California ISO

2025-2026
TRANSMISSION PLAN

ISO Board Approved

May 19, 2026

Forward

At the May 19th, 2026, ISO Board of Governors meeting the ISO Board of Governors approved the 2025-2026 Transmission Plan. The following projects were approved in the Transmission Plan but will be on hold for further coordination with Silicon Valley Power. The ISO will seek future Board of Governors approval after this has been done to remove the hold on these projects or approval of any modification or additions to these projects resulting from the review with Silicon Valley Power.

- DeAnza 115 kV Substation project
- South Bay Reinforcement Project (Re-scope) - Segment G

TABLE OF CONTENTS

Executive Summary

The California Independent System Operator's (ISO) 2025-2026 Transmission Plan demonstrates the ISO's integrated and comprehensive approach to transmission planning and represents the most cost-effective and affordable way of meeting forecasted demand and the state's energy policy objectives in the years ahead. The ISO routinely considers a wide array of technical options in the transmission planning process, ranging from conventional transmission additions, reinforcements or upgrades to existing facilities to fully utilize existing infrastructure, and grid-enhancing technologies that can, where feasible, increase capacity more economically than building new transmission lines. The transmission projects identified in this plan over the next 10 years are driven primarily by increased load growth including building and transportation electrification, manufacturing, and large loads including data centers, and the state's projection that the grid will need an additional 107 gigawatts of installed capacity by 2040.

The ISO has prepared this 2025-2026 Transmission Plan as part of its core responsibility to identify and plan the development of most cost-effective solutions to comprehensively meet the future needs of the ISO-controlled transmission grid. The Comprehensive Transmission Plan was prepared through the annual transmission planning process (TPP) that will culminate in an ISO Board of Governors (Board)-approved Comprehensive Transmission Plan drafted to help meet the state's energy policy objectives in a reliable, integrated, least-cost and technology informed manner. This plan was developed in coordination with the California Public Utilities Commission (CPUC), California Energy Commission (CEC), industry participants and stakeholder input.

This transmission plan reflects significant additional transmission expansion requirements consistent with, and building on, the transmission needs identified in recent transmission plans. The plan is also consistent with the ISO's 20-Year Transmission Outlook initially published in 2022 and updated two years later. As those longer-term analyses reflect, over the last five years, under California's highly integrated resource and transmission planning process, the need for transmission expansion has grown steadily with the emphasis evolving from primarily accessing low-cost renewable generation basins to now also reliably meeting growing customer demand. The increasing customer demand is driven by several factors, including building and transportation electrification, manufacturing, and large loads including data centers. The ISO recognizes the concerns around electricity affordability and is committed to ensuring that system needs are met with the transmission upgrades that most efficiently and cost-effectively meet those needs while providing the best customer value over the long term. In addition, as part of our commitment to strive for the most innovative, efficient and cost-effective transmission solutions, the ISO routinely considers a wide array of technical options in the transmission planning process, ranging from conventional transmission additions, reinforcements or upgrades to existing facilities to fully utilize existing infrastructure, and grid-enhancing technologies that can, where feasible, increase capacity more economically than building new transmission lines. While each transmission plan builds on previously approved plans and projects, the ISO also reviews previously approved projects, on a case-by-case basis, when there is a material change in circumstances that warrant reconsideration.

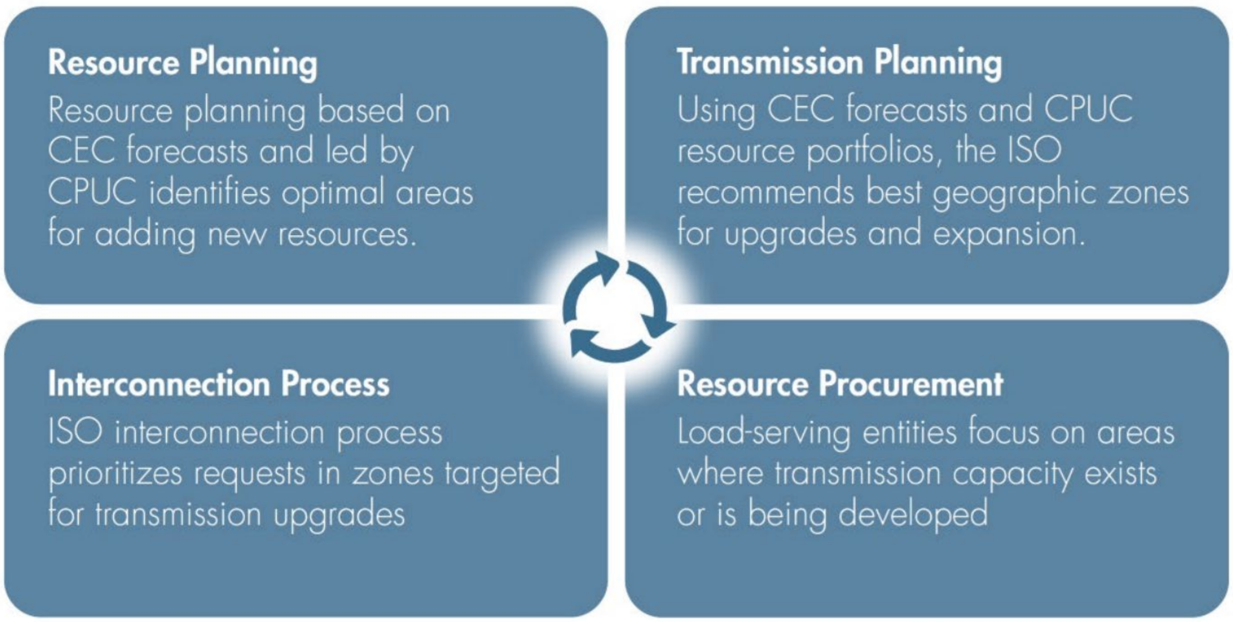
The transmission projects recommended for approval in this plan represent significant investments that are phased in over lead times of up to eight to 10 years, which are reasonable for some of the projects to be completed. These costs translate to approximately 0.5 cents per kWh over the life of the projects, phased in as the new facilities come online. The costs for consumers are ultimately determined as part of the rate design process between utilities and their regulatory authorities. These projects are consistent with the ISO's 20-Year Transmission Outlook and co-optimized with resource planning through the CPUC's integrated resource planning process. The ISO also conducted detailed evaluations of alternatives to ensure achievement of the most efficient and cost-effective long-term solutions. The infrastructure investments also have tremendous reliability and economic benefits for California, and the transmission upgrades are required to cost-effectively bring reliable decarbonized power to California consumers and industry across all seasons of the year.

> Transmission projects are categorized as reliability-driven needed to serve load reliably and meeting NERC national standards; policy-driven needed to deliver renewable generation to load centers to meet state clean energy goals, and economic-driven that will reduce the cost of energy to ratepayers by, for example, reducing grid congestion costs.

Integrated Zonal Planning and Interconnection

Proactive and coordinated resource and transmission planning are the cornerstone of the ISO's transmission planning process and have taken on even greater importance over the past several years. The strategic direction of this approach was initially set forth in a joint Memorandum of Understanding (MOU) signed in December 2022 by the ISO and the state's two principal energy policy entities, the CEC and the CPUC. Consistent with that agreement, this Transmission Plan represents the latest iteration of our integrated approach whereby the CEC completes annual energy demand forecasting, which is used as the basis of the CPUC's Integrated Resource Planning process. The ISO then supplements the CPUC's Integrated Resource Plans with the plans of other Local Regulatory Authorities (e.g. municipal utilities) as the central inputs into the annual transmission planning process (TPP). The zones identified for new transmission are prioritized for development and procurement in the ISO's interconnection process to ensure that resource and transmission planning are complementary and co-optimized. The highly integrated process described in the MOU is designed to ensure that California is equipped to meet its reliability needs and clean-energy policy objectives required by Senate Bill 100.[1]

Figure ES-1: Tightening linkages of resource and transmission planning activities, interconnection processes and resource procurement



This year's transmission plan is based on the state projections[2] provided to the ISO in 2025 that the California load[3] will grow by 15 gigawatts (GW) by 2035 and 20 GW by 2040 while the installed resource capacity[4] will need to increase by more than 74 GW and 107 GW, respectively. This reflects greenhouse gas reduction goals and load growth, including the potential for increased electrification occurring in other sectors of the economy, most

[1] SB 100, the 100% Clean Energy Act of 2018, 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

[2] In planning for the new resources required to meet system-wide resource needs, CPUC 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 planned retirement of the Diablo Canyon Power Plant. The ISO is not relying on the gas-fired generation or Diablo Canyon Power Plant to meet any local capacity or grid support purposes beyond the planned retirement dates. However, the ISO must continue to ensure that they are reliably interconnected and can continue to operate through any potential extension period, so the resources are modeled in the ISO's studies for those purposes only.

[3] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0

[4] The CPUC-provided portfolio calls for 107 GW of installed capacity, beyond its baseline of existing resources and resources already contracted for and under development.

notably in transportation and the building industry. This capacity requirement is consistent with the base portfolio amounts that were the basis of the 2024-2025 Transmission Plan and aligns with the ISO's most recent 20-Year Transmission Outlook. The sensitivity assessment, which examines how an outcome is affected when the impact of different variables is considered, provided information related to the potential additional geothermal, long duration energy storage (LDES), and offshore wind resources by 2035.

