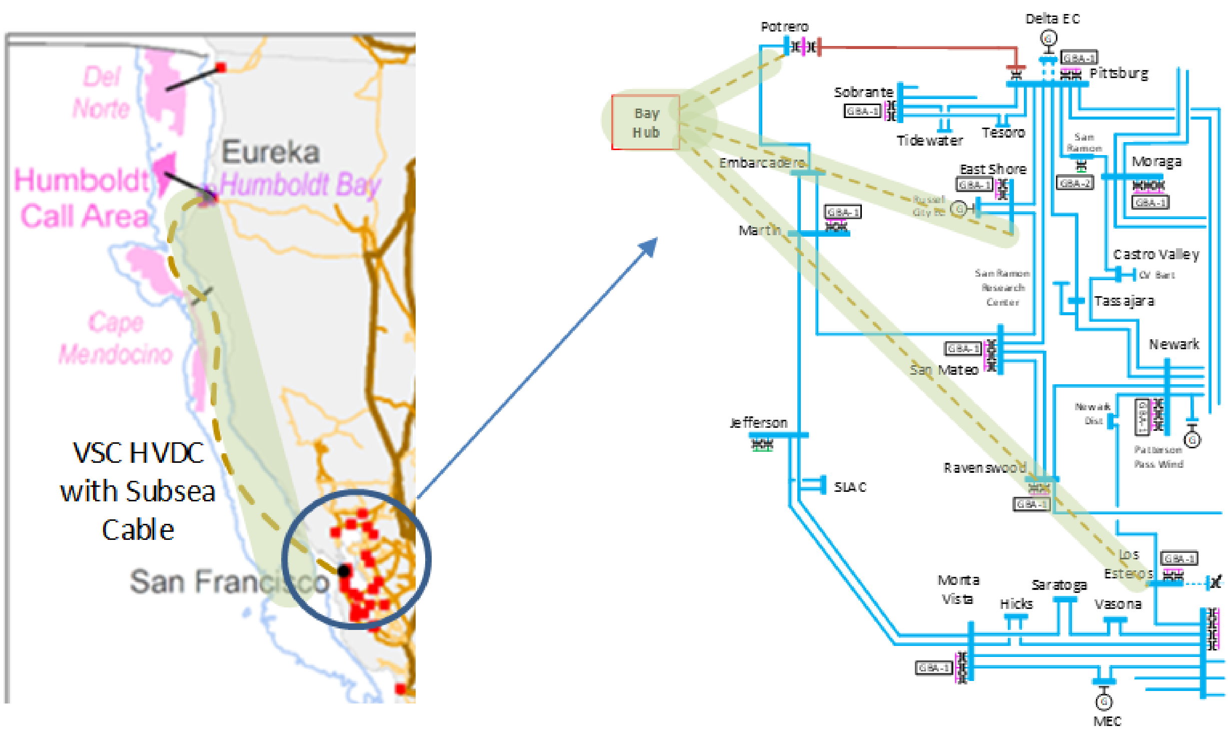
Figure 3.7-4: AC Option to Interconnect Humboldt Bay Offshore Wind (Option 1)



Option 2: VSC-HVDC subsea cable connection to a converter station in the Bay area

In this option, it is assumed that a VSC-HVDC link will connect the Humboldt offshore wind to a Bay Hub substation in the Bay area through a subsea cable. Three cables will then connect the Bay Hub 230 kV substation to major load centers in the area (Figure 3.1-5). The cost estimate for option 2 is $4B.

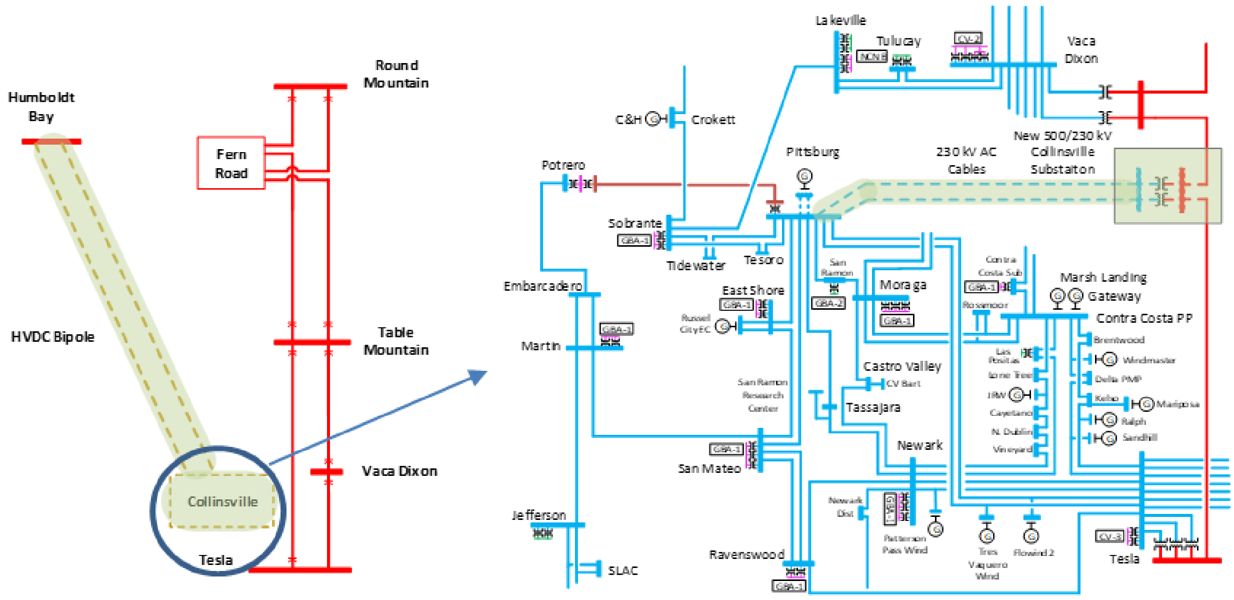
Figure 3.7-5: VSC-HVDC Option to Interconnect Humboldt Bay Offshore Wind (Option 2)



Option 3: LCC HVDC Bipole to Collinsville 500/230 kV substation

Collinsville substation is studied in prior transmission planning cycles to reduce reliance on gas generation in the Bay area. Vaca Dixon – Tesla 500 kV line is looped into it with two 230 kV connections to Pittsburg 230 kV substation. In this study it is assumed that the Humboldt Bay offshore wind will be connected to Collinsville substation with an HVDC bipole link (Figure 3.1-6). The cost estimate for option 3 is $3B.

Figure 3.7-6: LCC HVDC Option to Interconnect Humboldt Bay Offshore Wind (Option 3)



A base case was developed for the deliverability studies for each of the above three options for the Humboldt Bay offshore wind interconnection. In all three cases, the Diablo and Morro Bay offshore wind were interconnected to the system as described earlier in this chapter. The results of the on-peak and off-peak deliverability studies are provided in the following sections.

3.7.3 On-Peak Deliverability Assessment Results

Fern Road-Table Mountain #1, #2, and Table Mountain-Vaca Dixon 500 kV line constraints

The deliverability of renewable portfolio resources in the Northern California and Humboldt Bay Offshore wind area is limited by thermal overloading of the Fern Road – Table Mountain 500kV and Table Mountain – Vaca Dixon 500 kV lines under normal (N-0) and contingency (N-1) conditions as shown in Table 3.1-1. This constraint was identified only under sensitivity 2, option 1 under HSN conditions. As shown in Table 3.1-2, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by building a new 500 kV line from Fern Road to Tesla.

Table 3.7-1: Fern Road-Table Mountain #1 and #2 and Table Mountain – Vaca Dixon 500kV lines on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Fern Road-Table Mountain #1 and #2 500kV lines	Base Case	HSN	<100%	<100%	112%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Table Mountain-Vaca Dixon 500 kV Line	Base Case	HSN	<100%	<100%	116%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Fern Road-Table Mountain #1 and #2 500kV lines	Fern Road-Table Mountain #2 or #1 500kV lines	HSN	<100%	<100%	138%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Table Mountain-Rio Oso 230 kV Line	Table Mountain-Vaca Dixon 500 kV Line	HSN	<100%	<100%	112%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Round Mountain-Cottonwood #3 230 kV Line	Table Mountain-Vaca Dixon 500 kV Line	HSN	<100%	<100%	101%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
North Dublin-Vineyard 230 kV line	Contra Costa-Moraga #1 and #2 230kV lines	HSN	<100%	<100%	101%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.7-2: Fern Road-Table Mountain #1 and #2 and Table Mountain – Vaca Dixon 500kV lines on-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="5">Northern California and Humboldt Bay Off-Shore Wind (Fern Road)</td></tr>
<tr><td colspan="2" rowspan="2"></td><td rowspan="2">Base Portfolio</td><td rowspan="2">S1 Portfolio</td><td colspan="3">S2 Portfolio</td></tr>
<tr><td>Option 1</td><td>Option 2</td><td>Option 3</td></tr>
<tr><td colspan="2">Renewable portfolio MW behind the constraint (installed FCDS capacity)</td><td>N/A</td><td>N/A</td><td>437 Wind
1607 OSW</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>N/A</td><td>N/A</td><td>0</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>N/A</td><td>N/A</td><td>0</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)</td><td>N/A</td><td>N/A</td><td>2,305</td><td>N/A</td><td>N/A</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td colspan="2">Not Needed</td><td>N/A, N-0 Overload</td><td colspan="2">Not Needed</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td colspan="2">Not Needed</td><td>N/A</td><td colspan="2">Not Needed</td></tr>
<tr><td>Transmission upgrade including cost</td><td colspan="2">Not Needed</td><td>Build a new 500 kV line from Fern Road to Tesla ($1.1B)</td><td colspan="2">Not Needed</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="2">Not Needed</td><td>Build a new 500 kV line from Fern Road to Tesla</td><td colspan="2">Not Needed</td></tr>
</table>

Diablo-Midway #2, #3 and Morro Bay-Gates 500 kV line constraints

The deliverability of renewable portfolio resources in the Diablo/Morro Bay Offshore wind area is limited by thermal overloading of the Diablo-Midway #2, #3 and Morro Bay-Gates 500 kV lines under normal (N-0) and contingency (N-1) conditions as shown in Table 3.1-3. This constraint was identified only for sensitivity 2 under HSN conditions. As shown in Table 3.1-4, more than 5,300 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by a number of alternatives which all will add to power transfer capacity out of the area. The recommended mitigation for the purpose of this study is to build a new 500 kV AC line from Diablo to Gates substations.

Table 3.7-3: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Diablo-Midway 500 kV Lines	Base Case	HSN	<100%	<100%	112%	112%	112%
		SSN	<100%	<100%	<100%	<100%	<100%
	Remaining Diablo-Midway 500 kV Line	HSN	<100%	<100%	114%	114%	114%
		SSN	<100%	<100%	<100%	<100%	<100%
Morro Bay-Gates 500 kV Line	Base Case	HSN	<100%	<100%	125%	125%	125%
		SSN	<100%	<100%	<100%	<100%	<100%
	Diablo-Midway 500 kV Line	HSN	<100%	<100%	136%	136%	136%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.7-4: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines on-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="5">Northern California and Diablo/Morro Bay Off-Shore Wind</td></tr>
<tr><td colspan="2" rowspan="2"></td><td rowspan="2">Base Portfolio</td><td rowspan="2">S1 Portfolio</td><td colspan="3">S2 Portfolio</td></tr>
<tr><td>Option 1</td><td>Option 2</td><td>Option 3</td></tr>
<tr><td colspan="2">Renewable portfolio MW behind the constraint (installed FCDS capacity)</td><td>0</td><td>0</td><td>6,743 OSW</td><td>6,743 OSW</td><td>6,743 OSW</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>0</td><td>0</td><td>5,355</td><td>5,379</td><td>5,380</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)</td><td>0</td><td>0</td><td>1,388</td><td>1,364</td><td>1,363</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td colspan="2">Not Needed</td><td colspan="3">N/A, N-0 Overload</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td colspan="2">Not Needed</td><td colspan="3">N/A</td></tr>
<tr><td>Transmission upgrade including cost</td><td colspan="2">Not Needed</td><td colspan="3">• Diablo – North HVDC ($1.6B)
• Diablo – South HVDC (1.85B)
• Second Diablo – Gates 500 kV line ($0.4B)</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="2">Not Needed</td><td colspan="3">Second Diablo – Gates 500 kV line</td></tr>
</table>

3.7.4 Off-Peak Deliverability Assessment Results

Diablo-Midway #2, #3 and Morro Bay-Gates 500 kV line constraints

Portfolio resources in the Diablo/Morro Bay Offshore wind area are subject to up to around 1,350 MW of curtailment due to thermal overloading of the Diablo-Midway #2, #3 and Morro Bay-Gates lines under normal (N-0) and contingency (N-1) conditions as shown in Table 3.1-5 and Table 3.1-6. The overload can be mitigated by a number of alternatives which all will add to power transfer capacity out of the area. Building a new 500 kV AC line from Diablo to Gates substation that was recommended to mitigate on-peak deliverability constraint will also address the overload identified in the off-peak assessment.

Table 3.7-5: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines off-peak deliverability constraint

Overloaded Facility	Contingency	Loading				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Diablo-Midway 500 kV Lines	Base Case	<100%	<100%	106%	121%	121%
	Remaining Diablo-Midway 500 kV Line	<100%	<100%	109%	121%	121%
Morro Bay-Gates 500 kV Line	Base Case	<100%	<100%	127%	121%	121%
	Either Diablo-Midway 500 kV Line	<100%	<100%	131%	121%	121%

Table 3.7-6: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines off-peak deliverability constraint summary

Affected transmission zones		Northern California and Diablo/Morro Bay Offshore Wind				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint		0	0	6,743 OSW	6,743 OSW	6,743 OSW
Energy storage portfolio MW behind the constraint		0	0	0	0	0
Renewable MW curtailment		0	0	1,333	1,349	1,219
Portfolio energy storage MW re-dispatched in charging mode		0	0	0	0	0
Mitigation Options	RAS	Not Needed		N/A, N-0 Overload		
	Re-locate portfolio battery storage (MW)	Not Needed		N/A		
	Transmission upgrade including cost	Not Needed		• Diablo – North HVDC ($1.6B) • Diablo – South HVDC (1.85B) • Second Diablo – Gates 500 kV line ($0.4B)		
Recommended Mitigation		Not Needed		Second Diablo – Gates 500 kV line that was recommended to address on-peak deliverability constraints.		

3.7.5 Deliverability Assessment Summary for 8,350 MW of Offshore Wind

The study results indicated that the following transmission alternatives will facilitate the interconnection and will address any constraints and overload identified in the studies for north coast (Humboldt Bay) and central cost (Diablo and Morro Bay) offshore wind areas with a total of 8,350 MW of wind generation capacity.

<u>Humboldt Bay (1,607 MW)</u>

- Option 1: 500 kV AC connection to Fern Road substation and a new 500 kV line from Fern Road to Tesla. The overall cost estimate for option 1 is $2.3B
- Option 2: VSC-HVDC connection to a Bay Hub substation with three connections to load centers in the Bay area. The overall cost estimate for option 2 is $4.0B
- Option 3: LCC-HVDC connection to Collinsville substation, recommended for approval in this planning cycle in section 3.5.7. The cost estimate for option 3 is $2.1B

<u>Diablo and Morro Bay (6,743 MW)</u>

- Connect Diablo offshore wind to Diablo 500 kV substation.
- Connect Morro Bay offshore wind to a new Morro Bay 500 kV substation with the cost estimate of $110M.
- Without mitigation, around 5,300 MW of the Diablo/Morro Bay area offshore wind will be deliverable. Any of the following transmission projects will make the entire 6,753 MW deliverable:
  - Diablo – North HVDC with a cost estimate of $1.6B
  - Diablo – South HVDC with a cost estimate of $1.85B. The source of the cost estimate is the Pacific Transmission Expansion Project (PTE) submission.
  - Second Diablo – Gates 500 kV line with a cost estimate of $0.4B

3.7.6 Outlook Assessment with 21,171 MW of Offshore Wind

The following topics are discussed at a high level for the outlook wind scenario with 21,171 MW of offshore wind development of which 14,428 MW are in the north coast of California:

- Interconnection to the ISO System
- Offshore Grid Considerations
- Increased Transfer Capacity between California and Pacific Northwest

Interconnection to the ISO System

As discussed earlier, a concept based on two high-capacity AC lines, two LCC HVDC lines, and two VSC-HVDC lines would have enough capacity to transfer 14,428 MW of north coast offshore wind out of the area. However, further reliability, deliverability, and production cost simulation studies are required to determine the optimum configuration, capacity, interconnection points, and staging of different components of required system enhancements. An optimum system enhancement plan developed in close coordination with the gas retirement and the long-term renewable resource development plans across the state.

Offshore Grid Considerations

One option for offshore wind connection to the system on the shore is to interconnect each wind project with the system through a dedicated cable. In this configuration, there would be no power flow between different offshore wind projects. An alternative approach is to have an offshore grid to interconnect a number of projects offshore and bring the aggregated power to shore. The potential advantage of such a configuration is to have fewer cables coming to the shore and to also increase the overall reliability of supply under contingency conditions. The idea has been explored in other systems such as New York[137] and Denmark[138].

It should be noted that offshore wind developments in California and other systems might have a major difference considering the depth of the water which may require solutions that are specifically designed for deep-water applications.

Increased Transfer Capacity between California and Pacific Northwest

The interconnection solution along with the mitigation measures studied in the assessment will potentially create two strong connection points in California that enable more interconnections between California and the Pacific Northwest. One strong point would be the Fern Road 500 kV substation, which —with the addition of the Fern Road–Tesla 500 kV line —will have capacity available for another connection to the Pacific Northwest similar to the Malin – Round Mountain 500 kV lines. Another strong point could be either the offshore or the onshore grid required for the 14,428 MW of north coast wind development. This will also require coordination with the offshore wind potential in the Pacific Northwest and would need to further explore the concept of an offshore grid, as indicated above, to collect the resources from the offshore wind farms off the California coast and connect to offshore wind developments in the Pacific Northwest that could also increase the transfer capabilities between the regions.

[137] The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York (brattle.com)

[138] A132994-2-4 Elektriske systemer for Bornholm I + II, Nordsøen II + III og Området vest for Nordsøen II + III (ens.dk) (in Danish)

3.8 Production cost model simulation (PCM) study

3.8.1 PCM assumptions

The Base portfolio and the two sensitivity portfolios described in section 3.4 were utilized for the PCM study in the policy-driven assessment in this planning cycle. Details of PCM assumptions and development can be found in Chapter 4.

3.8.2 Congestion and curtailment results

The ISO conducted production cost simulations on the PCM cases of all three portfolios. The congestion and curtailment analysis of the Base portfolio PCM is also a part of the ISO economic assessment, as set out in section 4.7. Out-of-state wind and the associated transmission upgrades were studied in this planning cycle using both the Base portfolio and the Sensitivity 1 portfolio. The out-of-state wind study results were discussed in section 4.10, which included additional congestion and curtailment results of the Base portfolio PCM, and the congestion and curtailment results of the Sensitivity 1 portfolio PCM. The Sensitivity 2 portfolio PCM was simulated focusing on the offshore wind and the associated injection and transmission scenarios, as set out in section 3.8.3.

3.8.3 Sensitivity 2 portfolio offshore wind PCM study

The Sensitivity 2 portfolio PCM study in this planning cycle focused on evaluating the impact of offshore wind resources on the ISO system's congestion and renewable curtailment. The injection points of offshore wind resources and transmission upgrades identified in the Sensitivity 2 portfolio deliverability assessment in section 3.7 were considered in developing the scenarios of the Sensitivity 2 portfolio PCM.

3.8.3.1 Offshore wind model and transmission alternatives in PCM

In the Sensitivity 2 portfolio offshore wind PCM study, it was assumed that the capacity of offshore wind generated in the CPUC Sensitivity 2 portfolio is the capacity at the injection point. The study used the offshore wind hourly profiles provided by NREL. The profiles of the year of 2009 were used, consistent with the ADS PCM 2030.

Table 3.8-1 listed the offshore wind capacity and capacity factors of the offshore wind profiles that were modeled in the Sensitivity 2 PCM in this planning PCM.

Table 3.8-1: Offshore Wind Capacity and Capacity Factor of Profile in PCM

	Humboldt	Diablo	Morro Bay
Capacity (MW)	1,607	4,419	2,324
Capacity factor of profile	53.09%	58.59%	55.54%

Three injection and transmission alternatives for the Humboldt offshore wind were considered in the PCM study, consistent with the Sensitivity 2 offshore wind policy study in section 3.7:

- Humboldt offshore wind modeled at the Fern Road 500 kV bus
- Humboldt offshore wind modeled at the proposed Collinsville 500 kV bus
- Humboldt offshore wind modeled at the proposed Bay Hub 230 kV bus

The Diablo offshore wind was modeled at the Diablo 500 kV bus and the Morro Bay offshore wind was modeled at the proposed Morro Bay offshore wind 500 kV substation with the existing Diablo - Gates 500 kV line looped in. The transmission alternatives for the Diablo and Morro Bay offshore wind considered in the PCM study were also consistent with the policy study in section 3.7:

- New HVDC line from the Diablo 500 kV to Southern California. Different from the policy deliverability assessment, the model of the Pacific Transmission Expansion HVDC (PTE) project, which was an economic study request to the 2021-2022 planning cycle, was used to in the PCM study. The details of the PTE project scope can be found in section 4.8.2.
- New HVDC line between the proposed Morro Bay offshore wind 500 kV bus and the Moss Landing 500 kV bus
- New 500 kV line between the Diablo 500 kV bus and the Gates 500 kV bus

A total nine scenarios with different combinations of injection and transmission alternatives were considered for the Sensitivity 2 portfolio offshore wind PCM study. These scenarios were summarized in Table 3.8-2.

Table 3.8-2: Scenarios with Different Injection and Transmission Alternatives for Offshore Wind PCM Study

	Humboldt offshore wind at Fern Road	Humboldt offshore wind at Collinsville	Humboldt offshore wind at Bay Hub
PTE	X	X	X
Morro Bay DC	X	X	X
New Diablo-Gates 500 kV line	X	X	X

3.8.3.2 Humboldt offshore wind at Fern Road

Table 3.8-3 summarized the congestion results of the scenarios with Humboldt offshore wind modeled at Fern Road 500 kV bus and with different transmission upgrade modeled for the Diablo and Morro Bay offshore wind. Three scenarios with different transmission alternatives for the Diablo and Morro Bay offshore wind generators were studied. Table 3.8-3 showed congestion with cost greater than $2 million per year for at least one of the three scenarios.

Table 3.8-3: Congestion Results with Humboldt Offshore Wind at Fern Road

Area or Branch	Congestion Cost ($M): Fern Road and PTE	Congestion Cost ($M): Fern Road and Morro Bay DC	Congestion Cost ($M): Fern Road and New Disablo-Gates 500 kV line
PG&E Table Mt 500/230 kV transformer	1,006.70	977.00	1,003.66
PG&E Gates-Morro Bay OSW 500 kV	168.46	16.76	142.76
Path 15 Corridor	113.98	26.69	131.36
PG&E VacaDixon-TESLA 500 kV	58.51	104.29	45.97
PG&E Sierra	45.10	42.57	44.75
PG&E POE-RIO OSO 230 kV	36.84	36.89	36.61
SDGE DOUBLTTP-FRIARS 138 kV	25.43	28.25	28.48
PG&E Eight Mile-Tesla 230 kV	23.50	28.29	23.42
Path 26 Corridor	20.47	64.30	64.17
PG&E Tesla 500/230 kV Transformer	18.60	13.47	16.93
Path 15 Corridor - Panoche-Gates 230 kV	17.65	7.74	12.60
COI Corridor	8.34	6.80	5.99
PG&E Fresno	6.61	7.49	5.97
Path 45	6.54	5.93	5.26
PG&E Moss Landing-Las Aguilas 230 kV	4.95	0.64	4.50
PDCI	4.79	5.76	5.58
Path 61/Lugo-Victorville	4.67	3.58	7.31
Path 60 Inyo-Control 115 kV	4.18	4.60	4.76
SCE RedBluff-Devers 500 kV	2.51	2.71	2.83
SCE Antelope 66 kV system	2.01	2.37	2.48
Path 25 PACW-PG&E 115 kV	1.65	2.11	2.17
SCE LCIENEGA-LA FRESA 230 kV	1.44	3.11	3.66
PG&E North Valley	1.15	3.51	1.85
PG&E Tulucay-VacaDixon 230 kV	0.74	2.16	0.55
SCE Litehipe-Mesa Cal 230 kV	0.13	3.31	3.44
PG&E Tesla-Los Banos 500 kV	0.02	4.36	0.01
PG&E Diablo-Midway 500 kV	0.00	12.19	0.00

With further detailed analyses of the congestion results and comparison with the Base portfolio PCM results, there are some key observations for the impact of offshore wind on the congestion within the ISO system:

- The Table Mountain 500/230 kV transformer was congested when the flow was from 230 kV to 500 kV, and the COI flow was from south to north. The congestion mainly happened in spring months
- PG&E Sierra congestion is related to the Table Mountain congestion
- Offshore wind injected at the PG&E buses helped to reduce the Path 26 congestion (flow from south to north) and COI congestion (flow from north to south)
- The Diablo and Morro Bay offshore wind caused Diablo-Gates 500 kV line and Diablo-Midway 500 kV line congestion. These offshore wind resources contributed to Path 15 congestion as well, which was mainly observed when the flow was from south to north
- The PTE alternative and the Diablo – Gates 500 kV line alternative aggravated Path 15 congestion compared with the Morro Bay DC alternative
- Humboldt offshore wind contributed to the Vaca Dixon-Tesla 500 kV congestion
- The Morro Bay DC scenario, which included a new HVDC line between the Morro Bay offshore wind 500 kV bus and the Moss Landing 500 kV bus, had the least congestion on the Moss Bay offshore wind – Gates 500 kV line among all three scenarios that had different transmission upgrade modeled for the Diablo and Morro Bay offshore wind. The Morro Bay HVDC scenario, however, had the largest Vaca Dixon – Tesla congestion among the three scenarios

Table 3.8-4 showed the wind and solar curtailment by zone of the three scenarios with Humboldt offshore wind modeled at Fern Road and with different transmission upgrades modeled for the Diablo and Morro Bay offshore wind. It also showed the offshore wind generation and curtailment. Curtailment ratio was calculated as the curtailment divided by the summation of generation and curtailment. The ISO system curtailment ratio and the curtailment ratio by zone were not impacted significantly by the transmission alternatives. The offshore wind curtailments were also similar among the three scenarios, although they had different transmission upgrades modeled for the Diablo and Morro Bay offshore wind. The Diablo and Morro Bay offshore wind had about an 8% curtailment ratio each, and the Humboldt wind had about a 3% curtailment ratio. The PTE scenario had less Morro Bay and Diablo offshore wind curtailment than the Morro Bay HVDC scenario and the Diablo-Gates 500 kV line scenario.

Table 3.8-4: Curtailment Results with Humboldt Offshore Wind at Fern Road

	Fern Road and PTE			Fern Road and Morry Bay DC			Fern Road and New Diablo-Gates 500 kV line		
Zone	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio
SCE Tehachapi	30,441	4,570	13%	30,545	4,520	13%	30,491	4,466	13%
OSW_Diablo	19,039	1,548	8%	18,868	1,719	8%	18,868	1,702	8%
SCE Eastern	11,578	1,421	11%	11,729	1,271	10%	11,729	1,301	10%
PG&E Fresno-Kern	9,191	2,485	21%	9,143	2,532	22%	9,143	2,605	22%
OSW_MorroBay	10,442	930	8%	10,424	948	8%	10,424	1,017	9%
NM	9,318	1,382	13%	9,290	1,411	13%	9,290	1,381	13%
SDGE IV	8,994	559	6%	9,060	493	5%	9,060	497	5%
OSW_Humboldt	7,976	237	3%	7,942	272	3%	7,942	263	3%
NW	5,430	340	6%	5,421	349	6%	5,421	348	6%
WY	4,862	657	12%	4,836	682	12%	4,836	661	12%
PG&E Solano	5,112	181	3%	5,096	197	4%	5,096	190	4%
AZ	3,513	1,531	30%	3,452	1,592	32%	3,452	1,551	31%
SCE EOL	4,116	492	11%	4,192	416	9%	4,192	453	10%
SCE NOL	3,801	759	17%	3,874	686	15%	3,874	720	16%
PG&E Carrizo	2,570	490	16%	2,561	499	16%	2,561	506	16%
PG&E N. CA	2,884	149	5%	2,870	163	5%	2,870	157	5%
VEA	1,281	33	2%	1,291	23	2%	1,291	33	3%
SCE Vestal	1,096	182	14%	1,101	177	14%	1,101	174	14%
IID	719	63	8%	730	52	7%	730	57	7%
SCE Others	463	70	13%	467	66	12%	467	67	13%
SDGE San Diego	255	18	7%	257	17	6%	257	17	6%
PG&E Central	91	20	18%	90	21	19%	90	21	19%
PG&E Bay	47	9	17%	46	10	18%	46	10	18%
Total	**143,218**	**18,129**	**11%**	**143,284**	**18,116**	**11%**	**143,231**	**18,198**	**11%**

3.8.3.3 Humboldt offshore wind at Collinsville

Table 3.8-5 and Table 3.8-6 showed the congestion and curtailment results, respectively, of the three scenarios with the Humboldt offshore wind modeled at the Collinsville 500 kV bus and with different transmission upgrades modeled for the Diablo and Morro Bay offshore wind. The overall congestion and curtailment patterns were similar to the corresponding scenarios with the Humboldt offshore wind modeled at the Fern Road 500 kV bus. The most noticeable difference is that injecting the Humboldt offshore wind at Collinsville caused less congestion on the PG&E's Vaca Dixon – Tesla 500 kV line, compared with injecting the Humboldt offshore wind at Fern Road. On the other hand, the curtailment ratio of the Humboldt offshore wind increased from 3% to 5%, as the injection point of the Humboldt offshore wind was moved from Fern Road to Collinsville. The ISO overall curtailment was about the same between these two Humboldt offshore injection point scenarios. Both had about an 11% overall curtailment ratio.

Table 3.8-5: Congestion Results with Humboldt Offshore Wind at Collinsville

Area or Branch	Congestion Cost ($M): Collins-PTE	Congestion Cost ($M): Collins-Morro Bay HVDC	Congestion Cost ($M): Collins-New Disablo-Gates 500 kV line
PG&E Table Mt 500/230 kV transformer	969.11	914.93	967.72
PG&E Gates-MorroBay_OSW 500 kV	164.50	18.03	144.43
Path 15 Corridor	121.09	49.07	139.80
PG&E Sierra	42.42	39.02	41.66
PG&E POE-RIO OSO 230 kV	36.81	36.65	36.60
PG&E Eight Mile-Tesla 230 kV	25.48	32.92	25.07
SDGE DOUBLTTP-FRIARS 138 kV	25.31	28.55	27.51
Path 26 Corridor	22.43	68.23	67.80
Path 15 Corridor - Panoche-Gates 230 kV	16.83	7.42	11.93
COI Corridor	10.93	10.64	9.25
PG&E VacaDixon-TESLA 500 kV	8.10	18.12	7.14
Path 45	6.74	7.23	6.49
PG&E Fresno	6.68	7.50	6.02
PDCI	6.49	8.79	7.55
Path 61/Lugo-Victorville	4.70	4.06	7.01
Path 60 Inyo-Control 115 kV	4.37	4.69	4.87
PG&E Moss Landing-Las Aguilas 230 kV	2.91	0.39	2.27
SCE RedBluff-Devers 500 kV	2.77	2.41	2.56
Path 25 PACW-PG&E 115 kV	2.22	1.84	1.96
SCE Antelope 66 kV system	2.04	2.35	2.48
SCE LCIENEGA-LA FRESA 230 kV	1.51	2.24	4.59
SCE J.HINDS-MIRAGE 230 kV	1.45	1.55	1.54
SCE Pardee-S.Clara 230 kV	1.26	0.08	0.09
Path 41 Sylmar transformer	0.54	0.56	0.53
SCE Tehachapi Windhub 500 kV Xfmr	0.51	0.47	0.48
PG&E GBA	0.40	0.48	0.48
SCE Mira Loma -Chino 230 kV	0.31	0.00	0.00
Path 46 WOR	0.30	0.79	0.23
SDGE-CFE OTAYMESA-TJI 230 kV	0.26	0.23	0.25
PG&E Weber-Testa 230 kV	0.21	0.65	0.21
SDGE-CFE IV-ROA 230 kV line and IV PFC	0.20	0.28	0.42
SDGE Silvergate-Bay Blvd 230 kV	0.11	0.13	0.11
SCE Litehipe-Mesa Cal 230 kV	0.08	3.50	2.90
PG&E Tesla-Los Banos 500 kV	0.02	5.07	0.02
SCE Vincent 500 kV Transfomer	0.00	0.47	1.44
PG&E Diablo-Midway 500 kV	0.00	11.20	0.00

Table 3.8-6: Curtailment Results with Humboldt Offshore Wind at Fern Road

	Collinsville and PTE			Collinsville and Morro Bay DC			Collinsville and New Diablo-Gates 500 kV line		
Zone	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio
SCE Tehachapi	30,357	4,654	13%	30,461	4,652	13%	30,359	4,550	13%
OSW_Diablo	18,963	1,624	8%	18,826	1,761	9%	18,826	1,743	8%
SCE Eastern	11,680	1,320	10%	11,811	1,189	9%	11,811	1,236	9%
PG&E Fresno-Kern	9,167	2,509	21%	9,125	2,551	22%	9,125	2,620	22%
OSW_MorroBay	10,404	968	9%	10,397	975	9%	10,397	1,039	9%
NM	9,365	1,335	12%	9,359	1,341	13%	9,359	1,341	13%
SDGE IV	9,030	523	5%	9,076	477	5%	9,076	477	5%
OSW_Humboldt	7,789	425	5%	7,783	431	5%	7,783	449	5%
NW	5,456	313	5%	5,437	333	6%	5,437	332	6%
WY	4,891	627	11%	4,868	651	12%	4,868	641	12%
PG&E Solano	5,115	178	3%	5,093	200	4%	5,093	191	4%
AZ	3,566	1,478	29%	3,501	1,543	31%	3,501	1,515	30%
SCE EOL	4,139	470	10%	4,229	379	8%	4,229	412	9%
SCE NOL	3,824	736	16%	3,901	659	14%	3,901	679	15%
PG&E Carrizo	2,567	493	16%	2,557	503	16%	2,557	507	17%
PG&E N. CA	2,886	147	5%	2,871	163	5%	2,871	156	5%
VEA	1,275	39	3%	1,292	22	2%	1,292	24	2%
SCE Vestal	1,096	182	14%	1,096	181	14%	1,096	173	14%
IID	731	51	7%	742	40	5%	742	47	6%
SCE Others	464	69	13%	469	64	12%	469	65	12%
SDGE San Diego	256	18	6%	257	17	6%	257	17	6%
PG&E Central	91	20	18%	90	22	20%	90	21	19%
PG&E Bay	47	9	17%	46	10	18%	46	10	18%
Total	**143,158**	**18,189**	**11%**	**143,287**	**18,162**	**11%**	**143,184**	**18,244**	**11%**

3.8.3.4 Humboldt offshore wind at Bay Hub

Table 3.8-7 and Table 3.8-8 showed the congestion and curtailment results, respectively, of the three scenarios with the Humboldt offshore wind modeled at the Bay Hub 230 kV bus and with different transmission upgrade modeled for the Diablo and Morro Bay offshore wind. The overall congestion and curtailment patterns were similar to the corresponding scenarios with the Humboldt offshore wind modeled at the Fern Road 500 kV bus or at the Collinsville 500 kV bus. With injecting the Humboldt offshore wind at Bay Hub, the congestion of the PG&E's Vaca Dixon – Tesla 500 kV line was significantly lower than the other two Humboldt offshore wind scenarios. On the other hand, the curtailment ratio of the Humboldt offshore wind in the Bay Hub scenario was the highest at 7%, compared with the curtailment ratios at 3% and 5% in the Fern Road scenario and Collinsville scenario, respectively. The ISO overall curtailment was about the same between these two Humboldt offshore injection point scenarios. All had an overall curtailment ratio of about 11%.

Table 3.8-7: Congestion Results with Humboldt Offshore Wind at Bay Hub

Area or Branch	Congestion Cost ($M): Bay Hub-PTE	Congestion Cost ($M): Bay Hub-Morro Bay HVDC	Congestion Cost ($M): Bay Hub-New Diablo-Gates 500 kV line
PG&E Table Mt 500/230 kV transformer	943.23	889.52	946.74
PG&E Gates-MorroBay_OSW 500 kV	170.73	17.38	151.16
Path 15 Corridor	120.66	49.74	137.70
PG&E Sierra	41.13	38.58	40.61
PG&E POE-RIO OSO 230 kV	37.11	36.61	36.59
PG&E Eight Mile-Tesla 230 kV	26.43	35.01	26.94
SDGE DOUBLTTP-FRIARS 138 kV	25.38	26.49	28.18
Path 26 Corridor	21.96	65.55	66.38
Path 15 Corridor - Panoche-Gates 230 kV	17.51	7.20	11.78
COI Corridor	12.12	16.86	10.50
PG&E Fresno	6.71	7.52	6.13
PDCI	6.56	9.13	7.44
Path 45	6.08	6.56	6.02
Path 61/Lugo-Victorville	4.60	3.83	6.75
Path 60 Inyo-Control 115 kV	4.22	4.64	4.81
SCE RedBluff-Devers 500 kV	2.53	2.40	2.47
PG&E Moss Landing-Las Aguilas 230 kV	2.32	0.34	1.82
SCE Antelope 66 kV system	2.04	2.28	2.51
Path 25 PACW-PG&E 115 kV	1.80	2.00	1.46
SCE LCIENEGA-LA FRESA 230 kV	1.47	1.79	1.33
SCE J.HINDS-MIRAGE 230 kV	1.44	1.57	1.56
SCE Pardee-S.Clara 230 kV	1.26	0.04	0.07
PG&E VacaDixon-TESLA 500 kV	0.65	1.86	0.62
PG&E Tulucay-VacaDixon 230 kV	0.55	0.00	0.44
SCE Mira Loma -Chino 230 kV	0.28	0.00	0.00
SCE Litehipe-Mesa Cal 230 kV	0.14	3.55	3.36
PG&E Tesla-Los Banos 500 kV	0.03	5.37	0.02
SCE Vincent 500 kV Transfomer	0.00	0.62	1.31
PG&E Diablo-Midway 500 kV	0.00	11.21	0.00

Table 3.8-8: Curtailment Results with Humboldt Offshore Wind at Bay Hub

	BayHub and PTE			BayHub and Morro Bay DC			BayHub and New Diablo-Gates 500 kV line		
Zone	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**
SCE Tehachapi	30,397	4,614	13%	30,510	4,621	13%	30,391	4,501	13%
OSW_Diablo	18,984	1,603	8%	18,836	1,750	9%	18,836	1,730	8%
SCE Eastern	11,654	1,346	10%	11,835	1,164	9%	11,835	1,231	9%
PG&E Fresno-Kern	9,164	2,512	22%	9,120	2,556	22%	9,120	2,612	22%
OSW_MorroBay	10,408	964	8%	10,399	973	9%	10,399	1,032	9%
NM	9,363	1,338	13%	9,362	1,338	13%	9,362	1,348	13%
SDGE IV	9,023	530	6%	9,102	452	5%	9,102	472	5%
OSW_Humboldt	7,638	576	7%	7,605	608	7%	7,605	599	7%
NW	5,459	310	5%	5,442	328	6%	5,442	328	6%
WY	4,900	619	11%	4,884	635	12%	4,884	631	11%
PG&E Solano	5,119	174	3%	5,099	194	4%	5,099	185	4%
AZ	3,551	1,493	30%	3,499	1,545	31%	3,499	1,516	30%
SCE EOL	4,146	462	10%	4,228	380	8%	4,228	418	9%
SCE NOL	3,832	728	16%	3,905	655	14%	3,905	683	15%
PG&E Carrizo	2,568	492	16%	2,559	501	16%	2,559	504	16%
PG&E N. CA	2,892	141	5%	2,880	153	5%	2,880	150	5%
VEA	1,281	33	3%	1,288	27	2%	1,288	28	2%
SCE Vestal	1,097	180	14%	1,098	180	14%	1,098	173	14%
IID	729	53	7%	745	37	5%	745	49	6%
SCE Others	464	69	13%	470	63	12%	470	65	12%
SDGE San Diego	256	18	6%	258	16	6%	258	17	6%
PG&E Central	91	20	18%	90	22	20%	90	21	19%
PG&E Bay	46	10	17%	46	10	18%	46	10	18%
Total	**143,063**	**18,284**	**11%**	**143,259**	**18,207**	**11%**	**143,140**	**18,303**	**11%**

3.8.3.5 Summary of offshore wind PCM results

The key observations from the production cost simulation results of the above nine scenarios of offshore wind and the associated injection and transmission alternatives are summarized below:

- The Fern Road scenario had the least Humboldt offshore wind curtailment among the three transmission scenarios for the Humboldt offshore wind, which was not impacted by the transmission alternative modeled for the Diablo and Morro Bay offshore wind resources
- The PTE scenario had less Diablo and Morro Bay offshore wind curtailment than the Morro Bay DC scenario and the Diablo-Gates 500 kV line scenario, which was not

impacted by the transmission alternative modeled for the Humboldt offshore wind resource

- Offshore wind generators impacted curtailment at different local areas depending on the offshore wind injection point and transmission alternatives, but the ISO system overall curtailment ratios were similar among all scenarios studied in the offshore wind PCM study in this planning cycle
- The Table Mountain 500/230 kV transformer was congested when the flow was from 230 kV to 500 kV, and the COI flow was from south to north. The congestion mainly happened in spring months
- The Humboldt offshore wind aggravated the congestion of the Vaca Dixon-Tesla 500 kV line, as the Fern Road scenario had the largest and the Bay Hub scenario had the least congestion of this line among all three transmission scenarios for the Humboldt offshore wind
- The offshore wind at Diablo and Morro Bay resulted in congestion on the 500 kV lines coming out of the Diablo 500 kV bus, specifically the Diablo-Gates and Diablo-Midway 500 kV lines
- The offshore wind at Diablo and Morro Bay aggravated the Path 15 congestion when the Path 15 flow was from south to north. The scenarios with the PTE project or with the new Diablo-Gates 500 kV line had a higher Path 15 congestion cost than the scenario with Morro Bay HVDC
- The offshore wind helped to reduce the Path 26 congestion. Among the three transmission alternatives studied for Diablo and Morro Bay offshore wind, the PTE project is more effective to reduce Path 26 congestion than the other two transmission alternatives for the Diablo and Morro Bay offshore wind resources, i.e., the Morro Bay offshore wind – Moss Landing HVDC alternative and the Diablo-Gates 500 kV line alternative.