The increased rate of load growth reflected in the most recent CEC load forecast, associated with building and other electrification, data center growth, and transportation electrification, results in significant reliability-driven needs in this year's transmission plan. In contrast, the need for new generation and other resources has only increased modestly from those reflected in last year's transmission plan.

This plan, and the projects described on the following page, will enable the grid to accommodate the forecasted load growth and critical resource development, including:

- An increase in the year-over-year rate of peak demand growth from 1.53 to 2.42 percent, and in particular, a change from 2.21 to 3.95 percent in the Greater Bay area, which represents an increase in the 2035 peak load forecast of over 1,800 MW in the Greater Bay from the previous planning cycle.
- 45 GW of solar generation from regions that include the Westlands area in the Central Valley, Tehachapi, the Kramer area in San Bernardino County, Riverside County, as well as southern Nevada and western Arizona;
- 8 GW of in-state wind generation in existing wind development regions, including Tehachapi;
- Over 2 GW of geothermal development, primarily in the Imperial Valley and in southern Nevada;
- Access for battery storage projects co-located with renewable generation projects across the state, as well as stand-alone storage located closer to major load centers in the LA Basin, greater Bay Area, and San Diego;
- The import of over 10 GW of out-of-state wind generation from Idaho, Wyoming and New Mexico, by enhancing corridors from the ISO border in southeastern Nevada and from western Arizona into California load centers; and
- Over 4.5 GW of offshore wind with 2.9 GW in the Central Coast (Morro Bay call area) and 1.6 GW in the North Coast area (Humboldt call area) that were identified in the CPUC portfolio.

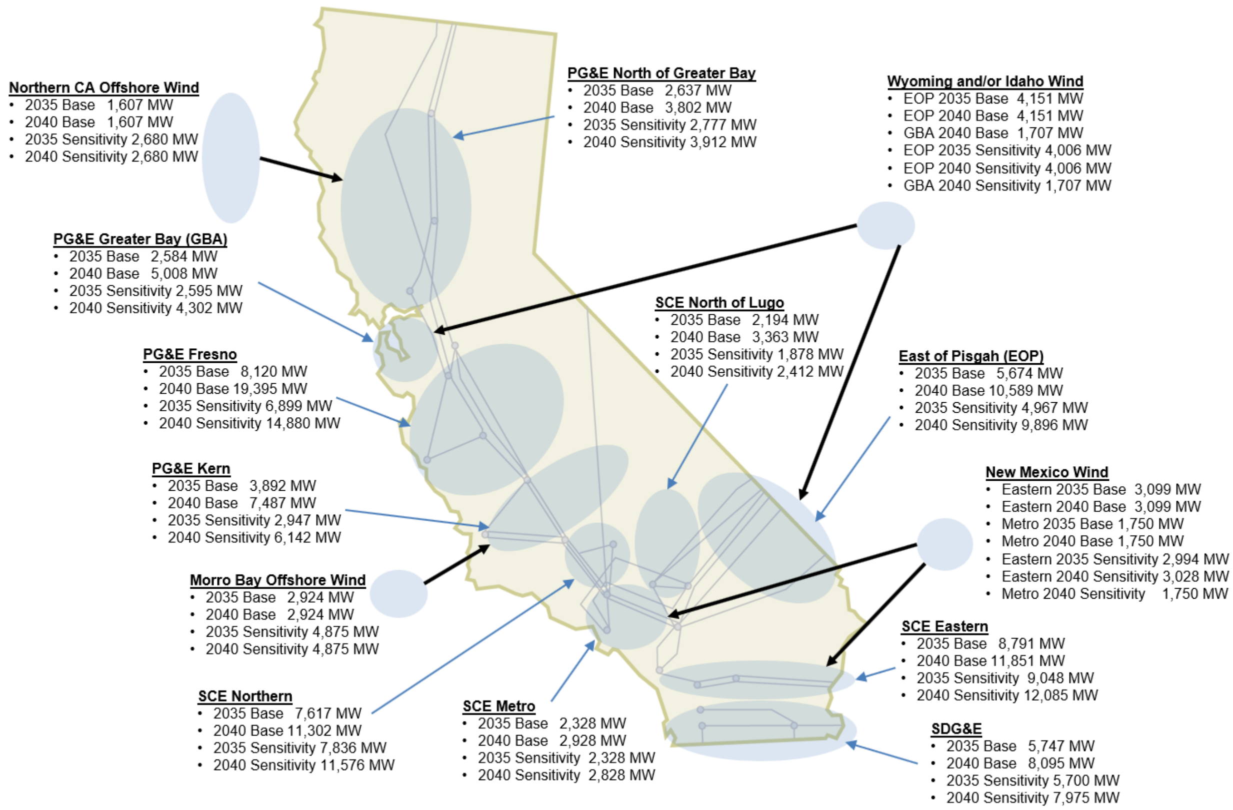
To achieve these outcomes, the ISO has found the need for 38 transmission projects for a total infrastructure investment of an estimated $6.7 billion at full buildout over the next 10 years. The comprehensive analysis included screening of hundreds of options and detailed assessments of alternatives in addition to the recommended projects. The alternative analysis considered transmission upgrades, preferred resources (such as storage), grid-enhancing technologies (GETs) and remedial action schemes and recommends their deployment where feasible. The recommended reliability-driven and policy-driven projects, most notably related to load growth in the Greater Bay area, include:

- Greater Bay Area Tesla – Trimble – Metcalf 230 kV Corridor Expansion to supply the south Greater Bay area;
- Trout Canyon – Lugo 500 kV Line to access resources in the East of Pisgah area;
- Short-circuit duty upgrades at a number of stations to accommodate increases in resources in the CPUC portfolio;
- Gates – Los Banos #3 500 kV Line Series Compensation to address congestion on Path 15; and
- A host of smaller upgrades improving supply of load and access to other smaller resource zones.

The ISO has also determined the need for a 500 kV line from Windhub to Tesla substation to address congestion on the Path 15 corridor. However, further technical bulk system assessment of the recommended alternative is required, which the ISO will conduct in the next planning cycle, prior to recommending approval of a transmission solution.

Figure ES-2 illustrates the specific zones and capacities in each zone enabled by this Transmission Plan. The network upgrades are recommended in this plan to make all of the base amounts available with the focus on the sensitivity portfolio to assess the transmission needs with additional offshore wind in the North Coast area.

Figure ES-2: ISO Transmission Planning Zones with CPUC Resource Busbar Mapping Results



Transmission congestion

The ISO's transmission planning process has consistently monitored and reported anticipated economic congestion over the planning horizon through production cost modeling, consideration of evolving load and generation patterns, and transmission system development. Congestion occurs when transmission constraints into an area result in higher cost generation being dispatched to serve load inside the area, because of the limitation precluding more lower cost generation being transmitted into the area from outside. The resulting overall higher cost generally finds its way to consumers, resulting in higher energy bills. Calculating the overall impact on consumers is complex, as removing a transmission constraint will result in lower costs in the constrained area, and lower costs overall, but can also drive-up costs outside of the constrained area. As part of our planning analysis, the costs of congestion to consumers in aggregate are weighed against the cost of transmission reinforcement to reduce or eliminate the congestion. The amount of forecasted congestion is considered on major transfer paths (including the 500 kV corridor in the Central Valley), local capacity areas where reliability needs are dependent in part on local resources, and in paths exporting generation from major resource basins.

Over the last 15 years of this monitoring and reporting, the ISO observed many periods of relatively low load growth where congestion on major paths was a potential concern but found to be insufficient to warrant the cost of upgrades, particularly on major transfer paths. The transmission needed to ensure sufficient deliverability for resources to provide resource adequacy capacity also tended to keep congestion from resource basins manageable and below the levels that would justify additional enhancements. Within this environment, several economically justified projects did proceed, but this represented a relatively small number of upgrades.

As set out in this transmission plan, the pace of increasing load growth, resource development and evolving transfer patterns inside and outside of California are changing future expectations, and the ISO now sees significant and increasing value in addressing growing congestion costs on the transmission system. For example, the ISO's 2021-2022 10-year plan forecast 244 hours of congestion on the most limiting circuit in Path 15 for 2030. Five years later, this 2025-2026 plan's studies forecast 3,256 hours of congestion for 2035 for the most limiting circuit in the corridor. This 10-fold increase in the number of forecast congestion hours in this one corridor alone is an indicator of increasing system inefficiency driving up generation costs due to transmission constraints. Reducing the amount of congestion provides economic value in reduced generation costs that warrants transmission reinforcement on key transfer paths, particularly Path 15, which the ISO expects to advance in this and future transmission plans.

Similarly, opportunities for economically driven upgrades to reduce the cost to customers of renewable generation production may also expand in the future. These may also create opportunities for products such as dynamic thermal line-rating tools that enable greater access to markets over meaningful windows even if not during peak load times that are driven by high temperature events.

While the cost of transmission upgrades is more visibly reflected in the transmission component of ratepayers' bills, the benefits of transmission reinforcements providing access to lower cost resources for consumers and lower congestion costs are contained in energy charges and difficult to isolate. The ISO is committed to focusing on providing the best overall value for end-use consumers in its planning processes.

Transmission Projects Recommended for Approval

The 38 new transmission projects found to be needed in the 2025-2026 transmission planning process totaling $6.7 billion at full buildout are as follows:

Reliability-Driven Projects: Reliability projects driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation represent 33 of the new projects, totaling $4.2 billion. The projects are required to reliably meet the increase in forecasted load related to electrification, large loads such as data centers and electric vehicle transportation loads.

Table ES-1: Reliability Driven Projects Recommended for Approval

#	ID	Project Name	PTO	Area	Est. Cost ($M)
1	1011-R-16	Oro Loma 70 kV Area Reinforcement (Re-scope)[5]	PG&E	GFA	38
2	2526-R-01	Walnut 230 kV CB Upgrade[5]	SCE	Metro	15
3	2526-R-02	Ames 115 kV Short Circuit Mitigation	PG&E	GBA	5
4	2526-R-03	DeAnza 115 kV Substation[6]	PG&E	GBA	260
5	2526-R-04	Lincoln - Pleasant Grove Line Reconductoring	PG&E	CVLY	120
6	2526-R-05	Los Esteros 230 kV Short Circuit Mitigation	PG&E	GBA	20
7	2526-R-06	Mariposa 70 kV Voltage Support	PG&E	GFA	63
8	2526-R-07	Metcalf 230 kV Short Circuit Mitigation	PG&E	GBA	405
9	2526-R-08	Midway 115 kV Bus Upgrade	PG&E	Kern	89
10	2526-R-09	Monta Vista – Loyola – Los Altos 60 kV Line Reconductoring	PG&E	GBA	64
11	2526-R-10	Monta Vista 230/115 kV Transformer Bank Addition	PG&E	GBA	104
12	2526-R-11	Newark 115 kV Short Circuit Mitigation	PG&E	GBA	60
13	2526-R-12	Newark 230/115 kV Bank Upgrade	PG&E	GBA	63
14	2526-R-13	Nortech 115 kV Short Circuit Mitigation	PG&E	GBA	5
15	2526-R-14	San Jose B 230/115 kV Transformer Bank Addition	PG&E	GBA	69
16	2526-R-15	Saratoga-Vasona 230 kV Line Reconductoring	PG&E	GBA	178
17	2526-R-16	South Oakland Reinforcement (Phase 2)	PG&E	GBA	86
18	2526-R-17	Tesla – Trimble – Metcalf 230 kV Corridor Expansion	PG&E	GBA	1424
19	2526-R-18	Trimble 115 kV Short Circuit Mitigation	PG&E	GBA	16
20	2526-R-19	Lugo 230 kV CB Upgrade	SCE	NOL	5
21	2526-R-20	Devers 230 kV SCD Upgrade	SCE	Eastern	186
22	2526-R-21	Lugo 500 kV Reactive Power Reinforcement	SCE	Bulk	450
23	2526-R-22	Mesa - Laguna Bell 230 kV #2 Upgrade	SCE	Metro	56
24	2526-R-23	Etiwanda and Mira Loma 230 kV SCD Upgrade	SCE	Metro	55
25	2526-R-24	Penasquitos- Mira Sorrento 69 KV #2 line	SDG&E	SDG&E	115

[5] These projects have already been approved by ISO Management, ahead of the rest of the Plan being considered by the ISO's Board of Governors, pursuant to the ISO's tariff, after stakeholders were informed of Management's intention to approve, and given an opportunity to raise concerns with Management or the Board of Governors

[6] The project has been approved but is on hold pending further coordination with Silicon Valley Power.

#	ID	Project Name	PTO	Area	Est. Cost ($M)
26	2526-R-25	TL600B Reconductor	SDG&E	SDG&E	8
27	2526-R-26	TL623C Reconductor	SDG&E	SDG&E	5
28	2526-R-27	TL690B & TL 697 Reconductor	SDG&E	SDG&E	33
29	2425-R-02	Ames Distribution – Palo Alto 115 kV line (Re-scope)[7]	PG&E	GBA	52
30	1314-R-17	Morgan Hill Area Reinforcement project (Re-scope)[7]	PG&E	GBA	28
31	2425-R-25	South Bay Reinforcement Project (Re-scope) [7][8]	PG&E	GBA	0
32	1819-E-01	East Marysville 115/60 kV Project (Re-scope) [7]	PG&E	CVLY	69
33	2324-R-20	Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers (Re-scope) [7]	SDG&E	SDG&E	33
				TOTAL	4178

The following reliability-driven reconductoring projects will utilize advanced conductors and GETs to achieve the required ratings.

- Mesa - Laguna Bell 230 kV #2 Upgrade
- Lugo 500 kV Reactive Power Reinforcement
- Ames Distribution – Palo Alto 115 kV line (rescope of previously approved project)

Projects that are also being evaluated to determine if the structures are adequate to accommodate advanced conductor without replacement,

- TL623C Reconductor
- TL600B Reconductor

The reliability-driven projects listed above, and, in particular, the Mesa - Laguna Bell 230 kV #2 Upgrade meets the needs anticipated in the 10-year planning horizon for the LA Basin area that were planned to be met by the Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement project approved in the 2022-2023 transmission planning cycle with an estimated cost of $1.25 billion. That project, originally approved as a policy-driven transmission project but also meeting reliability needs in the LA Basin, is recommended to be canceled in this planning cycle due to significantly higher cost estimates resulting from increased requirements identified in the detailed engineering phase.

[7] Estimated cost for Re-scope projects represents the increase from the originally scoped project cost.

[8] The project was approved but part G of the rescoping of the project is on hold pending further coordination with Silicon Valley Power.

Policy-Driven Projects: The ISO found the need for four transmission projects that are policy driven, totaling $2.4 billion and listed in Table ES-2. They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios.

Table ES-2: Policy Driven Projects Recommended for Approval

ID	Project Name	PTO	Area	Est. Cost ($M)
2526-P-01	Drum - Higgins 115 kV Line Reconductoring	PG&E	CVLY	308
2526-P-02	East Shore 230 kV Area Reinforcement	PG&E	GBA	257
2526-P-03	Oleum Area Reinforcement	PG&E	GBA	144
2526-P-04	Trout Canyon - Lugo 500 kV Line	SCE	EOP	1685
			TOTAL	2395

Economic-Driven Projects: The ISO is recommending for approval one transmission project that is economic-driven, totaling $150 million and listed in Table ES-2. This project is needed to address congestion on Path 15 to accommodate the renewable generation requirements established in the CPUC-developed renewable generation portfolios and the increasing load in the CEC forecast. The economic assessment identified the need for one other project as well, but it is not being recommended for approval in this cycle, as discussed below the table.

Table ES-3: Economic Driven Projects Recommended for Approval

ID	Project Name	PTO	Area	Est. Cost ($M)
2026-E-01	Gates – Los Banos #3 500 kV Line Series Compensation	WAPA	Fresno	150

While the Gates – Los Banos #3 500 kV Line Series Compensation project is the sole economic-driven project being recommended in this planning cycle, this transmission plan has identified and confirmed the need for new additional transmission on the 500 kV corridor in the San Joaquin Valley, encompassing the Path 15 corridor and portions of Path 26. The ISO has identified a preferred option to meet these needs, extending as far north as Tesla and south to Midway and Windhub. Given the magnitude and impact on the 500 kV backbone grid, the ISO has identified the need for additional engineering details to be completed before a functional specification can be completed and a competitive process launched, so the ISO plans to seek Board of Governors approval and move forward with transmission reinforcement in the 2026-2027 transmission planning cycle[9].

Other Studies

As in past transmission planning cycles, the ISO undertook additional technical studies to help inform future transmission or resource planning activities. These are informational only but may be of interest to stakeholders. They include the local capacity technical study analyses, frequency response analysis and examination of viability of congestion revenue rights. These studies are set out in Chapters 6 and 7.

Other Findings and Observations

The ISO considers a number of social, economic, and policy-related drivers in the resource planning, transmission planning and infrastructure development process, and will continue to adapt to the policy landscape in future planning cycles. These include the following:

- Relevant federal rulemakings such as FERC Orders No. 1920 and 1920-A, requiring long-term transmission planning;
- West-wide transmission planning in the context of FERC Orders No. 1920 and 1920-A and development of an actionable West-wide transmission study through the Western Transmission Expansion Coalition (WestTEC);
- Planning for large loads associated with development of new infrastructure such as data centers or hydrogen facilities;
- Transmission project execution and the importance of addressing barriers to timely siting, permitting, financing, and construction of energy infrastructure;
- Continued consideration of grid-enhancing technologies, not only as a best practice, but as required by FERC Orders No. 1920/1920-A and 2023, and encouraged in California legislation;
- Coordination and consultation with state agencies and local regulatory authorities to meet legislative requirements;
- The Plan also confirms the cancelation of the Del Amo - Mesa - Serrano 500 kV project, earlier approved in the 2022-2023 Transmission Plan, due to cost increases. The plan also confirms canceling four other smaller projects, as their requirements

[9] The ISO has also been informed of the Valley Clean Infrastructure Project being advanced by Golden State Clean Energy and the Westlands Water District, and the ISO will monitor the progress as it advances the engineering detail in the 2026-2027 planning process.

were found to be met by new projects otherwise required in this plan. The cancelation of these projects will have no impact on reliability: and

- Opportunities to continue to lead and innovate in execution of the ISO's transmission planning and interconnection processes.