3.9 Transmission Plan Deliverability with Approved 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 monitors the available transmission plan deliverability (TPD) 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. An estimate of the generation deliverability supported by the existing system and approved upgrades is provided in the transmission capability estimates white paper the ISO published in October 2021[139]. The white paper considered queue clusters up to and including queue cluster 13. The transmission plan

[139] http://www.caiso.com/Documents/RevisedWhitePaper-2021TransmissionCapabilityEstimates-CPUCResourcePlanningProcess.pdf.

deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. The white paper provides the deliverable study amount beyond the existing and contracted resources. The relationship between generation interconnection service capacity and deliverability study amount is discussed in Section 3.5.1.

3.10 Summary of findings

The Policy-driven assessment analyzed the Base Portfolio and the two sensitivity portfolios the CPUC transmitted for use in the 2021-2022 transmission planning process. The Base Portfolio is based on a 46 MMT GHG reduction target for the electric sector by 2030 and is used to identify needed transmission upgrades for approval. The sensitivity portfolios are based on 38 MMT GHG target (Sensitivity Portfolio 1) and a 30 MMT GHG target intended to test the transmission needs associated with 8.3 GW of offshore wind (OSW) (Sensitivity Portfolio 2 or Offshore Wind Portfolio). In accordance with the CPUC's request, two variations of the Base Portfolio were assessed. One variation includes 1062 MW of Wyoming Wind injected at Eldorado 500 kV (Base Portfolio A) while the other variation instead includes the same amount of New Mexico Wind injected at Paloverde 500 kV (Base Portfolio B).In the deliverability assessment, Wyoming/Idaho and New Mexico out-of-state wind portfolio resources on new out-of-state transmission were modeled at Eldorado 500 kV and Paloverde 500 kV, respectively, and were dispatched over above the MIC.

The offshore wind portfolio in Sensitivity 2 is comprised of 4.4 GW of offshore wind at Diablo Canyon, 2.3 GW at Morro Bay and 1.6 MW at Humboldt Bay. The Diablo Canyon offshore wind was connected to the Diablo 500 kV substation. The Morro Bay offshore wind was assumed to be connected to a new 500 kV substation at Morro Bay looping into the existing Diablo – Gates 500 kV line. The three interconnection alternatives below were considered for Humboldt offshore wind:

Option 1: 500 kV AC lines to the planned Fern Road 500 kV substation ($1.2B)

Option 2: HVDC subsea cables to a converter station in the Bay area with 230 kV AC connections to Potrero, East Shore, and Los Esteros ($4B)

Option 3: HVDC bipole lines to a converter station at a new Collinsville 500/230 kV substation with 230 kV AC connections to Pittsburg Substation ($3B)

The analysis performed includes: 1) on-peak deliverability assessment, which is intended to support deliverability of FCDS portfolio resources that were selected to meet resource adequacy needs; 2) off-peak deliverability assessment, which is designed to identify transmission constraints that could cause excessive renewable curtailment; and 3) production cost simulation, which is designed to support the economic delivery of renewable energy during all hours of the year.

3.10.1 Summary of on-peak deliverability assessment results

The on-peak deliverability assessment identified several constraints in the base and sensitivity portfolios. Remedial Action Schemes (RAS), reduction of portfolio battery storage behind constraints and transmission upgrades were considered to mitigate the constraints. RAS was recommended as a mitigation for several deliverability constraints. Reducing portfolio battery storage was not found to be a viable mitigation for any of the constraints identified. Table 3.10-1 summarizes the constraints for which transmission upgrades are found to be the preferred mitigation for the base or one or both of the sensitivity portfolios. The transmission upgrades identified for the base portfolio are recommended for approval as Policy-driven upgrades.

Table 3.10-1: On-peak deliverability constraints requiring transmission upgrades

Constraint	Contingency	Portfolio Resources Behind Constraint (MW)		Total Undeliverable MW	Recommended/Potential Mitigation	Portfolio for which Mitigation is Needed		
		Renewables (Base/Sens-1/Sens-2)	Battery Storage (Base/Sens-1/Sens-2)			Base	Sens-01	Sens-02
Mesa–Laguna Bell No.1 230 kV line	P7	0	500	3098/3048/2329	Reconductor Laguna Bell-Mesa No. 1 230 kV line ($17.3M)	✓	✓	✓
Encina–San Luis Rey 230 kV line	P1/P7	809/1595/1595	720	1609/2496/2431	New Encina-San Luis Rey 230 kV line ($102M)		✓	✓
San Luis Rey-San Onofre 230 kV constraint	P7	809/1595/1595	720	1264/2082/2004	New San Luis Rey-San Onofre 230 kV line ($237M)		✓	✓
Delevan-Cortina 230kV line	P0/P1/P7	437	0	564/588/479-713	Reconductor Delevan-Cortina 230kV line ($17.7M – $35.4 M)	✓	✓	✓
Cayetano-North Dublin 230kV line	P7	102	5.4/0/0	260/299/0-422	New Collinsville 500 kV substation ($400M-$600M)	✓	✓	✓*
Lone Tree-USWP-JRW-Cayetano 230kV line	P0/P1/P7	102	5.4/0/0	500/533/201-642		✓	✓	✓
Las Positas-Newark 230kV line	P1/P7	102	5.4/0/0	510/476/116-638		✓	✓	✓
Rio Oso-SPI Jct-Lincoln 115kV line	P7	152	0	396/403/368-615	Reconductor Rio Oso–SPI Jct–Lincoln 115kV line ($10.6M - $21.2M)	✓	✓	✓
Borden-Storey #2 230kV line	P1	733/733/0	0	44/181/0	New Manning 500 kV substation ($312M - $406M)	✓	✓	
Fulton 60kV lines	P7	0	0	40/40/0-38	ISO is exploring cost-effective alternatives	✓	✓	✓*
Humboldt 60kV Lines	P0/P1/P7	0	0	80/106/68-110	ISO is exploring cost-effective alternatives	✓	✓	✓
Fern Road-Table Mountain #1 and #2 500kV lines	P0/P1	0/0/2044 (Option 1)	0	0/0/2305 (Option 1)	New 500 kV line from Fern Road to Tesla ($1.1B)			✓ (Option 1 only)
Table Mountain-Vaca Dixon 500 kV Line	P0							
Table Mountain-Rio Oso 230 kV Line	P1							
Round Mountain-Cottonwood #3 230 kV Line	P1							
North Dublin-Vineyard 230 kV line	P7							

Diablo-Midway 500 kV Lines	P0/P1	0/0/6743	0	0/0/1388	• Diablo – Moss Landing HVDC ($1.6B)or • Diablo – South HVDC ($1.85B) or • Second Diablo – Gates 500 kV line ($0.4B)			✓
Morro Bay-Gates 500 kV Line	P0/P1							

* Constraint was not identified under one or more interconnection option for Humboldt offshore wind wind

3.10.2 Summary of off-peak deliverability assessment results

The off-peak deliverability assessment identified several constraints in the base and sensitivity portfolios. Remedial Action Schemes (RAS), dispatching/adding portfolio battery storage behind constraints in charging mode and transmission upgrades were considered to mitigate the constraints. RAS and/or dispatching portfolio battery storage in charging mode were recommended as mitigations for several off-peak deliverability constraints. Table 3.10-2 summarizes the constraints for which transmission upgrades are found to be the preferred mitigation for the base or one or both of the sensitivity portfolios. The transmission upgrades identified for the base portfolio were considered as candidates for further evaluation using production cost simulation based on an assessment of priority.

Table 3.10-2: Off-peak deliverability constraints that may require transmission upgrades

Constraint	Contingency	Portfolio Resources Behind Constraint (MW)		Renewable Curtailment (MW) (Base/Sens-1/Sens-2)"	Recommended/Potential Mitigation	Portfolio for which Mitigation is Needed		
		Renewables (Base/Sens-1/Sens-2)	Battery Storage (Base/Sens-1/Sens-2)			Base	Sens-01	Sens-02
Midway–Whirlwind 500 kV line (PG&E's segment of the line)	P0	3952/4734/ 3952	3228/2854/ 2389	1593/2029/ 1622	Re-rate the PG&E segment of the Midway–Whirlwind 500 kV line (~$0)	✓	✓	✓
GLW/VEA area constraints	P0/P1	2024/624/624	248/136/136	1482/130/130	GLW/VEA area upgrades	✓		
Diablo-Midway 500 kV Lines	P0/P1	0/0/6743	0	0/0/1219-1349	Same as on-peak			✓
Morro Bay-Gates 500 kV Line	P0/P1							

3.10.3 Summary of production simulation results

Production cost simulations were conducted for all three portfolios in this planning cycle. The congestion and curtailment results for the Base portfolio as a part of the economic assessments are set out in Chapter 4. The out-of-state wind study was conducted using the Base portfolio and the Sensitivity 1 portfolio, which can be found in Chapter 4 as well. The Sensitivity 2 portfolio was studied focusing on the offshore wind assessment, including the curtailment and transmission congestion. The Sensitivity 2 portfolio production cost simulation results were summarized in section 3.8.3.

3.11 Conclusion

The policy-driven assessment found the following transmission upgrades to be needed to ensure deliverability of resources that are needed to meet the State's policy goals and resource adequacy needs:

- Reconductor Laguna Bell-Mesa No. 1 230 kV line ($17.3M)
- Reconductor Delevan-Cortina 230kV line ($17.7M – $35.4M)
- New Collinsville 500 kV substation ($400M-$600M)
- Reconductor Rio Oso–SPI Jct–Lincoln 115kV line ($10.6M - $21.2M)
- New Manning 500 kV substation ($312M-$406M)
- GLW/VEA area upgrades ($278M).

The ISO recommends approval of the above policy-driven transmission upgrades as part of the 2021-2022 transmission planning process.

The ISO will coordinate with PG&E and SCE to further investigate re-rating of the PG&E segment of the Midway-Whirlwind 500 kV line and the bypassing the series capacitor at Midway on the Midway-Whirlwind 500 kV line.

<u>Base Portfolio 1062 MW out-of-state wind injection alternatives</u>

- The on-peak deliverability assessment did not identify material differences between the results of the 1062 MW injection of Wyoming Wind at Eldorado 500kV and injection of the same amount of New Mexico Wind at Palo Verde 500 kV.
- In the off-peak deliverability study with the GLW upgrade modeled, the Eldorado – McCullough 500 kV tie-line loaded above its normal rating with all elements in-service and under contingency conditions. This tie-line overload was worse with the 1062MW out-of-state wind at Eldorado instead of at Palo Verde.
- The out-of-state wind scenarios were further assessed in production cost simulation, as set out in Chapter 4.

<u>Sensitivity 2 Portfolio offshore wind transmission requirements</u>

The following conclusions can be drawn regarding the transmission requirements for offshore wind based on the assessment of Sensitivity Portfolio 2:

- A total of approximately 5,355 MW out of 6,743 MW of Diablo and Morro Bay offshore wind is deliverable without major transmission upgrades. Major transmission upgrades will be needed to make the remaining 1,388 MW of Diablo/Morro Bay portfolio offshore wind deliverable as shown in Table 3.11-1

- None of the 1,607 MW of Humboldt offshore wind is deliverable without transmission upgrades if injected at Fern Road 500 kV (Option 1). All of Humboldt offshore wind is deliverable without major transmission upgrades if it is injected to the Bay area (Option 2) or Collinsville 500 kV (Option 3). However, the Fern Road interconnection has the lowest total cost shown in Table 3.11-1.

Table 3.11-1 provides the transmission alternatives identified to interconnect and deliver the 8.3 GW offshore wind in the Sensitivity 2 Portfolio ranked according to estimated cost.

Table 3.11-1: Sensitivity 2 OSW transmission requirements

OSW Resource	**Interconnection option and cost**	**Network upgrade alternative and cost**	**Total cost**
Diablo & Morro Bay OSW (6743 MW)	New Morro Bay 500 kV Substation for Morro Bay OSW ($0.11 Billion)	Second Diablo – Gates 500 kV line ($0.4 Billion)	$0.51 Billion
		Diablo – Moss Landing HVDC line ($1.6 Billion)	$1.71 Billion
		Diablo – Southern California Subsea HVDC line ($1.85 Billion)	1.96 Billion
Humboldt OSW (1607 MW)	500 kV AC connection to planned Fern Road Substation($1.2 Billion)	New 500 kV line from Fern Road to Tesla ($1.1 Billion)	$2.3 Billion
	HVDC connection to new Collinsville 500/230 kV substation ($3.0 Billion)	None	$3.0 Billion
	Subsea HVDC connection to Bay Area ($4.0 Billion)	None	$4.0 Billion

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 cycle'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 analyses 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 (LCR) – considering capacity costs in particular, and
- Considering interregional transmission projects as potential alternatives to regional solutions to regional needs.

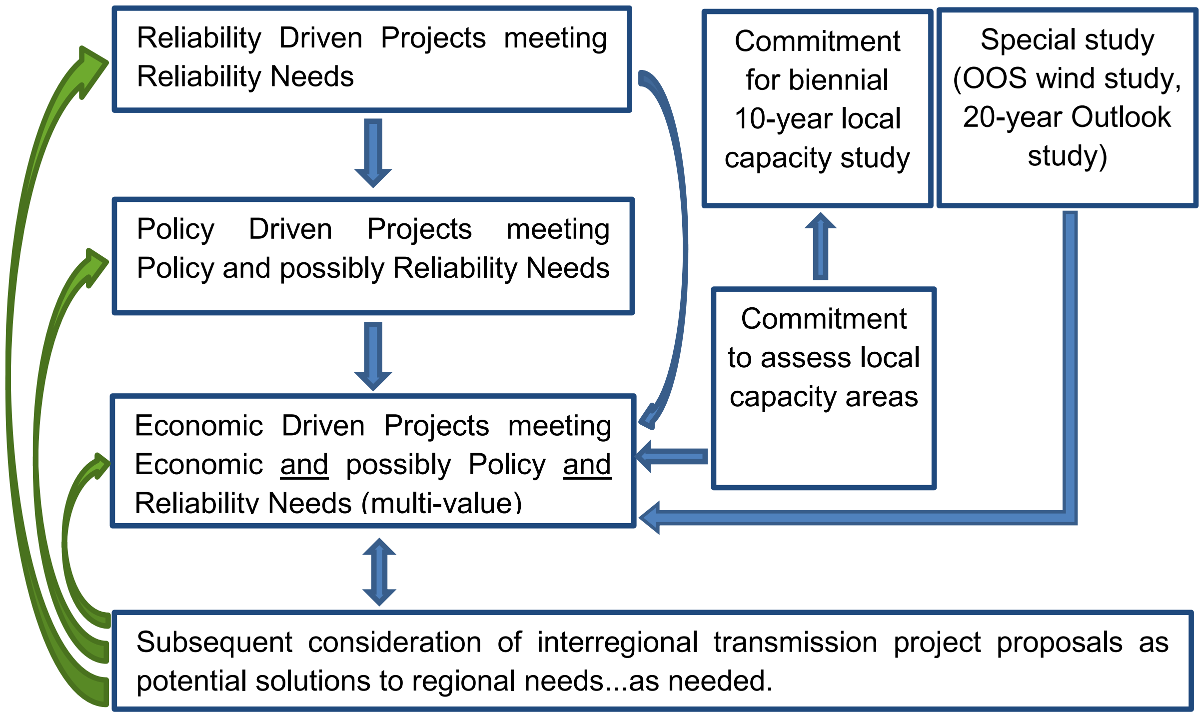
These more diverse drivers require a broader view of economic study methodologies and coordination between study efforts than in the past. Also, the economic assessment of the reduction or elimination of gas-fired generation in local capacity areas was conducted in previous planning cycles using the assumptions, criteria and models first outlined in the 2019-2020 planning cycle. The local capacity requirements technical study criteria in the ISO tariff, approved by FERC on January 17, 2020, were applied to the LCR reduction assessment in the 2020-2021 planning cycle. No detailed assessment for local capacity requirement reduction was conducted in this planning cycle, as the transmission and resource assumptions in local capacity areas did not change in a material way since the last planning cycle and system capacity needs largely remained the same as well. The results of the local capacity reduction assessment in the 2020-2021 planning cycle were used in one of the economic assessments in this planning cycle.

All transmission solutions identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation database. This ensured that all economic planning studies would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan. The ISO then performed the economic planning study to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the ISO. Selection of preferred solutions at “reliability” and “policy” stages are initially based on more conventional cost comparisons to meet reliability needs, *e.g*. capital and operating costs, transmission line loss savings, etc. As consideration of more comprehensive benefits, *e.g*. broader application of the TEAM, are conducted at the economic study stage, this can lead to replacing or upscaling a solution initially identified at the reliability or policy stage. The potential economic benefits are quantified as reductions of ratepayer costs based on the ISO Transmission Economic Analysis Methodology (TEAM).[140]

The above issues resulted in stronger interrelationships between studies conducted under different aspects of the transmission planning process. As a result, there are strong linkages and cross-references between different chapters, with the economic study process becoming somewhat of a central or core feature to the overall analysis. These interrelationships are captured to some extent in Figure 4.1-1.

[140] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Figure 4.1-1: Interrelationship of Transmission Planning Studies



The production cost modeling simulations discussed thus far focus primarily on the benefits of alleviating transmission congestion to reduce energy costs. Other benefits are also taken into account where warranted, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven. Local capacity benefits, *e.g.* reducing the requirement for local – and often gas-fired – generation capacity due to limited transmission capacity into an area can also be assessed and generally rely on a power flow analysis. This is discussed in section 4.2 below.

The more localized benefits discussed above were largely conceptualized around conventional transmission upgrades, with preferred resource procurement explored as an option where viable. With higher levels of renewable resource development and with the decline in the size of the gas-fired generation fleet, increased value is emerging for preferred resources, including storage, on a system basis regardless of local capacity and transmission congestion needs.

4.2 Technical Study Approach and Process

Different components of ISO ratepayer benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the “pre-project” and “post-project” study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit relied upon by the ISO includes three components of ISO ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Additionally, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a transmission solution for importing energy leads to a reduction of ISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource.

The production cost simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis is also used in quantifying other economic benefits such as system and local capacity savings.

Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles. The calculation of these benefits is discussed in more detail below.

In the production benefit assessments, the ISO calculates ISO ratepayer's benefits[141] as follows:

> <u>ISO ratepayers' production benefit = (ISO Net Payment of the pre-upgrade case) – (ISO Net Payment of the post-upgrade case)</u>
>
> <u>ISO Net Payment = ISO load payment - ISO generator net revenue benefiting ratepayer - ISO transmission revenue benefiting ratepayer</u>

The above calculation reflects the benefits to ISO ratepayers – offsetting other ISO ratepayer costs – of transmission revenues or generation profits from certain assets whose benefits accrue to ISO ratepayers. These include:

- PTO owned transmission
- Generators owned by the utilities serving the 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 where information available for the public may be reviewed for consideration of the type and the length of contract.

[141] WECC-wide societal benefits are also calculated to assess the overall reasonableness of the results and to assess the impact of the project being studied on the rest of the WECC-wide system, but not as the basis for determining whether the proejct is in the interests of the ISO ratepayer to proceed with. The WECC-wide societal benefits are assessed according to the following formula: *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*

How ISO ratepayer benefits relate to (and differ from) the ISO production cost benefits are shown in Figure 4.2-1.

Figure 4.2-1: Ratepayer Benefits vs. Production Cost Savings

ISO Net Ratepayer Benefits from Production Cost Simulations are the sum of:	Types of Revenues and Costs calculated in Production Cost Studies	ISO "Production Cost" Savings are the sum of:
	Load Payments at Market Prices for Energy	
Yes	Reductions in ISO Ratepayer Gross Load Payments	
	Generation Revenues and Costs	
Yes	Increases in generator profits inside ISO for generators owned by or under contract with utilities or load serving entities, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
	Increases in merchant (benefits do not accrue to ratepayers) generator profits inside the ISO, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
Yes	Increases in profits of dynamic scheduled resources under contract with or owned by utilities or load serving entities, being the sum of:	
	Increases in these dynamic scheduled resource revenues	
	Decreases in these dynamic scheduled resource costs	
	Transmission-related Revenues	
Yes	Increases in transmission revenues that accrue to ISO ratepayers	
	Increases in transmission revenue for merchant (e.g. non-utility owned but under ISO operational control) transmission	

In addition to the production and capacity benefits, any other benefits under TEAM— where applicable and quantifiable — can also be included. All categories of benefits identified in the TEAM document[142] and how they are addressed in the economic study process are summarized and set out in detail in Table 4.2-2.

[142] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.2-1: Summary of TEAM Benefit Categories

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
Production benefits: Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade.	In addition to production cost benefits themselves, focusing on ISO net ratepayer benefits;	Benefits focused on ISO net ratepayer benefits through production cost modeling.
	2.5.2 Transmission loss saving benefit (AND IN CAPACITY BENEFITS FOR CAPACITY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	Energy-related savings are reflected in production cost modeling results.
Capacity benefits: Benefits resulting from increased importing capability into the ISO BAA or into an LCR area. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.	2.5.1 Resource adequacy benefit from incremental importing capability A transmission upgrade can provide RA benefit when the following four conditions are satisfied simultaneously: • The upgrade increases the import capability into the ISO's controlled grid in the study years. • There is capacity shortfall from RA perspective in ISO BAA in the study years and beyond. • The existing import capability has been fully utilized to meet RA requirement in the ISO BAA in the study years. • The capacity cost in the ISO BAA is greater than in other BAAs to which the new transmission connects.	These benefits are considered where applicable; note that local capacity reduction benefits are discussed below. .
	2.5.2 Transmission loss saving benefit (AND IN PRODUCTION BENEFITS FOR ENERGY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	These benefits are considered, where applicable.
	2.5.3 Deliverability benefit Transmission upgrade can potentially increase generator deliverability to the region	This is primarily considered if the renewables portfolios identify the need for additional deliverability (as deliverability is

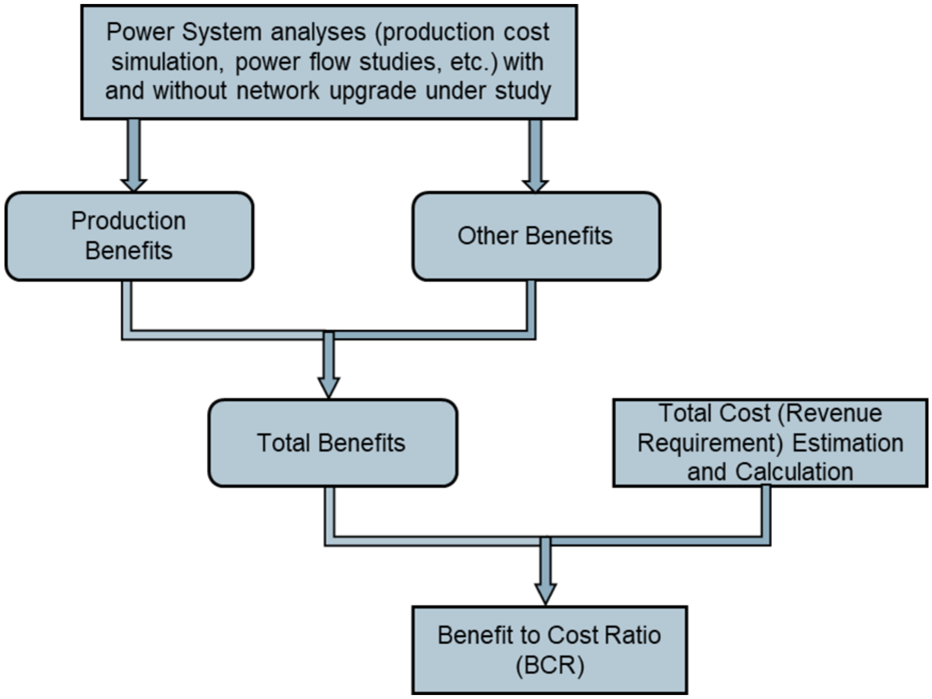
Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
	under study through the directly increased transmission capacity or the transmission loss saving. Similarly to the resource adequacy benefit as described in section 3.5.1, such deliverability benefit can only be materialized when there will be capacity deficit in the region under study. Full assessment for assessing the deliverability benefit will be on case by case basis.	used in TEAM and in ISO planning and generator interconnection studies) in which case the benefits may be policy benefits that have already been addressed in the development of portfolios, and further project development for this purpose for reducing local needs at this time is considered separately below.
	2.5.4 LCR benefit Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the ISO-controlled grid pay an annual fixed payment to the unit owner in exchange for the option to call upon the unit (if it is available) to meet local reliability needs. LCR units are used for both local reliability and local market power mitigation. LCR benefit is assessed outside the production cost simulation. This assessment requires LCR studies for scenarios with and without the transmission upgrades in order to compare the LCR costs. It needs to consider the difference between the worst constraint without the upgrade and the next worst constraint with the upgrade. The benefit of the proposed transmission upgrade is the difference between the LCR requirement with and without the upgrade.	LCR benefits are assessed, and valued according to prudent assumptions at this time given the state of the IRP resource planning at the time – and supported by the CPUC.
Public-policy benefit: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas, or by avoiding over-build.	2.5.5 Public-policy benefit If a transmission project increases the importing capability into the ISO-controlled grid, it potentially can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote areas. When there is a lot of curtailment of renewable generation, extra renewable generators would be built or procured to meet the goal of renewable portfolio standards (RPS). The cost of meeting the RPS goal will increase because of that. By reducing the curtailment of renewable generation, the cost of meeting the RPS goal will be reduced. This part of cost saving from avoiding over-build can be categorized as public-policy benefit.	With the current coordination of resource portfolios with the CPUC and CEC in place, these issues are addressed in the course of the portfolio development process.
Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by allowing	2.5.6 Renewable integration benefit As the renewable penetration increases, it becomes challenging to integrate renewable generation. Interregional coordination would help mitigating integration problems, such as over-supply and curtailment, by allowing	This can be considered as applicable, particularly for interregional transmission projects. Re-dispatch benefits would be included in the production cost savings in any event.

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
sharing energy and ancillary services (A/S) among multiple BAAs.	sharing energy and ancillary services (A/S) among multiple BAAs. A transmission upgrade that increases the importing and exporting capability of BAAs will facilitate sharing energy among BAAs, so that the potential over-supply and renewable curtailment problems within a single BAA can be relieved by exporting energy to other BAAs, whichever can or need to import energy. A transmission upgrade that creates a new tie or increases the capacity of the existing tie between two areas will also facilitate sharing A/S Sharing between the areas, if the market design allow sharing A/S. The total A/S requirement for the combined areas may reduce when it is allowed to share A/S. The lower the A/S requirement may help relieving over-supply issue and curtailment of renewable resources. It is worth noting that allowing exporting energy, sharing A/S, and reduced amount of A/S requirement will change the unit commitment and economic dispatch. The net payment of the ISO's ratepayers and the benefit because of a transmission upgrade will be changed thereafter. However, such a type of benefit can be captured by the production cost simulation and will not be considered as a part of renewable integration benefit.	
Avoided cost of other projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project.	2.5.7 Avoided cost of other projects If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project. Full assessment of the benefit from avoided costs is on a case-by-case basis.	This can be considered on a case by case basis, where applicable.

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement of the project under study, as described in the TEAM. To justify a proposed transmission solution, the ISO ratepayer benefit must be considered relative to the cost of the network upgrade. If the justification is successful, the proposed transmission solution may qualify as an economic-driven transmission solution. Note that other benefits and risks are taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven transmission solution.

The technical approach of the economic planning study is depicted in Figure 4.2-2. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis, which is a financial calculation that is generally conducted in spreadsheets.

Figure 4.2-2: Technical approach of economic planning study



4.3 Financial Parameters Used in Cost-Benefit Analysis

A cost-benefit analysis is made for each economic planning study performed where the total costs are weighed against the total benefits of the potential transmission solutions. In these studies, all costs and benefits are expressed in 2020 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net-present values.

4.3.1 Cost analysis

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

In calculating the total cost of a potential economic-driven transmission solution, when necessary, the financial parameters listed in Table 4.3-1 are used. The net present value of the costs (and benefits) is calculated using a social discount rate of 7% (real) with sensitivities at 5% as needed.

Table 4.3-1: Parameters for Revenue Requirement Calculation

Parameter	Value in TAC model
Debt Amount	50%
Equity Amount	50%
Debt Cost	6.0%
Equity Cost	11.0%
Federal Income Tax Rate	21.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2% and 2.5%

In the initial planning stage, detailed cash-flow information is typically not provided with the proposed network upgrade to be studied. Instead, lump-sum capital-cost estimates are provided. The ISO then uses typical financial information to convert them into annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. As an approximation, the present value of the utility's revenue requirement is calculated as the capital cost multiplied by a "CC-to-RR multiplier". For screening purposes, the multiplier used in this study is 1.3, reflective of a 7% real discount rate. This is an update to the 1.45 ratio set out in the ISO's TEAM documentation[143] that was based on prior experiences of the utilities in the ISO. The update reflects changes in federal income-tax rates and more current rate of return inputs. It should be noted that this screening approximation is generally replaced on a case-by-case basis with more detailed modeling as needed if the screening results indicate the upgrades may be found to be needed.

As the "capital cost to revenue requirement" multiplier was developed on the basis of the long lives associated with transmission lines, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and can then be 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.

[143] 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.[144]

When detailed analysis of a high priority study area is required, production-cost simulation and subsequent benefits calculations are conducted for the 10^{th} planning year - in this case, for 2031. For years beyond 2031 the benefits are estimated by extending the 2031-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 2031 = 0% (real), and
- Benefits discount rate = 7% (real) with sensitivities at 5% as needed.

4.3.3 Cost-benefit analysis

Once the total cost and benefit of a transmission solution is determined, a cost-benefit comparison is made. For a solution to qualify as an economic transmission solution under the tariff, the benefit has to be greater than the cost or the net benefit (calculated as gross benefit minus cost) has to be positive. If there are multiple alternatives, the alternative that has the largest net benefit is considered the most economical solution. As discussed above, the traditional ISO approach is to compare the present value of annualized revenue requirements and benefits over the life of a project using standardized capital cost-to-revenue requirement ratios based on lifespans of conventional transmission. Given the relatively shorter lifespans anticipated for battery storage projects, battery storage projects can be assessed by comparing levelized annual revenue requirements to annual benefits. As indicated above, the ISO must also assess any other risks, impacts, or issues.

4.3.4 Valuing Local Capacity Requirement Reductions

As noted in chapter 1 and earlier in this chapter, the ISO recognizes that additional coordination on the long-term resource requirements for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. This is particularly important in considering how to assess the value to

[144] 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%. 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 local capacity needs. If there are sufficient gas-fired generation resources to meet 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, as noted in Chapter 1, the ISO did not conduct detailed analyses for local capacity reduction benefits. The results from the 2020-2021 planning cycle were used in one of the economic assessments that potentially had local capacity reduction benefits, as set out in section 4.8.

4.4 Study Steps of Production Cost Simulation in Economic Planning

While the assessment of capacity benefits normally uses the results from other study processes, such as resource adequacy and local capacity assessment, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost model development needs coordination with the entire WECC and management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database (also called production cost model or PCM) development and validation, simulation and congestion analysis, and production benefit assessment for congestion mitigation.

PCM development and validation mainly include the following modeling components:

1. Network model (transmission topology, generator location, and load distribution)
2. Transmission constraint model, such as transmission contingencies, interfaces, and nomograms, etc.
3. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, energy storage model, renewable profiles, and renewable curtailment and price model
4. Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers such as DG, DR, and EE

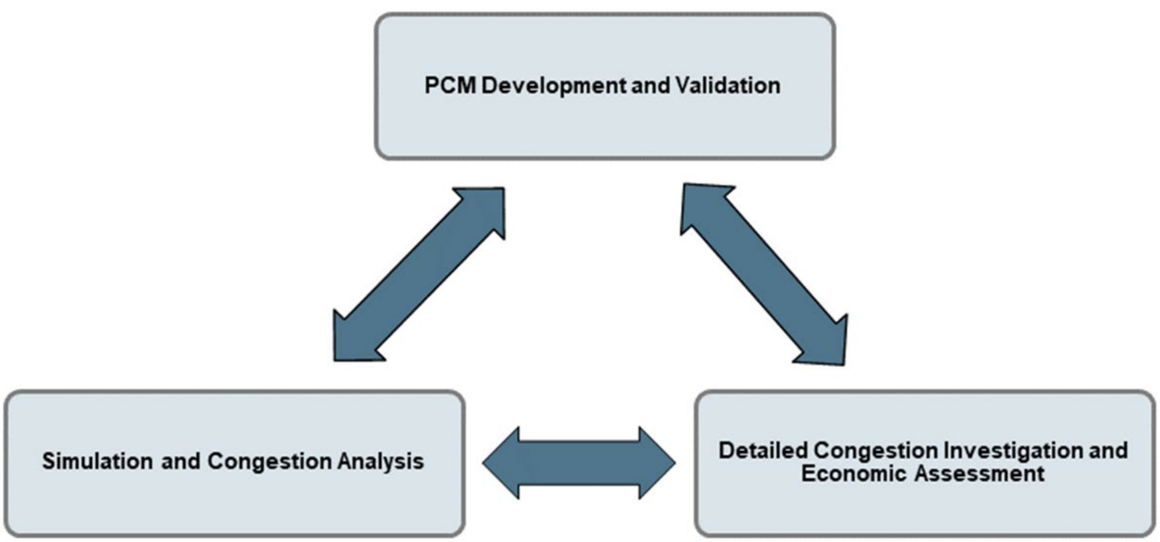
5. Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission cost and assignment, fuel price and assignment, etc.

Congestion analysis is based on production cost simulation that is conducted for each hour of the study year. Congestion can be observed on transmission lines 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 purposes, 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 provides sufficient economic benefits 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
Hitachi ABB GridView™	10.3.6	The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year (8784 hours for leap year)

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO may also develop an optional 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five year period of benefits before the 10-year case becomes relevant.

4.6 ISO GridView Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the GridView PCM development for the economic planning study. The section also highlights the major ISO enhancements and modifications to the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) database that were incorporated into the ISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized in this document, but the final PCM is posted on the ISO's market participant portal once the study is final.

4.6.1 Starting database

The 2021-2022 transmission planning process PCM development started from the ADS PCM 2030 version 2.3, which was released by WECC on May 7, 2021, and the ISO planning PCM in the 2020-2021 cycle. Using these databases, the ISO developed the base cases for the ISO 2021-2022 transmission planning process 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 system to exactly match the reliability assessment power flow cases for the entire ISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and reliability assessment power flow cases. In conjunction with modeling local transmission constraints and nomograms, unit commitment and dispatch can accurately respond to transmission limitations identified in reliability assessment. This enables the production cost simulation to capture potential congestion at any voltage level and in any local area.

4.6.3 Load

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions load in the system to represent typical or average load conditions across the ISO transmission network. The assessment used the California Energy Demand Updated Forecast, 2020-2030 adopted by CEC on January 25, 2021[145], which is consistent with the demand forecast in the reliability assessment as described in Chapter 2.

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 2021-2022 reliability assessment power flow case for 2031, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

4.6.5 Transmission constraints

As noted earlier, the production cost database reflects a nodal network representation of the western interconnection. Transmission limits were enforced on individual transmission lines, paths (*i.e.*, flowgates) and nomograms. However, the original ADS PCM database only enforced transmission limits under normal condition for transmission lines at 230 kV and above, and for transformers at 345 kV and above.

The ISO made an important enhancement in expanding the modeling of transmission contingency constraints, which the original ADS PCM database did not model. In the updated database, the ISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the 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 simulations, 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 ISO transmission grid at lower voltage than 230 kV are enforced.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the ISO were modeled. These nomograms were developed in the ISO's reliability assessments or identified in the operating procedures. In this

[145] https://efiling.energy.ca.gov/getdocument.aspx?tn=237269

planning cycle, the planning PCM continue to model critical credible contingencies in the COI corridor that were identified in the reliability assessment in lieu of COI nomograms, which is consistent with the planning PCM in the last planning cycle.

Scheduled maintenance of transmission lines was modeled based on historical data. Only the repeatable maintenances were considered. The corresponding derates on transmission capability were also modeled.

PDCI (Path 65) south to north rating was modeled at 1050 MW to be consistent with the operation limit of this path identified by LADWP, which is the operator of PDCI within California.

4.6.6 Fuel price and CO2 price

The forecasts of Natural Gas price, Coal prices, and CO2 prices were the same as in the ADS PCM 2030. All prices are in 2020 real dollar.

4.6.7 Renewable curtailment price model

The 2021-2022 planning PCM continued to use the multi-block renewable generator model that was first developed and used in the 2019~2020 planning cycle PCM. This model was applied to all ISO wind and solar generators. Each generator was modeled as five equal and separate generators (blocks) with identical hourly profiles, and each block's Pmax was 20% of the Pmax of the actual generator. Each block had a different curtailment price around $-25/MWh, as shown in Table 4.6-1.

Table 4.6-1: Multi-blocks renewable model

Block	Price ($/MWh)
1	-23
2	-24
3	-25
4	-26
5	-27

4.6.8 Battery cost model and depth of discharge

The ISO also refined its modeling of battery storage through the course of the 2019-2020 planning cycle, to reflect limitations associated with the depth of discharge of battery usage cycles (DoD or cycle depth) and replacement costs associated with the number of cycles and depth of discharge the battery is subjected to. In this refined battery model, the battery's operation cost was modeled as a flat average cost:

$$Average\ Cost = \frac{Per\ unit\ replacement\ cost}{Cycle\ life * DoD * 2}$$

The baseline assumptions for battery parameters in the 2021-2022 planning cycle were based on the 2030 forecast in the updated DOE report prepared by PNNL in 2020[146]:

- DoD: 80%
- Cycle life: 2100 cycles
- Per unit replacement cost: $99,000/MWh

With the above parameters, the average cost was $29.54/MWh.

4.6.9 Co-located and hybrid resource model

Starting with this planning cycle, co-located and hybrid resource were modeled in the planning PCM. A co-located or hybrid resource normally includes battery components and solar components, but can also be combination of battery and other types of resources such as thermal generators. Except for where a hybrid resource has a single market ID and a co-located resource may have multiple market IDs, there are a log of similarity between the hybrid and co-located resources from operation and modeling perspectives, although there may be differences in financial and operational requirements. As the policy and operation requirements for co-located and hybrid resources are still under development, the planning PCM in this planning cycle used the same approach to model co-located and hybrid resources.

To model co-located and hybrid resources in PCM, two constraints that are similar to the P_{max} and P_{min} constraints of the any other generators can be added:

- P_{max} constraint

$$P_{solar} + P_{battery} + REGUP_{battery} + LFUP_{solar} + LFUP_{battery} + SPIN_{battery} + FR_{battery} \leq Pmax \quad (1)$$

- P_{min} constraint (charging constraint)

$$P_{solar} + P_{battery} - REGDOWN_{battery} - LFDOWN_{solar} - LFDOWN_{battery} \geq Pmin \quad (2)$$

The *Pmax* is normally the allowed maximum output at the point of interconnection of the generator. The *Pmin* can be negative if the co-located or hybrid resource can charge from the grid, or equal to zero if the battery component is not expected to charge from the grid. $P_{battery}$ is positive when the battery is discharging, and negative when the battery is charging. Ancillary services and operating reserves are considered in the P_{max} and P_{min} constraints, including regulation up and down (REGUP and REGDOWN), load following up and down (LFUP and LFDOWN), spinning reserve (SPIN), and frequency response (FR).

[146] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

It is noted that the *Pmin* constraint was not used in this planning cycle, because there is a lack of clarity of charging requirement for co-located and hybrid resources. It will be considered in future planning cycles when there is additional clarity for the charging requirement.