Conclusions and Recommendations

The 2025-2026 Transmission Plan relies on a highly integrated resource and transmission planning approach, providing a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately keep pace with California's policy goals, address grid reliability requirements, identify zones of resource development and bring economic benefits to consumers. This year's Plan identified 38 transmission projects, with a total capital cost estimate at buildout of $6.7 billion, as needed to maintain the reliability of the ISO transmission system and unlock access to renewable generation resources to meet state energy needs. Several of these projects include the use of grid-enhancing technologies that can increase capacity more economically than conventional products.

1 Overview of the 2025-2026 Transmission Plan

1.1 Introduction

The 2025-2026 Transmission Plan continues to build off the two significant course changes originally introduced in the 2022-2023 Transmission Plan. The first is the proactive zonal transmission planning model the ISO is pursuing in close coordination with the CPUC and the CEC to tighten linkages between resource and transmission planning activities, interconnection processes and resource procurement. The second responds to the rapid escalation in the projected resource requirements over the next 10 to 15 years to meet California's clean-energy goals. As part of these transformational changes, and to help shape and inform the generator interconnection process and procurement while also enhancing the state's ability to achieve reliability and decarbonization goals in a timely and cost-effective manner, the ISO continues to employ a highly proactive approach to transmission planning. This proactive zonal approach is grounded in the policy and reliability needs of the state. Our strategic intent in drafting the Transmission Plan in this manner is to take into account priority zones identified in resource portfolios to develop the transmission infrastructure required and recommended for approval.

The ISO relies on the resource plans of local regulatory authorities as the basis for the annual Transmission Plan. This 2025-2026 transmission planning cycle accounts for the needs of all local regulatory authorities, including non-CPUC jurisdictional load-serving entities, which the ISO looks forward to continuing to build upon in future cycles. The CPUC, in particular, plays a critical role in developing resource forecasts, with both the ISO and CEC providing input to the CPUC in development of the resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements. The MOU that was signed by the three parties in December 2022 reaffirms our respective roles and commitments to ensure we are working in concert with one another. As such, the MOU also sets the overall strategic direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement. The ISO is synchronized with state energy agencies and local regulatory authorities in working toward the timely integration of new resources.

In the 10-plus years since the ISO redesigned its transmission planning process and subsequently adapted it to meet provisions of Order No.1000 from the Federal Energy Regulatory Commission (FERC), challenges that have been placed on the electricity system – and correspondingly on the transmission system – have evolved and grown substantially. Over the last five years, the annual requirement for new resources has ramped up from about 1,000 MW per year to a sustained expectation of 5,000 to 7,000 MW per year. Recent transmission plans have accordingly advanced a great deal of policy-driven transmission needed to access renewable energy zones primarily inside California, or to boost transfer capacity from the ISO border to load centers, meeting forecast needs 10 and 15 years out. The ISO anticipates additional intra-ISO policy-driven upgrades to continue to be identified at a more measured pace now that the higher trajectory has been established, to address new emerging needs and push the planning horizon out further to the 2045 target for clean-energy goals. Additional development will be also required to access the necessary out-of-state resources and offshore wind. However, the increasing rate of load growth tied to the success of electrification of transportation and building electrification, and data center load growth, are expected to create new challenges, calling for additional strengthening of the grid to provide reliable service to load centers.

It will be essential for local regulatory authorities, including the CPUC, to continue the timely pace of new resource authorizations in parallel with reinforcement of the transmission system. Over the last five years, the ISO has seen tremendous success in the development of interconnection of new resources, stemming largely from authorizations by the CPUC As a result of CPUC procurement authorizations beginning in 2019 and continuing to the most recent procurement decision[10], which calls for 6,000 MW of Net Qualifying Capacity (NQC) by 2032 (structured as 2,000 MW requirements in 2030, 2031, and 2032) the ISO is observing new interconnections moving forward as load-serving entities move to comply with their own integrated resource plans – even if not required to do so – and the CPUC has further requested the California Department of Water Resources to explore contracts for certain long lead-time resources. The CPUC's anticipated Reliable and Clean Power Procurement Plan is also expected to set the stage for sustained resource development.

Resource Interconnections

The increasing need for large quantities of new clean resources to meet California's demand led to unmanageable increases in interconnection requests in 2021 and 2023. The sheer volume of interconnection requests received in cluster 14 (2021) and cluster 15 (2023) application windows compromised the accuracy and usability of the interconnection study results. It became necessary for the ISO to develop a means of prioritizing interconnection requests, with the most viable requests advancing to the study process. The ISO conducted a stakeholder initiative, Interconnection Process Enhancements Tracks 2 and 3 from 2023-2025, to establish new standards and processes for resource interconnection and queue management. The reformed interconnection

[10] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M600/K398/600398976.PDF

request intake process prioritizes alignment with state and local resource plans, transmission availability, procurement needs, and project readiness. Implementation of both IPE Tracks 2 and 3 and FERC Order No. 2023 is currently underway and will continue through Cluster 16 in 2026; however, preliminary data from Cluster 15 in 2024 and 2025 indicates that the reform effort successfully reduced study volumes to reasonable amounts that align with anticipated need.

The ISO is in the process of finalizing additional enhancements to the interconnection process related to transmission plan deliverability, a resource's ability to provide capacity during times of stressed system conditions. These further changes are responsive to stakeholder feedback and build on the ISO's fundamental approach that links resource and transmission planning, interconnection, and resource procurement, to ensure timely energization of new resources that aligns with resource and policy needs.

Procurement and Project Execution

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 in hosting the Transmission Development Forums held semi-annually 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; and
- Coordinate with the CPUC regarding procurement activity progress by load- serving entities and assessing the timeliness of those procured resources meeting near and mid-term reliability requirements.

Collectively, these enhancements and coordination efforts will support and help the state reliably reach its renewable energy objectives.

1.2 Key Inputs

This section provides background and detail on key load and resource forecast inputs into the 2025-2026 transmission planning process.

1.2.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

Base Forecasts

As discussed earlier, the ISO relies 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 are particularly important and have driven the need for far more attention not only on peak loads and total energy consumption but also on the characteristics 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. This has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted to later times of the day and out of the window when grid-connected solar generation is available.

The assessments in the 2025-2026 transmission planning process utilized the 2024 California Energy Demand Update (CEDU) Forecast 2024-2040 adopted by the California Energy Commission (CEC) on January 21st, 2025[11] using the corresponding LSE and BA Table Mid Baseline spreadsheet with applicable Additional Achievable Energy Efficiency (AAEE), Additional Achievable Fuel Substitution (AAFS), Additional Achievable Transportation Electrification (AATE) and Data Center (DC) load modifiers. The 2024 CEDU Forecast also includes 8760-hourly demand forecasts for the three major Investor-Owned Utility (IOU) TAC areas as well as for the entire ISO.

Figure 1-1 illustrates the ISO coincident peak load forecast, for the planning scenario 1-in-2 weather event, from the CEC 2024 IEPR and the increase the forecast over the past planning cycles. This increase in the forecasted load is due to electrification and an increase in data center loads.

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11 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report

Figure 1-1: ISO Coincident Peak – 2017 to 2024 CEC IEPR Energy Demand Forecast (Planning Scenario 1-in-2 Weather Event)

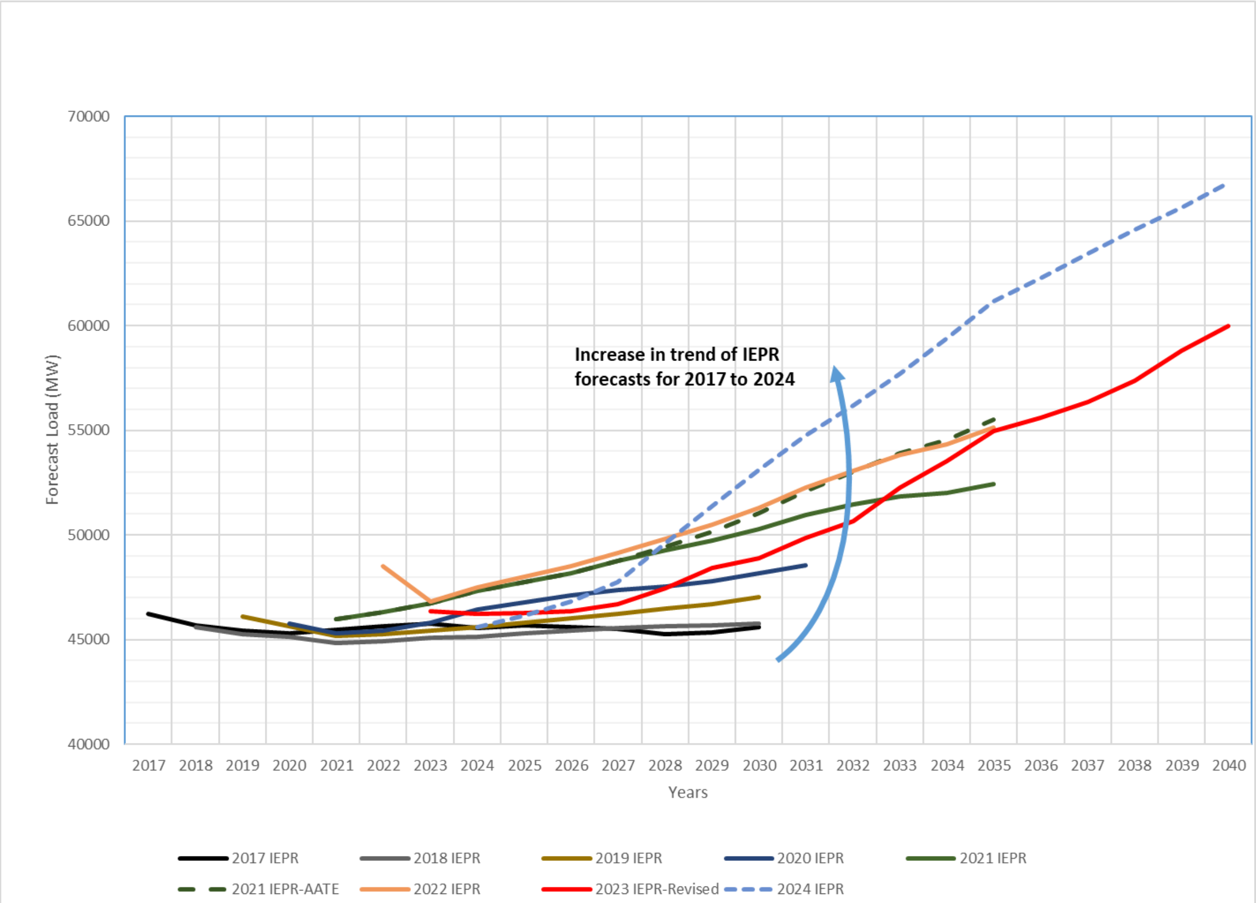
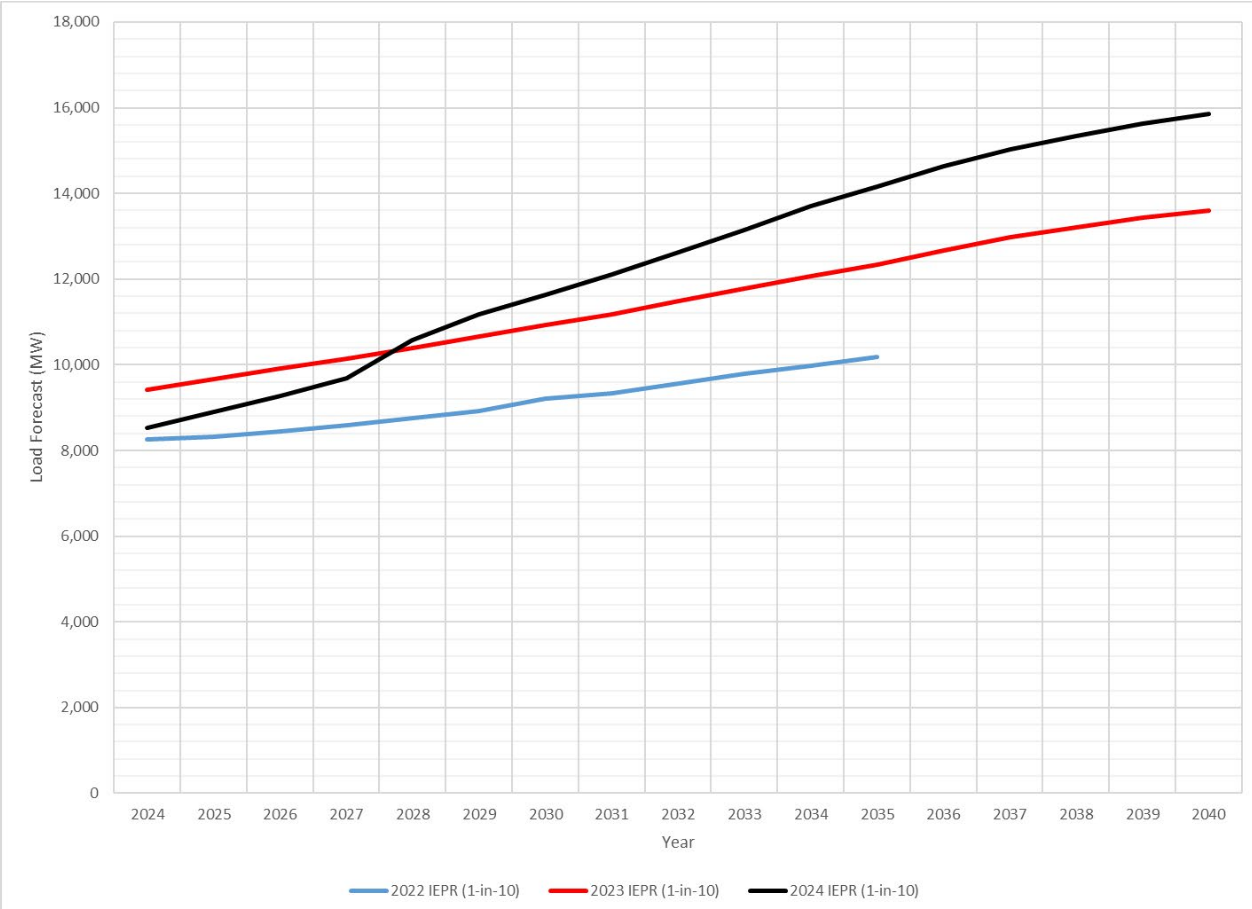


Figure 1-2 illustrates the load forecast for the Greater Bay area, for the local scenario 1-in-10 weather event, from the CEC 2024 IEPR and the increase in forecast over the past two planning cycles. The increase in the forecast is in part due to increasing data center loads in the area.

Figure 1-2 PG&E Greater Bay Area Comparison of CEC IEPR (2022, 2023 & 2024) Load Forecast Local Reliability Scenario for 1-in-10 Weather Event



1.2.2 Resource Planning and Portfolio Development

The ISO's transmission plan is built upon the inputs of the State's demand forecast and local regulatory authority resource plans. As described in the joint MOU signed in December 2022, the ISO relies extensively on coordination with the state energy agencies, in particular with the CPUC, which takes the lead in developing resource forecasts for the 10-year and 15-year planning horizon with input from the CEC and ISO. These resource forecasts are provided in the form of resource portfolios, with input also received on other key assumptions. In recent years, the focus has been on achieving 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. These targets also meet or exceed the current 2030 renewables portfolio standard (RPS) requirement established by SB 100. The past focus has also been on establishing a reasonable trajectory to meet the 2045 renewables portfolio standard goals that were also established in SB 100.

The CPUC adopts resource portfolios annually as part of its Integrated Resource Planning (IRP) process as a key input to the ISO's transmission planning process. The CPUC issued Decision 25-02-026[12] recommending transmittal of the base case portfolio and a sensitivity portfolio with a greater volume of long lead-time (LLT) resources mainly geothermal, long-duration energy storage (LDES) and offshore wind (OSW) for use in the 2025-2026 TPP.

The portfolios are comprised of in-development resources, which have been contracted for or have recently come online, and the incremental generic resources that are selected to achieve policy and reliability targets.

The portfolios are designed to reduce statewide yearly greenhouse gas (GHG) emissions from the electric sector to 25 million metric tons (MMT) by 2035. They are developed with updated assumptions from California Energy Commission's 2023 Integrated Energy Policy Report demand forecast. The base portfolio is comprised of in-development resources, IRPs submitted by load-serving entities (LSEs) in November 2022, and additional generic resources that are selected to achieve policy and reliability targets. The sensitivity portfolio is intended to help study the appropriate transmission development to support the LLT resources called for in the CPUC's D.24-08-064. The portfolio data is available on the CPUC website and includes:

- Final Modeling Assumptions for the 2025-2026 transmission planning process[13];
- Final busbar mapping dashboards for the base and sensitivity portfolios;
- Updated Baseline Reconciliation and In-development resources; and
- Updated Commercial Interest analysis from the ISO's interconnection queue.

1.2.2.1 Deliverability Reservations for Long Lead-Time Resources

In previous cycles, the ISO has reserved deliverability for long lead-time generation resources to ensure that policy-driven transmission projects are used to deliver resources specified in resource plans.

Table 1-1 lists the capacity that has been or that the ISO is reserving based on previous local regulatory authority portfolios, and the locations on the system where it is expected to interconnect.

The CPUC base portfolios for the 2025-2026 transmission planning process include the following resources in 2035 and 2040, for which the ISO will reserve deliverability. Many of these resources were included in the CPUC base portfolios for the 2024-2025 transmission

[12] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879249.PDF

[13] https://files.cpuc.ca.gov/energy/modeling/LTPP/Modeling_Assumptions_25-26TPP_Final_2025-02-20.pdf

planning process, and some of this deliverability has already been allocated. The amounts listed below reflect total cumulative reservations in the 2025-2026 Transmission Plan.