4.7 Base Portfolio 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 the 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 2031

No.	Area or Branch Group	Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
1	Path 26 Corridor	P26 WECC Northern-Southern California	4	4	68,701	1,922	68,705	1,926
2	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	44,800	1,243	44,800	1,243
3	SDGE DOUBLTTP-FRIARS 138 kV	DOUBLTTP-FRIARS 138 kV line, subject to SDGE N-2 SX-PQ + PQ-OT 230 kV with RAS	0	0	37,630	1,772	37,630	1,772
4	GridLiance West/VEA	TROUT CANYON-SLOAN CANYON 230 kV line #1	30,449	2,144	0	0	30,449	2,144
5	PG&E Moss Landing-Las Aguilas 230 kV	MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Moss Landing-LosBanos 500 kV	0	0	13,836	235	13,836	235
6	COI Corridor	P66 WECC COI	12,118	260	0	0	12,118	260
7	GridLiance West/VEA	GAMEBIRD-TROUT CANYON 230 kV line #1	0	0	8,816	838	8,816	838
8	Path 42 IID-SCE	P42 WECC IID-SCE	7,742	296	0	0	7,742	296
9	PDCI	P65 WECC Pacific DC Intertie (PDCI)	0	0	6,813	663	6,813	663
10	Path 60 Inyo-Control 115 kV	P60 WECC Inyo-Control 115 kV Tie	15	19	6,339	1,869	6,354	1,888
11	Path 45	P45 WECC SDG&E-CFE	1,237	144	3,755	544	4,991	688
12	Path 15 Corridor - Panoche-Gates 230 kV	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	4,461	244	4,461	244
13	Path 61/Lugo-Victorville	P61 WECC Lugo-Victorville 500 kV Line	1,571	61	2,711	254	4,282	315
14	SCE LCIENEGA-LA FRESA 230 kV	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2	0	0	3,961	34	3,961	34

No.	Area or Branch Group	Constraints Name	Costs_ F (K$)	Duration_ F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration_ T (Hrs)
		La Fresa-El Nido #3 and #4 230 kV						
15	PG&E Tesla 500 kV Transformer	TESLA 500/13.8 kV transformer #6	3,431	22	0	0	3,431	22
16	PG&E Fresno	ORO LOMA-EL NIDO 115 kV line #1	3,192	130	0	0	3,192	130
17	Path 26 Corridor	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	0	0	2,822	115	2,822	115
18	Path 46 WOR	P46 WECC West of Colorado River (WOR)	2,635	49	0	0	2,635	49
19	SCE RedBluff-Devers 500 kV	DEVERS-DVRS_RB_21 500 kV line #2	0	0	2,461	22	2,461	22
20	SCE Antelope 66 kV system	NEENACH-TAP 85 66.0 kV line #1	2,379	946	0	0	2,379	946
21	Path 15 Corridor	GATES-GT_MW_11 500 kV line #1	0	0	2,109	70	2,109	70
22	COI Corridor	TM_VD_11-TM_VD_12 500 kV line #1	1,886	34	0	0	1,886	34
23	PG&E Las Positas- Newark 230 kV	LS PSTAS-NEWARK D 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	1,809	46	0	0	1,809	46
24	Path 25 PACW-PG&E 115 kV	P25 WECC PacifiCorp/PG&E 115 kV Interconnection	0	0	1,758	193	1,758	193
25	SCE Alberhill-Valley 500 kV	ALBERHIL-VALLEYSC 500 kV line #1	0	0	1,707	125	1,707	125
26	Path 15 Corridor - Panoche-Gates 230 kV	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	1,129	44	1,129	44
27	PG&E Sierra	P24 WECC PG&E-Sierra	1,013	131	0	0	1,013	131
28	SDGE N.Gila-Imperial Valley 500 kV	N.GILA-IMPRLVLY 500 kV line #1	1,000	53	0	0	1,000	53
29	Path 41 Sylmar transformer	P41 WECC Sylmar to SCE	797	70	0	0	797	70
30	Path 15 Corridor	P15 WECC Midway-LosBanos	770	22	0	0	770	22
31	SCE RedBluff-Devers 500 kV	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	762	9	762	9
32	SCE J.HINDS-MIRAGE 230 kV	J.HINDS-MIRAGE 230 kV line #1	731	38	0	0	731	38
33	Path 15 Corridor	GT_MW_11-MIDWAY 500 kV line #1	0	0	652	13	652	13
34	SCE Tehachapi Windhub 500 kV Xfmr	WINDHUB 500/13.8 kV transformer #3	0	0	635	284	635	284
35	PG&E Moss Landing-Las Aguilas 230 kV	MOSSLNSW-LASAGUILASS 230 kV line #2	0	0	604	26	604	26
36	GridLiance West/VEA	NWEST-DESERT VIEW 230 kV line #1	0	0	595	147	595	147
37	PG&E Fresno	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	570	165	570	165

No.	Area or Branch Group	Constraints Name	Costs_ F (K$)	Duration_ F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration_ T (Hrs)
38	SDGE Silvergate-Bay Blvd 230 kV	SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2	0	0	525	16	525	16
39	Path 15 Corridor - Panoche-Gates 230 kV	PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	484	71	484	71
40	SDGE IV-San Diego Corridor	MIGUEL-MIGUEL 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #1 with RAS	0	0	428	20	428	20
41	PG&E GBA	NRS 230/115 kV transformer #1	390	5	0	0	390	5
42	COI Corridor	RM_TM_11-RM_DRS 500 kV line #1	386	22	0	0	386	22
43	SDGE-CFE OTAYMESA-TJI 230 kV	OTAYMESA-TJI-230 230 kV line #1	0	0	340	61	340	61
44	SCE Barre-Ellis 230 kV	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	259	19	0	0	259	19
45	PG&E Sierra	DRUM-DTCH FL1 115 kV line #1	254	20	0	0	254	20
46	PG&E VacaDixon-TESLA 500 kV	VACA-DIX-VD_TS_11 500 kV line #1	222	9	0	0	222	9
47	SCE Barre-Villa Park 230 kV	BARRE-VILLA PK 230 kV line, subject to SCE N-1 Lewis-Barre 230kV	0	0	216	38	216	38
48	SCE Litehipe-Mesa Cal 230 kV	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	0	0	214	7	214	7
49	PG&E Fresno	CHWCHLASLRJT-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	200	151	200	151
50	COI Corridor	RM_TM_21-RM_DRS 500 kV line #2	196	10	0	0	196	10
51	SCE Antelope 66 kV system	ANTELOPE-NEENACH 66 kV line, subject to SCE N-1 Neenach-Bailey-WestPack 66kV	0	0	195	162	195	162
52	PG&E POE-RIO OSO 230 kV	POE-RIO OSO 230 kV line #1	178	23	0	0	178	23
53	SCE Lugo 500 kV Transformer	LUGO 500/13.8 kV transformer #2	0	0	158	22	158	22
54	PG&E USWP JRW-Cayetano 230 kV	USWP-JRW-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	156	1	0	0	156	1
55	PG&E Sierra	CHCGO PK-HIGGINS 115 kV line #1	121	11	0	0	121	11
56	SCE Vista-SanBernadino 230 kV	VSTA-SANBRDNO 230 kV line #1	0	0	116	5	116	5
57	Path 15 Corridor - Panoche-Gates 230 kV	PANOCHE-GATES E 230 kV line, subject to PG&E N-	0	0	89	17	89	17

No .	Area or Branch Group	Constraints Name	Costs_ F (K$)	Duration_ F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration_ T (Hrs)
		2 Mustang-Gates #1 and #2 230 kV						
58	SDGE Sanlusry-S.Onofre 230 kV	SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	82	4	4	1	86	5
59	SCE Pisgah-Lugo 230 kV	CALCITE-LUGO 230 kV line #1	78	158	0	0	78	158
60	SCE Vincent 500 kV Transfomer	VINCENT-vincen1i 500 kV line, subject to SCE N-1 Vincent Transformer 500 kV #4	68	1	0	0	68	1
61	SDGE North	ENCINATP-SANLUSRY 230 kV line, subject to SDGE N-1 EN-SLR 230 kV with RAS	49	7	0	0	49	7
62	GridLiance West/VEA	INNOVATION-DESERT VIEW 230 kV line #1	46	27	0	0	46	27
63	COI Corridor	TABLE MT-TM_TS_11 500 kV line #1	43	3	0	0	43	3
64	SCE Pardee-S.Clara 230 kV	PARDEE-S.CLARA 230 kV line, subject to SCE N-2 MOORPARK-SCLARA #1 and #2 230 kV	43	10	0	0	43	10
65	SCE Antelope-Pardee 230 kV	ANTELOPE-PARDEE 230 kV line #1	39	4	0	0	39	4
66	Path 15 Corridor - Panoche-Gates 230 kV	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Henrieta1-Gregg 230 kV	0	0	33	1	33	1
67	SCE Tehachapi Windhub 500 kV Xfmr	WINDHUB 500/13.8 kV transformer #1	0	0	27	48	27	48
68	SCE NOL	KRAMER-VICTOR 230 kV line #1	25	31	0	0	25	31
69	SCE Tehachapi Wirlwind 500 kV xfmr	WIRLWIND 500/13.8 kV transformer #1	0	0	22	7	22	7
70	PG&E Sierra	DRUM-BRNSWCKP 115 kV line #2	22	5	0	0	22	5
71	PG&E Solano	WND MSTR-DELTAPMP 230 kV line #1	11	1	0	0	11	1
72	GridLiance West/VEA	MEAD S-SLOAN CANYON 230 kV line #1	0	0	11	2	11	2
73	Path 15 Corridor - Panoche-Gates 230 kV	PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	11	11	11	11
74	SDGE IV-San Diego Corridor	SUNCREST-SUNCREST TP2 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	9	2	0	0	9	2
75	SCE Devers 500/230 kV transformer	DEVERS 500/13.8 kV transformer #1	9	2	0	0	9	2
76	SCE J.HINDS-MIRAGE 230 kV	JHINDMWD-J.HINDS 230 kV line #r1	0	0	8	1	8	1
77	SCE Barre-Ellis 230 kV	BARRE-ELLIS 230 kV line, subject to SCE N-2 Barre-Ellis 230 kV	6	3	0	0	6	3

No.	Area or Branch Group	Constraints Name	Costs_ F (K$)	Duration_ F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration_ T (Hrs)
78	COI Corridor	TM_TS_11-TM_TS_12 500 kV line #1	5	3	0	0	5	3
79	SDGE-CFE IV-ROA 230 kV line and IV PFC	IV PFC1 230/230 kV transformer #1	5	4	0	0	5	4
80	SDGE IV-San Diego Corridor	MIGUEL 230/500 kV transformer #1	0	0	4	1	4	1
81	PG&E Gates-Arco 230 kV	GATES F-ARCO 230 kV line, subject to PG&E N-1 LosBanos-Midway 500kV	0	0	3	3	3	3
82	SCE NOL	KRAMER-VICTOR 230 kV line #2	2	3	0	0	2	3
83	Path 26 Corridor	MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	2	1	0	0	2	1
84	SDGE Talega-S.Onorfer 230 kV	TALEGA-S.ONOFRE 230 kV line #1	0	0	2	8	2	8
85	SCE Tehachapi Windhub 500 kV Xfmr	WINDHUB 500/13.8 kV transformer #2	0	0	1	5	1	5
86	SCE Tehachapi Windhub 500 kV Xfmr	WINDHUB 500/13.8 kV transformer #4	0	0	1	2	1	2

The branch group or local-area information was provided in the first column in Table 4.7-1. The branch groups were identified by aggregating congestion costs and hours of congested facilities to an associated branch or branch group for normal or contingency conditions. The congestions subject to contingencies associated with local capacity requirements were aggregated by PTO service area based on where the congestion was located. The results were ranked based on the 2031 congestion cost. The potential congestion across specific branch groups and local capacity areas is summarized in Table 4.7-2.

Table 4.7-2: Aggregated potential congestion in the ISO-controlled grid in 2030

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	Path 26 Corridor	116.33	3,285
2	GridLiance West/VEA	39.92	3,158
3	SDGE DOUBLTTP-FRIARS 138 kV	37.63	1,772
4	COI Corridor	14.63	332
5	PG&E Moss Landing-Las Aguilas 230 kV	14.44	261
6	Path 42 IID-SCE	7.74	296
7	PDCI	6.81	663
8	Path 60 Inyo-Control 115 kV	6.35	1,888
9	Path 15 Corridor - Panoche-Gates 230 kV	6.21	388
10	Path 45	4.99	688
11	Path 61/Lugo-Victorville	4.28	315
12	PG&E Fresno	3.96	446
13	SCE LCIENEGA-LA FRESA 230 kV	3.96	34
14	Path 15 Corridor	3.53	105
15	PG&E Tesla 500 kV Transformer	3.43	22
16	SCE RedBluff-Devers 500 kV	3.22	31
17	Path 46 WOR	2.64	49
18	SCE Antelope 66 kV system	2.57	1,108
19	PG&E Las Positas- Newark 230 kV	1.81	46
20	Path 25 PACW-PG&E 115 kV	1.76	193
21	SCE Alberhill-Valley 500 kV	1.71	125
22	PG&E Sierra	1.41	167
23	SDGE N.Gila-Imperial Valley 500 kV	1.00	53
24	Path 41 Sylmar transformer	0.80	70
25	SCE J.HINDS-MIRAGE 230 kV	0.74	39
26	SCE Tehachapi Windhub 500 kV Xfmr	0.66	339
27	SDGE Silvergate-Bay Blvd 230 kV	0.52	16
28	SDGE IV-San Diego Corridor	0.44	23
29	PG&E GBA	0.39	5
30	SDGE-CFE OTAYMESA-TJI 230 kV	0.34	61
31	SCE Barre-Ellis 230 kV	0.26	22
32	PG&E VacaDixon-TESLA 500 kV	0.22	9
33	SCE Barre-Villa Park 230 kV	0.22	38
34	SCE Litehipe-Mesa Cal 230 kV	0.21	7
35	PG&E POE-RIO OSO 230 kV	0.18	23
36	SCE Lugo 500 kV Transformer	0.16	22

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
37	PG&E USWP JRW-Cayetano 230 kV	0.16	1
38	SCE Vista-SanBernadino 230 kV	0.12	5
39	SDGE Sanlusry-S.Onofre 230 kV	0.09	5
40	SCE Pisgah-Lugo 230 kV	0.08	158
41	SCE Vincent 500 kV Transfomer	0.07	1
42	SDGE North	0.05	7
43	SCE Pardee-S.Clara 230 kV	0.04	10
44	SCE Antelope-Pardee 230 kV	0.04	4
45	SCE NOL	0.03	34
46	SCE Tehachapi Wirlwind 500 kV xfmr	0.02	7
47	PG&E Solano	0.01	1
48	SCE Devers 500/230 kV transformer	0.01	2
49	SDGE-CFE IV-ROA 230 kV line and IV PFC	0.00	4
50	PG&E Gates-Arco 230 kV	0.00	3
51	SDGE Talega-S.Onorfer 230 kV	0.00	8

4.7.2 Wind and solar curtailment results

Table 4.7-3 shows wind and solar generation curtailment in the ISO system in the base portfolio PCM. In this table, the renewable resources were aggregated by zone based on the transmission constraints to which the resources in the same zone normally contributed in the same direction, or based on geographic locations if there were not obvious transmission constraints nearby.

Table 4.7-3: Wind and solar curtailment summary in the base portfolio PCM

Zone	Generation (GWh)	Curtailment (GWh)	Ratio
SCE Tehachapi	32,594	2,418	7%
PG&E Fresno-Kern	12,358	2,241	15%
SCE Eastern	12,684	985	7%
NM	7,598	644	8%
SDGE IV	7,828	249	3%
GridLiance West/VEA	3,774	1,925	34%
AZ	4,407	1,030	19%
PG&E Solano	5,235	58	1%
SCE EOL	4,579	423	8%
SCE NOL	4,083	477	10%
PG&E Carrizo	2,977	222	7%
PG&E N. CA	2,986	47	2%
NW	2,445	57	2%
SCE Vestal	1,182	95	7%
IID	752	30	4%
SCE Others	498	35	7%
SDGE San Diego	263	11	4%
PG&E Central	105	6	5%
PG&E Bay	53	3	6%
Total	**106,401**	**10,956**	**9%**

4.7.3 High-level analysis of production cost simulation results

In this planning cycle, investigations were conducted on the constraints that may have a large impact on the bulk system or the heavily congested areas, and showed recurring congestion. Specifically, these constraints selected for further analysis are shown in Table 4.7-4. The detailed analysis results are in section 4.10.

Table 4.7-4: Constraints selected for Detailed Investigation

Constraints	Cost (M$)	Duration (Hours)	Overview of congestion investigation
Path 26 Corridor	116.33	3,285	Path 26 congestion was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio
GridLiance West/VEA	39.92	3,158	GridLiance West/VEA congestion was mostly caused by the large amount of renewable generation in the Gridliance West/VEA area in the CPUC portfolio. The ISO's policy assessment also identified off-peak deliverability constraints in this area
COI Corridor	14.63	332	COI congestion is further assessed in the out-of-state wind study in section 4.10.
PG&E Moss Landing-Las Aguilas 230 kV	14.44	261	Congestions were observed on multiple lines in the PG&E Fresno area, with relatively high congestion cost and duration, due to renewable and load forecast changes.
Path 15 Corridor - Panoche-Gates 230 kV	6.21	388	

Congestions were selected not solely based on congestion costs or duration, but by taking other considerations into account. Comparing the congestion and curtailment results, it was observed that some congestions with large costs 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 detailed analysis in this planning cycle, particularly, SCE Antelope 66 kV congestions and the Path 42 congestion.

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 the 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.

Congestions were observed in the SCE's Western LA Basin area, including the La Cienega – La Fresa 230 kV line. Potential mitigations were studied in the last planning cycle as part of the LCR reduction study. These congestions will be monitored and investigated in future planning cycles with further clarity of gas-fired generator retirement and battery development at the local areas.

No detailed analyses on other congestions in Table 4.7-1 were conducted as the congestions were not sufficient for justifying upgrades, based on either the studies in previous planning cycles or engineering judgement. They will be monitored in future planning cycles and will be studied as needed.

4.8 Economic Planning Study Requests

As part of the economic planning study process, economic planning study requests are accepted by the ISO, to be considered in addition to the congestion areas identified by the ISO. These study requests are individually considered for designation as a High Priority Economic Planning Study for consideration in the development of the transmission plan. These economic study requests are distinct from the interregional transmission projects discussed in Chapter 5, but the interregional transmission projects discussed in Chapter 5 may be considered as options to meeting the needs identified though the economic planning studies.

Other economic study needs driven by stakeholder input have also been identified through other aspects of the planning process as well – those are also set out here, with the rationale for proceeding to detailed analysis where warranted.

The ISO's tariff and Business Practice Manual allows the ISO to select from economic study requests and other sources the high priority areas that will receive detailed study while developing the Study Plan, based on the previous year's congestion analysis. Recognizing that changing circumstances may lead to more favorable results in the current year's study cycle, the ISO has over the past number of planning cycles carried all study requests forward as potential high-priority study requests, until the current year's congestion analysis is also available for consideration in finalizing the high-priority areas that will receive detailed study. This additional review gives more opportunity for the study requests to be considered, that can take into account on a case-by-case basis the latest and most relevant information available.

Accordingly, the ISO reviewed each regional study or project being considered for detailed analysis, and the basis for carrying the project forward for detailed analysis as high-priority economic planning studies – or not – is set out in this section. The section also describes how the study requests or projects selected for detailed analysis were studied, e.g. on a stand-alone basis or as one of several options of a broader area study. The received study requests are summarized in Table 4.8-1. Evaluations for the study requests for purposes of selecting the final list of high-priority economic planning studies are included in the following subsections.

Table 4.8-1: Economic study requests

No.	Study Request	Submitted By	Location
1	Moss Landing – Las Aguilas 230 kV line congestion mitigation	Vistra	Northern California PG&E area
2	Pacific Transmission Expansion Project (PTE Project)	Western Grid Development	Northern/Southern California PG&E and SCE areas
3	GLW Upgrade Project	GridLiance West	Southern Nevada GridLiance West/VEA
4	SWIP-North	LS Power	Idaho/Nevada

4.8.1 Study request for Moss Landing – Las Aguilas 230 kV line congestion mitigation

Study request overview

Vistra Corporation submitted a study request to conduct an economic study to identify cost-effective solutions to relieve the transmission congestion on the Moss Landing – Las Aguilas 230 kV line in the PG&E area.

Evaluation

The benefits described in the submission and ISO's evaluation of the economic study request are summarized in Table 4.8-2.

Table 4.8-2: Evaluating study request – Moss Landing – Las Aguilas 230 kV line congestion mitigation in PG&E area

Study Request: Congestion on Doublet Tap to Friars 138 kV in SDG&E area		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Vistra requested to study the benefit of mitigating the transmission congestion of the Moss Landing – Las Aguilas 230 kV line in the PG&E area	Congestion was identified on the Moss Landing – Las Aguilas 230 kV line.
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	Vistra stated that mitigating the congestion would have capacity benefit in local capacity requirements in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	Vistra stated that mitigating the congestion would help to reduce renewable curtailment	The congestion is correlated with PG&E Fresno area renewable curtailment.
Other	None	No benefits identified by ISO

Conclusion

Based on the congestion analysis results and comments provided, the Moss Landing – Las Aguilas 230 kV line congestion was selected for detailed analysis in this planning cycle. Please refer to section 4.9.3.

4.8.2 Study request for Pacific Transmission Expansion (PTE) project

Study request overview

Western Grid Development LLC (Western Grid) submitted the PTE project, which consists of a 2,000 MW controllable HVDC subsea-transmission cable that connects Northern and Southern California via submarine cables to be located in the Pacific Ocean off the coast of California. The project was previously submitted as an economic study request and was resubmitted with a modified study scope to the Reliability Request Window of the ISO 2021-2022 transmission planning process. The project, as proposed, will have one northern point of interconnection in the PG&E area and three points of interconnection in the SCE area for its southern terminals. The proposed project includes the Voltage Source Converter (VSC) stations as in the following:

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

- one 1,000 MW, 500 kV DC/220 kV AC converter station connected at El Segundo 230 kV substation, and
- one 500 MW, 500 kV DC/220 kV AC converter station connected at Huntington Beach.

The project will have a total transfer capacity of 2,000 MW from the PG&E area into the SCE/SDG&E area or vice versa.

Evaluation

The benefits described in the submission and ISO's evaluation of the economic study request are summarized in Table 4.8-3.

Table 4.8-3: Evaluating study request – Evaluating study request – Pacific Transmission Expansion (PTE) HVDC Project

Study Request: Pacific Transmission Expansion HVDC Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Not addressed in submission	The PTE project can create a path parallel to Path 26. The Path 26 congestion was selected in this planning cycle to receive detailed analysis
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Western Grid states that the proposed project's location off shore offers California an option to interconnect and deliver up to 2,000 MW of offshore wind energy as well as support delivery of renewable energy between northern and southern California.	No benefits identified by ISO
Local Capacity Area Resource requirements	Western Grid states that the proposed project would reduce local capacity requirements in the Western LA Basin thereby allowing 1,993 MWs of gas plant generating capacity to retire.	LCR reduction study for the Western LA Basin and SDG&E areas were conducted in the 2020-2021 planning cycle
Increase in Identified Congestion	Not addressed in submission	Detailed congestion analysis was conducted for the PTE project in this planning cycle
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	No benefits identified by ISO
Other	Western Grid states the following benefits of the proposed project: • The faster response for AC voltage control and frequency stabilization while providing effective short circuit capacity and system damping requirements. • Project can deliver system flexibility to the locally constrained area. • Project reduces the risk of wildfire cutting off electric service to the LA coastal area.	No benefits identified by ISO

Conclusion

Based on the congestion analysis results and comments provided, the PTE project was selected for detailed analysis in this planning cycle, as set out in section 4.9.1.

4.8.3 Study request for GLW Upgrade

Study request overview

Gridliance West (GLW) proposes to construct a portfolio of 230 kV circuit upgrades to address reliability issues, policy and economic needs, and eliminate NERC criteria violations. The project was previously submitted as an economic study request and was resubmitted with a modified study scope to the Reliability Request Window of the ISO 2021-2022 transmission planning process. Additional modifications to the project scope were identified as needed in the Policy-Driven transmission analysis documented in Chapter 3. The Gridliance West (GLW)/VEA system upgrades proposed in the request window along with the additional modifications, are summarized below:

- Rebuild to 230 kV double circuit from Desert View to Northwest
- Add a second 230 kV circuit from Innovation to Desert View
- Rebuild to 230 kV double circuit from Innovation to Pahrump 230 kV
- Rebuild to 230 kV double circuit from Pahrump to Gamebird to Trout Canyon
- Rebuild to 230 kV double circuit from Trout Canyon to Sloan Canyon
- Add a 500/230 kV transformer at Sloan Canyon and loop-in the Harry Allen to Eldorado 500 kV line at Sloan Canyon
- Add a 138 kV phase shifter at Innovation substation to the planned 138 kV tie-line with NVE Energy
- Upgrade WAPA's Amargosa 230/138 kV transformer

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-4.

Table 4.8-4: Evaluating study request – GLW Upgrade

Study Request: GLW Upgrade		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	GridLiance West stated the project can improve grid reliability by eliminating NERC criteria violations	Congestions were identified in the GLW 230 kV system. It is expected the propose GLW Upgrade can mitigate the congestions in the GLW 230 kV system.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	GridLiance West stated the project can facilitate the increased renewable integration in the CPUC portfolio	Pursuant to the study plan, the ISO studied only the CPUC provided resource portfolios.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See “Delivery of Location Constrained Resource Interconnection” above	No benefits identified by ISO
Other	GridLiance West states that the proposed upgrades will: (1) enable ISO-connected renewable generation in Southern Nevada to meet California carbon goals (2) meet the need of serving the increasing VEA load	No benefits identified by ISO

Conclusion

The ISO’s policy-driven assessment has identified that the GLW Upgrade was needed to mitigate off-peak deliverability issues in the GLW/VEA area, and needed to provide sufficient ISO transmission system capability for delivery of the renewable generation in the CPUC IRP portfolio in the GridLiance West/VEA area to the ISO’s system load, as described in section 3.6.4

The GLW Upgrade was selected to receive detailed economic assessment in this planning cycle. Please refer to section 4.9.2

4.8.4 Study request for SWIP-North project

Study request overview

LS Power Development, LLC submitted an economic study request to study congestion on the California-Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB). In addition, the study requests to study the Southwest Intertie Project – North (SWIP-North) project as an economic project.

LS Power requests the ISO to quantify financial congestion on the PACI, NOB, and COI paths in addition to the physical congestion that it has been quantified over the last few planning cycles.

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 project will provide approximately 1000 MW of bi-directional transmission capacity between Midpoint and Harry Allen.

Evaluation

The benefits described in the submission and ISO's evaluation of the study request are summarized in Table 4.8-5.

Table 4.8-5: Evaluating study request – COI congestion and SWIP-North project

Study Request: COI congestion and SWIP-North project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Request is for ISO to study congestion on California Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB)	Economic studies performed by the ISO have identified congestion on COI; these congestion costs did not change significantly from previous transmission plans; and were previously found not to be sufficient to warrant transmission solutions in previous transmission plans. However, the ISO selected to reevaluate COI congestion in this planning cycle because of the changes in the out-of-state wind resource assumption in the CPUC portfolios
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Request refers to the wind resources at/near Midpoint consistent with the potential OOS wind identified in the CPUC's Base Case Portfolio	The ISO's transmission planning studies use CPUC's assumption for out-of-state resources
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by ISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by ISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	Capacity Benefits, Renewable curtailment reduction benefits and diversity benefit	Capacity benefit from facilitating the access to out-of-state renewable resources needs to be assessed by the CPUC in the IRP portfolio development. Renewable curtailment and diversity benefit has been captured in production cost simulation study

Conclusion

The SWIP-North project was studied as a transmission upgrade alternative in the out-of-state wind study in this planning cycle, as set out in section 4.10.

4.9 Detailed Investigation of Congestion and Economic Benefit Assessment

The ISO selected the branch groups and study areas listed in Table 4.9-1 for further assessment as high-priority studies. This was done 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. The SWIP-North project was also selected for detailed analysis and was studied as a transmission upgrade alternative in the out-of-state wind study, as set out in section 4.10, instead of being included in this section.

Facilities identified as potential mitigations in those study areas include stakeholder proposals from a number of sources; request window submissions citing economic benefits, economic study requests, and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements.

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.9-1 for ease of tracking where and how these stakeholder proposals were addressed.

The detailed analysis also considers other ISO-identified potential mitigations which have been listed in Table 4.9-1 as well.

Table 4.9-1: Detailed Economic Benefit Investigation

Detailed investigation	Alternative	Proposed by	Reason
Congestion			
Path 26 corridor congestion	Re-rate the Midway-Whirlwind 500 kV line and bypass series cap of the line	ISO	The mitigation alternatives are expected to reduce or eliminate the congestion
	PTE project	Western Grid	
GLW/VEA area congestion	GLW Upgrade	GridLiance West	The mitigation alternatives are expected to reduce or eliminate the congestion and reduce renewable curtailment
PG&E Moss Landing – Las Aguilas 230 kV congestion	Series reactor on the Moss Landing – Las Aguilas 230 kV line	ISO	Potentially mitigate or reduce the identified congestion
PG&E Panoche – Gates 230 kV congestion	Series reactor on the Panoche – Gates 230 kV lines	ISO	Potentially mitigate or reduce the identified congestion

This study step consists of conducting detailed investigations and modeling enhancements as needed. To the extent that economic assessments for potential transmission solutions are necessary, the production benefits and other benefits of potential transmission solutions are based on the ISO's Transmission Economic Analysis Methodology (TEAM)[147], and potential economic benefits are quantified as reductions of ratepayer costs.

In addition to the production benefit, other benefits were also evaluated as needed. As discussed in section 4.2, other benefits are also taken into account on a case-by-case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven.

All costs and payments provided in this section are in 2020 real dollars.

Finally, it is important to reiterate that all regional transmission solutions – other than modifications to existing facilities, are subject to the ISO's competitive solicitation process as set out in the ISO's tariff. So, while many projects have been submitted with narrowly defined project scopes, the ISO is not constrained to only study those scopes without modification, or to study the projects exclusively on the basis under which the proponent suggested.

4.9.1 Path 26 corridor congestion

4.9.1.1 Congestion analysis

The production cost simulation results demonstrated congestion occurring on the Path 26 corridor mainly when the flow was from south to north. There was minor congestion on Path 26 and the Midway – Vincent 500 kV line when the flow was from north to south. Renewable generators in Southern California identified in the CPUC renewable portfolio were the main driver of the Path 26 corridor congestion. The congestion cost and hours of the Path 26 corridor congestion are shown in Table 4.9-2.

Table 4.9-2: Path 26 corridor congestion

Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
P26 WECC Northern-Southern California	4	4	68,701	1,922	68,705	1,926
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	44,800	1,243	44,800	1,243
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	0	0	2,822	115	2,822	115
MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	2	1	0	0	2	1

It was observed in Table 4.9-2 that the majority of the congestion on the Path 26 corridor occurred on the Midway to Whirlwind 500 kV line under normal condition and on the Path 26 due to the path rating binding. The congestion analysis in this section was focused on these two

[147] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

congested components. Table 4.9-3 shows the occurrences of the Midway – Whirlwind 500 kV line congestion. The congestion on this 500 kV line was only observed between April and October when the summer rating is applied. As discussed in section 3.6.3, the summer rating of the Midway – Whirlwind 500 kV line is currently rated 1503/3265 MVA based on conductor preload limits to gain higher summer emergency 30-minute rating. It is possible to implement higher summer normal rating to relieve congestion of the Midway – Whirlwind 500 kV line. It was also observed in Table 4.9-3 that about 80% of the congestion hours overlapped with solar hours, which indicated that a large part of the congestion is attributed to the high solar generation output in the Southern California areas.

Table 4.9-3: Occurrences of Midway – Whirlwind 500 kV Line Congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	15	19	10	6	5	4	3	4	5	4	13	25	27	22	15	12
May	0	0	0	0	0	0	0	5	25	18	12	10	5	7	7	7	7	8	11	16	14	13	9	5
Jun	0	0	0	0	0	0	0	2	16	23	22	12	10	4	6	7	7	8	3	5	8	7	5	4
Jul	0	0	0	0	0	0	0	0	14	28	21	17	14	15	15	17	14	9	10	9	8	8	3	2
Aug	0	0	0	0	0	0	0	0	6	28	25	18	14	14	15	17	15	14	12	13	15	10	7	7
Sep	0	0	0	0	0	0	0	0	4	26	21	6	4	8	13	8	6	8	12	14	8	5	5	5
Oct	0	0	0	0	0	0	0	0	2	19	9	9	4	3	7	10	2	7	20	22	13	5	4	3
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 4.9-4 shows the occurrences of the Path 26 congestion due to path rating binding. The congestion was also observed in solar hours when the solar generation output in the Southern California areas was high. Path 26 was less congested in the summer months than in the other months of the year, which was mainly because the Midway – Whirlwind 500 kV line was the limiting constraints as the low summer normal rating was applied. High Southern California load in summer months also helped to reduce flow on Path 26.

Table 4.9-4: Occurrences of Path 26 Congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	2	3	1	1	3	2	3	3	17	29	31	23	15	13	11	12	4	4	22	22	16	11	4	5
Feb	4	2	2	2	1	0	4	8	17	21	20	20	18	17	17	16	12	5	16	18	17	14	16	16
Mar	6	4	3	4	2	3	7	15	20	29	26	20	14	9	10	10	10	5	22	26	25	27	25	23
Apr	0	0	0	0	0	0	0	5	10	15	14	6	5	2	2	2	3	1	2	1	2	3	7	0
May	0	0	0	0	0	0	0	1	0	3	3	2	2	2	3	2	2	1	0	2	0	1	1	0
Jun	0	0	0	0	0	0	0	0	3	3	1	0	0	0	0	1	0	0	1	1	0	0	0	0
Jul	0	0	0	0	0	0	0	5	9	5	4	3	0	0	0	3	0	0	0	0	0	0	1	0
Aug	2	1	0	0	0	0	2	17	21	6	7	4	3	4	3	2	0	1	0	0	1	2	3	5
Sep	4	3	3	6	5	4	5	19	24	16	13	2	2	1	0	1	0	1	4	1	1	3	4	4
Oct	0	0	0	0	0	0	1	9	18	14	23	15	11	4	6	7	1	1	4	4	1	1	1	0
Nov	1	0	2	2	3	1	3	12	27	30	29	22	15	12	10	6	0	13	22	23	17	14	9	2
Dec	7	4	5	3	5	2	3	4	22	28	28	27	18	19	19	15	4	9	16	16	10	10	9	7

Midway – Whirlwind and Path 26 congestions were also observed outside solar hours. Further analysis demonstrated that the congestions outside solar ours were highly correlated with battery discharge in southern California areas. Table 4.9-5 showed the pattern of battery charge and discharge in the SCE and SDGE areas. It was observed that the batteries charged mainly in solar hours and discharged after sunset. It should be noted that the battery charge and discharge pattern shown in Table 4.9-5 were the results of economic dispatch in the production cost simulation.

Table 4.9-5: SCE and SDGE Battery Charge and Discharge Pattern

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	-425	-4,587	-8,263	-8,855	-6,966	-2,481	0	3,452	7,285	6,952	5,583	2,174	879	514
Feb	-1	0	0	0	0	0	1	1	0	-6	-1,220	-5,684	-8,090	-7,959	-6,863	-3,601	-389	1,457	6,743	7,061	6,317	4,104	1,833	1,224
Mar	0	0	-6	-1	0	0	0	0	0	-141	-2,656	-7,557	-10,216	-10,999	-10,218	-7,713	-1,881	417	7,353	10,213	10,134	8,188	4,714	2,659
Apr	0	0	0	0	0	0	0	0	0	-444	-3,836	-7,952	-9,538	-10,241	-9,620	-7,078	-1,581	423	4,573	9,104	9,687	8,240	6,303	4,417
May	0	0	0	0	0	0	0	-1	-22	-1,265	-4,581	-7,624	-9,172	-8,908	-7,389	-3,903	-548	1,093	4,575	8,221	8,822	6,925	4,560	2,696
Jun	0	0	0	0	0	0	0	0	-39	-656	-2,357	-5,023	-6,747	-7,270	-6,410	-4,419	-1,346	731	3,196	6,466	7,589	5,636	3,382	2,122
Jul	0	0	0	0	0	0	0	-6	-2	-841	-3,242	-6,256	-7,140	-6,380	-4,540	-2,387	-312	2,084	4,881	6,047	5,777	3,726	2,282	1,634
Aug	0	0	0	0	0	0	0	0	0	-686	-3,201	-6,903	-8,392	-7,799	-5,646	-2,475	-204	3,076	6,096	7,003	6,695	3,397	2,098	1,640
Sep	0	-19	-50	-81	-66	0	0	-7	-11	-890	-4,593	-7,811	-8,471	-6,375	-3,410	-1,004	1,231	4,445	6,635	7,060	4,375	1,875	1,233	1,011
Oct	0	0	0	0	0	0	-1	-8	-14	-600	-4,168	-8,168	-9,839	-9,080	-6,141	-2,395	447	5,409	8,450	8,203	6,228	3,001	1,430	1,179
Nov	0	0	0	0	0	0	0	0	0	-117	-3,470	-8,251	-9,668	-8,803	-5,484	-988	365	6,815	7,986	7,258	5,226	2,016	926	672
Dec	0	-1	0	0	0	0	0	0	-8	-2	-575	-4,184	-7,190	-6,890	-4,190	-570	51	4,645	5,483	5,016	3,417	771	401	285

Several mitigation alternatives were considered in this planning cycle for mitigating the Path 26 corridor congestion, as summarized below:

- Alternatives without capital cost as discussed in section 3.6.3
    - Rerate the summer rating of the Midway-Whirlwind 500 kV line, and adjust the emergency rating accordingly
    - Bypass the series capacitor on the Midway-Whirlwind 500 kV line, which was expected to balance flow among the three 500 kV lines of Path 26
- The Pacific Transmission Expansion (PTE) project – an economic study request with multi-terminals offshore HVDC lines between the Northern and Southern California systems

4.9.1.2 Rerating Midway-Whirlwind and bypassing series capacitor

Rerating the Midway-Whirlwind 500 kV line can mitigate the Midway-Whirlwind 500 kV line congestion under normal conditions, but it was expected to increase congestion under contingency conditions since the higher normal rating requires a lower emergency rating for this 500 kV line, as discussed in section 3.6.3. Bypassing the series capacitor of the Midway-Whirlwind 500 kV line can effectively reduce the flow on the line, hence reduce the congestion of the line under both normal and contingency conditions.

As the Midway – Whirlwind 500 kV line congestion was mitigated, it was expected to subsequently aggravate congestion of the parallel and downstream lines. Also, as the line congestion mitigated, Path 26 path rating would become the limiting constraint in many hours, as discussed earlier in this section. It is expected that a path rating increase can help to mitigate or reduce Path 26 congestion caused by path rating binding. It should be noted that path-rating change requires to go through the WECC path-rating process. In addition, as discussed earlier in section 4.9.1, the Path 26 corridor congestion happened when the flow was from south to north. Mitigating Path 26 corridor congestion would allow higher flow through Path 15 and PG&E's Fresno area from south to north and would aggravate congestion along the Path 15 corridor and some PG&E's transmission lines.

Table 4.9-6 summarized the congestions along Path 26 corridor, Path 15 corridor, and the PG&E's Moss Landing-Las Aguilas 230 kV line in the Base portfolio PCM case, and the PCM case with modeling the rerated rating of the Midway-Whirlwind 500 kV line, and the combination of rerating the line and bypassing its series capacitor.

Table 4.9-6: Path 26 Corridor Congestion Mitigation – Rerate the Midway-Whirlwind line and Bypass Series Capacitor

	Base		Midway-Whirlwind re-rate		MW-WW Re-rate and bypass series cap	
Constraints Name	Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)
P26 WECC Northern-Southern California	68.71	1,926	80.09	2,346	84.67	2,363
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	44.80	1,243	0.00	0	0.00	0
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	2.82	115	9.91	436	1.48	51
MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	0.00	1	0.00	0	0.03	5
PG&E Moss Landing-Las Aguilas 230 kV	14.44	261	15.73	285	16.01	280
Path 15 Corridor - Panoche-Gates 230 kV	6.21	388	7.80	439	7.88	431
Path 15 Corridor	3.53	105	3.38	108	3.14	96

<u>Production benefits</u>

The production benefits of the two alternatives for the ISO's ratepayers and the production cost savings are shown in Table 4.9-7.

Table 4.9-7: Production Benefits of the Rerating the Midway-Whirlwind line and Bypassing the Series Capacitor

	Base case	Midway-Whirlwind re-rate		MW-WW Re-rate and bypass series cap	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,259	6	9,258	7
ISO generator net revenue benefiting ratepayers	4,206	4,228	22	4,226	20
ISO transmission revenue benefiting ratepayers	484	460	-24	464	-20
ISO Net payment	4,575	4,572	3	4,569	6
WECC Production cost	13,184	13,182	2	13,173	11

Note that ISO ratepayer "savings" are a <u>decrease</u> in load payment, but an <u>increase</u> in ISO generator net revenue benefiting ratepayers and an <u>increase</u> in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a <u>decrease</u> in overall production cost. A negative saving is an incremental cost or loss.

As shown in Table 4.9-7, rerating the Midway-Whirlwind 500 kV line and the combination of rerating the line and bypassing its series capacitor can reduce the ISO's net payment, i.e. create product benefit for the ISO's ratepayers, by $2 million per year and $6 million per year, respectively. The production benefit is the summation of the changes of load payment, generator net revenue, and transmission revenue.

Conclusion

The economic assessment results showed that rerating the summer rating of the Midway-Whirlwind 500 kV line and bypass the series capacitor of the line had positive benefits to the ISO ratepayers.