Table 1-1: Deliverable Resources and Resource Locations

	Base Portfolio		Deliverability reservation
Resource type and Location	**2035**	**2040**	
Out-of-State Wind			
Wyoming wind (Eldorado)	3,000 MW	3,000 MW	1,500 MW
Wyoming wind (Tesla)	0 MW	1,707 MW	0 MW
Idaho wind (Harry Allen)	1,100 MW	1,100 MW	1,100 MW
New Mexico Wind (Palo Verde)	3,099 MW	3,099 MW	3,099 MW
New Mexico Wind (Mead) [14]	350 MW	350 MW	350 MW
Offshore Wind			
Offshore wind (North Coast - Humboldt 500 kV)	1,607 MW	1,607 MW	1,607 MW
Offshore wind (Central Coast - Diablo 500 kV)	2,924 MW	2,924 MW	2,924 MW
Long Duration Energy Storage (LDES)			
LDES (Bellota)	310 MW	310 MW	310 MW
LDES (Gregg)	140 MW	140 MW	140 MW
LDES (Sycamore Canyon)	409 MW	409 MW	409 MW
LDES (Whirlwind)	400 MW	400 MW	400 MW
Geothermal - Out-of-CAISO			
Geothermal (Imperial Irrigation District)	655 MW	655 MW	655 MW
Geothermal (IPP & IPPUtah) [15]	90 MW	90 MW	90 MW
Geothermal (Mead)[13]	45 MW	45 MW	45 MW
Geothermal (Summit)[13]	40 MW	40 MW	40 MW

1.3 The Transmission Planning Process

The transmission plan's primary purpose is to identify, using the best available information at the time the plan is 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

[14] These resources were identified in portfolios of previous planning cycles and are included in the baseline of the CPUC portfolio.

[15] These resources are in the CPUC portfolio baseline or identified as in-development. In the 2026-2027 transmission planning process, transmission plan deliverability for geothermal resources that are out-of-state will not be reserved for beyond the resources identified in previous processes that are in the baseline or identified as in-development in the portfolio per the CPUC.

account an array of considerations, with advancing the state's objectives of a cleaner future grid playing 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, as well as the ISO's own transmission planning standards. The reliability studies, necessary to ensure such compliance, comprise a foundational element of the transmission planning process. During the 2025-2026 planning cycle, ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable NERC reliability standards.[16] The ISO performed this analysis across a 15-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.

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 these goals was on the renewables portfolio standard (RPS) set out in various legislation. First, on the trajectory to achieving the 33% renewables portfolio standard set out in the state directive SBX1-2, and then, on the 60% renewables portfolio standard by 2030 objective in

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

Senate Bill (SB) 100[17] that became law in September 2018, which also requires a 100% carbon-free grid by the end of 2045. More recently, the focus has shifted to the more aggressive 2030 greenhouse gas reduction target established by the California Air Resources Board (CARB). This is also in coordination with the CPUC and CEC as directed by SB 350[18] 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 include 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 four 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 2025-2026 transmission planning study, the focus has been on specific economic study requests whether in or outside local capacity 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 of the process if an alternative project identified in a subsequent stage can meet the previously identified need and provide additional benefits not considered earlier in the process. Thus, the ISO's iterative planning process ultimately allows the ISO to consider and approve

[17] SB 100, the 100% Clean Energy Act of 2018, 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

[18] 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.

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. For example, the ISO's transmission planning process does not allow earlier-identified reliability projects to reduce the benefits that potential economic projects might produce. That is because the ISO's sequential process enables 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.

Consideration of Interregional Transmission Solutions

A final step in the development of recommendations in each year's transmission plan is the consideration of potential interregional transmission solutions through a biennial process in place with the ISO's neighboring planning regions, WestConnect and NorthernGrid, pursuant to each party's coordinated processes established under FERC Order No. 1000. Through that process, each planning entity assesses if it has regional needs that an interregional project can meet more efficiently and cost-effectively, and if so, the cost allocation that would result based on each party's benefits. The actions taken by the ISO in each year's transmission planning cycle differ based on whether that planning cycle is the first or second year of the biennial coordination process. The 2025-2026 transmission planning cycle is the second year of the two-year interregional coordination planning cycle.

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 the following:

- Reliability Requirement for Resource Adequacy: Local Capacity Requirements and Resource Adequacy import capability.
- Long Term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test Studies: Ensuring 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.
- Frequency Response Assessment and Data Requirements: Assessing frequency response impact from increase in inverter-based resources (IBR) when unplanned system outages and events occur.

1.3.1 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 2025-2026 planning cycle began in January 2025 and concludes in May 2026.

1.3.1.1 Phase 1

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.

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, CEC, and 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 each study's purpose, 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 later modify the list of high-priority studies based on new information such as revised generation development assumptions and preliminary production cost simulation results.

1.3.1.2 Phase 2

In Phase 2, the ISO performs studies to identify solutions to meet the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 14 months and ends with Board approval of the transmission plan. Thus, Phases 1 and 2 take 17 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 non-transmission alternatives are aware of the reliance being placed on those alternatives.

In this phase, 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. Accordingly, the ISO conducts several 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 Generator Interconnection Procedures (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,[19] which are intended to minimize the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner.
- Identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle.
- Performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan.
- Performs technical studies to assess the reliability impacts of new environmental policies such as 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.
- 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.

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

[19] Pursuant to the ISO tariff, the transmission plan may designate both category 1 and category 2 policy-driven solutions. Using these categories better enables the ISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key factors that materially affect the determination of what transmission is needed. Section 24.4.6.6 of the ISO tariff specifies the criteria considered in this evaluation.

projects included in the Plan that require Board approval.[20] 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, remain as category 2 projects for another cycle, or be removed from the transmission plan.

1.3.1.3 Phase 3

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 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.

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

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

finance, build, and own the same facilities, the ISO will select an approved project sponsor by comparatively evaluating all of the qualified project sponsors based on the tariff selection criteria. Where there is only one qualified project sponsor, the ISO will authorize that sponsor to move forward to project permitting and siting.

1.3.2 Interregional Transmission Coordination per FERC Order No. 1000

Following guiding principles largely developed through coordination activities, the ISO along with the Western Planning Regions[21], participates in and advances interregional transmission coordination within the broader landscape of the Western Interconnection. These guiding principles were established to ensure that an annual exchange and coordination of planning data and information is achieved in a manner consistent with expectations of FERC Order No. 1000. The guiding principles are documented in the ISO's Transmission Planning Business Practice Manual, as well as in comparable documents of the other Western Planning Regions.

The 2025-2026 transmission planning cycle is the second year of the two-year interregional coordination planning process that the ISO conducts with its neighboring planning regions WestConnect and NorthernGrid. Accordingly, the Western Planning Regions initiated a new biennial Interregional Transmission coordination cycle beginning in January 2024. The ISO hosted its submission period in the first quarter of 2024 in which proponents were able to request evaluation of an interregional transmission project. The submission period began on January 1 and closed March 31, 2024 with five interregional transmission projects being submitted to the ISO. The Western Planning Regions host an Annual Interregional Coordination meeting in the first quarter of each year to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[22] This process and results of the evaluations conducted in coordination with the other relevant planning regions are set out in Chapter 5.

1.4 FERC Order 1920/1920A

FERC Order No. 1920 requires transmission providers to conduct long-term planning for regional transmission facilities over a 20-year horizon to anticipate future needs and determine how to pay for those transmission facilities.

The ISO submitted its Order No. 1920 compliance filing in December of 2025. Features of the ISO compliance filing include the following:

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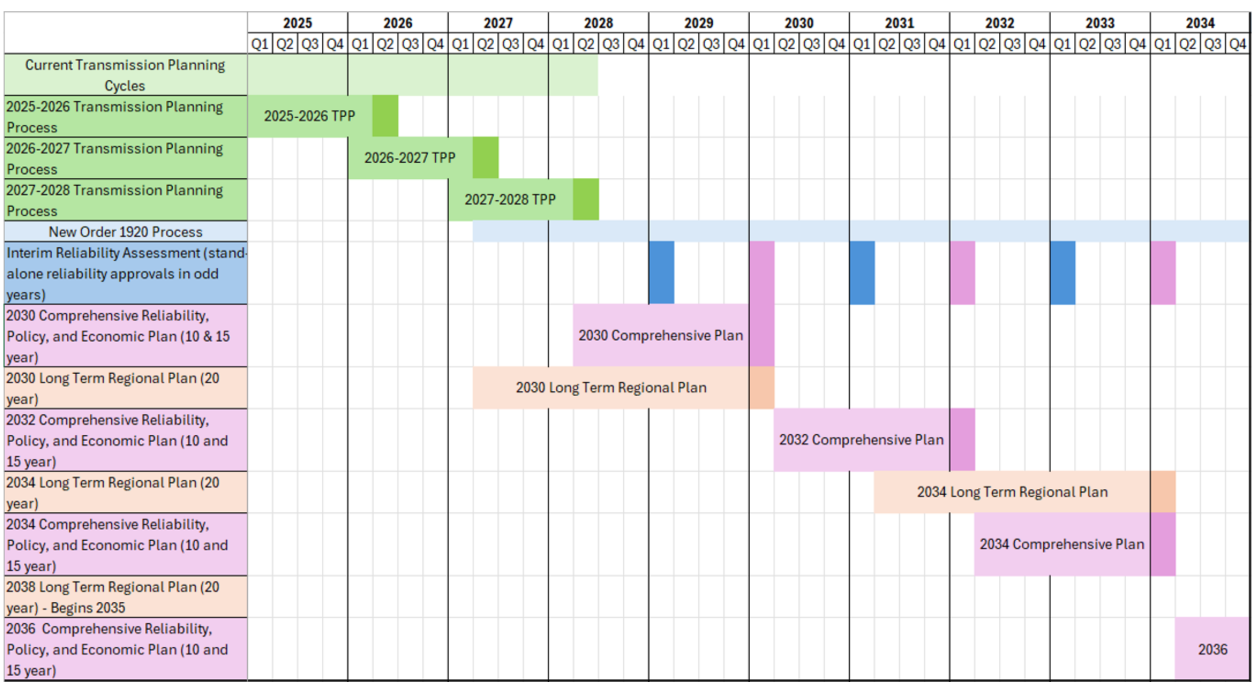
[21] The Western Planning Regions neighboring the ISO are WestConnect and NorthernGrid.

[22] Information related to the Interregional Coordination process and Meeting Schedule is available on the ISO website at http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

- Transition of the current annual comprehensive transmission planning process to a biennial cycle with an interim reliability assessment. See Figure 1-3 for the revised Transmission Planning timelines under Order No. 1920 implementation.
- The current annual comprehensive transmission planning cycles will continue through approval of the 2027-2028 Transmission Plan in spring of 2028, then transition to a biennial process with the first biennial comprehensive transmission plan to be completed in spring of 2030.
- Transition to the new Long-Term Regional Transmission Planning process will begin in 2027 for the first 4-year Long-Term Regional Transmission Plan to be completed in spring, 2030.
- The process for evaluating and selecting Long-Term Regional Transmission Facilities will remain fundamentally the same as the ISO's current process but incorporate enhancements from the Order.
- The new Long-Term Regional Transmission Planning cycle will be integrated with existing comprehensive reliability, economic, and policy assessments.
- The ISO is not proposing changes to cost allocation methodology, after consultation with Relevant State Entities.
- Continued engagement and alignment with neighboring planning regions, WestConnect and NorthernGrid.

Figure 1-3: Revised transmission planning process timeline for 1920 implementation



Tribal engagement on Order No. 1920 Compliance

The Order provides new and enhanced opportunities for engagement with Tribes in the planning processes to reflect Tribal policies regarding decarbonization and electrification, resource mix and demand, and other policies that affect long-term planning. The ISO is seeking input from Tribes throughout 2026, prior to implementation of Order No. 1920, to establish opportunities for transparency and coordination in the updated transmission planning process.

Stakeholder engagement on Order No. 1920 Compliance

The ISO will initiate additional stakeholder engagement beyond discussions with Tribes and Relevant State Entities upon receiving a ruling from FERC on the ISO's compliance filing to the Order. Specifically, the ISO intends to gather stakeholder feedback on implementation of the necessary tariff changes through the Proposed Revision Request (PRR) process to update the ISO Business Practices Manual (BPM). This process is open and transparent to the public, and will be addressed in multiple phases.

1.5 Large Load Assessment

The ISO is aware of the growing need to address new types of large loads including but not limited to data centers, electrification, and hydrogen electrolyzers. To this end, and specifically as it relates to transmission planning, the ISO has opened a stakeholder initiative on the topic of large loads, which began with an issue paper describing the current roles and treatment of large loads, and will seek to address emerging issues in future papers and stakeholder discussions.

As set out in the 2022 MOU mentioned earlier, the CEC develops a statewide long-term energy demand forecast, which incorporates information from utilities across the ISO footprint. The CEC's demand forecast includes large loads mapped to substation locations used in the ISO's transmission studies. Using the CEC's forecast, the CPUC provides resource planning information to the ISO for each annual transmission planning process. The ISO also receives resource planning information from publicly owned utilities and local regulatory authorities. The ISO uses these inputs to develop a transmission plan and initiate development of the recommended transmission projects. Developers and stakeholders then use the transmission plan to understand new transmission approvals and available capacity.

As of January 2026, the California Energy Commission (CEC) forecasts data center load in the ISO Balancing Authority (BA) area to increase by 1.8 GW by 2030 and 4.9 GW by 2040.[23] The ISO also is aware that utilities are receiving an increasing number of large load interconnection and service applications. The CPUC's resource planning information expects that new generation and storage resources will be built to meet more than 30 GW of new peak demand by the mid-2030s.[24] The CPUC shares detailed information about the location of expected new resources so the ISO can consider the need for new transmission and the expected transmission availability in studying developers' generator interconnection requests.

In each transmission planning process, Participating Transmission Owners propose transmission solutions to best meet the needs of the system. To address a new large load interconnection request made after development of the demand forecast and CPUC resource portfolios, Participating Transmission Owners may submit proposals into the ISO's Transmission Planning Process for the ISO's concurrence in the Transmission Plan, as in Section 2.3.6 below. The concurrence for load interconnections only considers the transmission component of the load interconnection. The ISO reviews and provides concurrence that the load interconnection and potential network upgrades to interconnect the load meet the transmission reliability requirements and are consistent with the long-term transmission plans in the area.

Large loads can interconnect on either the distribution or transmission system. The end-customer interaction in the load interconnection process for CPUC-jurisdictional utilities is regulated through CPUC-approved rules. At the transmission level, Participating Transmission owners manage load interconnection requests.

1.6 ISO Processes coordinated with the Transmission Plan

The ISO coordinates the transmission planning process with several other ISO processes in addition to the generator interconnection procedures.

1.6.1 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

[24] See CPUC Transmission Planning Process information from the Integrated Resource Planning Process, available here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/resource-and-transmission-development

2013 in time to qualify additional distributed generation resources to provide RA capacity for the 2014 RA compliance year.

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

In the first step, during the transmission planning process, the ISO performs a DG deliverability study to identify available transmission capacity at specific grid nodes to support deliverability status for distributed generation resources. 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. This is done 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.

1.6.2 Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[25] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution in 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.

1.6.3 Planning Coordinator Footprint

The ISO provides planning coordinator services to Hetch Hetchy Water and Power, the Metropolitan Water District, the City of Santa Clara, and the California Department of Water Resources. Since the execution of the service agreements with these parties, the ISO has conducted the relevant study efforts to meet 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 implementation schedules agreed upon with each entity.

The ISO had initially developed its interpretation of its planning authority/planning coordinator area in 2014 based on its operational control of its participating transmission owner assets. This was done partly in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities, and the ISO documented its interpretation in a technical bulletin.[26]

[25] 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.

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

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 had a planning coordinator out of concern for overall system reliability and, if they did not have one, offered to provide planning coordinator services 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 is only responsible 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.

In addition to the entities discussed above, the ISO provides 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 facilities as defined by NERC.

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

1.6.4 Engagement with Tribes

The ISO recognizes that Tribes seek more meaningful and ongoing engagement in the infrastructure development process and is seeking feedback from Tribes on how best to ensure awareness and open communication regarding infrastructure decisions. To this end, and inclusive of the Order No. 1920 considerations, the ISO is developing a Tribal Engagement Policy in coordination with Tribal representatives. The ISO is convening separate meetings with Tribes and Tribal representatives in the development of this Tribal Engagement Policy.

1.6.5 Transmission Project Execution and Completion

In recognition of the significant increase in transmission that has been approved for reliability, economic, and policy needs in the past several Transmission Plans, the ISO is working with transmission owners and state agencies to address barriers to transmission development, including financing, engineering and design, permitting, supply chain, and construction. The ISO's Transmission Development Forum, which the ISO convenes twice a year in coordination with Transmission Owners and the CPUC, provides key information on the schedule of transmission projects approved through the ISO's transmission planning process.

1.6.6 West-Wide Transmission Planning

Given the need for increased regional diversity in resource portfolios needed to achieve reliability and policy goals at lowest cost, the ISO will continue to participate in West-wide regional transmission planning discussions. These discussions can occur under the FERC Order No. 1000 interregional transmission planning process, however, the ISO has had more success approving multi-state transmission projects through the negotiated agreement option, which allows for voluntary agreements between states and transmission providers to plan and pay for transmission facilities outside of the Order No. 1000 process.

Delivery of energy from out-of-state resources to the ISO balancing authority area will require development of long-distance transmission infrastructure to deliver power across multiple states and balancing authority areas. The ISO developed the subscriber participating transmission owner (SPTO) model to enable efficient and cost-effective delivery of generation from areas outside of the ISO's balancing area without increasing the transmission access charge. Once in service, these transmission facilities will be placed under the ISO's operational control.