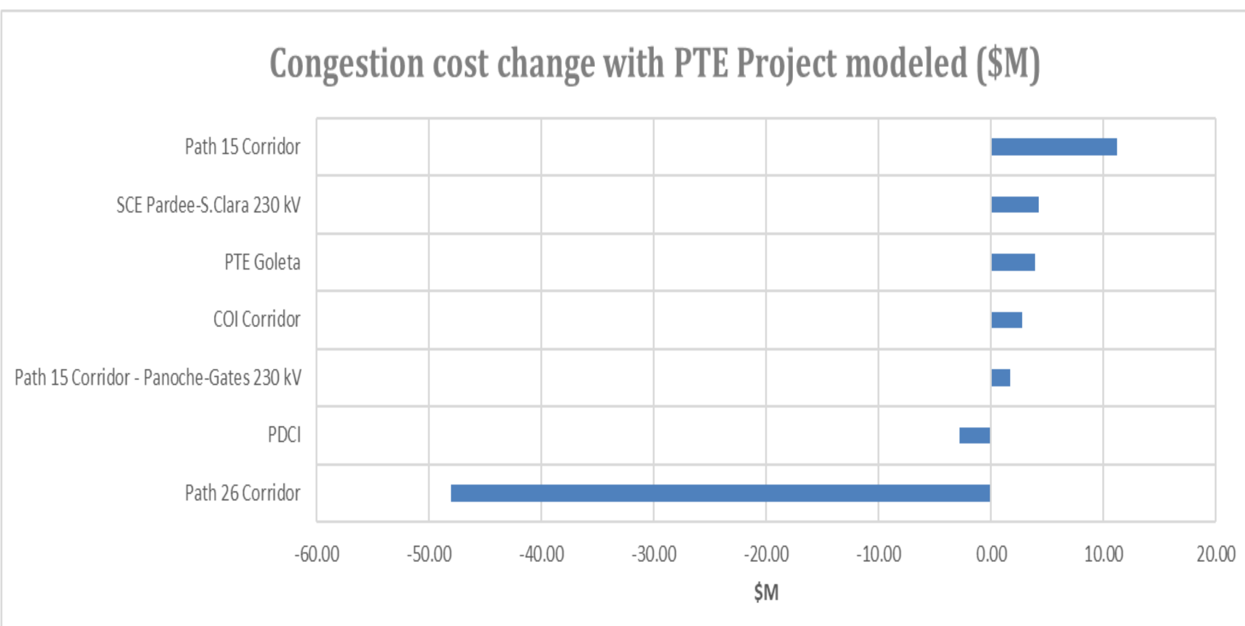
Based on the results of the economic assessment and the discussion in section 3.6.3, the ISO will coordinate with PG&E and SCE to further investigate the new ratings on PG&E'S portion of the Midway-Whirlwind line to mitigate the off-peak deliverability constraint and the bypassing the series capacitor at Midway on the Midway-Whirlwind 500 kV line.

4.9.1.3 Pacific Transmission Expansion Project

The Pacific Transmission Expansion (PTE) project was submitted to the ISO as an economic study request in this planning cycle, and in the previous planning cycle as well. The PTE project includes multi-terminals offshore-HVDC lines between the Northern and Southern California systems. It was considered as an alternative to mitigating the Path 26 corridor congestion in this planning cycle. Detailed information of the PTE project can be found in section 4.8.2.

As the PTE project provides a parallel path to Path 26, it was expected that the Path 26 corridor congestion would reduce with the PTE project modeled. The noticeable congestion changes resulted from modeling the PTE project is shown in Figure 4.9-1.

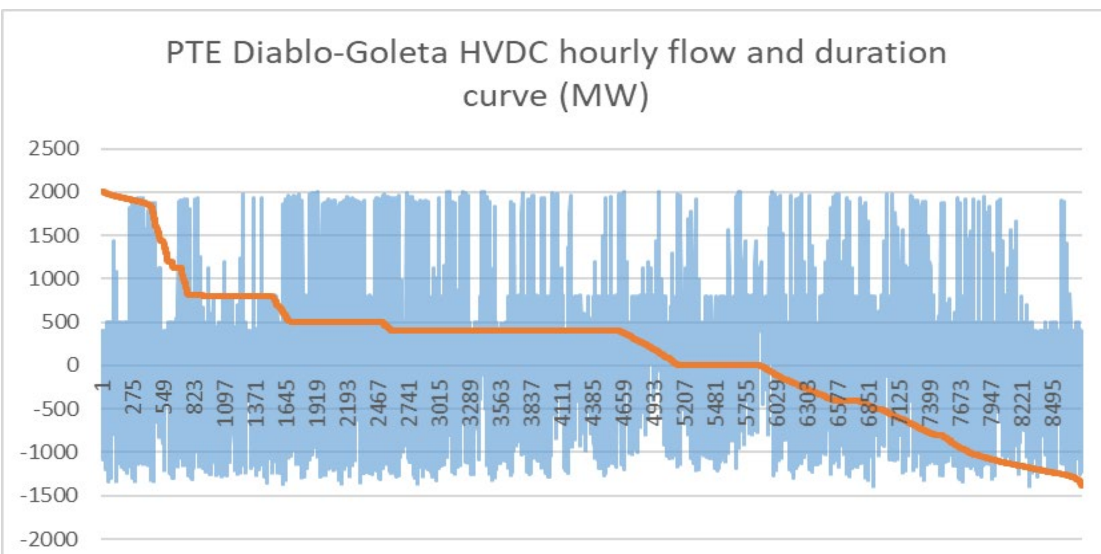
Figure 4.9-1: Congestion changes with PTE project modeled



Compared with the results of the PTE project study in previous planning cycles, the PTE project was more effective to reduce the Path 26 corridor congestion in the study of this planning cycle. This is mainly because of the changes of renewable resource and battery assumptions in the Southern California areas in this planning cycle. The PTE project not only helped to reduce the Path 26 corridor congestion caused by the solar generation in the Southern California area, but can also help to mitigate congestion caused by battery discharging outside solar hours. Path 15 congestion increased as expected when the PTE project was modeled. SCE's Pardee-Santa Clara 230 kV line is a local downstream line of the PTE HVDC lines terminated at the Goleta 230 kV substation. The congestion cost of this line was observed to increase with the PTE project modeled. Slight congestion cost decrease along COI corridor was also observed, which was attributed to the mitigation of Path 26 corridor congestion that allowed more flow from south to north.

Loop flow between the PTE HVDC lines and the Path 26 corridor was still observed in this planning cycle. Figure 4.9-2 shows the Diablo – Goleta HVDC line hourly flow and duration in the PTE PCM case. The positive direction is from Diablo to Goleta. It was observed that there were more hours when the flow on the HVDC line was from north to south than from south to north. Consequently, the total congestion hours of the Path 26 corridor congestion increased to 4,023 hours in the PCM case with the PTE project modeled from 3,285 hours in the base planning PCM, although the congestion cost reduced. The south to north flow on the PTE HVDC line also contributed to the congestion cost increase along the Path 15 corridor.

Figure 4.9-2: PTE project Diablo – Goleta HVDC line flow



Production benefits

The production benefit of the PTE project for ISO's ratepayers and the production cost savings are shown in Table 4.9-8.

Table 4.9-8: Production Benefits for the PTE HVDC project

	Base case	PTE case	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,262	3
ISO generator net revenue benefiting ratepayers	4,206	4,233	27
ISO transmission revenue benefiting ratepayers	484	469	-15
ISO Net payment	4,575	4,560	15
WECC Production cost	13,184	13,155	29

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

The total production cost benefit of the PTE project to the ISO ratepayers is $15 million per year based on the production cost simulation results in this planning cycle, which is the summation of the changes of load payment, generator net revenue, and transmission revenue. The production cost simulation results showed that modeling the PTE project results in a decrease in load payment and an increase in generator net revenue. Transmission revenue benefiting ratepayers reduced because congestion cost reduced with the PTE project modeled. The WECC production-cost saving with the PTE was $29 million per year.

Cost estimates

The cost estimate provided by the project sponsor in the last planning cycle is $1,850 million for the proposed project. As the project sponsor did not provide updated cost, the cost estimate for this project in this planning cycle continues to use the $1,850 million capital cost. Applying the ISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", translates to a total cost of $2,405 million.

Benefit-to-cost ratio

The present value of the production benefit of $15 million per year is $221 million based on the parameters provided in section 4.3.2, assuming 7% real discount rate and 50-year project life of the project.

In this planning cycle, the potential LCR reduction benefit of the PTE project was not assessed. The LCR reduction assessment results from the last planning cycle were used to calculate the benefit-to-cost ratio, since the SCE transmission system did not change significantly compared with the last planning cycle, and likely the SCE's resources were still needed to meet the similar local and system requirements. The LCR reduction benefit of PTE project was assessed in the last planning cycle for several PTE configuration options, which were not exactly the same as the updated PTE configuration in this planning cycle. The range of the present value of the LCR reduction benefit of the PTE project in the last planning cycle was $125 million to $405 million. This range was used in the total benefit calculation in this planning cycle. Combining the production benefit and the LCR reduction benefit, the total benefit of the PTE project is between $346 million and $626 million, which resulted in benefit-to-cost ratio between 0.14 and 0.26.

Conclusion

Based on the above estimate of the benefit-to-cost ratio, there was not sufficient economic justification to approve the PTE project as an economically driven transmission upgrade in this planning cycle. It should be noted that that the assumptions around the value of reducing capacity requirements directly affects the value of the project. The potential PTE project benefit of reducing capacity requirements needs to be reassessed in future planning cycles as the assumptions change, particularly if the need to retain the existing gas-fired fleet for system-wide resource reliability purposes is relaxed.

The PTE project was also assessed in the Sensitivity 2 portfolio associated with the offshore wind study in section 3.7.3.

4.9.2 GridLiance West/VEA Congestion and Mitigations

Congestion analysis

Congestion in the GridLiance West/VEA area was observed in this planning cycle as summarized in Table 4.9-9.

Table 4.9-9: GridLiance West/VEA Area Congestion

Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
TROUT CANYON-SLOAN CANYON 230 kV line #1	30,449	2,144	0	0	30,449	2,144
GAMEBIRD-TROUT CANYON 230 kV line #1	0	0	8,816	838	8,816	838
NWEST-DESERT VIEW 230 kV line #1	0	0	595	147	595	147
INNOVATION-DESERT VIEW 230 kV line #1	46	27	0	0	46	27
MEAD S-SLOAN CANYON 230 kV line #1	0	0	11	2	11	2

The GLW Upgrade project was assessed as the mitigation for the GridLiance West/VEA area congestion. The detailed scope of the GLW Upgrade project was described in section 4.8.3. The simulation results showed that the GLW Upgrade project was effective to mitigate the most of the GridLiance West/VEA area congestions. As the congestion was mitigated in the GridLiance West/VEA area, the solar generation curtailment in this area was significantly reduced. As a result, it was observed that the congestion of the Sloan Canyon – Mead S 230 kV line increased, and the Path 46, PDCI and Path 26 congestion increased as well. Table 4.9-10 showed the congestion changes with the GLW Upgrade project modeled.

Table 4.9-10: Congestion Change with GLW Upgrade modeled

Area or Branch Group	Base case - Congestion Cost ($M)	GLW Upgrade case - Congestion Cost ($M)	Congestion cost change (>$2M)
GridLiance West/VEA	39.92	4.13	-35.79
Path 46 WOR	2.64	4.82	2.18
PDCI	6.81	9.22	2.41
Path 26 Corridor	116.33	121.59	5.26

Production benefits

The production benefit for ISO ratepayers and the production-cost savings of the GLW Upgrade project are shown in Table 4.9-11.

Table 4.9-11: Production Benefits of GLW Upgrade

	Base case	GLW Upgrade case	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,184	81
ISO generator net revenue benefiting ratepayers	4,206	4,186	-20
ISO transmission revenue benefiting ratepayers	484	467	-17
ISO Net payment	4,575	4,530	45
WECC Production cost	13,184	13,159	25

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

Cost estimates

The estimated capital cost for the GLW Upgrade project is about $278 million provided by the project sponsor, GridLiance West. 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 $278 million capital cost translates to a total cost of $361 million.

Benefit-to-cost ratio

The present value of the sum of the production cost of the GLW Upgrade project is shown in Table 4.9-12 followed by the calculation of the benefit-to-cost ratio. As the project included both reconductor and new transmission, 40 year project file was used in the present value calculation for conservativeness. No capacity saving was identified in this planning cycle.

Table 4.9-12: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of GLW Upgrade

GLW Upgrade	
Production cost savings ($million/year)	45
Capacity saving ($million/year)	0
Capital cost ($million)	278
Discount Rate	7%
PV of Production cost savings ($million)	642
PV of Capacity saving ($million)	0
Total benefit ($million)	642
Total cost (Revenue requirement) ($million)	361
Benefit-to-cost ratio (BCR)	1.77

Conclusions

The economic assessment results in this planning cycle demonstrated that the GLW Upgrade has 1.77 of benefit-to-cost ratio. This project was also identified as a policy deliverability mitigation, and needed to provide sufficient ISO transmission system capability for the renewable generators in the CPUC IRP portfolio in the GridLiance West/VEA area to ISO system load, as described in section 3.6.4. The benefit-to-cost ratio supports the policy-driven recommendation for approval.

4.9.3 PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion and Mitigations

Congestion analysis

Table 4.9-13 showed the congestions on the PG&E's Moss Landing – Las Aguilas and Panoche – Gates 230 kV lines that were observed in this planning cycle. The congestions were mainly observed under emergency conditions with P1 or P7 contingencies. The only exception is that the Moss Landing – Las Aguilas 230 kV line was congested under normal condition for 26 hours over the year. The congestion on the Panoche – Gates 230 kV lines was observed when the flow was from Gates to Panoche, and the congestion on the Moss Landing – Las Aguilas 230 kV line was observed when the flow was from Las Aguilas to Moss Landing.

Table 4.9-13: PG&E Moss Landing – Las Aguilas and Panoche – Gates Congestions

Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Moss Landing-LosBanos 500 kV	0	0	13,836	235	13,836	235
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	4,461	244	4,461	244
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	1,129	44	1,129	44
MOSSLNSW-LASAGUILASS 230 kV line #2	0	0	604	26	604	26
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	484	71	484	71
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	89	17	89	17
PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Henrieta1-Gregg 230 kV	0	0	33	1	33	1
PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	11	11	11	11

Table 4.9-14 and Table 4.9-15 showed the occurrences of the Moss Landing – Las Aguilas and Panoche – Gates congestions, respectively, in the hours of the day in each month. It was observed that the congestions on these 230 kV transmission lines happened in solar hours, which indicated that the congestions were highly correlated with solar generation output in the PG&E's Fresno area. In addition, congestions of these 230 kV lines were mainly observed in summer months, which is attributed to the summer ratings of the congested transmission lines that are less than the winter ratings.

Table 4.9-14: Occurrences of Moss Landing-Las Aguilas Congestion under Moss Landing-Los Banos N-1 Contingency

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	2	4	4	2	2	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	3	8	7	6	5	3	3	1	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	8	15	10	4	4	3	4	1	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	1	14	14	7	5	4	4	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	9	19	12	7	7	2	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	1	8	3	4	2	2	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	1	3	1	2	4	0	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 4.9-15: Occurrences of Panoche-Gates Congestion under Gates-Gregg and Gates-McCall N-2 Contingency

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	2	6	6	3	2	3	2	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	2	3	4	3	3	2	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	1	11	5	4	4	2	1	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	3	7	5	7	7	6	2	0	1	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	16	10	11	9	8	4	0	2	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	1	6	5	4	5	5	4	1	1	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	5	11	12	4	4	3	2	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Congestion mitigation alternatives

Installing series reactors on the congested lines was assessed in this planning cycle. First, different size of reactors were examined. It was found that a 10-ohms reactor was effective to mitigate the congestions on the Moss Landing – Las Aguilas 230 kV line. A 20-ohms reactor on each of the two Panoche – Gates 230 kV lines was effective to mitigate the congestion on the Panoche – Gates 230 kV lines.

The series reactors can be switched in for whole year or for summery months only, from the congestion mitigation perspective, as the congestions were observed mainly in summer months. The congestions on the Moss Landing – Las Aguilas line and the Panoche – Gates lines can be mitigated effectively in both scenarios. Economic assessments were conducted for both the scenarios with the series reactors switched in for the whole year and the scenario with the series reactor switched in for summer months only.

Production benefits

The production benefits for ISO ratepayers and the production cost savings of installing a 10-ohms series reactor on the Moss Landing – Las Aguilas 230 kV line, and a 20 ohms series reactor on each of the two Panoche – Gates 230 kV lines were shown in Table 4.9-16 and Table 4.9-17 for the scenarios with the series reactors switched in for whole year and for summer months only, respectively.

In the scenario with the series reactors switched in for whole year, as shown in Table 4.9-16, installing Moss Landing – Las Aguilas reactor or Panoche – Gates reactors alone showed positive benefits for ISO ratepayers, mainly attributed to the ISO gross-load payment reduction although the generator profit and transmission revenue reduced. However, it was observed that the combination of the Moss Landing – Las Aguilas and Panoche – Gates reactors did not show a benefit for ISO ratepayers, which was mainly because the ISO gross-load payment did not reduce much, but the transmission revenue reduced by $10 million per year due to the mitigation of congestion with the series reactors installed.

Table 4.9-16: Production Benefits of Series Reactors on Moss Landing – Las Aguilas line and Panoche – Gates #1 and #2 lines: Swithced in for whole year

	Base case	Reactor on Moss Landing – Las Aguilas		Reactors on Panoche - Gates		Reactors on Moss Landing – Las Aguilas and Panoche - Gates	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,241	24	9,227	38	9,263	2
ISO generator net revenue benefiting ratepayers	4,206	4,198	-8	4,196	-10	4,213	7
ISO transmission revenue benefiting ratepayers	484	474	-10	467	-17	474	-10
ISO Net payment	4,575	4,570	5.6	4,564	11	4,576	-1
WECC Production cost	13,184	13,187	-3	13,196	-12	13,176	8

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative savings is an incremental cost or loss.

In the scenario with the series reactors switched in for summer months, as shown in Table 4.9-17, the Moss Landing – Las Aguilas reactor alone still showed benefit for ISO ratepayers. However, the Panoche – Gates reactors alone did not show a benefit for ISO ratepayers, mainly because the ISO gross-load payment reduction and the generator profit increase were not sufficient to compensate for the reduction of transmission revenue. With installing series reactors on the Moss Landing – Las Aguilas line and the Panoche – Gates lines and all switched in for summer only, on the other hand, the production benefit for ISO ratepayers turned to positive at $5.0 million per year attributed to the improved ISO gross load-payment reduction and generator profit increase.

Table 4.9-17: Production Benefits of Series Reactors on Moss Landing – Las Aguilas line and Panoche – Gates #1 and #2 lines: Switched in for summer months only

	Base case	Reactors on Moss Landing – Las Aguilas		Reactors on Panoche - Gates		Reactors on Moss Landing – Las Aguilas and Panoche - Gates	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,244	21	9,264	1	9,249	16
ISO generator net revenue benefiting ratepayers	4,206	4,205	-1	4,211	5	4,213	7
ISO transmission revenue benefiting ratepayers	484	473	-11	475	-9	466	-18
ISO Net payment	4,575	4,567	8.5	4,579	-3.4	4,570	5.0
WECC Production cost	13,184	13,191	-7	13,180	4	13,190	-6

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Cost estimates

One 10-ohms reactor is needed to mitigate the Moss Landing – Las Aguilas congestion. PG&E further confirmed that station expansion or re-configuration is required to provide space for the reactor as well as a bypass breaker, which resulted in about $40 million of total capital cost. 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 $40 million capital cost translates to a total cost of $52 million. Two 20-ohms reactors are needed to mitigate the Panoche – Gates congestion as there are two Panoche – Gates 230 kV lines, which have a total cost of $156 million. This cost estimate assumed the same cost of station expansion or reconfiguration and bypass breaker as for the Moss Landing – Las Aguilas series reactor. Subsequently, the combination of installing series reactors on the Moss Landing – Las Aguilas line and the Panoche – Gates lines have a total cost of $208 million.

Switching the series reactor in for the whole year or for summer months only may have slightly different costs. The same cost estimate was used for these two scenarios in this planning cycle.

Benefit-to-cost ratio

The present value of the sum of the production benefit of the two mitigation scenarios are shown in Table 4.9-18 and Table 4.9-19, respectively. The benefit-to-cost ratio was calculated on a 50-year project life. No capacity savings was identified in this planning cycle.

Table 4.9-18: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of Series Reactors on the Moss Landing-Las Aguilas and Panoche-Gates 230 kV lines: Switched in for whole year

	10 ohms Reactors on Moss Landing – Las Aguilas	20 ohms Reactors on Panoche - Gates	Reactors on Moss Landing – Las Aguilas and Panoche - Gates
Production cost savings ($million/year)	5.6	11.1	-0.7
Capacity saving ($million/year)	0	0	0
Capital cost ($million)	20	80	100
Discount Rate	7%	7%	7%
PV of Production cost savings ($million)	82.9	164.2	-10.52
PV of Capacity saving ($million)	0	0	0
Total benefit ($million)	82.9	164.2	-10.52
Total cost (Revenue requirement) ($million)	52	156	208
Benefit-to-cost ratio (BCR)	1.59	1.05	-0.05

Table 4.9-19: Benefit-to-cost ratios (Ratepayer Benefits per TEAM) of Series Reactors on the Moss Landing-Las Aguilas and Panoche-Gates 230 kV lines: Switched in for summer months only

	10 ohms Reactors on Moss Landing – Las Aguilas	20 ohms Reactors on Panoche - Gates	Reactors on Moss Landing – Las Aguilas and Panoche - Gates
Production cost savings ($million/year)	8.5	-3.4	5.0
Capacity saving ($million/year)	0	0	0
Capital cost ($million)	20	80	100
Discount Rate	7%	7%	7%
PV of Production cost savings ($million)	125.9	-50.4	73.7
PV of Capacity saving ($million)	0	0	0
Total benefit ($million)	125.9	-50.4	73.7
Total cost (Revenue requirement) ($million)	52	156	208
Benefit-to-cost ratio (BCR)	2.42	-0.32	0.35

<u>Conclusions</u>

Based on the ISO's analysis, consistent with its Transmission Economic Analysis Methodology, the benefit-to-cost ratio of installing a 10-ohms series reactor on the Moss Landing – Las Aguilas 230 kV line was 1.59 and 2.42 in the two scenarios studied, switched the reactor in for whole year or for summer months only, respectively. The benefit-to-cost ratio of installing a 20-ohms series reactors on each of the two Panoche – Gates 230 kV line varied from 1.05 in the scenario with the reactors switched in for the whole year to -0.32 in the scenario with the reactors switched in for summer months only. The combination of Moss Landing – Las Aguilas reactor and Panoche – Gates reactors did not have benefit-to-cost ratio greater than 1.0 in neither scenario studied in this planning cycle.

The ISO is recommending the 10-ohms series reactor on the Moss Landing – Las Aguilas 230 kV line for approval as an economically driven upgrade in this planning cycle, and recommends deferring approval of the mitigation of the Panoche – Gates 230 kV line congestion to the future planning cycles, for the following reasons:

- Installing a 10-ohms series reactor on the Moss Landing – Las Aguilas 230 kV line had the greatest benefit-to-cost ratio among the studied scenarios. Also, the addition of the 10-ohms series reactor helped to balance the impedances and flow between the Moss Landing – Las Aguilas line and the parallel Las Aguilas – Coburn – Moss Landing 230 kV line
- Installing series reactors on all three congested lines together did not show sufficient economic benefit, i.e. its benefit-to-cost ratio was less than 1.0
- The Panoche – Gates 230 kV lines are a part of the Path 15 WECC path. Adding series reactors on these lines potentially impacts flow on the other lines of Path 15, which was also observed as congested in this planning cycle and required further investigation
- The Moss Landing – Las Aguilas reactor showed consistent benefits for ISO ratepayers in the two scenarios studied with the reactor switched in for the whole year or for

summer months only. The Panoche – Gates reactors did not show benefit for ISO ratepayers in one of the two scenarios, which was worth further investigating in future planning cycles.

4.9.4 PG&E Manning and Collinsville Upgrades

The Manning 500 kV Upgrade and the Collinsville 500 kV Upgrade were identified as policy upgrades in Chapter 3 to address transmission constraints identified in the policy on-peak deliverability assessment in the PG&E Fresno and Greater Bay areas, respectively, as well as to allow advancement of renewable generation, in the PGE& Westland/San Joaquin and Northern areas, respectively. The detailed policy assessment for the PG&E areas can be found in section 3.5.7. The production benefits of the Manning Upgrade and the Collinsville Upgrade were assessed based on the ISO TEAM methodology, as set out in this section. It should be noted that the purpose of the production benefit assessment in this section was to examine whether there is potential economic impact of the upgrades on ISO ratepayers. As the Manning and Collinsville Upgrades had been identified as policy upgrades in this planning cycle, economic justification is not needed for the approval of these two upgrades. The economic assessment results showed that these two upgrades can provided incremental production benefits for the ISO's ratepayers.

Production benefits of Manning Upgrade

The production benefits for ISO ratepayers and the production cost savings of the Manning Upgrade are shown in Table 4.9-20.

The results showed that the production benefits for ISO ratepayers of the Manning Upgrade is $15 million per year. The present value of the production benefit is about $218 million, assuming 7% discount rate and 50-year project life.

Table 4.9-20: Production Benefits of Manning Upgrade

	Base case	Manning Upgrade	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,198	67
ISO generator net revenue benefiting ratepayers	4,206	4,157	-49
ISO transmission revenue benefiting ratepayers	484	480	-4
ISO Net payment	4,575	4,561	15
WECC Production cost	13,184	13,187	-3

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Production benefits of Collinsville Upgrade

The production benefits for ISO ratepayers and the production cost savings of the Collinsville Upgrade are shown in Table 4.9-21.

The results showed that the production benefits for ISO ratepayers of the Collinsville Upgrade is $10 million per year. The present value of the production benefit is about $145 million, assuming 7% discount rate and 50-year project life.

Table 4.9-21: Production Benefits of Collinsville Upgrade

	Base case	Collinsville Upgrade	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,251	14
ISO generator net revenue benefiting ratepayers	4,206	4,192	-14
ISO transmission revenue benefiting ratepayers	484	494	10
ISO Net payment	4,575	4,565	10
WECC Production cost	13,184	13,181	3

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

4.10 Out-of-State Wind Study

In the 2021-2022 planning cycle, the CPUC provided a base portfolio and two sensitivity portfolios to the ISO. The CPUC IRP Base portfolio and the Sensitivity 1 portfolio included out-of-state (OOS) resources, particularly the out-of-state wind resources in the New Mexico, Wyoming and/or Idaho areas.

The ISO wished to address the request from CPUC staff to investigate potential out-of-state implications of wind development and also be responsive in assessing the economic benefits of potential out-of-state transmission upgrades to access out-of-state wind resources, as well as to address the economic study request from LS Power for the SWIP North project (see section 4.8.4). This study addresses both topics. In this analysis, the resources have been modeled at out-of-state locations together with the appropriate transmission upgrade intended to access those resources. The benefits therefore comingle the impacts of the transmission upgrades themselves as well as the benefits of the differences in resource characteristics as well.

In contrast, as requested by the CPUC[148], the ISO considered only the potential impact on transmission upgrades inside the ISO footprint in assessing the potential for approval of in-state policy-driven transmission projects, as set out in chapter 3. Accordingly, the ISO modeled those

[148] Page 34, D.21-02-008 that transferred the portfolios to the ISO. "The CAISO, in reply comments, suggested that they could study separately the injection of the full amount of energy at both the El Dorado substation representing resources from Wyoming, Idaho, or potentially other locations, and the Palo Verde substation, presentation resources from New Mexico or other Southwest locations, delivering results for further consideration at the end of this TPP cycle. We understand this to be a unique situation where the CAISO may be able to offer optionality within the base case analysis, and therefore we will take the CAISO up on this offer and work with them to understand better the transmission buildout requirements associated with generation siting in both locations." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF

out-of-state resources at the actual injection points into the ISO footprint and did not assess out-of-state implications in that analysis.

4.10.1 Out-of-state wind in CPUC IRP portfolios

The CPUC IRP Base and Sensitivity 1 portfolios included out-of-state wind resources in different areas. Some of the out-of-state wind resources in the CPUC IRP portfolios expected to require new transmission, while some rely on existing transmission, to deliver their wind energy to the ISO load. Specifically, the CPUC IRP Base portfolio included out-of-state wind with 1062 MW of capacity identified in two alternative locations, Wyoming or New Mexico areas, which are expected to require new transmission. The Base portfolio also included out-of-state wind with 530 MW of capacity in Pacific Northwest on existing transmission. The CPUC IRP Sensitivity 1 portfolio included out-of-state wind requiring new transmission with 1500 MW of capacity in Wyoming area and 1500 MW of capacity in New Mexico area. The Sensitivity 1 portfolio also includes another out-of-state wind resource with 500 MW of capacity in New Mexico area and 1500 MW of capacity in Pacific Northwest area, both on existing transmission.

For the out-of-state wind resources that require new transmission, the CPUC IRP portfolio provided specified injection points to the ISO system, but did not specify particular out-of-state transmission projects to deliver the resources to the ISO boundary.

4.10.2 Alternative transmission upgrades for out-of-state wind

The alternative transmission upgrades for out-of-state wind considered in this planning cycle include projects that have been submitted previously as interregional transmission projects or assessed in the previous planning cycles:

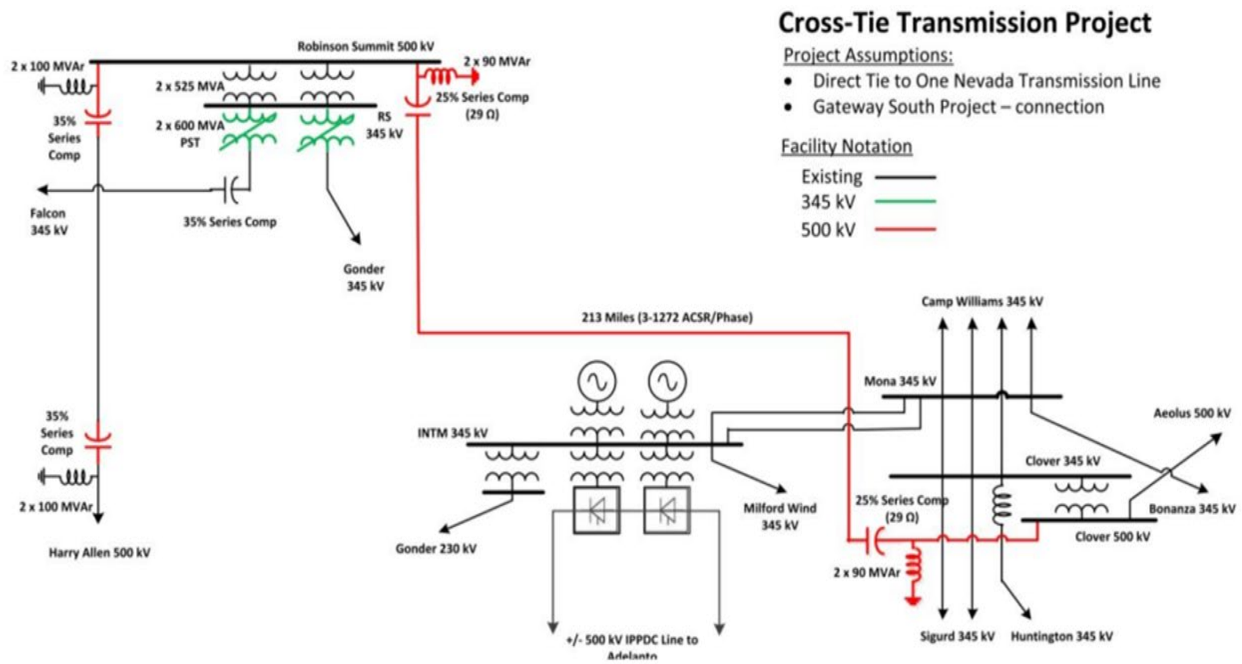
- Cross-Tie project
- SWIP North project
- TransWest Express project

These projects either access the same or similar resources, or have the potential to have implications for the other alternatives in accessing Wyoming or Idaho resources. They are also proposals that would directly access the ISO footprint. In contrast, resources developing in New Mexico are expected to rely to some extent on the existing transmission system inside the Arizona/New Mexico and in particular access through the existing Palo Verde facilities, although additional reinforcements inside Arizona and New Mexico would be expected. While the ISO is aware of projects including the SunZia project, the ISO did not study alternatives inside New Mexico and Arizona.

Cross-Tie project

Figure 4.10-1 showed the diagram of the Cross-Tie project, which was copied from the TransCanyon's 2020 ITP submittal.

Figure 4.10-1 Cross-Tie Project

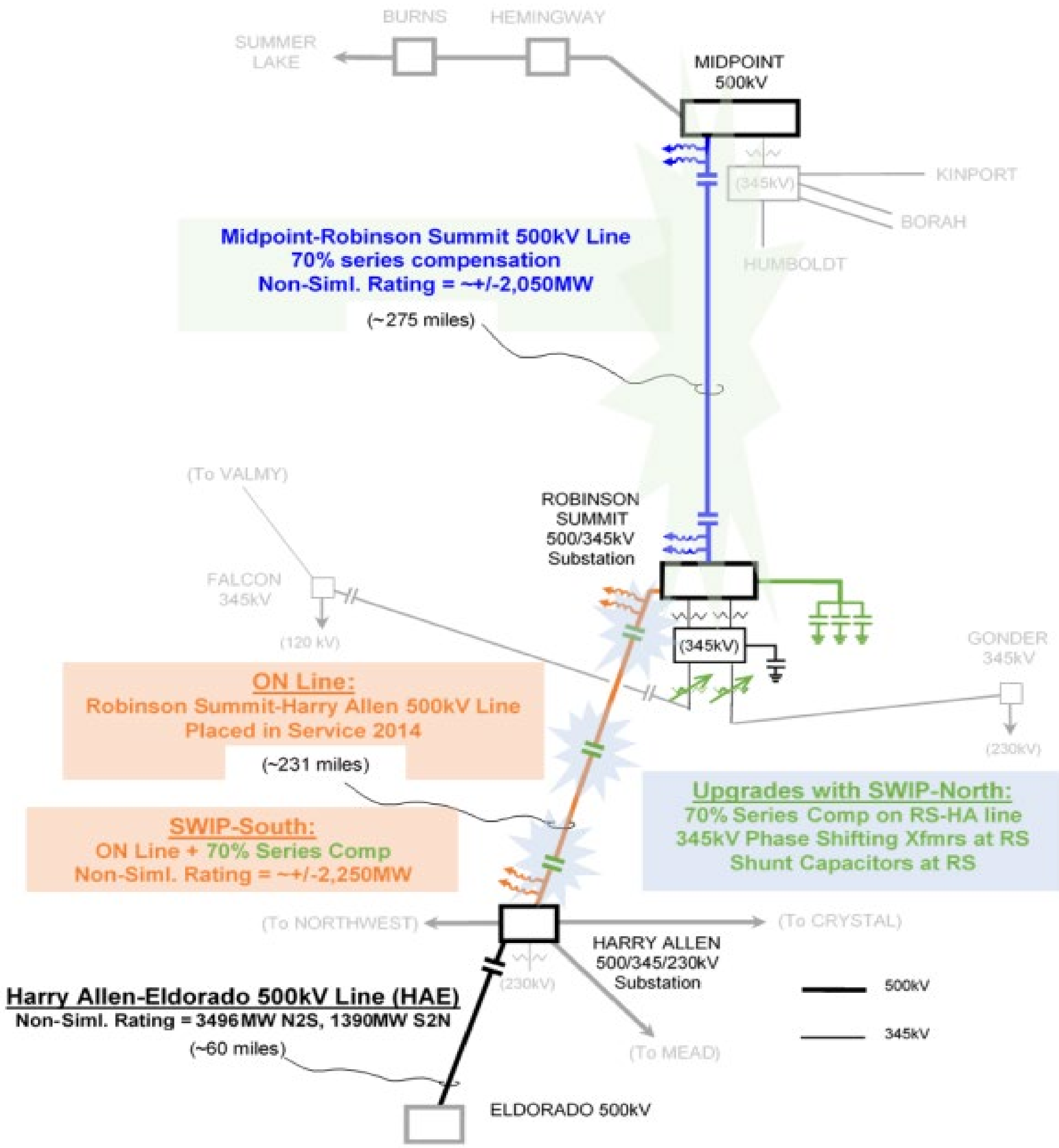


The Cross-Tie project included the new 500 kV line between the Clover and Robison Summit 500 kV buses, the series compensation on the Robinson Summit – Harry Allen 500 kV line, and the 500/345 kV phase shifters at the Robinson Summit substation. TransCanyon modified the Robinson Summit – Harry Allen configuration to a five-segment configuration with the same compensation ratio in its 2021 update. TransCanyon indicated that the SWIP South (i.e. the Robinson Summit – Harry Allen 500 kV line) path rating can be increased from the current 900 (N-S)/600 (S-N) MW to 2000/2000 MW with the Cross-Tie upgrade. The estimated cost of the Cross-Tie project is $667M (2015 dollar, based on 2020 ITP submission).

SWIP North project

Figure 4.10-2 showed the diagram of the SWIP North project provided by LS Power in the 2021-2022 transmission planning process economic study request.

Figure 4.10-2 SWIP North Project



The SWIP North project included the new 500 kV line between the Midpoint and Robinson Summit 500 kV buses, the series compensation on the Robinson Summit – Harry Allen 500 kV line, and the 500/345 kV phase shifters at the Robinson Summit substation. LS Power updated the impedances of the SWIP-North conductor and series capacitors in September 2021, and suggested that the path rating of SWIP South (i.e. the Robinson Summit – Harry Allen 500 kV line) can be increased from 900 (N-S)/600 (S-N) MW to 2000/2000 MW. LS Power also stated that the SWIP North can provide 1100 MW of transmission right to the ISO between Midpoint and Harry Allen. Accordingly, this portion of SWIP North capacity was modeled as the ISO owned transmission capacity in the planning PCM for the SWIP North study. The estimated cost of the project is $636 M in 2020 dollars, based on the 2020 ITP submission.

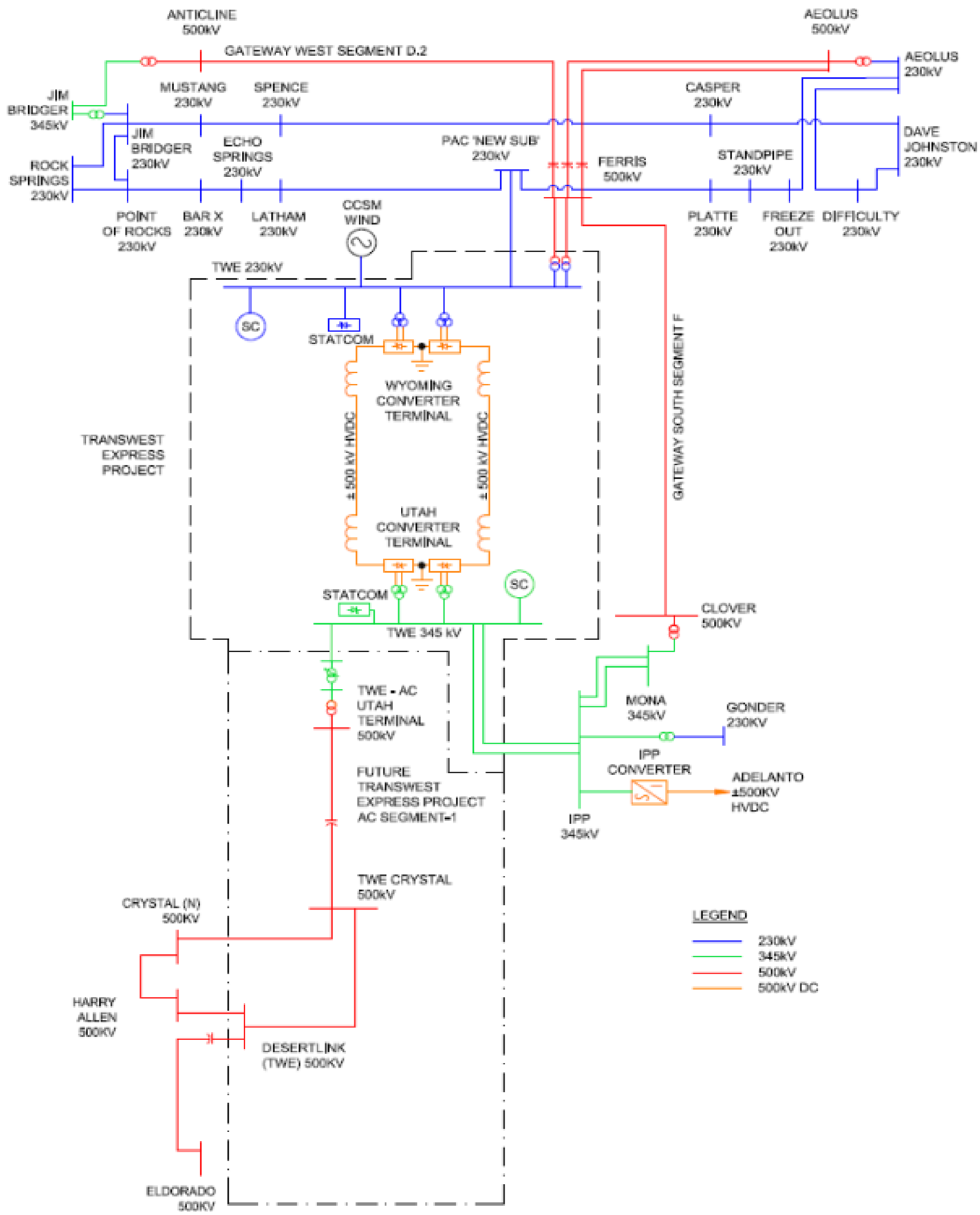
TransWest Express project

Figure 4.10-3 showed the updated diagram of the TransWest Express project, provided by TransWest Express (TWE) in September 2021. The project includes three segments:

1. TWE_WY substation in Wyoming, including
    - New TWE_WY 500 kV substation in Wyoming
    - Gateway West and Gateway South 500 kV lines loop-in to the TWE_WY 500 kV bus
    - Platte - Latham 230 kV line loop-in to the TWE_WY 230 kV bus
2. New Bi-poles HVDC lines between the TWE_WY substation in Wyoming and the new TWE_IPP substation in Utah with 3000 MW capacity, and a 345 kV connection to the LADPW's Intermountain 345 kV bus
3. 500 kV AC upgrade between the TWE_IPP substation and the ISO's Harry Allen – Eldorado 500 kV line. The capacity of this segment is 1500 MW
    - Three 500/345 kV phase shifters at the TWE_IPP substation.
    - New 500 kV line between the TWE_IPP 500 kV bus and the Crystal North 500 kV bus
    - New 500 kV line between the TWE_IPP 500 kV bus and a 500 kV bus on the Harry Allen – Eldorado 500 kV line.

The estimated cost of segments 1 and 2 was about $2.1 billion, and the estimated cost of segment 3 was about $660 million, based on the TWE's 2020 ITP submission and the updated scope of the project. TWE also indicated that the TWE project would use a subscriber model. It was assumed in this study for purposes of calculating benefit-to-cost ratios that ultimately half of the cost of segments 1 and 2 would ultimately be recovered from ISO ratepayers and all of the cost of segment 3, totaling $1.71 billion.

Figure 4.10-3 TransWest Express Project



4.10.3 Out-of-state wind model in PCM

In the out-of-state wind PCM study, in addition to considering the New Mexico and Wyoming wind scenarios, the Idaho wind scenario was studied as well as an alternative to the Wyoming wind scenario. The out-of-state wind generators were modeled in the PCM cases close to or at the terminal buses of the transmission upgrade assessed in the out-of-state wind study. Specifically, the Wyoming wind generator was modeled at the Aeolus 500 kV bus in Wyoming in the Cross-Tie and SWIP North project studies, which is the junction terminal of the Gateway West and Gateway South projects. In the TWE project study, the Wyoming wind generator was modeled at the proposed TWE_WY 230 kV bus as requested by TWE. Idaho wind generator was modeled at the Midpoint 500 kV bus, which is the terminal in Idaho of the proposed SWIP-North project.

New Mexico wind generation that requires new transmission was modeled at the Pinal Central 500 kV bus in Arizona. This is equivalent to assuming that a new transmission line would be built to deliver New Mexico wind generation to the Pinal Central 500 kV bus. The 500 MW of New Mexico wind resource that uses the existing transmission was modeled on an existing 345 kV bus in the New Mexico system, specifically the WESTMESA 345 kV bus that was used for modeling New Mexico wind in the previous planning cycles.

All out-of-state wind generators identified in the CPUC IRP portfolios were modeled as ISO's remote generators in the planning PCM, which is equivalent to assuming that these out-of-state generators should have sufficient transmission right to delivery their energy to the ISO load.

Out-of-state wind generators in the planning PCM used the hourly profiles included in the ADS PCM. The profiles were originally provided by NREL, as a part of the ADS PCM development. The hourly profiles used for the out-of-state wind generators in this study were selected based on the following steps:

- Assumed the out-of-state wind generators close the terminal buses of the transmission upgrades in Wyoming or Idaho
- A set of wind profiles wind resources close to the terminal buses of the transmission upgrades in Wyoming or Idaho were selected
- Simple average annual capacity factor was calculated for the selected wind profiles
- The wind profile selected to be modeled for the out-of-state wind generator in the PCM was the one whose annual capacity factor is close to the average capacity factor

This process was summarized in Table 4.10-1.

Table 4.10-1: OOS Wind Hourly Profile Selection based on Capacity factor

OOS wind location	Average capacity factor of the hourly profiles at the location close to the transmission project terminals	Capacity factor of the OOS wind profile used in the PCM
NM	41.4%	41.5%
WY	41.9%	42.0%
ID	33.9%	33.8%

4.10.4 Out-of-state wind study approach and study scenarios

In the out-of-state wind study, alternative transmission projects were assessed for the out-of-state wind in the Wyoming (or Idaho) area. The primary purpose of this study is to do a comparative assessment for alternative transmission projects outside of the ISO system for integrating the out-of-state wind identified in the CPUC IRP portfolios.

In considering how to do a comparative analysis, the ISO took into account the context of the studies and of the different alternatives.

As all portfolios provided by the CPUC called for at least 1062 MW of out-of-state wind to be brought into California, there was no scenario that called for zero out-of-state requiring additional out-of-state transmission. Therefore, the effectiveness of the different transmission and resource options were compared against each other, and not against a “no out-of-state wind” scenario.

To select a reference case against which the other alternatives could be assessed, the ISO took the following into account:

- There are various alternatives accessing the Wyoming resources and potential interactions with alternatives accessing Idaho resources
- The TransWest Express project is being developed providing transmission service to resources seeking access to California markets on a subscriber model, whereas the SWIP North project and (possibly) the Cross-Tie projects are being proposed to receive regulated, cost-of-service cost recovery as a participating transmission owner asset.

Accordingly, the New Mexico out-of-state resource development was selected as the reference case against which other alternatives were compared to access Wyoming and/or Idaho resources. In the Base portfolio out-of-state wind study, the Base portfolio PCM case that had the 1062 MW of New Mexico wind resource modeled was used as the reference case, i.e. the “pre upgrade” case. This is the same base PCM case used in the economic assessment in section 4.9. Then the “post upgrade” PCM cases with the 1062 MW of Wyoming or Idaho wind and transmission alternatives outside of the ISO system were simulated and the results were compared against the reference case results to calculate the production benefit for the ISO ratepayers. Benefit-to-cost ratios then were calculated with the same approach used in the economic assessment as illustrated in section 4.9. In the “post- upgrade” PCM cases, the New Mexico wind resources were not modeled. Because the New Mexico wind resources were modeled at Pinal Central rather than in New Mexico and the Arizona/New Mexico reinforcements were not assessed in this plan, benefit-to-cost ratios were first calculated without assessing the costs of Arizona /New Mexico reinforcements, and the ISO then also calculated an alternative benefit-to-cost ratio for each project and alternative configuration assuming an added benefit of avoiding half of the cost of the SunZia project, as a proxy for the cost of delivering New Mexico wind generation to Pinal Central.

In the Sensitivity 1 portfolio out-of-state wind study, unlike from the Base portfolio out-of-state wind study, the ISO’s ratepayers’ net payments of the study scenarios with Wyoming or Idaho wind and the transmission alternatives were directly compared. A reference “pre-upgrade” PCM case was not needed for this study.

Study scenarios were selected with considering key parameters of the study, such as out-of-state wind location and transmission upgrades. Different phase shifter (Robinson PST for Cross-Tie and SWIP-N, IPP PST for TWE) settings were considered, as they were also identified critical to impact the system-wide generation dispatch, hence the flow through the studied transmission projects. Table 4.10-2 summarized the study scenarios in the Base portfolio out-of-state wind study. Similar scenarios were studied in the Sensitivity 1 portfolio out-of-state wind study, except the Sensitivity 1 portfolio out-of-state wind study used Sensitivity 1 portfolio and did not need a “pre upgrade” reference PCM case.

Table 4.10-2: OOS Wind Study Scenarios – Base portfolio

Index	OOS wind Scenario	Alternative	OOS wind location	Transmission Upgrade	PST angle cost	PST initial angle	Note
0	00-Base-NM	00-Base-NM	NM - Pinal C 500 kV	N/A	N/A	N/A	Used as the reference case. Pinal C is the AZ terminal of the SunZia project
1	01-Base-WY	01-CrossTie-0cost	WY - Aeolus 500 kV	Cross-Tie	0	0	Robinson PST $0 cost allows the angle to move frequently in simulation
2	01-Base-WY	02-CrossTie-Neg48	WY - Aeolus 500 kV	Cross-Tie	100	-48	High cost restrict the angle movement in simulation; Negative angle pushes flow to the Robinson 500 kV direction
3	01-Base-WY	03-CrossTie-0deg	WY - Aeolus 500 kV	Cross-Tie	100	0	Similar to no PST
4	01-Base-WY	04-SWIPN-0cost	WY - Aeolus 500 kV	SWIP-N	0	0	Robinson PST $0 cost allows the angle to move frequently in simulation
5	01-Base-WY	05-SWIPN-Neg48	WY - Aeolus 500 kV	SWIP-N	100	-48	High cost restrict the angle movement in simulation; Negative angle pushes flow to the Robinson 500 kV direction
6	01-Base-WY	06-SWIPN-0deg	WY - Aeolus 500 kV	SWIP-N	100	0	Similar to no PST
7	01-Base-WY	07-TWE-IPPPST-0cost	WY - TWE 230 kV	TWE	0	0	TWE-IPP PST
8	01-Base-WY	08-TWE-IPPPST-Neg45	WY - TWE 230 kV	TWE	100	-45	Negative angle pushes flow to the TWE-IPP 500 kV direction
9	01-Base-WY	09-TWE-IPPPST-0deg	WY - TWE 230 kV	TWE	100	0	Similar to no PST
10	02-Base-ID	01-CrossTie-0cost	ID - Midpoint 500 kV	Cross-Tie	0	0	Robinson PST $0 cost allows the angle to move frequently in simulation
11	02-Base-ID	02-CrossTie-Neg48	ID - Midpoint 500 kV	Cross-Tie	100	-48	High cost restrict the angle movement in simulation; Negative angle pushes flow to the Robinson 500 kV direction
12	02-Base-ID	03-CrossTie-0deg	ID - Midpoint 500 kV	Cross-Tie	100	0	Similar to no PST

Index	OOS wind Scenario	Alternative	OOS wind location	Transmission Upgrade	PST angle cost	PST initial angle	Note
13	02-Base-ID	04-SWIPN-0cost	ID - Midpoint 500 kV	SWIP-N	0	0	Robinson PST $0 cost allows the angle to move frequently in simulation
14	02-Base-ID	05-SWIPN-Neg48	ID - Midpoint 500 kV	SWIP-N	100	-48	High cost restrict the angle movement in simulation; Negative angle pushes flow to the Robinson 500 kV direction
15	02-Base-ID	06-SWIPN-0deg	ID - Midpoint 500 kV	SWIP-N	100	0	Similar to no PST
16	02-Base-ID	07-TWE-IPPPST-0cost	ID - Midpoint 500 kV	TWE	0	0	TWE-IPP PST
17	02-Base-ID	08-TWE-IPPPST-Neg45	ID - Midpoint 500 kV	TWE	100	-45	Negative angle pushes flow to the TWE-IPP 500 kV direction
18	02-Base-ID	09-TWE-IPPPST-0deg	ID - Midpoint 500 kV	TWE	100	0	Similar to no PST

In the Base portfolio out-of-state wind study, the development status of the Gateway West project, especially the segments between Bridger to Hemingway, was considered as a critical parameter. These segments provide additional transmission connections between the Wyoming and Idaho systems. Sensitivity studies assuming these segments of the Gateway West project not in service were conducted.

It was also noticed that the transmission upgrades assessed in the out-of-state wind study all have injection points to the ISO system through the Harry Ellen – Eldorado 500 kV line. The GLW Upgrade, which reinforces the GridLiance West/VEA system with additional 500 kV connection to the Harry Allen – Eldorado 500 kV line, was identified as an economically driven transmission upgrade in this planning cycle as described in section 4.9.2. The ISO conducted additional sensitivity study with the GLW Upgraded modeled in the planning PCM to examine potential impact of the GLW Upgrade on the out-of-state wind study results.

4.10.5 Base portfolio out-of-state wind study

Production benefits

The production benefits for ISO ratepayers were calculated for each scenario of the Base portfolio out-of-state wind study. The New Mexico wind scenario was used as the reference in the production benefit calculation. The results were shown in Table 4.10-3. As noted in section 4.10.2, in the scenarios with the SWIP North project modeled, the 1100 MW of transmission capacity between Midpoint and Harry Allen was modeled as ISO “owned” transmission capacity. Congestion revenue from this 1100 MW of transmission capacity was counted to the ISO’s production benefit. Also as noted in section 4.10.2, in the scenarios with the TransWest Express project modeled, it was assumed that the ISO would have 1,500 MW of transmission rights that need to be modeled as ISO-“owned” transmission capacity. Specifically, in the scenarios with the TransWest Express project modeled, half of the capacity of its HVDC component and all capacity of its AC component were modeled as ISO- “owned transmission capacity. Congestion revenue from these portions of the TransWest Express transmission capacity was counted as contributing to the ISO's production benefit.

In Table 4.10-3, and other result tables in section 4.10 as well, the rows for different out-of-state wind scenarios were shaded using different colors.

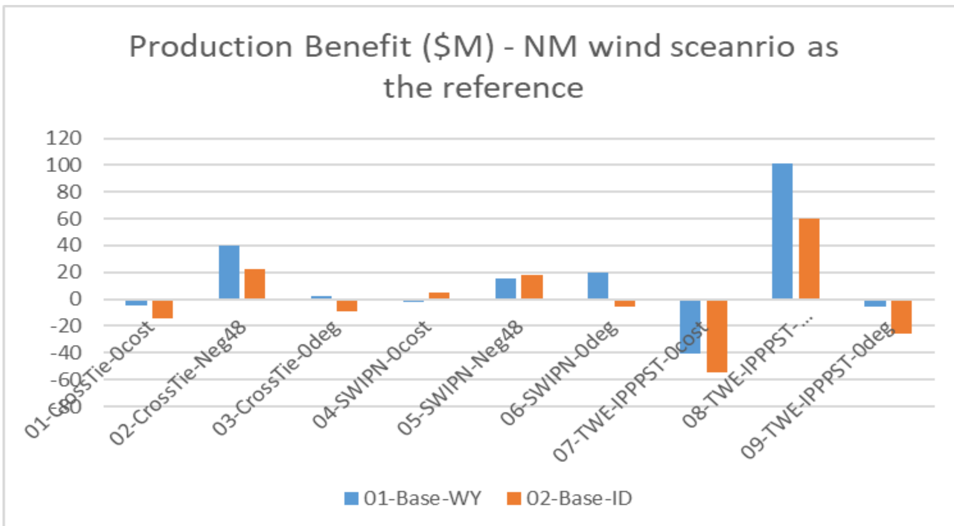
Table 4.10-3: Base Portfolio OOS Wind Study – Production Benefit

OOS wind Scenario	Alternative	Load Payment ($M)	Gen Profit ($M)	Trans Revenue ($M)	Net Payment ($M)	Production Benefit ($M)
00-Base-NM	00-Base-NM	9,265	4,206	484	4,575	
01-Base-WY	01-CrossTie-0cost	9,267	4,202	485	4,580	-4.9
01-Base-WY	02-CrossTie-Neg48	9,196	4,160	500	4,535	39.9
01-Base-WY	03-CrossTie-0deg	9,270	4,210	488	4,573	2.7
01-Base-WY	04-SWIPN-0cost	9,236	4,174	484	4,577	-2.0
01-Base-WY	05-SWIPN-Neg48	9,233	4,169	504	4,560	15.5
01-Base-WY	06-SWIPN-0deg	9,207	4,163	489	4,555	20.1
01-Base-WY	07-TWE-IPPPST-0cost	9,257	4,178	463	4,616	-40.3
01-Base-WY	08-TWE-IPPPST-Neg45	9,209	4,147	588	4,474	101.5
01-Base-WY	09-TWE-IPPPST-0deg	9,232	4,168	482	4,581	-5.9
02-Base-ID	01-CrossTie-0cost	9,293	4,223	480	4,589	-14.1
02-Base-ID	02-CrossTie-Neg48	9,283	4,230	501	4,553	22.6
02-Base-ID	03-CrossTie-0deg	9,300	4,230	486	4,584	-8.7
02-Base-ID	04-SWIPN-0cost	9,258	4,208	480	4,571	4.7
02-Base-ID	05-SWIPN-Neg48	9,252	4,191	504	4,557	18.4
02-Base-ID	06-SWIPN-0deg	9,298	4,233	483	4,581	-5.9
02-Base-ID	07-TWE-IPPPST-0cost	9,288	4,205	454	4,630	-54.4
02-Base-ID	08-TWE-IPPPST-Neg45	9,323	4,236	571	4,515	60.0
02-Base-ID	09-TWE-IPPPST-0deg	9,271	4,203	466	4,601	-26.0

It was observed in Table 4.10-3 that for each transmission upgrade its production benefit was impacted by both the out-of-state wind location and the setup of the proposed phase shifters at Robinson Summit or Intermountain substations. In the Base portfolio out-of-state wind study, for example, the largest ratepayers' benefit of the Cross-Tie project was observed in the scenario that had Wyoming wind modeled and had the Robinson Summit phase shifters angles at negative 48 degrees, while the other phase shifter angle setups gave the Cross-Tie much smaller or negative benefit. For the SWIP North project, in the meantime, the largest ratepayer benefit was observed in the scenario that had Wyoming wind modeled and had the phase shifter angles at 0 degrees. It should be noted that the scenarios assuming different phase shifter parameters were not for recommendation of the phase shifter parameters. As the phase shifter angles may move up and down in actual operation to respond different operation conditions, the robustness of the production benefit of the out-of-state wind transmission upgrades needs to be evaluated for a range of phase shifter angle setups, as demonstrated in the out-of-state wind study in this planning cycle.

Also, the scenarios with Wyoming wind generally had higher production benefits than the scenarios with Idaho wind. One of the reasons for this is that the Wyoming wind generally has a better capacity factor than the Idaho wind, as discussed in section 4.10.3. It can also be attributed to the overall generation dispatch, which was impacted by the location of out-of-state wind, and the transmission topology change due to modeling transmission upgrades. The production benefits of the studied scenarios were plotted in Figure 4.10-4 to illustrate the impact of Wyoming wind and Idaho wind on the production benefits.

Figure 4.10-4: Base Portfolio OOS Wind Study – Production Benefit



Benefit-to-cost ratio

Table 4.10-4 showed the present value of the production benefit, total cost, and the benefit-to-cost ratio of the transmission alternatives in the Base portfolio out-of-state wind study. The present value of the production benefit was calculated based on a 50-year project life and 7% real discount rate, consistent with the economic assessment assumption described in section 4.3.3. The capital cost of the transmission alternatives was the cost submitted by project proponents and was converted to 2020 real dollars. The capital cost was then converted to the present value of annualized revenue requirement, referred to as the “total cost”, by applying the ISO’s screening factor of 1.3. It should be noted that the costs of procuring out-of-state wind capacity and acquiring necessary transmission rights to deliver the out-of-state wind energy to the ISO load were not included in the cost estimate for the out-of-state wind transmission alternatives. Those costs need to be considered in the CPUC IRP portfolio calculation.

The last column in Table 4.10-4 showed the benefit-to-cost ratio of each transmission upgrade with different out-of-state wind scenarios and different phase shifter setups. Specifically, the Cross Tie project has benefit-to-cost ratio range between -0.08 and 0.62 for the Wyoming wind scenario, and between -0.22 and 0.35 for the Idaho wind scenario; the SWIP North project has benefit-to-cost ratio range between -0.04 and 0.36 and between -0.1 and 0.33 for the Wyoming wind and Idaho wind scenarios, respectively. The benefit-to-cost ratio was also calculated for the TransWest Express project although its proponent indicated to adopt a subscriber model for the project. The range of benefit-to-cost ratio of the TransWest Express project is between -0.23 and 0.04. Based on the benefit-to-cost ratio results in the Base portfolio out-of-state wind study, none of the transmission alternatives had sufficient economic justification.

The ISO also calculated an alternative benefit-to-cost ratio for each project and alternative configuration assuming an added benefit of avoiding half of the cost of the SunZia project, as a proxy for the cost of delivering New Mexico wind generation to Pinal Central. This represents a 1,500 MW share of the 3,000 MW, $2.6 billion SunZia project[149], or $1.3 billion capital cost. This provides a high end of the range of potential benefit-to-cost ratios, highlighting the challenges of comparing rate-base projects to subscriber-based projects. In the benefit-to-cost ratio calculation, the present value of the annualized revenue requirement for the 1,500 MW share of the SunZia project was considered as the avoided cost. Applying the ISO's screening factor of 1.3, the $1.3 billion capital cost translates to $1.69 billion avoided cost.

Table 4.10-4: Base Portfolio OOS Wind Study – Benefit-to-cost ratio

OOS Wind Scenario	Alternative	Production Benefit ($M)	PV of Production Benefit ($M)	Capital Cost ($M)	Total cost ($M)	BCR not considering avoided cost of SunZia	Avoided cost for 50% of SunZia ($M)	BCR considering avoided cost of SunZia
01-Base-WY	01-CrossTie-0cost	-4.9	-71.9	727	945	-0.08	1,690	1.71
01-Base-WY	02-CrossTie-Neg48	39.9	588.8	727	945	0.62	1,690	2.41
01-Base-WY	03-CrossTie-0deg	2.7	39.3	727	945	0.04	1,690	1.83
01-Base-WY	04-SWIPN-0cost	-2.0	-29.7	635	826	-0.04	1,690	2.01
01-Base-WY	05-SWIPN-Neg48	15.5	228.5	635	826	0.28	1,690	2.32
01-Base-WY	06-SWIPN-0deg	20.1	296.4	635	826	0.36	1,690	2.41
01-Base-WY	07-TWE-IPPPST-0cost	-40.3	-594.4	1,710	2,223	-0.27	1,690	0.49
01-Base-WY	08-TWE-IPPPST-Neg45	101.5	1498.7	1,710	2,223	0.67	1,690	1.43
01-Base-WY	09-TWE-IPPPST-0deg	-5.9	-87.0	1,710	2,223	-0.04	1,690	0.72
02-Base-ID	01-CrossTie-0cost	-14.1	-208.3	727	945	-0.22	1,690	1.57
02-Base-ID	02-CrossTie-Neg48	22.6	333.3	727	945	0.35	1,690	2.14
02-Base-ID	03-CrossTie-0deg	-8.7	-129.0	727	945	-0.14	1,690	1.65
02-Base-ID	04-SWIPN-0cost	4.7	68.8	635	826	0.08	1,690	2.13
02-Base-ID	05-SWIPN-Neg48	18.4	271.6	635	826	0.33	1,690	2.38
02-Base-ID	06-SWIPN-0deg	-5.9	-86.6	635	826	-0.10	1,690	1.94
02-Base-ID	07-TWE-IPPPST-0cost	-54.4	-803.5	1,710	2,223	-0.36	1,690	0.40
02-Base-ID	08-TWE-IPPPST-Neg45	60.0	886.0	1,710	2,223	0.40	1,690	1.16
02-Base-ID	09-TWE-IPPPST-0deg	-26.0	-383.2	1,710	2,223	-0.17	1,690	0.59

Curtailment and congestion

Table 4.10-5 showed the wind and solar generation and curtailment of the ISO system including ISO's remote generators. The curtailment ratio was calculated as the curtailment divided by the

[149] http://sunzia.net/wp-content/uploads/2021/12/SunZia-Economic-Analysis-Executive-Summary-FINAL.pdf

generation plus curtailment. It was observed that all studied transmission alternatives have similar curtailment ratios. The Idaho wind cases in general had less renewable curtailment than the Wyoming wind cases, which was mainly because the Idaho wind has smaller capacity factor than the Wyoming wind as discussed in section 4.10.3.

Table 4.10-5: Base Portfolio OOS Wind Study – Wind and Solar Curtailment

OOS Wind Scenario	Alternative	Wind and Solar Generation (GWh)	Curtailment (GWh)	Ratio
00-Base-NM	00-Base-NM	106,401	10,956	9.34%
01-Base-WY	01-CrossTie-0cost	106,445	10,961	9.34%
01-Base-WY	02-CrossTie-Neg48	106,364	11,042	9.41%
01-Base-WY	03-CrossTie-0deg	106,418	10,988	9.36%
01-Base-WY	04-SWIPN-0cost	106,444	10,962	9.34%
01-Base-WY	05-SWIPN-Neg48	106,419	10,987	9.36%
01-Base-WY	06-SWIPN-0deg	106,415	10,991	9.36%
01-Base-WY	07-TWE-IPPPST-0cost	106,471	10,935	9.31%
01-Base-WY	08-TWE-IPPPST-Neg45	106,453	10,953	9.33%
01-Base-WY	09-TWE-IPPPST-0deg	106,441	10,965	9.34%
02-Base-ID	01-CrossTie-0cost	105,879	10,766	9.23%
02-Base-ID	02-CrossTie-Neg48	105,804	10,841	9.29%
02-Base-ID	03-CrossTie-0deg	105,852	10,794	9.25%
02-Base-ID	04-SWIPN-0cost	105,856	10,789	9.25%
02-Base-ID	05-SWIPN-Neg48	105,773	10,873	9.32%
02-Base-ID	06-SWIPN-0deg	105,835	10,811	9.27%
02-Base-ID	07-TWE-IPPPST-0cost	105,914	10,731	9.20%
02-Base-ID	08-TWE-IPPPST-Neg45	105,927	10,719	9.19%
02-Base-ID	09-TWE-IPPPST-0deg	105,908	10,738	9.21%

Table 4.10-6 showed the COI and Path 26 corridor congestions. Wyoming or Idaho wind and the out-of-state transmission upgrades have the largest impact on the congestions of these two paths among all major transmission lines or corridors within the ISO system. Compared with the reference case, which is the New Mexico wind case, COI and Path 26 congestion may increase or decrease as the Wyoming or Idaho wind and out-of-state transmission upgrades were modeled. The setup of the phase shifters at Robinson Summit or Intermountain substations was a critical parameter for the congestion pattern change. It was also observed in many studied scenarios that the congestion on COI and Path 26 changed in opposite directions, i.e. as the COI congestion decreased the Path 26 congestion likely increased, and vice versa. In all studied scenarios, the COI congestion were observed when its flow was from north to south, and the Path 26 congestion were mainly observed when its flow was from south to north.

Table 4.10-6: Base Portfolio OOS Wind Study – COI and Path 26 Congestion

OOS Wind Scenario	Alternative	Congestion Cost COI ($M)	Congestion Cost Path26 Corridor ($M)
Base-NM	Base-NM	12.12	113.50
01-Base-WY	01-CrossTie-0cost	16.30	114.46
01-Base-WY	02-CrossTie-Neg48	9.04	132.72
01-Base-WY	03-CrossTie-0deg	13.02	119.62
01-Base-WY	04-SWIPN-0cost	15.14	119.11
01-Base-WY	05-SWIPN-Neg48	10.52	132.89
01-Base-WY	06-SWIPN-0deg	11.96	123.52
01-Base-WY	07-TWE-IPPPST-0cost	15.36	95.38
01-Base-WY	08-TWE-IPPPST-Neg45	6.93	131.82
01-Base-WY	09-TWE-IPPPST-0deg	13.67	104.28
02-Base-ID	01-CrossTie-0cost	14.89	112.76
02-Base-ID	02-CrossTie-Neg48	9.16	135.48
02-Base-ID	03-CrossTie-0deg	12.96	118.27
02-Base-ID	04-SWIPN-0cost	17.72	115.67
02-Base-ID	05-SWIPN-Neg48	10.37	132.55
02-Base-ID	06-SWIPN-0deg	14.12	119.63
02-Base-ID	07-TWE-IPPPST-0cost	14.40	92.48
02-Base-ID	08-TWE-IPPPST-Neg45	7.66	124.04
02-Base-ID	09-TWE-IPPPST-0deg	14.08	99.84

4.10.6 Sensitivity 1 portfolio out-of-state wind study

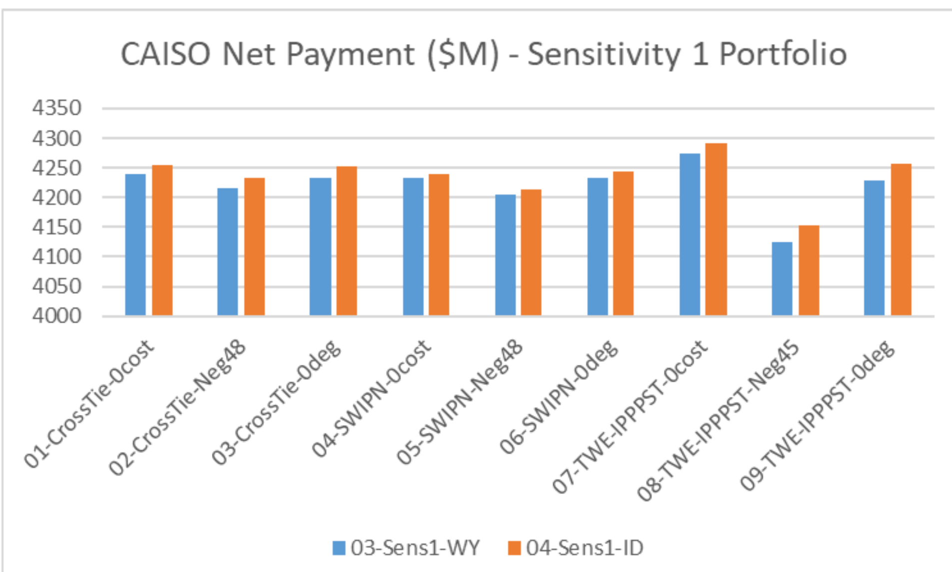
ISO net payment

The same transmission alternatives and phase shifter setups as assessed in the Base portfolio out-of-state wind study were studied on the Sensitivity 1 portfolio PCM. As described in section 4.10.4, all studied scenarios were directly compared based on the ISO net payment, as shown in Table 4.10-7. Similarly to the Base portfolio out-of-state wind study, the out-of-state wind location and the phase shifter setup impacted the ISO net payment. It was also observed that the ISO net payments in the Wyoming wind scenarios were generally less than the net payment in the Idaho wind scenarios for the same transmission upgrade and phase shifter setup, which were illustrated in Figure 4.10-5. Different phase shifter setups impacted the ISO net payment as well. Specifically, in the Sensitivity 1 portfolio out-of-state wind study, the scenarios with the Robinson Summit phase shifters at negative 48 degree or the Intermountain phase shifters at negative 45 degree had relatively lower ISO net payment than other scenarios with the same out-of-state wind and transmission upgrade modeled.

Table 4.10-7: Sensitivity 1 Portfolio OOS Wind Study – ISO Net Payment

OOS Wind Scenario	Alternative	Load Payment ($M)	Gen Profit ($M)	Trans Revenue ($M)	Net Payment ($M)
03-Sens1-WY	01-CrossTie-0cost	9,100	4,434	427	4,239
03-Sens1-WY	02-CrossTie-Neg48	9,107	4,445	447	4,215
03-Sens1-WY	03-CrossTie-0deg	9,103	4,440	431	4,233
03-Sens1-WY	04-SWIPN-0cost	9,089	4,419	436	4,234
03-Sens1-WY	05-SWIPN-Neg48	9,059	4,401	452	4,205
03-Sens1-WY	06-SWIPN-0deg	9,124	4,445	447	4,233
03-Sens1-WY	07-TWE-IPPPST-0cost	9,178	4,486	419	4,274
03-Sens1-WY	08-TWE-IPPPST-Neg45	9,060	4,397	540	4,124
03-Sens1-WY	09-TWE-IPPPST-0deg	9,144	4,474	441	4,229
04-Sens1-ID	01-CrossTie-0cost	9,196	4,513	429	4,253
04-Sens1-ID	02-CrossTie-Neg48	9,204	4,527	445	4,232
04-Sens1-ID	03-CrossTie-0deg	9,209	4,523	435	4,251
04-Sens1-ID	04-SWIPN-0cost	9,174	4,498	436	4,240
04-Sens1-ID	05-SWIPN-Neg48	9,162	4,489	458	4,214
04-Sens1-ID	06-SWIPN-0deg	9,194	4,508	443	4,243
04-Sens1-ID	07-TWE-IPPPST-0cost	9,184	4,485	407	4,292
04-Sens1-ID	08-TWE-IPPPST-Neg45	9,169	4,488	528	4,152
04-Sens1-ID	09-TWE-IPPPST-0deg	9,161	4,483	422	4,256

Figure 4.10-5: ISO Net Payment - Sensitivity 1 Portfolio



Curtailment and congestion

Table 4.10-8 showed the wind and solar generation and curtailment of the ISO system, including the out-of-state wind generators, in the Sensitivity 1 portfolio out-of-state wind study. The total renewable curtailment in the Sensitivity 1 portfolio PCM cases was less than the curtailment in the Base portfolio PCM cases, mainly because the Sensitivity 1 portfolio used additional out-of-state wind to replace internal solar and wind resources that may be curtailed due to local congestions in the Base portfolio PCM. The impacts of the out-of-state wind transmission upgrades on the overall renewable curtailment in the ISO system are similar to the Base portfolio out-of-state study results. The Idaho wind scenarios still had less curtailment than the Wyoming wind scenarios, mainly because of the Idaho wind has smaller capacity factor than the Wyoming wind in the out-of-state wind study PCM model in this planning cycle.

Table 4.10-8: Sensitivity 1 Portfolio OOS Wind Study – Wind and Solar Curtailment

OOS Wind Scenario	Alternative	Wind and Solar Generation (GWh)	Curtailment (GWh)	Ratio
03-Sens1-WY	01-CrossTie-0cost	118,982	10,706	8.25%
03-Sens1-WY	02-CrossTie-Neg48	118,847	10,841	8.36%
03-Sens1-WY	03-CrossTie-0deg	118,923	10,765	8.30%
03-Sens1-WY	04-SWIPN-0cost	118,954	10,733	8.28%
03-Sens1-WY	05-SWIPN-Neg48	118,911	10,777	8.31%
03-Sens1-WY	06-SWIPN-0deg	118,908	10,780	8.31%
03-Sens1-WY	07-TWE-IPPPST-0cost	118,987	10,701	8.25%
03-Sens1-WY	08-TWE-IPPPST-Neg45	118,997	10,691	8.24%
03-Sens1-WY	09-TWE-IPPPST-0deg	118,993	10,695	8.25%
04-Sens1-ID	01-CrossTie-0cost	118,166	10,448	8.12%
04-Sens1-ID	02-CrossTie-Neg48	118,121	10,494	8.16%
04-Sens1-ID	03-CrossTie-0deg	118,076	10,538	8.19%
04-Sens1-ID	04-SWIPN-0cost	118,172	10,443	8.12%
04-Sens1-ID	05-SWIPN-Neg48	118,158	10,456	8.13%
04-Sens1-ID	06-SWIPN-0deg	118,117	10,497	8.16%
04-Sens1-ID	07-TWE-IPPPST-0cost	118,255	10,359	8.05%
04-Sens1-ID	08-TWE-IPPPST-Neg45	118,333	10,282	7.99%
04-Sens1-ID	09-TWE-IPPPST-0deg	118,218	10,397	8.08%

The impacts of out-of-state wind and the transmission upgrades on COI and Path 26 congestion in the Sensitivity 1 portfolio out-of-state wind study were similar to the Base portfolio out-of-state wind study. As the COI congestion is relatively large in some of the studied scenarios, the Path 26 congestion tends to be relatively small. The COI congestion were observed when the flow was from north to south, and the Path 26 congestion were mainly observed when its flow was from south to north.

Table 4.10-9: Sensitivity 1 Portfolio OOS Wind Study – COI and Path 26 Congestion

OOS Wind Scenario	Alternative	Congestion Cost COI ($M)	Congestion Cost Path26 Corridor ($M)
03-Sens1-WY	01-CrossTie-0cost	16.86	86.27
03-Sens1-WY	02-CrossTie-Neg48	11.91	104.44
03-Sens1-WY	03-CrossTie-0deg	14.21	91.24
03-Sens1-WY	04-SWIPN-0cost	14.14	97.27
03-Sens1-WY	05-SWIPN-Neg48	10.37	108.42
03-Sens1-WY	06-SWIPN-0deg	14.45	103.26
03-Sens1-WY	07-TWE-IPPPST-0cost	14.52	75.88
03-Sens1-WY	08-TWE-IPPPST-Neg45	5.93	108.16
03-Sens1-WY	09-TWE-IPPPST-0deg	14.37	84.51
04-Sens1-ID	01-CrossTie-0cost	12.96	89.07
04-Sens1-ID	02-CrossTie-Neg48	12.65	106.62
04-Sens1-ID	03-CrossTie-0deg	13.33	94.74
04-Sens1-ID	04-SWIPN-0cost	15.37	95.87
04-Sens1-ID	05-SWIPN-Neg48	11.03	109.32
04-Sens1-ID	06-SWIPN-0deg	14.48	100.45
04-Sens1-ID	07-TWE-IPPPST-0cost	14.57	73.61
04-Sens1-ID	08-TWE-IPPPST-Neg45	7.78	104.59
04-Sens1-ID	09-TWE-IPPPST-0deg	13.99	80.70

4.10.7 Sensitivity study with Gateway West not in service

The development status of the Gateway West project, especially the segments between Bridger to Hemingway, was considered as critical parameter for the out-of-state wind study in this planning cycle. These segments provide additional transmission connection between the Wyoming and Idaho systems. Given the uncertainty of the Gateway West project development, sensitivity studies were conducted assuming these segments of the Gateway West project would not be in service as scheduled.

Table 4.10-10 showed the Base portfolio out-of-state wind study results with the Gateway West project turned off in the PCM. It was observed that all studied scenarios with Wyoming wind had negative production benefit, except for a scenario with TransWest Express modeled and with the IPP phase shifter angle set at negative 45 degree. There were several scenarios with Idaho wind had positive production benefit but were less than the production benefit in the baseline study as shown in section 4.10.5. The production benefit results in this sensitivity study were also illustrated in Figure 4.10-6.

Table 4.10-10: OOS Wind Sensitivity Study without Gateway West – Production Benefit in Base Portfolio Study

OOS Wind Scenario	Alternative	Load Payment ($M)	Gen Profit ($M)	Trans Revenue ($M)	Net Payment ($M)	Production Benefit ($M)
00-Base-NM	00-Base-NM	9,227	4,183	495	4,549	
01-Base-WY	01-CrossTie-0cost	9,212	4,119	502	4,591	-42.1
01-Base-WY	02-CrossTie-Neg48	9,220	4,132	513	4,575	-25.9
01-Base-WY	03-CrossTie-0deg	9,229	4,127	505	4,597	-48.6
01-Base-WY	04-SWIPN-0cost	9,198	4,112	497	4,589	-40.5
01-Base-WY	05-SWIPN-Neg48	9,157	4,092	503	4,561	-12.5
01-Base-WY	06-SWIPN-0deg	9,195	4,118	500	4,578	-29.0
01-Base-WY	07-TWE-IPPPST-0cost	9,284	4,218	471	4,595	-45.8
01-Base-WY	08-TWE-IPPPST-Neg45	9,228	4,161	572	4,495	53.9
01-Base-WY	09-TWE-IPPPST-0deg	9,282	4,221	502	4,559	-9.8
02-Base-ID	01-CrossTie-0cost	9,283	4,228	489	4,566	-16.8
02-Base-ID	02-CrossTie-Neg48	9,295	4,244	508	4,543	6.1
02-Base-ID	03-CrossTie-0deg	9,267	4,221	488	4,557	-8.2
02-Base-ID	04-SWIPN-0cost	9,220	4,182	498	4,540	8.9
02-Base-ID	05-SWIPN-Neg48	9,261	4,217	510	4,535	14.3
02-Base-ID	06-SWIPN-0deg	9,248	4,196	505	4,546	2.7
02-Base-ID	07-TWE-IPPPST-0cost	9,285	4,223	464	4,598	-48.8
02-Base-ID	08-TWE-IPPPST-Neg45	9,385	4,278	593	4,515	34.3
02-Base-ID	09-TWE-IPPPST-0deg	9,279	4,228	486	4,565	-16.2

Figure 4.10-6: Base Portfolio OOS Wind Study – Production Benefit, Gateway West was not modeled

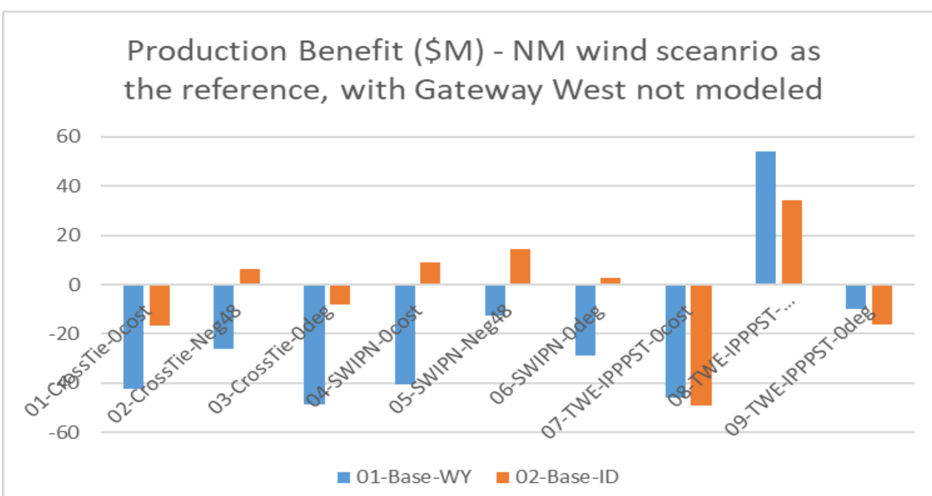


Table 4.10-11 showed the benefit-to-cost ratios in the sensitivity study without Gateway West in the model. Compared with the baseline study results, the benefit-to-cost ratios reduced in most of the studied scenarios, except for two scenarios with Idaho wind and SWIP North project modeled and with the Robinson phase shifter angle set at 0 degree or $0 cost.

Table 4.10-11: OOS Wind Sensitivity Study without Gateway West – Benefit-to-cost ratio

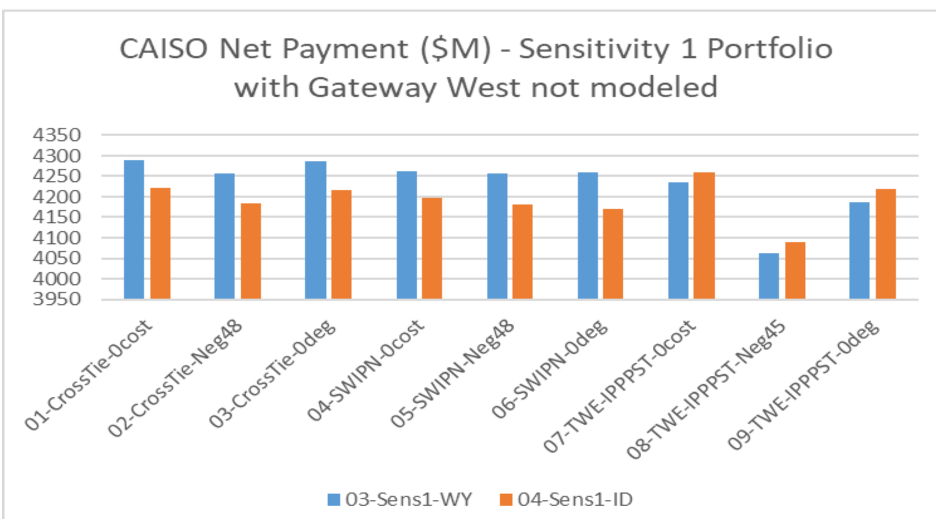
OOS Wind Scenario	Alternative	Production Benefit ($M)	PV of Production Benefit ($M)	Capital Cost ($M)	Total cost ($M)	BCR not considering avoided cost of SunZia	Avoided cost for 50% of SunZia ($M)	BCR considering avoided cost of SunZia
01-Base-WY	01-CrossTie-0cost	-42.1	-622.2	727	945	-0.66	1,690	1.13
01-Base-WY	02-CrossTie-Neg48	-25.9	-382.6	727	945	-0.40	1,690	1.38
01-Base-WY	03-CrossTie-0deg	-48.6	-717.0	727	945	-0.76	1,690	1.03
01-Base-WY	04-SWIPN-0cost	-40.5	-597.4	635	826	-0.72	1,690	1.32
01-Base-WY	05-SWIPN-Neg48	-12.5	-184.0	635	826	-0.22	1,690	1.82
01-Base-WY	06-SWIPN-0deg	-29.0	-428.0	635	826	-0.52	1,690	1.53
01-Base-WY	07-TWE-IPPPST-0cost	-45.8	-676.2	1,710	2,223	-0.30	1,690	0.46
01-Base-WY	08-TWE-IPPPST-Neg45	53.9	796.4	1,710	2,223	0.36	1,690	1.12
01-Base-WY	09-TWE-IPPPST-0deg	-9.8	-144.2	1,710	2,223	-0.06	1,690	0.70
02-Base-ID	01-CrossTie-0cost	-16.8	-247.9	727	945	-0.26	1,690	1.53
02-Base-ID	02-CrossTie-Neg48	6.1	90.7	727	945	0.10	1,690	1.88
02-Base-ID	03-CrossTie-0deg	-8.2	-120.6	727	945	-0.13	1,690	1.66
02-Base-ID	04-SWIPN-0cost	8.9	131.0	635	826	0.16	1,690	2.21
02-Base-ID	05-SWIPN-Neg48	14.3	210.9	635	826	0.26	1,690	2.30
02-Base-ID	06-SWIPN-0deg	2.7	39.4	635	826	0.05	1,690	2.09
02-Base-ID	07-TWE-IPPPST-0cost	-48.8	-721.2	1,710	2,223	-0.32	1,690	0.44
02-Base-ID	08-TWE-IPPPST-Neg45	34.3	506.1	1,710	2,223	0.23	1,690	0.99
02-Base-ID	09-TWE-IPPPST-0deg	-16.2	-239.8	1,710	2,223	-0.11	1,690	0.65

Table 4.10-12 showed the Sensitivity 1 portfolio out-of-state wind study results with the Gateway West project turned off in the PCM. It was observed that all studied scenarios with Wyoming wind had higher net payment than the scenarios with Idaho wind for the Cross Tie and SWIP North projects. The net payments results for the TransWest Express project with Wyoming wind still lower than the Idaho wind scenarios. The difference of the ISO net payment between different studied scenarios was also illustrated in Figure 4.10-7.

Table 4.10-12: OOS Wind Sensitivity Study without Gateway West – ISO Net Payment in Sensitivity 1 Portfolio Study

OOS Wind Scenario	Alternative	Load Payment ($M)	Gen Profit ($M)	Trans Revenue ($M)	Net Payment ($M)
03-Sens1-WY	01-CrossTie-0cost	9,157	4,411	458	4,288
03-Sens1-WY	02-CrossTie-Neg48	9,092	4,366	469	4,256
03-Sens1-WY	03-CrossTie-0deg	9,169	4,421	462	4,287
03-Sens1-WY	04-SWIPN-0cost	9,052	4,341	450	4,261
03-Sens1-WY	05-SWIPN-Neg48	9,104	4,377	470	4,257
03-Sens1-WY	06-SWIPN-0deg	9,069	4,360	450	4,259
03-Sens1-WY	07-TWE-IPPPST-0cost	9,123	4,459	429	4,234
03-Sens1-WY	08-TWE-IPPPST-Neg45	8,999	4,368	569	4,063
03-Sens1-WY	09-TWE-IPPPST-0deg	9,120	4,465	467	4,188
04-Sens1-ID	01-CrossTie-0cost	9,178	4,521	436	4,221
04-Sens1-ID	02-CrossTie-Neg48	9,135	4,503	449	4,183
04-Sens1-ID	03-CrossTie-0deg	9,183	4,527	439	4,217
04-Sens1-ID	04-SWIPN-0cost	9,098	4,460	442	4,196
04-Sens1-ID	05-SWIPN-Neg48	9,104	4,463	458	4,182
04-Sens1-ID	06-SWIPN-0deg	9,062	4,446	446	4,170
04-Sens1-ID	07-TWE-IPPPST-0cost	9,147	4,479	408	4,260
04-Sens1-ID	08-TWE-IPPPST-Neg45	9,079	4,447	542	4,090
04-Sens1-ID	09-TWE-IPPPST-0deg	9,137	4,487	430	4,220

Figure 4.10-7: ISO Net Payment – Sensitivity 1 Portfolio with Gateway West not modeled



4.10.8 Sensitivity study with GLW Upgrade project modeled

The transmission upgrades assessed in the out-of-state wind study all were proposed to connect to the ISO system through the Harry Ellen – Eldorado 500 kV line. In the meantime, it was noticed that the GLW Upgrade project, which was an economically driven upgrade recommended in this planning cycle, included a new 500 kV substation with the Harry Allen – Eldorado 500 kV line loop-in. Essentially the Wyoming or Idaho wind and the GridLiance West/VEA renewable resources share the same transmission capacity of the Harry Allen – Eldorado 500 kV line and the lines beyond the Eldorado substation, specifically the Eldorado – Lugo and Mohave – Lugo 500 kV lines, to connect to the ISO load. It is worth noting though that the out-of-state wind and the GridLiance West/VEA renewable resources, which are all solar generators in the CPUC IRP portfolio for the 2021-2022 planning cycle, may not generate in the same hours of the day. This means that the out-of-state wind and the GridLiance West/VEA resources are not necessarily always compete for the transmission capacity. In fact, the out-of-state wind transmission upgrade may provide additional transmission capacity to accommodate ISO's renewable energy surplus either by delivering the energy to the load outside the ISO or circling the energy back to the ISO through other paths that have available transmission capacity. To examine the impact of the GLW Upgrade on the out-of-state wind study results, the ISO conducted sensitivity study for both Base portfolio and Sensitivity 1 portfolio with the GLW Upgrade modeled in the planning PCM.

Table 4.10-13 showed production benefit of the Base portfolio out-of-state wind study with GLW Upgrade modeled. Compared with the baseline study results shown in section 4.10.5, it was observed that the production benefits of the out-of-state wind transmission upgrades increased in most of the studied scenarios in the sensitivity study with GLW Upgrade modeled. The production benefit results in this sensitivity study were also illustrated in Figure 4.10-8.

Table 4.10-13: OOS Wind Sensitivity Study with GLW Upgrade Modeled – Production Benefit in Base Portfolio Study

OOS Wind Scenario	Alternative	Load Payment ($M)	Gen Profit ($M)	Trans Revenue ($M)	Net Payment ($M)	Production Benefit ($M)
00-Base-NM	00-Base-NM	9,184	4,186	467	4,530	
01-Base-WY	01-CrossTie-0cost	9,199	4,195	464	4,539	-9.1
01-Base-WY	02-CrossTie-Neg48	9,108	4,142	479	4,487	43.0
01-Base-WY	03-CrossTie-0deg	9,190	4,192	467	4,531	-1.0
01-Base-WY	04-SWIPN-0cost	9,129	4,152	464	4,512	17.8
01-Base-WY	05-SWIPN-Neg48	9,126	4,144	485	4,498	32.7
01-Base-WY	06-SWIPN-0deg	9,111	4,143	466	4,502	28.7
01-Base-WY	07-TWE-IPPPST-0cost	9,187	4,169	444	4,574	-44.2
01-Base-WY	08-TWE-IPPPST-Neg45	9,153	4,153	565	4,434	96.0
01-Base-WY	09-TWE-IPPPST-0deg	9,180	4,173	469	4,538	-8.1
02-Base-ID	01-CrossTie-0cost	9,184	4,196	465	4,523	7.2
02-Base-ID	02-CrossTie-Neg48	9,177	4,196	481	4,500	30.0
02-Base-ID	03-CrossTie-0deg	9,192	4,199	469	4,524	6.7
02-Base-ID	04-SWIPN-0cost	9,152	4,182	458	4,512	18.8
02-Base-ID	05-SWIPN-Neg48	9,160	4,175	479	4,506	24.7
02-Base-ID	06-SWIPN-0deg	9,142	4,170	462	4,510	20.2
02-Base-ID	07-TWE-IPPPST-0cost	9,184	4,176	437	4,571	-41.0
02-Base-ID	08-TWE-IPPPST-Neg45	9,192	4,188	578	4,427	103.3
02-Base-ID	09-TWE-IPPPST-0deg	9,169	4,175	457	4,537	-6.5

Figure 4.10-8: Base Portfolio OOS Wind Study – Production Benefit, with GLW Upgrade modeled

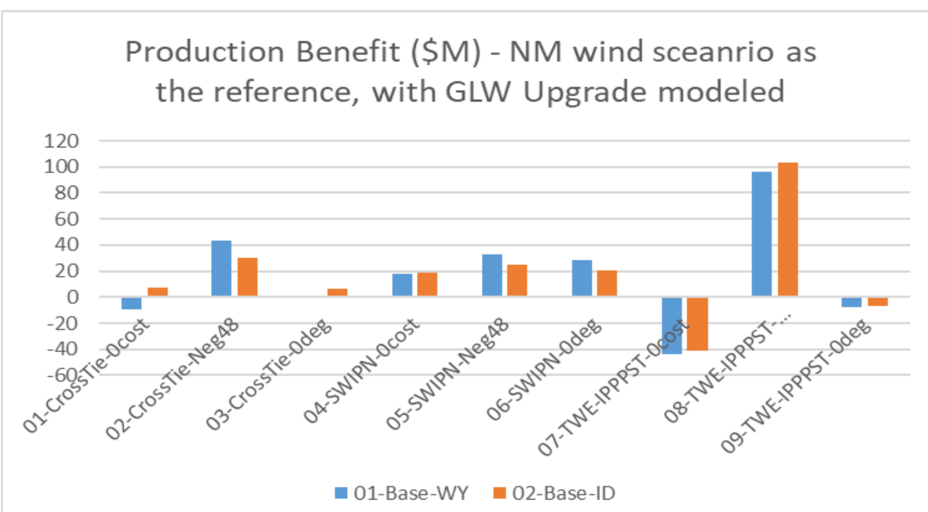


Table 4.10-14 showed benefit-to-cost ratio results of the Base portfolio out-of-state wind study with GLW Upgrade modeled. Compared with the baseline study results shown in section 4.10.5, it was observed that the benefit-to-cost ratios of the out-of-state wind transmission upgrades increased in most of the studied scenarios in the sensitivity study with GLW Upgrade modeled. For example, the highest benefit-to-cost ratios without considering the SunZia avoided cost are 0.67 and 0.59 for the Cross Tie and SWIP North projects, respectively, with certain Robinson Summit phase shifter setup in the planning PCM. As a comparison, the highest benefit-to-cost ratio in the baseline study in section 4.10.5 are 0.62 and 0.36 for the Cross Tie and SWIP North projects, respectively.

Table 4.10-14: OOS Wind Sensitivity Study with GLW Upgrade Modeled – Benefit-to-cost ratio in Base Portfolio Study

OOS Wind Scenario	Alternative	Production Benefit ($M)	PV of Production Benefit ($M)	Capital Cost ($M)	Total cost ($M)	BCR not considering avoided cost of SunZia	Avoided cost for 50% of SunZia ($M)	BCR considering avoided cost of SunZia
01-Base-WY	01-CrossTie-0cost	-9.1	-134.9	727	945	-0.14	1,690	1.65
01-Base-WY	02-CrossTie-Neg48	43.0	634.7	727	945	0.67	1,690	2.46
01-Base-WY	03-CrossTie-0deg	-1.0	-14.8	727	945	-0.02	1,690	1.77
01-Base-WY	04-SWIPN-0cost	17.8	262.6	635	826	0.32	1,690	2.37
01-Base-WY	05-SWIPN-Neg48	32.7	483.4	635	826	0.59	1,690	2.63
01-Base-WY	06-SWIPN-0deg	28.7	423.2	635	826	0.51	1,690	2.56
01-Base-WY	07-TWE-IPPPST-0cost	-44.2	-652.0	1,710	2,223	-0.29	1,690	0.47
01-Base-WY	08-TWE-IPPPST-Neg45	96.0	1417.7	1,710	2,223	0.64	1,690	1.40
01-Base-WY	09-TWE-IPPPST-0deg	-8.1	-119.5	1,710	2,223	-0.05	1,690	0.71
02-Base-ID	01-CrossTie-0cost	7.2	106.7	727	945	0.11	1,690	1.90
02-Base-ID	02-CrossTie-Neg48	30.0	442.9	727	945	0.47	1,690	2.26
02-Base-ID	03-CrossTie-0deg	6.7	98.8	727	945	0.10	1,690	1.89
02-Base-ID	04-SWIPN-0cost	18.8	277.1	635	826	0.34	1,690	2.38
02-Base-ID	05-SWIPN-Neg48	24.7	364.6	635	826	0.44	1,690	2.49
02-Base-ID	06-SWIPN-0deg	20.2	298.7	635	826	0.36	1,690	2.41
02-Base-ID	07-TWE-IPPPST-0cost	-41.0	-605.5	1,710	2,223	-0.27	1,690	0.49
02-Base-ID	08-TWE-IPPPST-Neg45	103.3	1,525.4	1,710	2,223	0.69	1,690	1.45
02-Base-ID	09-TWE-IPPPST-0deg	-6.5	-95.4	1,710	2,223	-0.04	1,690	0.72

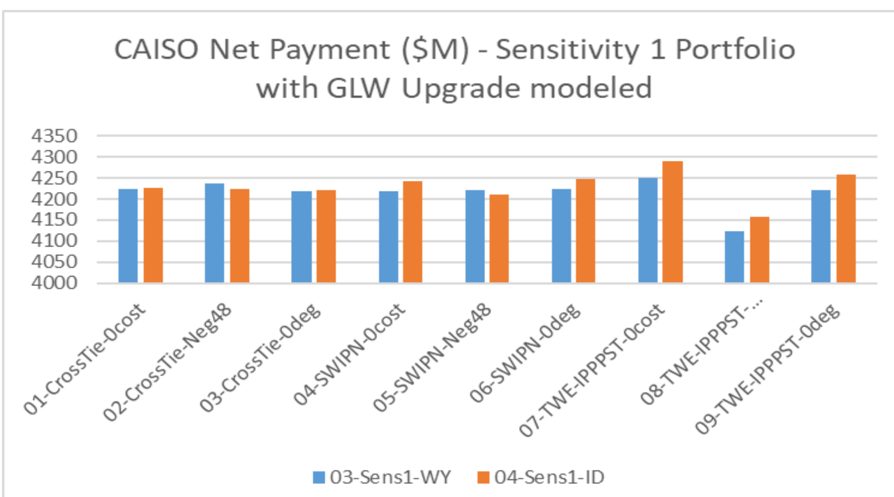
Table 4.10-15 showed the ISO net payment of the Sensitivity 1 portfolio out-of-state wind study with the GLW Upgrade modeled. The impact of the phase shifters setup on the ISO net load payment was similar to the results in the baseline Sensitivity 1 portfolio out-of-state study. However, it was observed that the Wyoming wind scenario was not always better than the Idaho wind scenario in terms of the ISO net payment in this sensitivity study, which is different from the Sensitivity 1 portfolio out-of-state wind baseline study results described in section 4.10.6. This was mainly because the system dispatch changed with the GLW Upgrade project modeled. Figure 4.10-9 illustrated the differences of ISO net payments between the Wyoming wind and

Idaho wind scenarios in the Sensitivity 1 portfolio out-of-state wind study with the GLW Upgrade modeled.

Table 4.10-15: OOS Wind Sensitivity Study with GLW Upgrade Modeled – ISO Net Payment in Sensitivity 1 Portfolio Study

OOS Wind Scenario	Alternative	Load Payment ($M)	Gen Profit ($M)	Trans Revenue ($M)	Net Payment ($M)
03-Sens1-WY	01-CrossTie-0cost	9,082	4,423	435	4,225
03-Sens1-WY	02-CrossTie-Neg48	9,169	4,487	446	4,236
03-Sens1-WY	03-CrossTie-0deg	9,091	4,433	438	4,220
03-Sens1-WY	04-SWIPN-0cost	9,080	4,420	442	4,218
03-Sens1-WY	05-SWIPN-Neg48	9,126	4,448	458	4,221
03-Sens1-WY	06-SWIPN-0deg	9,090	4,426	441	4,224
03-Sens1-WY	07-TWE-IPPPST-0cost	9,136	4,458	427	4,251
03-Sens1-WY	08-TWE-IPPPST-Neg45	9,092	4,427	540	4,124
03-Sens1-WY	09-TWE-IPPPST-0deg	9,117	4,454	442	4,221
04-Sens1-ID	01-CrossTie-0cost	9,166	4,508	430	4,227
04-Sens1-ID	02-CrossTie-Neg48	9,190	4,518	448	4,224
04-Sens1-ID	03-CrossTie-0deg	9,170	4,511	438	4,222
04-Sens1-ID	04-SWIPN-0cost	9,191	4,509	439	4,242
04-Sens1-ID	05-SWIPN-Neg48	9,158	4,498	449	4,211
04-Sens1-ID	06-SWIPN-0deg	9,216	4,527	442	4,247
04-Sens1-ID	07-TWE-IPPPST-0cost	9,203	4,507	406	4,290
04-Sens1-ID	08-TWE-IPPPST-Neg45	9,212	4,511	542	4,158
04-Sens1-ID	09-TWE-IPPPST-0deg	9,196	4,514	424	4,258

Figure 4.10-9: ISO Net Payment – Sensitivity 1 Portfolio with GLW Upgrade modeled



4.11 Summary and Recommendations

The ISO conducted production cost modeling simulations in this economic planning study and grid congestion were 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. 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. Alternatives also included interregional transmission projects as set out in chapter 5 of the 2020-2021 Transmission Plan.

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. As there were no material change in the assumption around the value of reducing capacity requirements in this planning cycle, the ISO did not update the results of the local capacity reduction assessment; rather, the capacity value results of the last planning cycle were used in the economic assessment for the transmission projects that potentially had benefit of reducing local capacity. 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.

Out-of-state wind and transmission upgrades were assessed in this planning cycle using both the Base portfolio and the Sensitivity 1 portfolio. In the Base portfolio study, the out-of-state transmission upgrades were compared based on their economic benefits that were calculated consistently with the ISO TEAM methodology. Alternatively, the out-of-state transmission upgrades were compared based on the results of the ISO net payment in the Sensitivity 1 portfolio.

The ISO's focus on ratepayer benefits, rather than broader WECC-wide societal benefits, was another difference between a number of stakeholder proposals. The overall economic planning study results in the 2021-2022 planning cycle are summarized in Table 4.11-1, including the Base portfolio out-of-state wind study results.

Table 4.11-1: Summary of economic assessment in the 2021-2022 planning cycle

Congestion or study area	Alternative	Benefits Consideration	Economic Justification
Path 26 corridor congestion	Modify Midway-Whirlwind rating and series compensation	Production cost ratepayer benefits sufficient	Yes
Path 26 corridor congestion	PTE project	Production cost ratepayer benefits sufficient	No
GridLiance West/VEA congestion	GLW Upgrade	Production cost ratepayer benefits not sufficient	Yes
PG&E Moss Landing-Las Aguilas 230 kV line congestion	Install 10 ohms series reactor on the Moss Landing – Las Aguilas 230 kV line	Production cost ratepayer benefits sufficient	Yes
PG&E Panoche-Gates 230 kV lines congestion	Install 20 0hms series reactors on the Panoche – Gates 230 kV lines	Production cost ratepayer benefits not sufficient	No
OOS wind transmission upgrades	Cross-Tie	Production cost ratepayer benefits not sufficient	No
	SWIP North	Production cost ratepayer benefits not sufficient	No
	TransWest Express	Production cost ratepayer benefits not sufficient	No

In summary, three transmission solutions were found to have sufficient economic benefits. The ISO recommended one of them for approval as an economic driven transmission upgrade in this planning cycle.

- Installing 10-ohms series reactors on the PG&E's Moss Landing – Las Aguilas 230 kV line to mitigate congestion of the Moss Landing – Las Aguilas230 kV line in the PG&E area.

The benefit-to-cost ratio also supports the following policy-driven upgrade:

- GLW Upgrade project

Based on the results of the economic assessment and the policy assessment, the ISO will coordinate with PG&E and SCE to further investigate the new ratings on PG&E'S portion of the Midway-Whirlwind line to mitigate the off-peak deliverability constraint and the bypassing the series capacitor at Midway on the Midway-Whirlwind 500 kV line.

Installing series reactors on Panoche – Gates 230 kV lines was not recommended for approval as an economic driven project because it did not always show sufficient benefit for ISO ratepayers in different study scenarios. It will be monitored and investigated in future planning cycles to take into account the updated renewable resource assumption in the PG&E Fresno area and consideration of the overall Path 15 corridor congestion mitigation.

Out-of-State Wind Resources

The ISO explored the implications of out-of-state transmission needed to bring the base case amounts and sensitivity amounts to the ISO boundary. These were conducted in the course of the economic study process, considering and comparing a number of alternative transmission developments including TransWest Express and Cross-Tie accessing Wyoming resources, and the SWIP-North project accessing Idaho resources. The latter was an economic study request submitted into the planning process. All portfolios provided by the CPUC called for at least 1,062 MW of out-of-state wind to be brought into California. There was no scenario that called for zero out-of-state resources requiring additional out-of-state transmission. Therefore, the effectiveness of the different transmission and resource options were compared against each other and the various options were compared to each other with the New Mexico resources being selected as the reference case.

Several out-of-state wind and transmission upgrade scenarios showed positive benefits for ISO ratepayers, however, all transmission alternatives studied had a benefit-to-cost ratio of less than 1.0 for a number of study assumption conditions in the Base portfolio baseline studies, which indicated that there was not sufficient economic justification for the out-of-state wind transmission upgrades in this planning cycle. Two sensitivity studies with the Gateway West project turned off and with the GLW Upgrade project modeled, respectively, were conducted for the out-of-state wind study. The sensitivity study results did not have directional change in the economic assessment results compared with the baseline study results.

The Sensitivity 1 portfolio out-of-state wind study and the sensitivity studies without Gateway West or with the GLW Upgrade modeled demonstrated the impact of the changes in out-of-state wind capacity in the portfolio and the transmission topology change on the assessment results for the out-of-state wind and the transmission upgrades. The out-of-state wind and the transmission upgrades will be monitored in future planning cycles to take into account further consideration of suggested changes to ISO economic modeling for transmission and resources, including further clarity on renewable resources, battery, and gas-fired generation supporting California's renewable energy goals. The benefits provided by the various alternatives are heavily dependent on the wind regimes and resulting resource output profiles of wind resources in those geographically diverse regions. The TransWest Express project is being developed providing transmission service to resources seeking access to California markets, whereas the SWIP North project (and presumably the Cross-Tie project) are being proposed to receive regulated, cost-of-service cost recovery as a participating transmission owner asset. Further, the proponents of SWIP North project have a pre-existing agreement with NV Energy regarding accessing capacity on the existing Robinson Summit-Harry Allen 500 kV transmission line that other projects do not. These differing cost and cost recovery mechanisms make direct comparisons of benefit-to-cost ratios problematic, but several key issues stand out.

As TransWest Express is seeking cost recovery through a subscriber model, e.g. providing transmission service to resources seeking access to California markets, without necessitating specific approvals by the ISO, comparability can be provided by the ISO testing the market interest in accessing Idaho wind resources through the SWIP North project. The SWIP North project is in a somewhat unique position due to its existing agreement with NV Energy regarding access to capacity on the Robinson Summit to Harry Allen 500 kV One Nevada (ON) Line, and appears well positioned based on LS Power submissions to move forward expeditiously.

The ISO is intending to engage further with industry to gauge interest in accessing Idaho resources through a separate process. This process will require more time than is available before this plan is finalized leading up to the annual approval of the 2021-2022 Transmission Plan scheduled for March, 2022, and will extend beyond that date. This process will be considered an extension of the existing 2021-2022 transmission planning cycle, rather than shifting it to the next 2022-2023 planning cycle, and any recommendations resulting from this effort will be considered for approval as an extension of this 2021-2022 Transmission Plan. The ISO will have to engage separately with stakeholders regarding the design of this outreach, which would be expected to follow the approaches of an open season or competition.

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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 2020-2021 transmission planning cycle was completed during the even-year portion of the 2020-2021 interregional transmission coordination cycle.

The ISO hosted its 2020-2021 ITP submission period in the first quarter of 2020 in which proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2020-2021 transmission planning process. During the submission period, four interregional transmission projects and their documentation were submitted by their project sponsors for consideration by the ISO. However, based on the study assumptions and the reliability, policy, and economic regional assessments documented in this 2020-2021 transmission plan, no further consideration of the submitted ITPs was required beyond the 2020-2021 transmission planning process.

5.1 Background on the Order No. 1000 Common Interregional Tariff

FERC Order No. 1000 broadly reformed the regional and interregional planning processes of public utility transmission providers. While instituting certain requirements to clearly establish regional transmission planning processes, Order No. 1000 also required improved coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. Since the final rule was issued, the ISO has continued to collaborate with neighboring transmission utility providers and Western Planning Regions (WPRs) across the Western Interconnection through a coordinated process for considering interregional projects.

Early on in the interregional transmission coordination process, the WPRs developed certain business practices for the specific purpose of providing stakeholders visibility and clarity on how the WPRs would engage in interregional coordination activities among their respective regional planning processes. Commensurate with each WPR's regional arrangement with its members, these business practices were incorporated into the WPR regional processes to be followed within the development of regional plans. For the ISO, these business practices have been incorporated into the ISO's Business Practice Manual (BPM) for the Transmission Planning Process.

Commensurate with past interregional transmission coordination cycles, the ISO continued to play a leadership role in Order 1000 processes within the ISO's planning region, through direct coordination with the other WPRs and representing and supporting interregional coordination concepts and processes in public forums such as WECC. The WPRs have actively engaged to resolve conflicts and challenges that have arisen since the first coordination cycle was initiated in 2016. The ISO and other WPRs have continued to consider and forge new opportunities to facilitate coordination among its stakeholders and neighboring planning regions for the benefit of interregional coordination.

5.2 Interregional Transmission Project Submittal Requirements

As described in the ISO's BPM for the Transmission Planning Process, ITPs may be submitted into the ISO's transmission planning process on January 1 through March 31 of every even year of the interregional transmission coordination process. The ITPs must be properly submitted and in doing so must meet the following requirements:

- 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 it is seeking cost allocation from that Order 1000 planning region, andWhen 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 reasonably 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 its 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 transmission planning process.

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 transmission planning process. 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. WestConnect hosted the 2020 meeting and NorthernGrid is hosting the 2021 meeting.

In general, the purpose of the coordination meeting is to provide a forum for stakeholders to discuss planning activities in the West, including a review of each region's planning process, its needs and potential interregional solutions, update on ITP evaluation activities, and other related issues. It is important to note that the ISO's planning processes is annual while the planning processes of NorthernGrid 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 Are being considered within the previous odd-year draft transmission plan for approval and/or awaiting "final approval" from the relevant planning regions; and, 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, 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 transmission planning process, the ISO provides a submission window during which proponents may submit their ITPs into the ISO's annual planning process within the current interregional coordination cycle. The submission window is open from January 1st through March 31st of every even-numbered year. Interregional Transmission Projects will be considered by the WPRs on the basis that:

- The ITP must electrically interconnect at least two Order 1000 planning regions
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO's transmission planning process
- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region, and When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

An ITP submittal must include specific technical and cost information for the ISO to consider during its validation/selection process of the ITP. For the ISO to consider a proponent's project as an ITP, it must have been submitted to and validated by at least one other WPR. Once the validation process has been completed, each WPR is then considered to be a Relevant Planning Region. All Relevant Planning Regions consider the proposed ITP in their regional process. For the ISO, validated ITPs will be included in the ISO's Transmission Planning Process Unified Planning Assumptions and Study Plan for the current planning cycle and evaluated in that year's transmission planning process.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

5.3.3 Evaluation of Interregional Transmission Projects by the ISO

Once the submittal and validation process has been completed, the ISO shares its planning data and information with the other Relevant Planning Regions and develops a coordinated evaluation plan for each ITP to be considered in its regional planning process. The process to evaluate an ITP can take up to two years where an "initial" assessment is completed in the first or even year and, if appropriate, a final assessment is completed in the second or odd year. The assessment of an ITP in a WPR's regional process continues until a determination is made on whether the ITP will or 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.

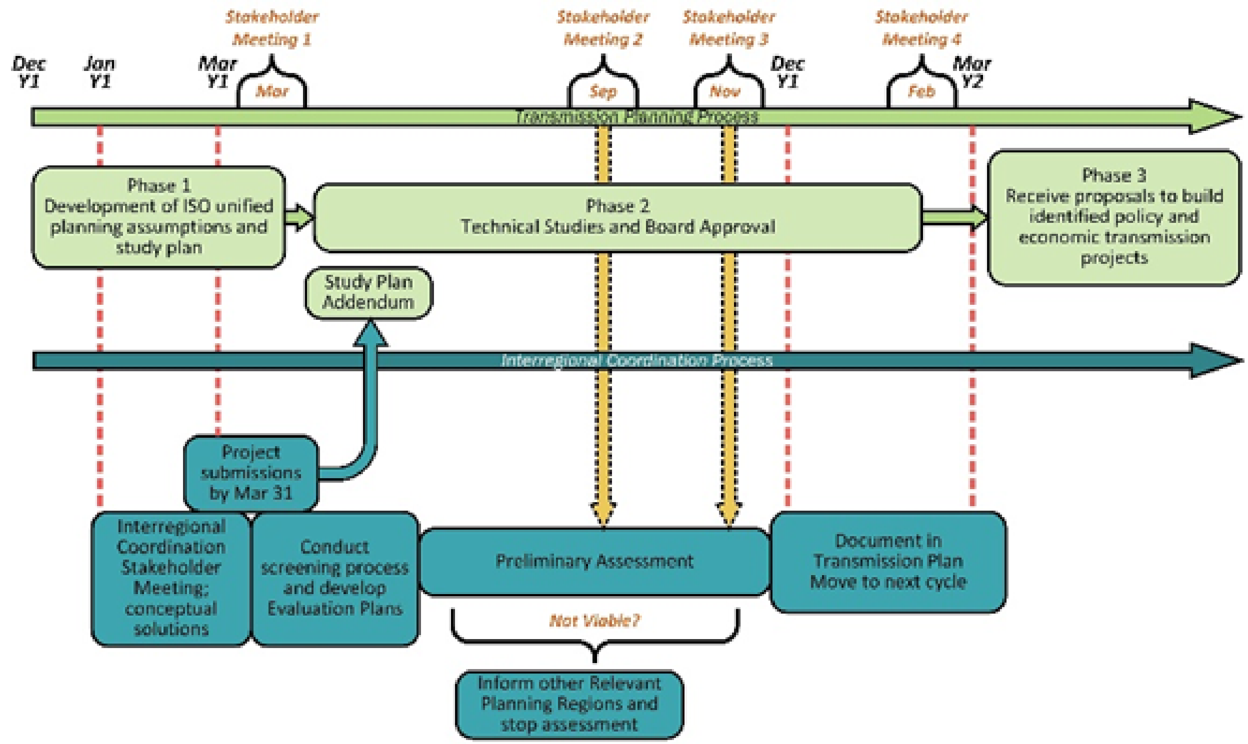
5.3.3.1 Even Year ITP Assessment

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 regions in their individual evaluations of the ITPs. 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 final, each relevant planning region independently considers the ITPs that have been submitted into its regional planning process.

As with the other relevant planning regions, the ISO assesses the ITP proposals under the ISO tariff. As illustrated in the ISO shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the ISO manages its assessment of an ITP proposal across the two-year interregional coordination cycle in two steps. During the even year, the ISO makes a preliminary assessment of the ITP and once it completes that task, the ISO must consider whether 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

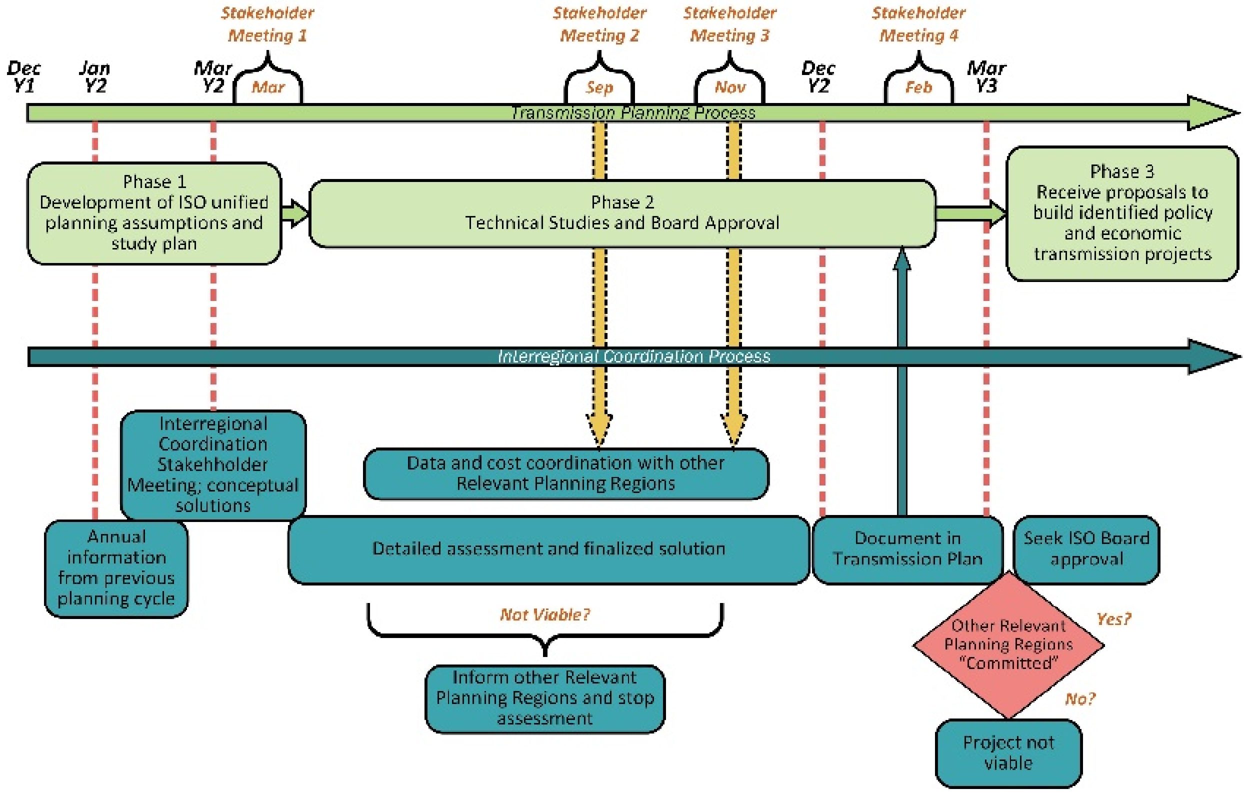


The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation to continue or not continue assessment of the ITP in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission 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 a project sponsor has committed to pursue or build the project. Based on the information available, the ISO may inform the ISO Board on the status of the ITP proposal and if appropriate, seek approval from the board to continue working with all relevant parties associated with the ITP to determine if the ITP can viably be constructed. Determining viability may take several years during which time the ISO will continue to consider the ITP it its transmission planning process and if appropriate, select it as the preferred solution. The ISO may seek ISO Board approval to build the ITP once the ISO receives a firm commitment to construct the ITP.

5.4 Formation of Northern Grid

Since the first interregional transmission coordination cycle was initiated, four WPRs closely coordinated the development of the necessary processes, protocols, and guidelines that were required to fully implement the requirements of Order No. 1000 and the Order No. 1000 Common Interregional Tariff. During 2019, two WPRs, the Northern Tier Transmission Group and ColumbiaGrid, merged into NorthernGrid, a single transmission planning region to facilitate regional transmission planning, enable one common set of data and assumptions, identify regional transmission projects through a single stakeholder forum, and eliminate duplicative administrative processes. During the 2021-2022 transmission planning process the ISO has proactively engaged in NorthernGrid's development and implementation process to facilitate coordination and data sharing between the ISO and NorthernGrid. During the early part of 2021 NorthernGrid focused on implementing its planning process.

It is important to note that the coordination guides and protocols that were developed over the last two interregional coordination cycles that have been effective in ensuring transparency and comparability of the existing ITP coordination process remain in place and will continue forward to future interregional transmission coordination cycles. Although NorthernGrid has yet to formally adopt the coordination guidelines shared by the ISO and WestConnect, The ISO has continued to advocate that NorthernGrid consider and adopt the coordination guidelines by the close of the 2020-2021 ITP coordination cycle.

5.5 Development of the Anchor Data Set (ADS)

The 2030 ADS was made available to WECC members on June 30, 2020. While WECC delivered the ADS on schedule, it was generally considered incomplete as it included data and representation errors. Since its release, updates were made and continued to be made well into 2021. While progress on ADS development has been achieved during 2021, WECC continues to fall short in developing a fully vetted ADS process that is consistent and repeatable on a biennial basis.

The ISO continues to support WECC's ADS activities and remains engaged in the ADS development process through standing WECC subcommittees and workgroups. The ADS remains the best representative approach to addressing existing and ongoing data inconsistencies and applications, while facilitating a common dataset that accurately represents the regional plans of the WPRs. Each year the ISO builds over 100 power-flow cases to perform its reliability assessment of the ISO-controlled grid as well as a detailed production cost model dataset from which it performs economic, policy, and other "special studies". Clearly, significant ISO resources are committed to developing these study models during each planning cycle and, as such, their accuracy is of paramount importance to that process. The ISO believes that the successful development and implementation of the ADS will yield, through a consistent and repeatable process, better coordinated and more accurate datasets that will maximize their use and minimize errors in WPR regional and WECC assessments

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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, simultaneous feasibility test studies, a system frequency response assessment, and a flexible capacity deliverability assessment.

6.1 Reliability Requirement for Resource Adequacy

Section 6.1.1 summarizes 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 2022. 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 2021. A short-term analysis was conducted for the 2022 system configuration to determine the minimum local capacity requirements for the 2022 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the ISO tariff section 40.3. This study was conducted in January through April through a transparent stakeholder process with a final report published on April 30, 2021. For detailed information on the 2022 LCT Study Report please visit:

http://www.caiso.com/InitiativeDocuments/Final2022LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2026 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 2026 LCT Study Report was published on April30, 2021 and for detailed information please visit:

http://www.caiso.com/InitiativeDocuments/Final2026Long-TermLocalCapacityTechnicalReport.pdf

The ISO also conducts a 10-year local capacity technical study every second year, as part of the annual transmission planning process. The 10-year LCT studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide an indication of whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding and, per agreement between state agencies, they are done on an every-other-year cycle.

The most recent 10-year LCR study was initiated in the 2020-2021 transmission planning process. The ISO undertook a comprehensive study of local capacity areas, examining both the load shapes and new battery charging and discharging characteristics underpinning local-capacity requirements, and evaluating reduction alternatives, mostly proposed by stakeholders, even if it is unlikely that the economic benefits alone would outweigh the costs. A number of these alternatives received detailed economic evaluations in the same 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 2030 long-term LCT study results, please refer to the stand-alone report in the Appendix G of the 2020-2021 transmission planning process.

As shown in the LCT study reports and indicated in the LCT study manual, that the ISO prepares each year setting out how that year's LCT studies will be performed, 12 load pockets are located throughout the ISO-controlled grid as shown in Table 6.1-1; however only 10 of them have local capacity area requirements as illustrated in Figure 6.1-1.

Table 6.1-1: List of Local Capacity Areas and the corresponding service territories within the ISO Balancing Authority Area

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

Figure 6.1-1: Approximate geographical locations of LCR areas

Each load pocket is unique and varies in its capacity requirements because of different system configurations. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 130 MW. In contrast, the requirements of the Bay Area are approximately 7,000 MW. The short-term and long-term LCR needs from this year's studies are shown in Table 6.1-2.

Table 6.1-2: Local capacity areas and requirements for 2022, 2026 and 2030

LCR Area	LCR Capacity Need (MW)		
	2022	**2026**	**2030**
Humboldt	111	128	135
North Coast/North Bay	834	834	842
Sierra	1,220	1,690	1,518
Stockton	562	586	619
Greater Bay Area	7,231	7,674	7,344
Greater Fresno	1,987	2,314	2,296
Kern	356	418	413
Big Creek/Ventura	2,173	982	1,151
Los Angeles Basin	6,649	6,359	6,194
Greater San Diego/Imperial Valley	3,993	4,684	3,718
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	25,113	24,379	24,230

Notes:
For more information about the LCR criteria, methodology and assumptions please refer to the ISO LCR manual.[150]
For more information about the 2022 LCT study results, please refer to the report posted on the ISO website.
For more information about the 2026 LCT study results, please refer to the report posted on the ISO website.

[150] "Final Manual 2022 Local Capacity Area Technical Study," January 15, 2021, http://www.caiso.com/InitiativeDocuments/2022LocalCapacityRequirementsFinalStudyManual.pdf .

6.1.2 Resource adequacy import capability

The ISO has established the maximum resource adequacy (RA) import capability to be used in year 2022 in accordance with the ISO tariff section 40.4.6.2.1. These data can be found on the ISO website[151]. The entire import allocation process[152] 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 2031.

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

http://www.caiso.com/Documents/Advisory-estimates-of-future-resource-adequacy-import-capability-for-years-2022-2031.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2023 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.

[151] "California ISO Maximum RA Import Capability for year 2022," available on the ISO's website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2022.pdf.

[152] See general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

6.2 Long-Term Congestion Revenue Rights Simultaneous Feasibility Test Studies

The Long-term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test studies evaluate the feasibility of the fixed LT CRRs previously released through the CRR annual allocation process under seasonal, on-peak and off-peak conditions, consistent with section 4.2.2 of the Business Practice Manual for Transmission Planning Process and tariff sections 24.1 and 24.4.6.4

6.2.1 Objective

The primary objective of the LT CRR feasibility study is to ensure that fixed LT CRRs released as part of the annual allocation process remain feasible over their entire 10-year term, even as new and approved transmission infrastructure is added to the ISO-controlled grid.

6.2.2 Data Preparation and Assumptions

The 2021 LT CRR study leveraged the base case network topology used for the annual 2022 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 2021-2022 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% of available transmission capacity. The fixed CRR representing the transmission ownership rights and merchant transmission were also set to 60%. All earlier LT CRR market awards were set to 100%, since they were awarded with the system capacity already reduced to 60%. For the study year, the market run was set up for two seasons (with season one being January through March and season three 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% of enforced branch rating,and

- 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, the 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 December of 2021 that there are no existing released LT CRRs at-risk” that require further analysis. Thus, the transmission projects and elements approved in the 2021-2022 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 synchronous generators are being displaced with renewable resources using converter-based technologies. 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. One of the primary concerns is that there be adequate frequency response from inverter-based resources (IBR) when unplanned system outages and events occur.

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 the analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

In the subsections below, the progress achieved and issues to be considered going forward has been summarized, as well as the background setting the context for these efforts and the study results.

6.3.1 Frequency Response Methodology & Metrics

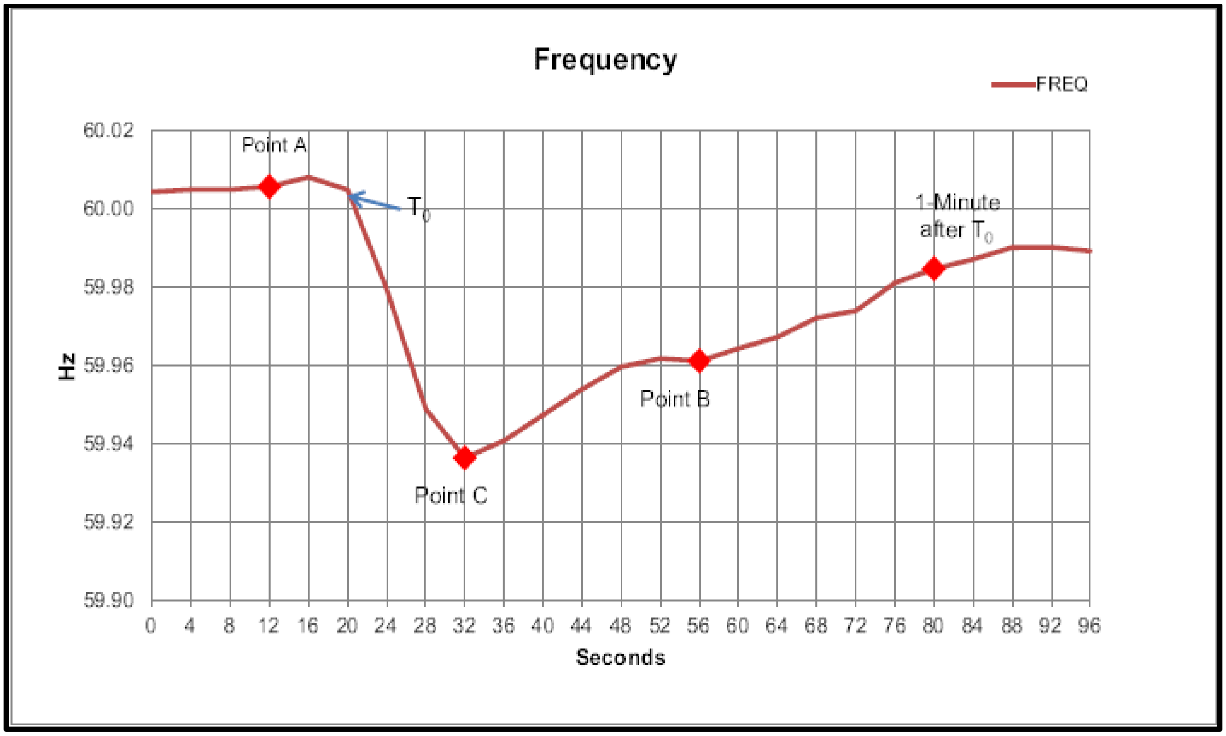
The ISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in subsequent years, using the latest dynamic stability models. In this planning cycle, the potential impact of inverter-based resources (IBR), particularly battery energy storage systems (BESS) as a means of aiding frequency response, was investigated.

Background on Frequency Response and Frequency Bias Setting Methodology

NERC has established the methodology for calculating frequency response obligations (FRO) outlined in Reliability Standard BAL-003-2 (Frequency Response and Frequency Bias Setting). 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.

A generic system disturbance that results in frequency decline, such as a loss of a large generating facility, is illustrated in Figure 6.3-1. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 6.3-1: Illustration of Primary Frequency Response



The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

The Interconnection Frequency Response Obligation changes from year to year primarily as the result of the changes in the statistical frequency variability during actual disturbances, and statistical values of the frequency nadir and settling frequency observed in the actual system events. Allocation of the Interconnection FRO to each balancing authority also changes from year to year depending on the balancing authority's portion of the interconnection's annual generation and load. This year NERC has maintained the 2016 IFRO value of 858 MW/0.1 Hz be retained for the present operating year. The ISO's share of this obligation remains at 257.4 MW/0.1 Hz.

More conventional generators are being displaced with renewable resources. This has a significant effect on frequency response. 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 specifically have a dedicated control mechanism to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their MW output. When a frequency response characteristic is incorporated into IBR control parameters, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has headroom remaining. As more wind and solar resources displace conventional synchronous generation, the mix of the remaining synchronous generators may not be able to adequately meet the ISO's FRO under BAL-003-2 for all operating conditions.

The most critical condition when frequency response may not be sufficient is when a large amount of renewable resources are online with high output concurrently with a low system load. In such cases 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

One operating condition that is important for frequency response studies is 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, units at maximum capacity and units that don't respond to changes in frequency 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[153]; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt has not been standardized.

For the ISO studies, the comparable metric is 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.

Rate of Change of Frequency (ROCOF)

ROCOF is defined as the rate of change of frequency and is proportional to power imbalance during a system disturbance. The ROCOF value is most responsive immediately after a contingency and is increasingly being used by the industry to gauge the severity of the event and the ability of connected generators to respond in a timely manner to arrest excessive frequency excursions. ROCOF is particularly important as it anticipates the magnitude of frequency changes and in real time can be used to signal and react quickly to excessive frequency excursions.

ROCOF is difficult to accurately measure post-contingency as the change in frequency is inherently noisy with multiple slope profiles potentially resulting in a wide margin of error. Despite this challenge, the ROCOF is a good predictor of system response to a bulk system

[153] Undrill, J. (2010). Power and Frequency Control as it Relates to Wind-Powered Generation. LBNL-4143E. Berkeley, CA: Lawrence Berkeley National Laboratory

frequency event. When reliably measured it also provides a good means of ranking contingencies in terms of severity.

6.3.2 FERC Order 842

On February 15, 2018 FERC issued Order 842 that requires newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. Based on FERC Order 842, all generators including wind and solar generators that execute an LGIA on or after May 15, 2018 are required to provide frequency response.

6.3.3 2019-2020 Transmission Plan Study

In the prior 2019-2020 transmission planning cycle the frequency response was assessed and determined that the Frequency Response Obligation (FRO) required from ISO was being met. Particular focus was centered on IBR contribution to that response. Headroom, IBR units with frequency regulation turned on and to some extent a lower droop, all cause a higher increase in response than would otherwise be provided.

6.3.4 2021-2022 Transmission Plan Study

As in the 2019-2020 transmission planning process, this study is to re-assess the contribution to frequency response provided by IBR resources with a particular emphasis on Battery Energy Storage Systems. BESS plants cyclically charge and discharge on an intra-day basis. This energy can be readily modulated during system events to help minimize significant frequency deviations. New plants coming on-line as per FERC Order 842 will have frequency regulation. If enabled and with enough diversity between charging and discharging plants, BESS units can help support the system during significant frequency events.

The spring off peak case was chosen as there is a lower number of conventional gas units in operation. This case has a high proportion of solar plants on-line which, for the most part, do not have frequency regulation or are dispatched at a level with little to no additional headroom.

The study scenarios are summarized in Table 6.3-1. The study results for the baseline scenarios and the sensitivity study scenarios are illustrated in Figures 6.3-2 through 6.3-5.

Table 6.3-1: Study Scenarios for Frequency Response Study in the 2021-2022 TPP

	Study Scenarios			
	SC1	SC2	SC3	SC4
PFR enabled for existing IBRs?	No	No	No	No
PFR enabled for new IBRs?	No	Yes	Yes	Yes
Headroom	Existing	Existing	10%	WECC spinning reserve
Existing IBRs and other gens droop	5%	5%	5%	5%
Existing IBRs and other gens deadband (Hz)	±0.036	±0.036	±0.036	±0.036

Scenario 1 is the reference against which to compare all others, where all existing plants and new IBR plants have frequency regulation shut off. The results for both 2016 and 2031 are comparable with 2031 having a lower overall frequency droop and lower ROCOF suggesting it to be more robust than the original 2016 base case.

Scenario 2 has all new IBR plant frequency regulation turned on. The resultant 2031 system frequency profile shows a considerable improvement over that of 2016. The nadir is only slightly higher but the recovery occurs sooner and to a higher level than for 2016.

For scenario 3, all new IBR plants were adjusted to 10% headroom from the closest operating limit. For BESS plants in charging mode, they are at 10% from their minimum absorbing power limit. This was done so as not to appreciably change the character of the case. The net result is that there is similar response profile for both scenarios 2 (Figure 6.3-2) and scenario 3. In charging mode a BESS plant has an inherent large headroom so a slight shift up from the original lower level is not significant.

Scenario 4 is one where all ISO generation has minimal headroom. This case is only marginally better than the base scenario.

These results indicate that by enabling the frequency response of the new units coming online, particularly in 2031, the system recovers from frequency events faster and settles at higher frequencies. There is a higher proportion of IBR plants in 2031 which significantly aids the system frequency response when enabled.

The 2026 and 2031 peak-off spring load case used for these studies have most BESS units operating in charging mode. These plants are acting as a load and represent the highest headroom possible. As per the 2020-2021 transmission planning process analysis, a higher headroom leads to a better overall frequency response.

Figure 6.3-3: System Frequency Response for Baseline Case (No IBR frequency control)

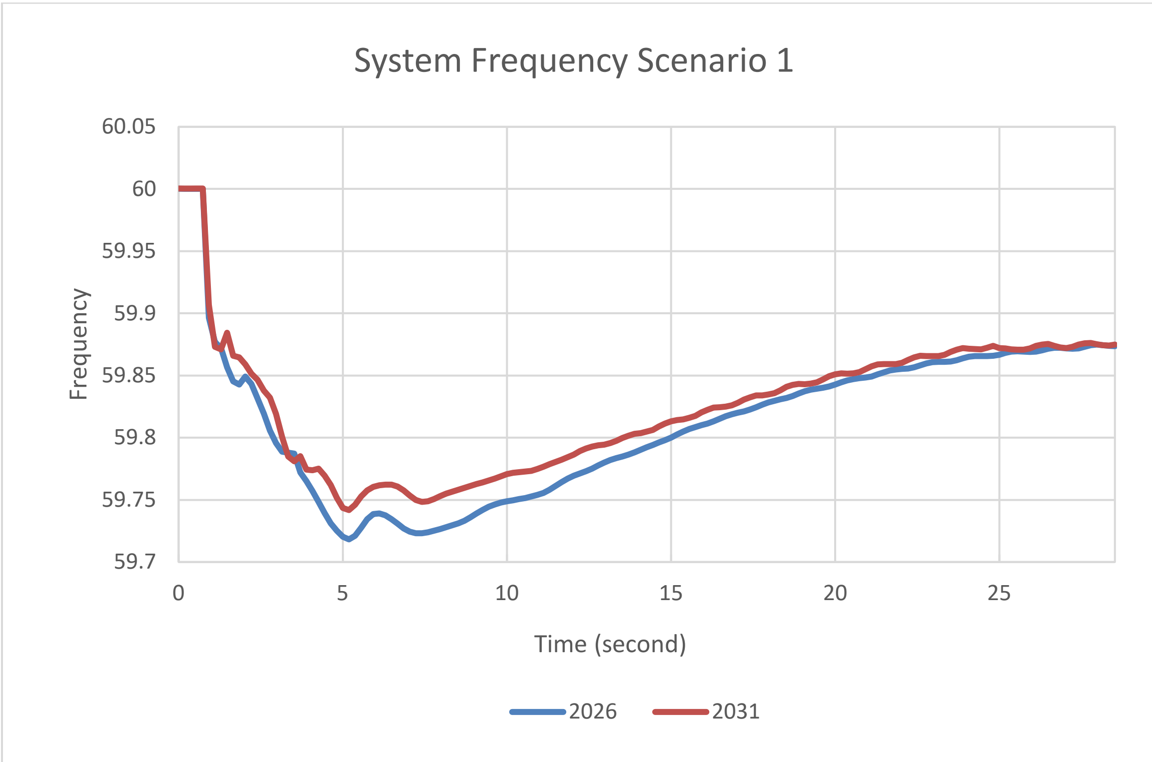


Figure 6.3-4: System Frequency for new BESS Plants on Frequency Control

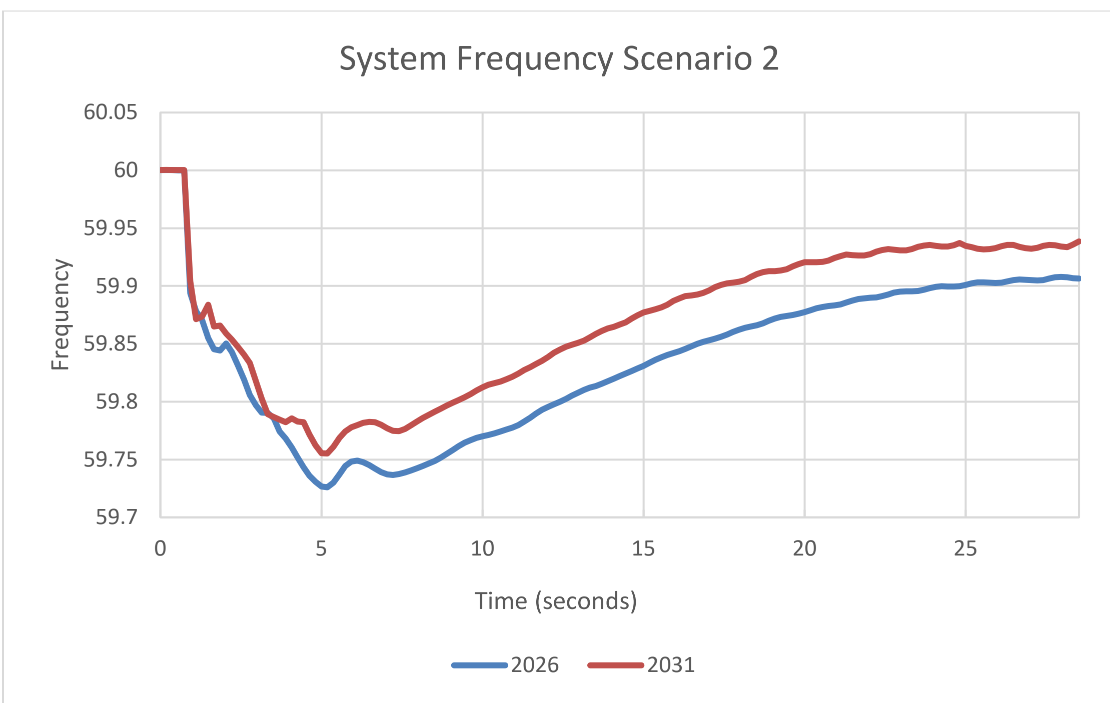


Figure 6.3-5: System Frequency Response under Sensitivity Case (~10% headroom)

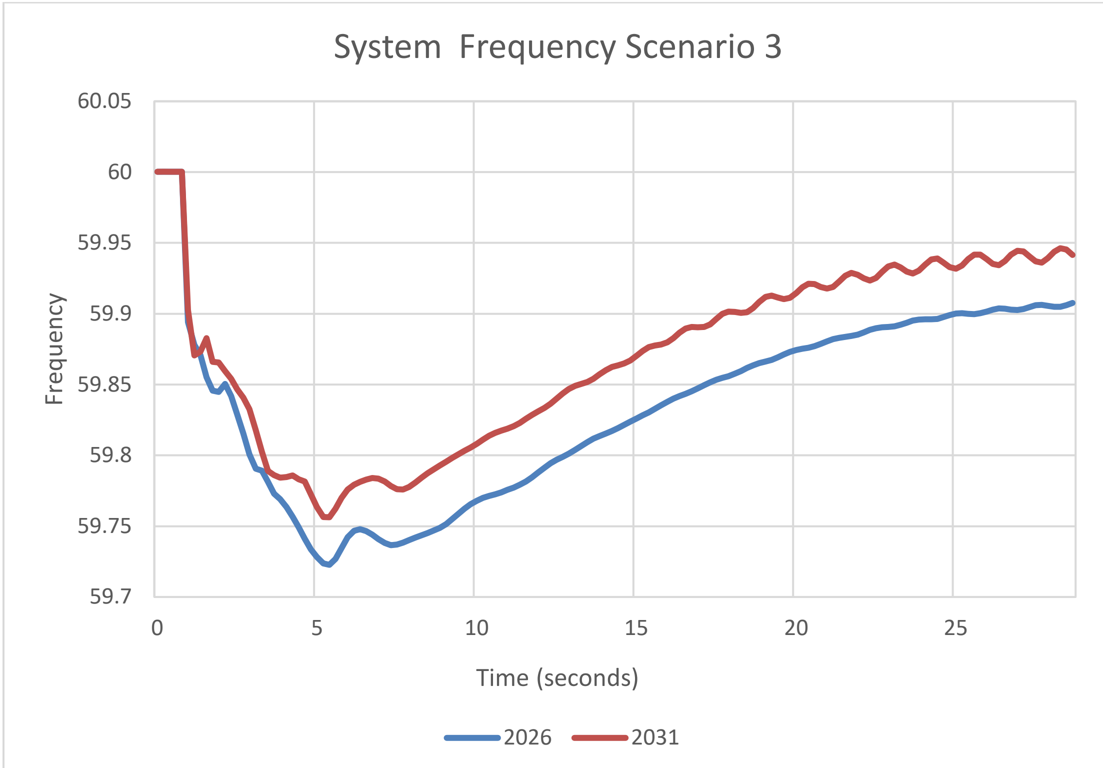
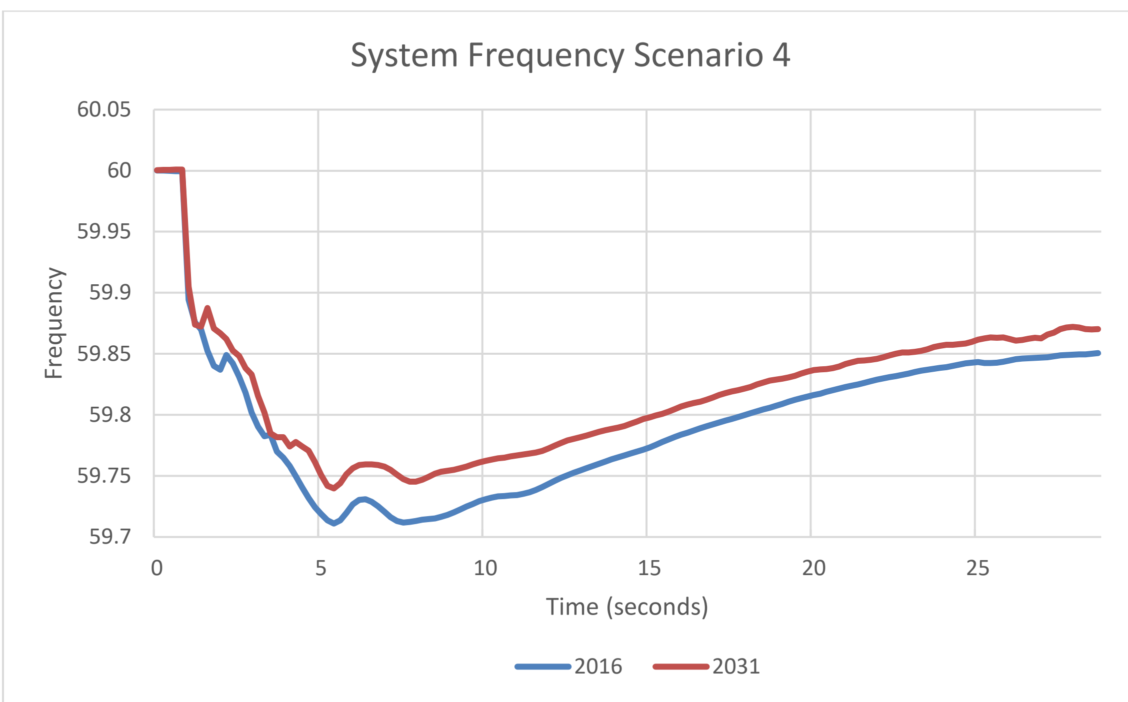


Figure 6.3-6: Scenario 1 with WECC at Spinning Reserve



Conclusions and recommendations from the 2021-2022 transmission planning process study

This study indicates that the ISO system response to major frequency events such as two Palo Verde units improves when IBRs have headroom, also when in charging mode (ample headroom), and have frequency response enabled.

The studies illustrated that the ISO is forecasted to meet its Frequency Response Obligation (FRO) with the frequency response of new IBRs enabled per FERC Order 842. It is sufficient to meet FRO just by enabling the PFR even with current values for droop and deadband.

A number of existing IBRs connected to the ISO footprint have primary frequency response (PFR) capability but there are still a significant number of units for which the PFR capabilities of the IBRs are not enabled. There were around 21 GW of existing installed IBRs across the ISO in 2020, which is now forecasted to reach 33 GW by year 2030. Considering the subset of existing IBRs that are BESS units with frequency response required and enabled, it is expected that the PFR capability of the IBRs would be beneficial to system recovery from frequency events and to meet the ISO Frequency Response Obligation (FRO).

The present heavy spring off-peak base case has most IBRs in charging mode which provides ISO with assistance for large frequency excursions. Consideration should be given to performing the same assessment with a similar or comparable realistic case but with IBRs in a net discharging mode.

A system-wide oscillation is evident on the curves and is expected to be an artifact of the dispatch. Root causes of the net improvement of the unassisted frequency response of 2031 over 2026 is also being investigated.

6.3.4.1 Progress in Updating and Validating Models

There are various standards and procedures in place for the collection of modeling information from Transmission Owners, developers and their vendors. The ISO also continues to validate existing generators' modes as set out in section 10 of the ISO's Transmission Planning Process business practice manual[154]. A whitepaper released in September 2021 entitled 'Dynamic Model Review Guideline for Inverter based Interconnection Requests'[155] outlines the selection of inverter parameters to ensure interconnection requirements. The later also ensures that frequency response from IBR resources, if enabled, will contribute to arresting abrupt frequency changes.

Validation of system models using simulations that emulate actual major frequency events is presently a process that may be more formally systematized during upcoming planning cycles. This will help ensure that primary frequency response from generators match the expected response and helps align operational results with planning studies. Also this provides an opportunity to determine that existing load models behave as realistically as possible.

[154] https://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

[155] http://www.caiso.com/Documents/InverterBasedInterconnectionRequestsIBRDynamicModelReviewGuideline.pdf

6.4 Flexible Capacity Deliverability

The ISO developed a methodology and tested the deliverability of flexible capacity in the 2019-2020 transmission planning process and updated the assessment in the 2020-2021 transmission planning process. The ISO has not updated the analysis in the 2021-2022 transmission planning process and will review the methodology and undertake analysis in future planning cycles.

6.5 PG&E Area Wildfire Impact Assessment

6.5.1 Background

High temperatures, extreme dryness and record-high winds have created conditions in the state of California increasing the risk of major wildfires. If severe weather threatens a portion of the electric system, it may be necessary for PG&E to turn off electricity in the interest of public safety. This practice is carried out by a Public Safety Power Shutoff or known as the PSPS events. In PG&E area, multiple PSPS events were carried out in 2019 and 2020. The multi-phase October 26 2019 event impacted customers in counties of Amador, Butte, Colusa, El Dorado, Glenn, Nevada, Placer, Plumas, San Joaquin, Sierra, Siskiyou, Shasta, Tehama, Yuba, Lake, Marin, Mendocino, Napa, Solano, Sonoma, Yolo, Alameda, Contra Costa, Monterey, San Benito, San Mateo, Santa Clara, Santa Cruz, Stanislaus, Alpine, Calaveras, Mariposa, Tuolumne, Humboldt, Trinity and Kern.

In the 2020-2021 transmission planning process, the ISO performed an assessment for PG&E service territory to provide insight into the potential range of load impacts if different combinations of transmission lines within fire threat zones are included in the scope of PSPS events. In performing the assessment, different scenarios were developed by taking out different combinations of transmission lines in fire zones within various planning areas. PG&E also has provided additional scenarios developed based on the historical weather conditions. The historical weather scenarios were studied by creating a single scenario by including all the lines included in one or more historical scenarios.

For the 2021-2022 transmission planning process, PG&E provided updated historical 'lookback' scenarios based on the weather data, past mitigations and refined methodology. The ISO reassessed the potential range of impact in the North Coast North Bay area based on the new set of scenarios provided by PG&E.

6.5.2 Objective

The objective of this assessment was to update the potential range of impact in the North Coast North Bay area based on the new set of scenarios provided by PG&E.

6.5.3 Study Approach

6.5.3.1 Scenario Development

There were 12 scenarios that include different combinations of North Coast North Bay Area transmission lines within the historical lookback weather scenarios provided by PG&E in this planning cycle as set out in Table 6.5-1.

Table 6.5-1: NCNB Weather Event with Lines Impact and Frequency

ETL	Line Name	Planning Area	Voltage	Total Count	1	2	3	4	5	6	7	8	9	10	11	12
ETL.4780	GEYSERS #9-LAKEVILLE	North Coast North Bay	230	10	1		1		1	1	1	1	1	1	1	1
ETL.4750	GEYSERS #12-FULTON	North Coast North Bay	230	5			1		1		1		1			1
ETL.4770	GEYSERS #17-FULTON	North Coast North Bay	230	5			1		1		1		1			1
ETL.4781	GEYSERS #13 TAP	North Coast North Bay	230	4			1				1		1			1
ETL.4950	FULTON-LAKEVILLE	North Coast North Bay	230	2							1		1			
ETL.4680	FULTON-IGNACIO #1	North Coast North Bay	230	1									1			
ETL.4392	EAGLE ROCK-FULTON-SILVERADO	North Coast North Bay	115	10	1		1		1	1	1	1	1	1	1	1
ETL.1330	CORTINA-MENDOCINO #1	North Coast North Bay	115	3			1						1			1
ETL.2410	MENDOCINO-REDBUD	North Coast North Bay	115	3			1						1			1
ETL.1650	GEYSERS #3-CLOVERDALE	North Coast North Bay	115	2			1						1			
ETL.1680	GEYSERS #7-EAGLE ROCK	North Coast North Bay	115	2			1						1			
ETL.3810	SONOMA-PUEBLO	North Coast North Bay	115	2			1						1			
ETL.4050	UKIAH-HOPLAND-CLOVERDALE	North Coast North Bay	115	2			1						1			
ETL.1470	EAGLE ROCK-CORTINA	North Coast North Bay	115	1									1			
ETL.1480	EAGLE ROCK-REDBUD	North Coast North Bay	115	1									1			
ETL.1600	FULTON-PUEBLO	North Coast North Bay	115	1									1			
ETL.1481	LOWER LAKE-HOMESTAKE	North Coast North Bay	115	1									1			
ETL.6880	FULTON-CALISTOGA	North Coast North Bay	60	10			1	1	1	1	1	1	1	1	1	1
ETL.6890	FULTON-HOPLAND	North Coast North Bay	60	7		1	1		1		1	1	1		1	
ETL.6852	CLEAR LAKE-KONOCTI	North Coast North Bay	60	2									1			1
ETL.8365	GARBERVILLE-LAYTONVILLE	North Coast North Bay	60	2			1								1	
ETL.6979	MONTE RIO-FORT ROSS	North Coast North Bay	60	2			1						1			
ETL.6980	FORT ROSS-GUALALA	North Coast North Bay	60	1									1			
ETL.7140	IGNACIO-BOLINAS #1	North Coast North Bay	60	1									1			
ETL.7360	LAKEVILLE #1	North Coast North Bay	60	1									1			
ETL.7390	LAYTONVILLE-COVELO	North Coast North Bay	60	1									1			
ETL.6981	SALMON CREEK TAP	North Coast North Bay	60	1									1			
ETL.8180	TULUCAY-NAPA #1	North Coast North Bay	60	1									1			

In the previous planning cycle, the historical weather scenarios were studied by creating a single scenario by including all the lines included in one or more historical scenarios. This year, the ISO assessed each historical weather scenarios separately.

6.5.3.2 Study scenarios

Using the approach mentioned in the above section, 12 scenarios were developed for the North Coast & North Bay planning area. Within the 12 scenarios, the four 230 kV gen-tie lines (connecting to Geysers generation) have relatively higher frequency in-terms of being included in the most number of scenarios. One 115 kV and two 60 kV lines also have relatively high frequency. However, the lines by themselves don't have direct load impact other than to one 60 kV substation.

Taking into consideration the composition of different scenarios, the ISO's assessment focused on two events as identified below:

- Weather Event 7 – Event with high frequency of transmission lines impacting local generation
- Weather Event 9 – Event with most number of North Coast North Bay transmission lines resulting in the large amount of direct load loss

The two scenarios, Weather Event 7 and 9 are considered boundary condition scenarios due to the high number of transmission line de-energized within these scenarios compared to actual events occurred in 2019 and 2020.

6.5.3.3 Scope of Assessment

The study approach included assessing the following sequence of impacts as a result of the transmission lines within the individual weather event being de-energized concurrently.

- Direct: Loss of load resulting from substations isolated by opening of the lines within the event. (i.e. radial supply)
- Indirect-thermal: Overloading of the remaining lines supplying the area resulting from opening of the lines within the event
- Indirect-contingency: Overloading of the remaining lines supplying the area under the next N-1 contingency condition

The first step of the assessment was to note which substation(s) and its load being lost as a result of radial system or island created due to the facilities de-energized as part of the scenario. This is also referred to as direct impact. The next step involved assessing base-case system performance after modeling each PSPS scenario. If any normal reliability issues identified in the base case, further actions were taken in the form of opening the overloaded lines or further load drop to alleviate issues in the base cases. These further actions are recorded as indirect-thermal impacts. Once the base case was prepared with no normal violations, relevant P1 contingencies were taken to make sure that the base case is secure for the next worst P1 contingency. System performance following the P1 contingencies were assessed and recorded as indirect-contingency impacts.

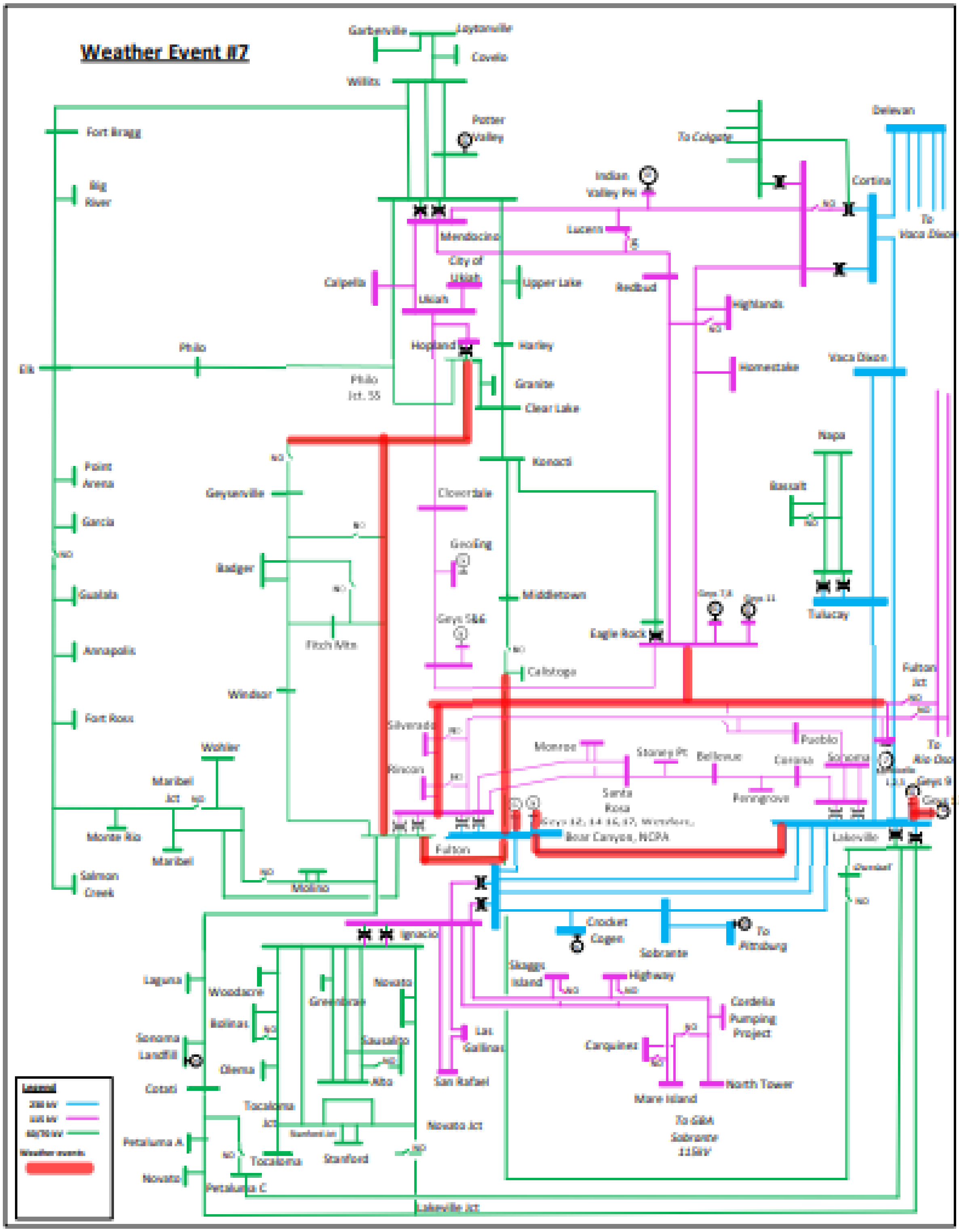
The year 2023 summer peak-base case for the North Coast North Bay planning area was used as a starting base case. Each scenario was applied to the starting case one at a time with all facilities within the PSPS scope being de-energized concurrently. The sequential load isolated due to application of PSPS scope is then identified as the direct load impact. Further, any normal overloads or voltage issues are identified and mitigated with generation re-dispatch, system reconfiguration or load drop. The load drop is thereafter identified as indirect load impact.

6.5.4 Assessment Results

<u>Weather Event 7</u>

Figure 6.5-1 illustrates the North Coast North Bay area transmission lines taken out as part of weather event 7.

Figure 6.5-1: North Coast North Bay area transmission lines taken out in weather event 7



<u>Direct Impact</u>

- Geysers #9-Lakeville 230 kV line is a radial line that is a non-ISO-controlled PG&E line that is a generation interconnection for the following resources Geysers 9&10 (retired), SMUD, Geyser 13, Geyser 18, NCPA 1 and NCPA 2.
- Geysers #12-Fulton 230 kV line is a radial line that is a non-ISO-controlled PG&E line that is a generation interconnection for the following resources Geysers 12 and 14.
- Geysers #17-Fulton 230 kV line is a radial line that is a non-ISO-controlled PG&E line that is a generation interconnection for the following resources Geysers 17 and Bottle Rock.
- Eagle Rock-Fulton-Silverado 115 kV line results in loss of supply to the following substations Rincon, Silverado, Monticello and Monticello PH. However, these stations can be served from the alternate (Fulton-Pueblo) 115 kV line.
- Fulton-Calistoga 60 kV line results in loss of supply to Calistoga substation

<u>Indirect Impact Thermal (Base Case overload)</u>

To identify the Indirect Thermal Impact, a base case was developed by scaling load in the North Coast North Bay area to represent load level during typical wildfire risk season. Following facilities were identified to have the Indirect Thermal Impact:

- Vaca Dixon-Lakeville 230 kV line
- Vaca Dixon –Tulucay 230kV line

<u>Indirect Impact Contingency</u>

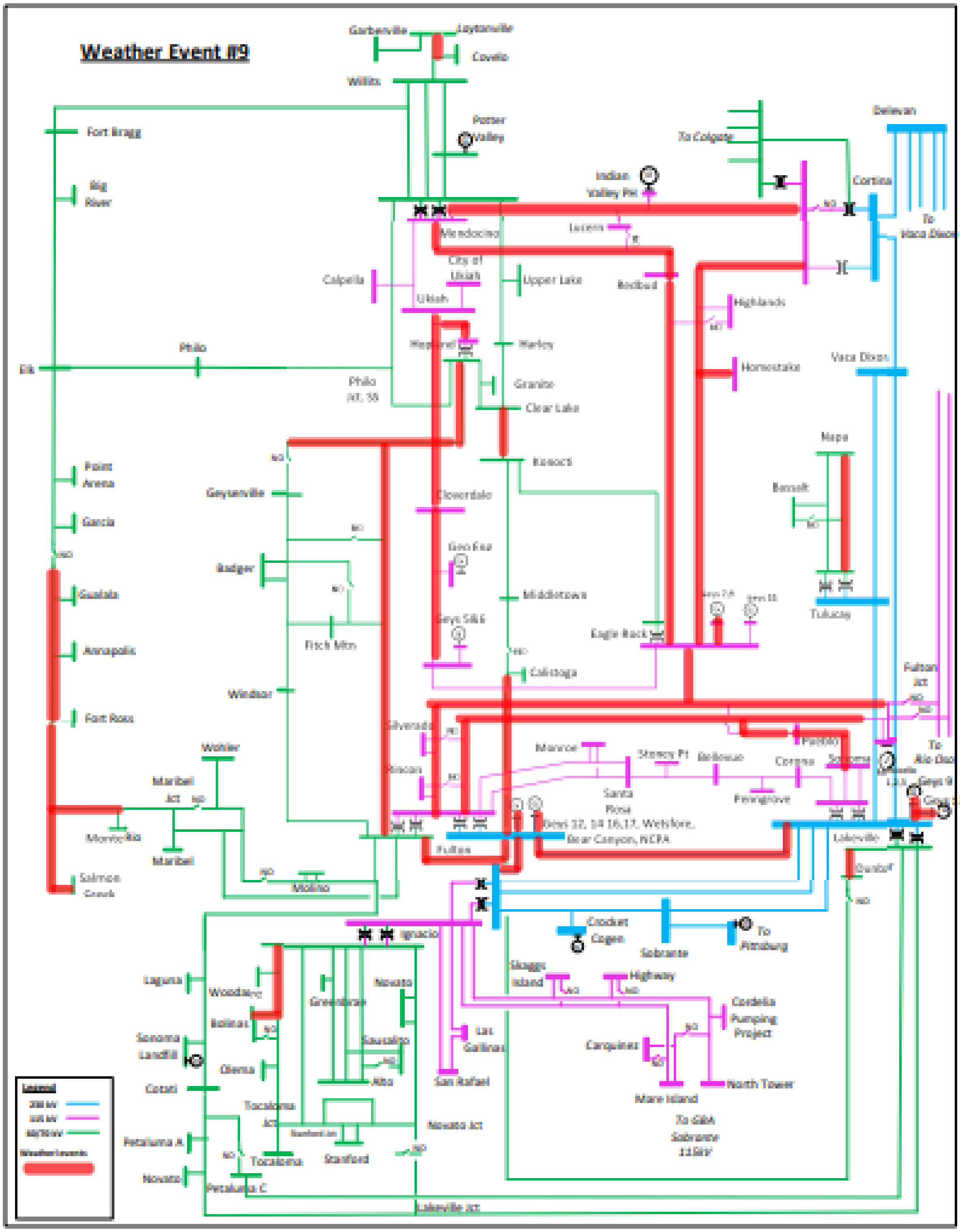
The following indirect impacts under contingency were observed for the weather event 7:

- Contingency of Fulton-Windsor 60 kV line results in loss of supply to the following substations: Windsor, Fitch Mtn, Badger and Geyserville.
- Contingency of Windsor-Fitch Mtn-Badger 60 kV line results in loss of supply to the following substations: Windsor, Fitch Mtn, Badger and Geyserville.

<u>Weather Event 12</u>

Figure 6.5-2 below depicts the North Coast North Bay area transmission lines taken out as part of weather event 9.

Figure 6.5-2: North Coast North Bay area transmission lines taken out as part of weather event 9



Direct Impact

- Geysers #9-Lakeville 230 kV line is a radial line that is a non-ISO-controlled PG&E line that is a generation interconnection for the following resources Geysers 9&10 (retired), SMUD, Geyser 13, Geyser 18, NCPA 1 and NCPA 2.
- Geysers #12-Fulton 230 kV line is a radial line that is a non-ISO-controlled PG&E line that is a generation interconnection for the following resources Geysers 12 and 14.
- Geysers #17-Fulton 230 kV line is a radial line that is a non-ISO-controlled PG&E line that is a generation interconnection for the following resources Geysers 17 and Bottle Rock.
- Eagle Rock-Fulton-Silverado 115 kV line results in loss of supply to the following substations Rincon, Silverado, Monticello and Monticello PH. However, these stations can be served from the alternate (Fulton-Pueblo) 115 kV line.
- Eagle Rock-Cortina 115 kV line results in loss of supply to Highlands and Homestake.
- Geyser 7-Eagle Rock 115 kV line results in loss of Geyser 7 resource.
- Geyser 7-Eagle Rock 115 kV line results in loss of Geyser 7 resource.
- Fulton-Calistoga 60 kV line results in loss of supply to Calistoga substation
- Mendocino-Cortina 115 kV line results in loss of supply to Lucern and Indian Valley PH.
- Mendocino-Redbud and Eagle Rock-Redbud 115 kV lines result in loss of supply to Redbud
- Loss of supply to Eagle Rock Substation due to Fulton-Silverado-Eagle Rock, Eagle Rock-Mendocino, Eagle Rock-Cortina and Hopland-Cloverdale 115 kV lines and Clear Lake-Konocti 60 kV line results in additional loss of supply to Cloverdale, Geo Eng, Geyser 5&6 and Geyser 11 115 kV stations and Konocti and Middletown 60 kV stations.
- Laytonville-Covelo 60 kV line results in loss of supply to Covelo

Indirect Impact Thermal

- Along with the loss of local generation similar to the Event 7, significant amount of load is also lost as a direct load impact due to the large number of 60 and 115 kV lines included within the scope.

Indirect Impact Contingency

- Under this extreme condition, no contingency assessment is further performed with the stressed base case condition.

6.5.5 Conclusion

The weather events that include the outage of the high-frequency 230 kV gen-tie lines (such as Event 7) result in significant loss of local generation in the area. Most of the 60 kV and 115 kV remain in-service supplying the load in the areas resulting in overloading the remaining 230 kV lines supplying the North Coast North Bay areas. Additional overloads that would be more severe could occur under contingency in this weather event scenarios.

Hardening the 230 kV non-ISO-controlled gen-tie lines that have a high-frequency of being taken out of service, in the weather event scenarios provided by PG&E, would prevent loss of the local generation that would address the overloads on identify 230 kV lines. Additionally, closing the normally open connection from the Fulton Junction to Pueblo could also be explored to bring supply into the North Coast North Bay area.

Weather event 9 represents a widespread extreme event in the area, which results in loss of multiple 230 kV lines with Geyser generation supply and 115 and 60 kV lines supplying the local loads in the area. This event includes a large number of transmission lines that are only taken out in this extreme weather event. There is no obvious transmission mitigation for this event due to the extreme nature of it. Additional supply lines to the area without hardening local lines does not provide much benefit from a load-loss perspective.

Also, impact from distribution-only outages needs to be considered before looking further into transmission mitigations. The ISO will continue to work with PG&E to evaluate the possibility of hardening the 230 kV gen-tie lines and to prevent loss of load served from Fulton-Calistoga 60 kV line.

6.6 Southern California Area Wildfire Impact Assessment

6.6.1 Background

As part of the 2021-2022 transmission planning process, the ISO has continued the assessment of the impacts of wildfire and PSPS events by also assessing the potential risks of de-energizing ISO-controlled facilities in the High Fire Risk Area's (HFRA) for SCE and SDG&E and developing potential mitigation options to alleviate the impacts.

As was the case with PG&E, in the SCE and SDG&E areas, multiple phases of PSPS transmission monitoring events were carried out in 2019 and 2020 potentially impacting customers in high fire risk areas across their service territories.

The assessment began with scenario development by SCE and SDG&E. The range of selected scenarios needed to represent a reasonable set of boundary conditions and was based on a fact-based framework. The scenarios also needed to be reasonable. As an example, de-energizing all facilities within a HFRA may not be reasonable for some areas. At the same time, the number of scenarios being considered also needed to be manageable within the planning cycle. A combination of voltage levels, common corridors, etc. were also considered in the development of scenarios.

6.6.2 Objective

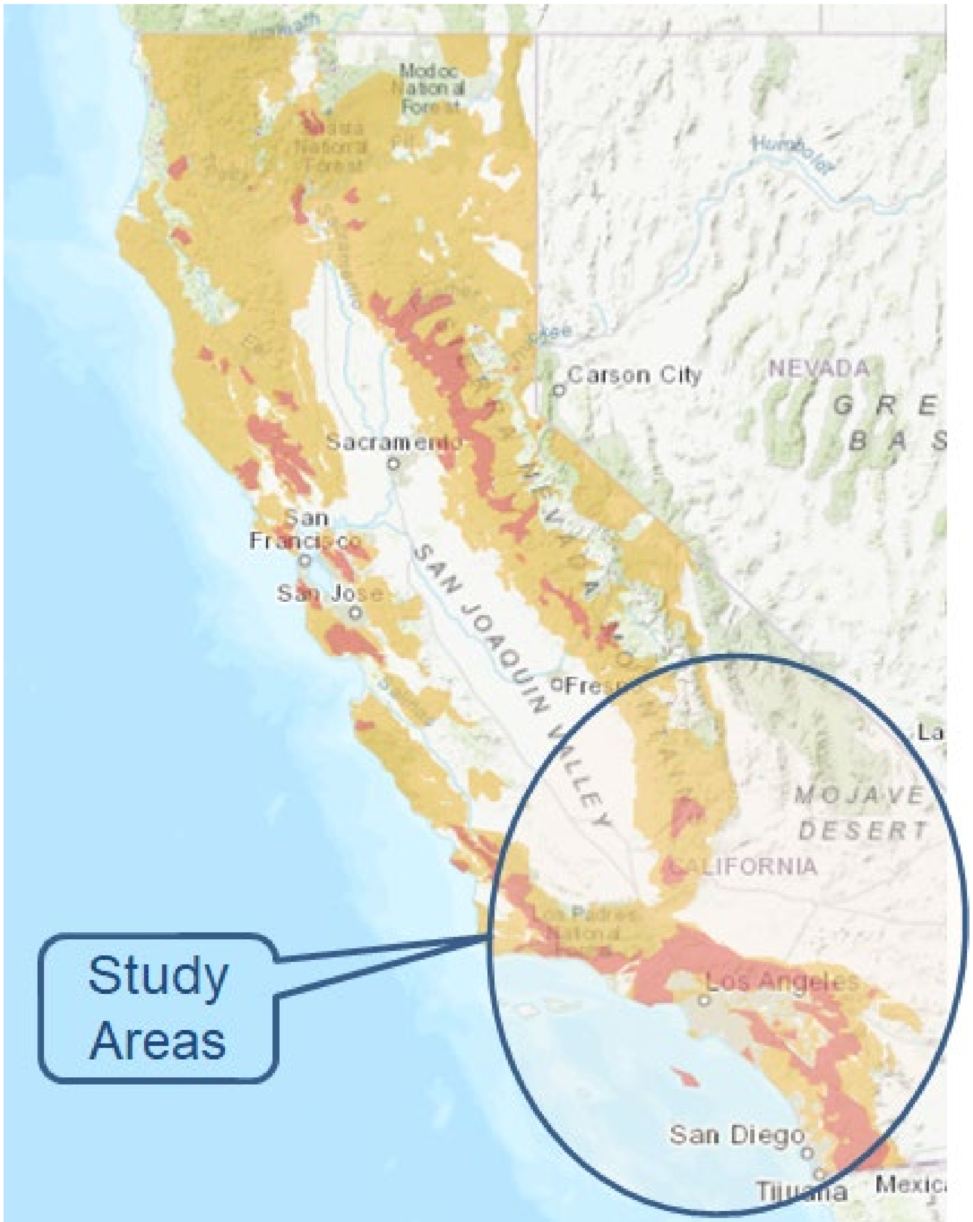
The objective of this assessment was to identify the potential load at risk and potential system reliability risks under various PSPS or wildfire scenarios and to develop potential mitigations to alleviate the impact of future PSPS or wildfire events from a long-term planning perspective.

6.6.3 Study Approach

6.6.3.1 Scenario Development

The ISO worked with SCE and SDG&E to develop various study scenarios that have been prone to past PSPS or wildfire events. For these areas, SCE and SDG&E created scenarios that remove specific ISO-controlled facilities from service to determine the risks and performance thresholds of 1) pre-emptively de-energizing these facilities as part of a potential PSPS, or 2) losing these facilities as a forced outage due to uncontrollable events such as wildfires. These scenarios may be categorized as "extreme events" if they are beyond the minimum requirements of NERC reliability standards and ISO planning standards. The high fire threat area map for southern California is depicted below.

Figure 6.6-1 – CPUC High Fire Threat District Map



Source: https://ia.cpuc.ca.gov/firemap/

Scenarios were developed in collaboration with SCE and SDG&E and reviewing historical data for the following:

- When PSPS events occurred or identified to be likely to occur and identifying facilities that were de-energized or flagged to be de-energized based on forecasted conditions
- Actual fire events and identifying facilities that were de-energized

The tier-2 or tier-3 fire zone maps were also utilized in the development of these study scenarios. Study scenarios included both localized and wide-area scenarios (see the next section).

6.6.3.2 Study scenarios

Using the approach mentioned above, 10 study scenarios were developed for the SCE service area and eight study scenarios for the SDG&E service area. Of these scenarios, two study scenarios for each of these areas are common scenarios to be jointly studied between these two areas. Due to the Participating Transmission Owners' request for confidentiality on the identity of the transmission lines that were de-energized as a result of PSPS or fire events, the ISO does not provide the transmission line names here but only the number of counts of de-energized transmission lines based on voltage levels. The study scenarios are listed below in the following tables:

Table 6.6-1 Study scenarios for SCE service area

Scenario ID	Scenario Description	Wildfire Event?	Potential PSPS Event?	Number of 500 kV Lines De-Energized	Number of 230 kV Lines De-Energized	Study Base Cases
1	Ventura PSPS event	No	Yes	**0**	**2**	Spring 2023 off-peak
2	Ventura & Los Angeles PSPS event	No	Yes	0	2	Spring 2023 off-peak
3	Kern localized PSPS event	No	Yes	1	2	Spring 2023 off-peak
4	San Bernardino & Orange PSPS event	No	Yes	2	2	Summer 2026 peak
5	Los Angeles PSPS event	No	Yes	1	6	Summer 2026 peak
6	San Bernardino PSPS event	No	Yes	0	2	Summer 2026 peak
7	SCE Main system-wide PSPS event	No	Yes	9	5	Spring 2023 off-peak
8	Big Creek fire scenario	Yes	No	0	4	Summer 2026 peak
9A	Bond fire scenario (joint SCE/SDG&E study scenario #1)	Yes	Yes	1	2	Spring 2023 off-peak
9B	Bond fire scenario (joint SCE/SDG&E study scenario #2)	Yes	Yes	1	4	Spring 2023 off-peak

Table 6.6-2 Study scenarios for SDG&E service area

	Scenario Description	Wildfire Event?	PSPS Event?	Number of 500kV Lines De-Energized	Number of 230kV Lines De-Energized	Number of 138kV Lines De-Energized	Number of 69kV Lines De-Energized	Study Base Cases
1	SDG&E 2007 fire event[156]	Yes	No	2	9	4	19	Summer 2026 peak
2	Eastern 69kV PSPS event	No	Yes				4	Spring 2023 off-peak
3	Southeastern fire event	Yes	No	1	1		1	Summer 2026 peak
4	Northern and Southeastern localized PSPS event	No	Yes		1		2	Summer 2026 peak
5	Various Eastern 69kV lines PSPS event	No	Yes				12	Spring 2023 off-peak
6	Various Eastern 69kV lines PSPS event (different than event #5)	No	Yes				5	Spring 2023 off-peak
7A	Bond fire scenario #1 (joint SCE/SDG&E study scenario #1)	Yes	No	1	2			Spring 2023 off-peak
7B	Bond fire scenario #2 (joint SCE/SDG&E study scenario #2)	Yes	No	1	4			Spring 2023 off-peak

[156] This study simulates SDG&E's 2007 fire event using updated power flow study case in the 2021-2022 transmission planning cycle.

6.6.3.3 Scope of Assessment

Using the scenarios developed, the ISO conducted a study with the following scope for assessment of the load drop and potential impact on grid performance:

- Local or radial system load impact (direct impact) and
- Area supply or system performance impact (indirect impact)

The first step of the assessment was to record the amount of load lost as a result of radial system or island created due to the facilities de-energized as part of the scenario. This is also referred to as direct impact. The next step involved assessing base case system performance after modeling each PSPS scenario. If any normal reliability issues identified in the base case, further actions were taken in the form of opening the overloaded lines or further load drop to alleviate issues in the base cases. These further actions are recorded as indirect impact. Once the base case was prepared with no normal violations, relevant P1 and/or P7[157] contingencies were taken to make sure that the base case is secure for the next worst contingency. System performance following the next contingencies were assessed and recorded for reporting.

The 2021-2022 transmission planning process 2023 spring off-peak or 2026 summer peak base case for the planning area was used as a starting base case. The choice of using either 2023 spring off-peak case, or 2026 summer-peak case was based on the season in which the PSPS or the wildfire event occurred or was deemed likely to occur in previous years. Each scenario was applied to the starting case one at a time with all facilities within the PSPS, or wildfire event study scope, being de-energized concurrently. The sequential load isolated due to application of PSPS or wildfire event is then identified as the direct load impact. In addition, any normal or emergency overloads, or voltage issues, were identified and mitigated with generation re-dispatch, system reconfiguration or load drop. The load drop is thereafter identified as indirect load impact.

6.6.3.4 Mitigation Development

Following the assessment and based on the evaluation of direct and indirect load impacts, high impact, or critical, facilities in each areas were identified. The high impact facilities are such that if excluded from the scope of PSPS or wildfire scenario, the exclusion will have a significant impact on reducing the risk of PSPS impact in terms of direct or indirect load loss. The ISO will coordinate with the Southern area PTOs to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS or wildfire events if possible.

The ISO has also looked into the active ISO-approved projects in the area to explore if any of the projects could potentially reduce the impact of load loss from the different scenarios assessed. One previously approved project and one project recommended for approval in this planning cycle were found to have a significant impact on reducing the risk of PSPS or wildfire

[157] Additional contingencies that are deemed credible P7 contingencies were performed for the SDG&E area only.

event impact from one of the study scenarios. The previously approved project is the S-Line (Imperial Valley-El Centro 230kV line) Upgrade, which had been approved by the ISO Board in the 2017-2018 Transmission Plan. This project has an in-service date of Q2 2023. The project recommended for approval is the Laguna Bell-Mesa 230 kV reconductoring project.

No new transmission upgrades were developed at this time other than identifying high impact critical facilities so that those could be considered further for further potential facility hardening. Excluding of high impact facilities from PSPS events, if possible, would help reduce direct and indirect load loss for the PSPS or wildfire events that were studied.

6.6.4 Assessment Results

6.6.4.1 Southern California Edison Area

The 10 wildfire study scenarios for the Southern California Edison service area cover a total of 38 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, thirteen lines are 500 kV and twenty five lines are 230 kV.

The results of the assessment of the ten scenarios identified in the section 6.6.4.1 show that there could be a significant amount of load and generation loss, along with system performance concerns in scenarios #5, #6, #7, and #8. For the remaining scenarios, no load or generation loss was identified. Table 6.6 3 summarizes the results from all ten scenarios in terms of the direct load impact and indirect load impact due to system performance following mitigation of either normal or contingency conditions. Below is a description of the identified system performance impacts along with the critical facilities and potential wildfire mitigation solutions.

- **Scenario #5:** about 1000 MW of indirect impact load loss was identified. This is related to an operational mitigation addressing P0 overloading concerns on the Mesa 500/230 kV bank No.2 and the Mesa – Laguna Bell 230 kV No.2 line, even after all of available non-storage resources in the Western LA Basin, San Bernardino, and San Diego areas were dispatched. If the Alamitos Energy Storage System could be dispatched, the indirect load loss would be reduced to 900 MW from the 1000 MW. As alternative, if the short circuit current duties allow, closing the sectionalizing bus-tie at Mesa 230 kV substation could drastically reduce the direct impact load loss to as low as 50 MW or 0 MW from 1000 MW or 900 MW if the Alamitos energy storage could be dispatched. No load loss impact was identified for P1 contingencies.
- **Scenario #6:** there is 751 MW direct impact load loss impact as a result of an island created due to the PSPS facilities de-energized. No load loss impact is identified for P1 contingencies.
- **Scenario #7:** in addition to the 751 MW direct impact load loss impact as the same result as Scenario #6, the P0 overload on Mesa – Laguna Bell No.1 230 kV line could be mitigated by operational mitigations dispatching available non-storage resources in the Western LA Basin, San Bernardino, and San Diego areas. The Mesa – Laguna Bell 230 kV No.2 reconductoring project recommended for approval in this planning cycle could

alleviate the need for the massive generation re-dispatch over a wide area when implemented. No load loss impact was identified for P1 contingencies.

- **Scenario #8:** there are about 7 MW of direct load loss and 900 MW of generation loss as a result of an island created due to the PSPS facilities de-energized. No load loss impact was identified for P1 contingencies.

Based on the study results, the high impact critical facilities shown in Table 6.6.3 were identified for Scenario #5, #6, #7, and #8 respectively. If one or more than one of the critical facilities are excluded for each of the Scenarios, most if not all of the load loss and significant system performance impact including generation loss and system adjustments could be avoided.

Table 6.6 3 SCE PSPS and Wildfire Study Scenario Impact

No.	**Scenario**	**Scenario Study Impact**		**Critical Facilities**
		Direct Load Impact (MW)	**System Performance Impact (MW)**	
1	Ventura PSPS event	0	0	None
2	Ventura & Los Angeles PSPS event	0	0	None
3	Kern localized PSPS event	0	0	None
4	San Bernardino & Orange PSPS event	0	0	None
5	Los Angeles PSPS event	1000 MW or 900 MW if energy storage could be dispatched	Significant generation re-dispatched in a wide area to mitigate the P0 normal overloads in addition to the load loss	Mesa-Vincent No.1 or No.2 230 kV, Eagle Rock-Sylmar 230 kV, or Goodrich-Gould and Gould-Sylmar 230 kV
6	San Bernardino PSPS event	751 MW	0	Information shared with PTO
7	SCE Main system-wide PSPS event	751 MW	Significant generation re-dispatched in a wide area to mitigate the P0 normal overload	Information shared with PTO
8	Big Creek fire scenario	7 MW	900 MW of generation loss	Big Creek 3-Rector No. 1 230 kV, Big Creek 3-Rector No. 2 230 kV, or Big Creek 1-Rector 230 kV
9A & 9B	Bond fire scenario #1 & 2	See notes under SDG&E on the next table		

6.6.4.2 San Diego Gas & Electric Company Service Area

The San Diego Gas & Electric Company service area has a total of 112 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, two lines are 500 kV, 26 lines are 230 kV, 20 lines are 138 kV and 64 ines are 69 kV lines.

The results of the assessment of the eight scenarios identified in the section 6.6.4.2 show that there could be a significant amount of load loss and system performance concerns in the wildfire event scenarios, especially wildfire scenario no. 1, which is an attempt to replicate the San Diego 2007 wildfire event. For the remaining scenarios, the amount of load losses were identified to be much less. Table 6.6-4 summarizes the results from all eight scenarios in terms of the direct load impact and indirect load impact due to system performance following mitigation of either normal or contingency conditions.

Table 6.6-4 SDG&E PSPS and Wildfire Study Scenario Impact

Scenario No.	Scenario Description	Study Base Case[158]	Direct Load Impact (MW)	Indirect Load Impact (MW)	High Impact Critical Transmission Facilities	Notes
1	SDG&E 2007 fire event	Summer 2026 peak	51	2539	ECO-Miguel and Ocotillo-Suncrest 500kV Lines	1) Indirect load loss to mitigate normal overloads and voltage stability related issue: 1577 MW; 2) Additional indirect load loss to mitigate P1 overloads: 962 MW.
2	Eastern 69kV PSPS event	Spring 2023 off-peak	10	0	TL625 Descanso - Loveland 69 kV line OR TL6923 Barrett - Cameron 69 kV line	
3	Southeastern fire event	Summer 2026 peak	0	420	Ocotillo-Suncrest 500kV Line	Indirect load loss to mitigate P1 and P7 overloads: 420 MW
4	Northern and Southeastern localized PSPS event	Summer 2026 peak	2	80	TL23030 Escondido - Talega - Capistrano 230 kV line	Indirect load loss to mitigate P7 overloads: 80 MW
5	Various Eastern 69kV lines PSPS event	Spring 2023 off-peak	56	0	TL6904 Alpine - Loveland 69 kV line TL6957 Barrett - Loveland 69 kV line TL6923 Barrett - Cameron 69 kV line TL629 Descanso - Crestwood - Glencliff 69 kV line TL625 Descanso - Loveland 69 kV line TL637 Creelman - Santa Ysabel 69 kV line TL685 Santa Ysabel - Warners 69 kV line	

158 Selection of the study base case was based on the study load season of the actual PSPS or wildfire events

Scenario No.	Scenario Description	Study Base Case[158]	Direct Load Impact (MW)	Indirect Load Impact (MW)	High Impact Critical Transmission Facilities	Notes
6	Various Eastern 69kV lines PSPS event (different than event #5)	Spring 2023 off-peak	10	0	TL686 Narrows - Warners 69 kV line TL682 Rincon - Warners 69 kV line OR TL685 Santa Ysabel - Warners 69 kV line	
7A	Bond fire scenario #1 (joint SCE/SDG&E study scenario #1)	Spring 2023 off-peak	0	0	None	
7B	Bond fire scenario #2 (joint SCE/SDG&E study scenario #2)	Spring 2023 off-peak	0	146	North of San Onofre 230kV lines, or Imperial Valley – North Gila 500kV Line	1) Indirect load loss to mitigate P1 only: 146 MW 2) The ISO Board-approved S-Line Upgrades would mitigate identified contingency loading concern.

Based on the scenario study results, the high impact critical facilities are noted in the summary table above. If excluded from the future scope of PSPS scenario or some wildfire scenarios if feasible, they will have a significant impact on reducing the risk of PSPS or wildfire impact in terms of direct and indirect load loss. The ISO will continue to coordinate with both SCE and SDG&E to evaluate potential mitigation options within the utilities' wildfire mitigation plan to be able to exclude some of these facilities from the future PSPS or wildfire events. In regards to the system performance concerns identified for Scenario 7B based on the contingency analyses, it is expected that the ISO Board-approved transmission planning process project in the area (i.e., S-line upgrade) will address the identified performance deficiencies.

6.6.5 Conclusion

The impact of potential PSPS or wildfire events was evaluated to quantify the direct load impact as well as indirect load impacts of the study scenarios. High-impact critical facilities from each study scenario was identified. The high impact critical facilities are such that if it's feasible to be excluded from the scope of similar future PSPS or wildfire scenarios, their exclusion will have a significant impact on reducing the risk of PSPS or wildfire load loss impact. The ISO will continue to coordinate with both SCE and SDG&E to evaluate potential mitigation options within the utilities' wildfire mitigation plans for potential exclusion of these facilities from the future PSPS events. These potential mitigations could include transmission line facility hardening, or potential transmission upgrades in meeting reliability, economic or policy needs in which additional assessment could be performed to determine if the evaluated transmission upgrades also bring additional benefits of reducing PSPS or wildfire related load loss impact.

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 cycles 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. A number of those studies have now been incorporated into analysis set out in chapter 4 exploring resource portfolio scenarios, or are now being conducted on an annual basis and are set out in chapter 6. Further, the ISO undertook a 20-Year Transmission Outlook exercise in parallel with this transmission planning cycle. Accordingly, in the 2021-2022 transmission planning cycle, the ISO did not undertake any additional "special studies".

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Chapter 8

8 Transmission Project List

8.1 Transmission Project Updates

Table 8.1-1 and Table 8.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous transmission plans, the ISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location constrained resource interconnection facility project or enhance economic efficiencies.

Table 8.1-1: Status of Previously Approved Projects Costing Less than $50 M

No	Project	PTO	Transmission Plan Approved	Current Expected In-service date
1	Fulton-Hopland 60 kV Line Project (Original project was the "Fulton-Fitch Mountain 60 kV Line Conductor" approved in 2009 Transmission Plan. The project was rescoped and renamed in the 2017-2018 Transmission Plan)	PG&E	2017-2018	Complete Mar 2020
2	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	2012-2013	Complete Jan 2020
3	Kern PP 230 kV Area Reinforcement	PG&E	2011-2012	Complete Mar 2021
4	Los Esteros 230 kV Substation Shunt Reactor	PG&E	2015-2016	Complete Mar 2021
5	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	2012-2013	Complete Dec 2020
6	San Bernard – Tejon 70 kV Line Reconductor	PG&E	2013-2014	Complete Jan 2020
7	Semitropic – Midway 115 kV Line Reconductor	PG&E	2012-2013	Complete Mar 2021
8	West Point – Valley Springs 60 kV Line	PG&E	2007	Complete May 2020
9	Wheeler Ridge Voltage Support	PG&E	2011-2012	Complete July 2021
10	Wilson 115 kV SVC	PG&E	2015-2016	Complete May 2021
11	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	2019-2020	2027
12	Cascade 115/60 kV No.2 Transformer Project	PG&E	2010-2011	Dec-23
13	Christie-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	Dec-28
14	Clear Lake 60 kV System Reinforcement	PG&E	2009	Feb-27
15	Coburn-Oil Fields 60 kV system project	PG&E	2017-2018	Jun-29
16	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	2008	Nov-22
17	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	2018-2019	Oct-25
18	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project (Original project was the "Cottonwood 115 kV substation shunt reactor" approved in 2015-2016 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan)	PG&E	2017-2018	Oct-24
19	East Marysville 115/60 kV Project	PG&E	2018-2019	Nov-27
20	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	2019-2020	Dec-26

No	Project	PTO	Transmission Plan Approved	Current Expected In-service date
21	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	2011-2012	Dec-22
22	Estrella Substation Project	NEET West / PGaE	2013-2014	May-26
23	Gates 500 kV Dynamic Voltage Support	PG&E	2018-2019	Mar-25
24	Giffen Line Reconductoring Project	PG&E	2018-2019	Jan-23
25	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	2013-2014	Dec-22
26	Gold Hill 230/115 kV Transformer Addition Project	PG&E	2018-2019	Jun-28
27	Herndon-Bullard 115 kV Reconductoring Project	PG&E	2017-2018	Dec-26
28	Ignacio Area Upgrade (Original project was the "Ignacio-Alto Voltage Conversion Project" approved in 2011-2012 Transmisison Plan. The project was re-scoped and renamed in the 2017-2018 Transmission Plan)	PG&E	2017-2018	Dec-27
29	Jefferson 230 kV Bus Upgrade	PG&E	2018-2019	May-26
30	Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Jun-27
31	Lakeville 60 kV Area Reinforcement	PG&E	2017-2018	Dec-27
32	Manteca #1 60 kV Line Section Reconductoring Project	PG&E	2020-2021	Jun-27
33	Maple Creek Reactive Support (Rescoped to Willow Creek 60 kV Substation)	PG&E	2009	Jul-26
34	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	2003	Apr-29
35	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	2010-2011	May-25
36	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	2012-2013	Oct-27
37	Monta Vista 230 kV Bus Upgrade	PG&E	2012-2013	Aug-24
38	Moraga 230 kV Bus Upgrade	PG&E	2019-2020	Dec-27
39	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	2010-2011	Dec-25
40	Moraga-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	On Hold
41	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	2013-2014	Apr-26
42	Mosher Transmission Project	PG&E	2013-2014	Dec-27
43	Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition	PG&E	2019-2020	Dec-26
44	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	2017-2018	Nov-22
45	North Tower 115 kV Looping Project	PG&E	2011-2012	Dec-30
46	Oakland Clean Energy Initiative	PG&E	2017-2018	Mar-23
47	Oro Loma 70 kV Area Reinforcement	PG&E	2010-2011	Dec-26
48	Palermo – Wyandotte 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Jul-22
49	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	2015-2016	Mar-23

No	Project	PTO	Transmission Plan Approved	Current Expected In-service date
50	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	2007	Jan-25
51	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	2017-2018	Jan-23
52	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	2018-2019	Dec-24
53	Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects)	PG&E	2017-2018	Dec-25
54	Rio Oso 230/115 kV Transformer Upgrades	PG&E	2007	Apr-24
55	Rio Oso Area 230 kV Voltage Support	PG&E	2011-2012	Oct-24
56	Round Mountain 500 kV Dynamic Voltage Support	PG&E	2018-2019	May-24
57	Salinas-Firestone #1 and #2 60 kV Lines	PG&E	2019-2020	2025
58	South of Mesa Upgrade	PG&E	2018-2019	Sep-26
59	South of San Mateo Capacity Increase	PG&E	2007	Mar-27
60	Tesla 230 kV Bus Series Reactor project	PG&E	2018-2019	Aug-23
61	Tie line Phasor Measurement Units	PG&E	2017-2018	Dec-26
62	Tulucay-Napa #2 60 kV Line Capacity Increase	PG&E	2019-2020	2026
63	Tyler 60 kV Shunt Capacitor	PG&E	2018-2019	Dec-26
64	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	2017-2018	Apr-27
65	Vierra 115 kV Looping Project	PG&E	2010-2011	Jun-25
66	Warnerville-Bellota 230 kV line reconductoring	PG&E	2012-2013	Dec-24
67	Wilson 115 kV Area Reinforcement	PG&E	2010-2011	Sep-26
68	Wilson-Le Grand 115 kV line reconductoring	PG&E	2012-2013	Mar-22
69	Wilson-Oro Loma 115kV Line Reconductoring	PG&E	2019-2020	May-26
70	Laguna Bell Corridor Upgrade	SCE	2014-2015	Complete May 2020
71	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	2016-2017	Jan-25
72	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	2008	Apr-24
73	Method of Service for Wildlife 230/66 kV Substation	SCE	2007	Oct-26
74	Moorpark-Pardee No. 4 230 kV Circuit	SCE	2017-2018	Mar-22
75	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	2019-2020	Dec-25
76	Tie line Phasor Measurement Units	SCE	2017-2018	Dec-25
77	2nd Escondido-San Marcos 69 kV T/L	SDG&E	2013-2014	Sep-22
78	Reconductor TL 605 Silvergate – Urban	SDG&E	2015-2016	May-24
79	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	2013-2014	May-23
80	Rose Canyon-La Jolla 69 kV T/L	SDG&E	2013-2014	Jun-23
81	Sweetwater Reliability Enhancement	SDG&E	2012-2013	Jun-27
82	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	2013-2014	Dec-23
83	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	2013-2014	Jun-28
84	TL644, South Bay-Sweetwater: Reconductor	SDG&E	2010-2011	May-22
85	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	2012-2013	Dec-22
86	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	2013-2014	Jun-26

No	Project	PTO	Transmission Plan Approved	Current Expected In-service date
87	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	2011-2012	Jun-24
87	Bob-Mead 230 kV Reconductoring	GLW	2017-2018	Dec-20
88	Gamebird 230/138 kV Transformer Upgrade	VEA/GLW	2019-2020	2021
88	Tie line Phasor Measurement Units	VEA	2017-2018	Dec-20
88	IID S-Line Upgrade	Citizens Energy	2017-2018	2023

Table 8.1-2: Status of Previously-Approved Projects Costing $50 M or More

No	Project	PTO	Transmission Plan Approved	Current Expected In-service date
1	South of Palermo 115 kV Reinforcement Project	PG&E	2010-2011	Complete Jan 2021
2	Kern PP 115 kV Area Reinforcement	PG&E	2011-2012	Aug-27
3	Lockeford-Lodi Area 230 kV Development	PG&E	2012-2013	Jun-27
4	Martin 230 kV Bus Extension	PG&E	2014-2015	May-24
5	Midway – Kern PP #2 230 kV Line	PG&E	2013-2014	Jun-24
6	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)	PG&E	2012-2013	On Hold
7	Red Bluff-Coleman 60 kV Reinforcement (Original project was the "Cottonwood-Red Bluff No2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project" approved in 2010-2011 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan.)	PG&E	2017-2018	Nov-25
8	Vaca Dixon Area Reinforcement (Original project was the "Vaca – Davis Voltage Conversion Project" approved in 2010-2011 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan)	PG&E	2017-2018	Jul-26
9	Wheeler Ridge Junction Substation	PG&E	2013-2014	On Hold
10	Alberhill 500 kV Method of Service	SCE	2009	Oct-25
11	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	2012-2013	Jun-23
12	Lugo-Mohave series capacitor upgrade	SCE	2012-2013	Apr-23
13	Mesa 500 kV Substation Loop-In	SCE	2013-2014	May-22
14	Artesian 230 kV Sub & loop-in TL23051	SDG&E	2013-2014	Jun-22
15	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	2010-2011	Dec-23
16	Delaney-Colorado River 500 kV line	DCR Transmission	2013-2014	Apr-24
17	Gates 500 kV Dynamic Voltage Support	LS Power	2018-2019	Jun-24
18	Round Mountain 500 kV Dynamic Voltage Support	LS Power	2018-2019	Dec-24

8.2 Transmission Projects found to be needed in the 2021-2022 Planning Cycle

In the 2021-2022 transmission planning process, the ISO determined that 16 transmission projects were needed to mitigate identified reliability concerns; seven policy-driven projects were needed to meet the GHG reduction goals and one economic-driven project 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 2021 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	Contra Costa PP 230 kV Line Terminals Reconfiguration Project	PG&E	2025	$5M - $10M
2	Cortina 23011560 kV Transformer Bank No. 1 Replacement Project	PG&E	2027	$21M - $42M
3	Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project	PG&E	2028	$6.8M - $13.6M
4	Coppermine 70 kV Reinforcement Project	PG&E	2027	$15.8M - $31.6M
5	Vasona-Metcalf 230 kV Line Limiting Elements Removal Project	PG&E	2025	$0.6M - $1.2M
6	Weber-Mormon Jct Line Section Reconductoring Project	PG&E	2027	$9.3M - $18.6M
7	San Jose Area HVDC Line (Newark - NRS)	PG&E	2028	$325M-$510M
8	San Jose Area HVDC Line (Metcalf – San Jose)	PG&E	2028	$425M-$615M
9	Series Compensation on Los Esteros-Nortech 115 kV Line	PG&E	2023	$10M-$15M
10	Metcalf 230 kV Substation Circuit Breaker #No 292 Upgrade	PG&E	2025	$0.9M - $1.35M
11	Cooley Landing Substation Circuit Breaker No #62 Upgrade	PG&E	2026	$0.75M - $1.13M
12	Table Mountain second 500/230 kV transformer	PG&E	2027	$38.4M - $76.8M
13	Atlantic 230/60 kV transformer voltage regulator	PG&E	2026	$5M - $10M
14	Antelope 66 kV Short Circuit Duty Mitigation Project	SCE	2026	$55M
15	Devers 230 kV Reconfiguration Project	SCE	2023	$6M
16	Victor 230 kV Switchrack Reconfiguration	SCE	2023	$5M

Table 8.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project	SCE	2023	$17.3M
2	Reconductor Delevan-Cortina 230kV line	PG&E	2028	$17.7M–$35.4 M
3	New Collinsville 500 kV substation	PG&E	2028	$475M-$675M
4	Reconductor Rio Oso–SPI Jct–Lincoln 115kV line	PG&E	2028	$10.6M - $21.2M
5	New Manning 500 kV substation	PG&E	2028	$325M - $485M
6	GLW/VEA area upgrades	GLW/VEA	TBD	$278M

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	Installing 10 ohms series reactors on the PG&E's Moss Landing – Las Aguilas 230 kV line	PG&E	2026	$30-40M

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 2021-2022 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 2021-2022 Transmission Planning Process Unified Planning Assumptions and Study Plan, the ISO assesses the potential for existing and planned demand side resources to meet identified needs as a first step in considering mitigations to address reliability concerns.

The bulk of the ISO's additional and more focused efforts consisted of the development of local capacity requirement-need profiles for all areas and sub-areas, as part of the biennial 10-year local capacity technical study completed as part of this transmission planning cycle. This provides the necessary information to consider the potential to replace local capacity requirements for gas-fired generation, depending on the policy or long term resource planning direction set by the CPUC's integrated resource planning process.

Additionally, the ISO studied numerous storage projects proposed as providing reliability and economic benefits, as set out in chapter 2 and 4. Given the circumstances of this year's limited planning needs, there were few opportunities for development.

In addition to relying on the preferred resources incorporated into the managed forecasts prepared by the CEC, the ISO is also relying on preferred resources as part of integrated, multi-faceted solutions to address reliability needs in a number of study areas.

LA Basin-San Diego

Considerable amounts of grid-connected and behind-the-meter preferred resources in the LA Basin and San Diego local capacity area, as described in Sections 2.6.1, 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 available within the SCE and SDG&E areas with the necessary operational characteristics (i.e., 20-minute response) for use during overlapping contingency conditions.

Oakland Sub-area

The reliability planning for the Oakland 115 kV system anticipating the retirement of local generation is advancing mitigations that include in-station transmission upgrades, an in-front-of-the-meter energy storage project and load-modifying preferred resources. These resources are being pursued through the PG&E "Oakland Clean Energy Initiative" approved in the 2017-2018 Transmission Plan. Based on the latest development in the procurement activities, the location of the entire 36 MW and 173 MWh storage need has been moved to Oakland C. This continues to satisfy the local area need in absence of the local thermal generation. The approved project is expected to be in-service in 2023.

Kern Area

There were several short and long-term Category P1, P2, P6 and P7 reliability issues in the Tevis 115 and Wheeler ridge 230 kV areas that could not be mitigated without the Wheeler Ridge Junction Station Project. This project was put on hold in the 2019-20 transmission planning process. In the 2020-2021 transmission planning process, the ISO recommended procurement of a 95 MW 4-hour energy storage option to mitigate the 115 kV issues on the Kern-Lamont 115 kV system. The cost of this option was compared against several options, including reconductoring of the 115 kV lines, and was determined to be the lowest cost based on CPUC recommendation of including only the interconnection cost and not the full capital cost of the energy storage projects that are otherwise needed for system capacity purposes according to the CPUC-provided resource portfolios.

Central Coast & Los Padres Area

To provide a sufficient maintenance window within winter months for facilities in the area as required by the ISO planning standards, in the 2020-2021 transmission planning process, the ISO recommended the mitigation plan for procurement of approximately 50 MW 4-hour BESS at Mesa 115 kV substation to address the maintenance requirements and for the North of Mesa upgrade project to remain on hold pending procurement of the battery storage.

Moorpark and Santa Clara Sub-areas

As set out in section 2.7.5, the ISO is supporting the SCE's preferred resource procurement effort for the Santa Clara sub-area submitted to the CPUC Energy Division on December 21, 2017, by providing input into SCE's procurement activities and validating the effectiveness of potential portfolios identified by SCE. This procurement, together with the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double-circuit towers which was approved in the ISO's 2017-2018 Transmission Plan and went into service January 2022, 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 2021-2022 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

- New Collinsville 500 kV substation
- New Manning 500 kV substation
- San Jose Area HVDC Line (Newark to NRS)
- San Jose Area HVDC Line (Metcalf – San Jose)

The descriptions and functional specifications for the facilities eligible for competitive solicitation can be found in Appendix G.

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 ISO recognizes and appreciates concerns regarding the ratepayer impacts of capital projects identified and approved in the ISO's planning process. As the ISO did in this planning cycle, the ISO will continue to explore with stakeholders cost-effective solutions to meeting long term needs in future planning cycles.

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 appropriate 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.

In reviewing the latest estimate, as illustrated in Figure 8.5 1, the trend of the 2022 TAC value for the 2022 projection remains relatively consistent with the 2021 projection. The projection also includes capital projects in this year’s plan and all other transmission plan projects not already energized. The increase of $2.70 from last year’s projection for January 1, 2022 to this year’s actuals reflects the increase in utility operating costs and capital maintenance costs above the historical average projections for those non-ISO-approved costs.

Figure 8.5-1 Forecast of ISO High Voltage Transmission Access Charge Trending from First Year of Transmission Plan