The ISO is also participating in the Western Transmission Expansion Coalition (WestTEC), a West-wide effort to develop an actionable transmission study to support the needs of the future energy grid. The WestTEC 10-year Horizon study, released in February of 2026, affirmed the ISO's previous approval of a number of transmission projects in California and throughout the west, and set the stage for additional transmission projects in the 20-year time horizon. The final WestTEC deliverable will be a West-wide transmission needs study looking out over 20-years, to be completed by the end of 2026.

1.6.7 Relevant State Legislation

The ISO is also aware of several pieces of California legislation related to infrastructure development and is committed to coordination with relevant entities in fulfillment of these responsibilities.

- Assembly Bill 2779 (Petrie-Norris, 2024) requires the ISO to provide an update to the CPUC and Legislature after each new Transmission Plan that outlines the new grid-enhancing technologies (GETs) approved and how they would save on costs and/or additional transmission buildout.

- Senate Bill 1006 (Padilla, 2024) requires the IOUs to evaluate their lines and submit a plan for GETs integration into the ISO's annual transmission planning process, beginning in 2026.
- AB 3264 (Petrie-Norris, 2024) requires the CPUC, in consultation with the ISO, CEC, and the California Infrastructure and Economic Development Bank, by July 1, 2025, to submit to the Governor and the Legislature a study identifying proposals to reduce the cost to ratepayers of expanding the state's electrical transmission grid as necessary to achieve the state's goals, to meet the state's requirements, and to reduce the emissions of greenhouse gases.
- AB 1373 (Garcia, 2023) accelerates permitting for electric transmission projects that have been identified as needed by the ISO by establishing a rebuttable presumption in CPUC proceedings evaluating the issuance of a certificate of public convenience and necessity for proposed transmission projects. The rebuttable presumption would be in favor of an ISO governing board-approved needs evaluation, if certain criteria are satisfied.
- Senate Bill 887 (Becker, 2022) provides state policy direction on a number of resource and transmission planning issues, including direction to the CPUC and CEC regarding inputs to be provided to the ISO in future planning cycles. The bill also provides direction about requests the CPUC is to make of the ISO in the process of conducting its FERC tariff-based planning processes in this and future planning cycles.
- Other legislation: In addition to the enacted legislation summarized above, the ISO will consult with state agencies on a number of reports and projects related to infrastructure development and California's generation resource portfolio.

1.6.8 Infrastructure Policy Catalog and Roadmap

The ISO is initiating an Infrastructure Policy Catalog and Roadmap in 2026 process to prioritize and sequence transmission planning and infrastructure enhancements. This process solicits proposals from stakeholders and will assess stakeholder support for proposed infrastructure policy initiative and document a work plan – referred to as the Infrastructure Policy Roadmap – for future infrastructure policy development.

The 2026 process began with stakeholders submitting potential infrastructure policy initiatives in January and February. In the spring, the ISO will assess stakeholder support and internal bandwidth to address each policy submission. In the summer of 2026, based on the priorities identified, the ISO will post the Infrastructure Policy Catalog, a focused list of discretionary policy initiatives under consideration for inclusion in the Infrastructure Policy Roadmap. The Infrastructure Policy Catalog and associated stakeholder feedback will inform the development of the Infrastructure Policy Roadmap over the next several years and will be finalized by the end of the year.

In the past, the ISO has addressed policy submissions from the ISO policy catalog in the Transmission Planning Process and/or the Interconnection Process Enhancements initiative, even if submissions were not directly related to either transmission planning or interconnection. This new approach is intended to improve stakeholder transparency and help the ISO allocate resources to priority infrastructure policy items.

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2 Reliability Assessment

2.1 Overview of the Reliability Assessment Studies

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, Western Electricity Coordinating Council (WECC) regional criteria, and ISO transmission planning standards. These requirements are set out in Section B2.2 of Appendix B. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2025-2026 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 15-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;
- Voltage stability studies; and
- Cascading studies.

The WECC full-loop power flow base cases provide the foundation for the study. The detailed assumptions, methodologies and reliability assessment results are provided in Appendix B and Appendix C.

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

2.1.1 Reliability Standards Compliance

The 2025-2026 transmission planning process was conducted to ensure the ISO-controlled grid is in compliance with NERC standards, WECC Regional Criteria, and ISO Planning standards.

2.1.2 Bulk 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,

2.1.3 Regional Study Area Assessment

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.

Regional studies are completed in the following study areas.

- Pacific Gas & Electric (PG&E)
  - Humboldt Area
  - North Cost and North Bay Area
  - North Valley Area
  - Central Valley Area
  - Greater Bay Area
  - Fresno Area
  - Kern Area
  - Central Coast and Los Padres Area
- Southern California Edison (SCE)
  - Tehachapi and Big Creek Corridor Area
  - North of Lugo Area
  - Eastern Area
  - SCE Main Area (Includes: East of Lugo, Metro, Ventura)
- San Diego Gas & Electric (SDG&E) Area
- Valley Electric Association (VEA) Area

2.2 Reliability Study Assumptions

In Phase 1 of the ISO annual transmission planning process, the ISO develops the Unified Planning Assumptions and Study Plan for the planning cycle. The following sections summarize the study assumptions used for the reliability assessment and are expanded on in Appendix B.

2.2.1 Load and Resource Assumptions

The ISO's annual transmission planning process reliability assessment uses as inputs assumptions developed by the CEC energy demand forecast and the CPUC base portfolio developed through the CPUC's integrated resource plan. As described in Section 1.2, the reliability analysis is based on the CEC's 2024 IEPR[27] and the base portfolio provided to the ISO via CPUC Decision (D) 25-02-026[28] issued on February 26, 2025.

2.2.2 Study Horizon and Years

The studies that comply with TPL-001-5.1 will be conducted for both the near-term[29] (2027-2030) and longer-term[30] (2030-2040) per the requirements of the reliability standards.

Within the identified near and longer-term study horizons, the ISO will be conducting detailed analysis on years 2027, 2030 and 2035. Additionally, for the long-term scenario 2040 will also be studied. If in the analysis it is determined that additional years are required to be assessed, the ISO will consider conducting studies on these years or utilizing past studies[31] in the areas as appropriate.

2.3 Reliability Projects

Additional details and results related to the reliability projects described below can be found in Appendix B. All project costs reflect the escalated costs for the year that they are expected to be in-service.

2.3.1 Management Approved Projects

The reliability-driven projects within this section were identified as being needed in the reliability assessment with an estimated cost of less than $50 million and were presented to stakeholders as being recommended for management approval at the November 19th, 2025 stakeholder meeting. Based on comments received and no objection raised at the following ISO Board of Governors meeting on December 18, 2025, ISO Management

27 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0

28 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879249.PDF

29 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.

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

31 Past studies may be used to support the Planning Assessment if they meet the following requirements:
1. For steady state, short circuit, or stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. 2. For steady state, short circuit, or stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

approved the transmission projects and informed the respective participating transmission owners of those approvals.

2.3.1.1 Oro Loma 70 kV Area Reinforcement (Re-scope)

Project Need and Background

Canal Substation, located in Merced County, is currently supplied by two 70 kV transmission lines, namely Los Banos - Livingston Jct. - Canal 70 kV Line and Mercy Springs SW. STA. – Canal - Oro Loma 70 kV Line. Due to the limited capacity on the Oro Loma - Canal #1 70 kV Line, the section from Canal to Santa Rita Substation is operated normally open during summer to avoid overloads. To relieve local transmission constraints in this area, there are two previously approved projects: Oro Loma 70 kV Area Reinforcement and the Los Banos 70 kV Area Reinforcement. The Oro Loma project will reconductor (i) 2.4 miles of the Los Banos– Livingston Jct.–Canal 70 kV line between Los Banos and Santa Nella Substation, and (ii) 10.8 miles of the Mercy Springs SW. STA. – Canal – Oro Loma 70 kV Line from Mercy Springs SW. STA. to Canal Substation. The Los Banos 70 kV Area Reinforcement project will convert the new generation interconnection driven 230 kV switching station near Dos Amigos PP into a 230/70 kV substation and install a new 230/70 kV transformer to deliver additional power to the local 70 kV area via Mercy Springs SW Station. However, distribution load at the Canal, Ortiga, and Santa Nella Substations has increased substantially in recent years, and demand forecast for these substations is expected to continue to increase significantly over the next decade. In addition, Ortiga Substation will be converted from a tap to a ring-bus configuration to accommodate a second distribution bank. As a result, under the new P1-2 contingency (Mercy Springs SW Station–Ortiga 70 kV line), all Ortiga, Canal, and Santa Nella load will be served by the Los Banos–Livingston Jct.–Canal 70 kV line. That will cause an overload of the line section from Santa Nella to Canal Substation and low voltage issue around Canal and Ortiga Substations.

Project Details

Original Scope:

This project was originally approved during TPP 2010-2011 and has the following scope:

- Reconductor 2.4 miles of the Los Banos - Livingston Jct. – Canal 70 kV Line from Los Banos to Santa Nella substation;
- Reconductor 10.8 miles of the Mercy Springs SW. STA. – Canal – Oro Loma 70 kV Line from Mercy Springs SW. STA. to Canal substation; and
- Replace associated structures and substation equipment as needed.

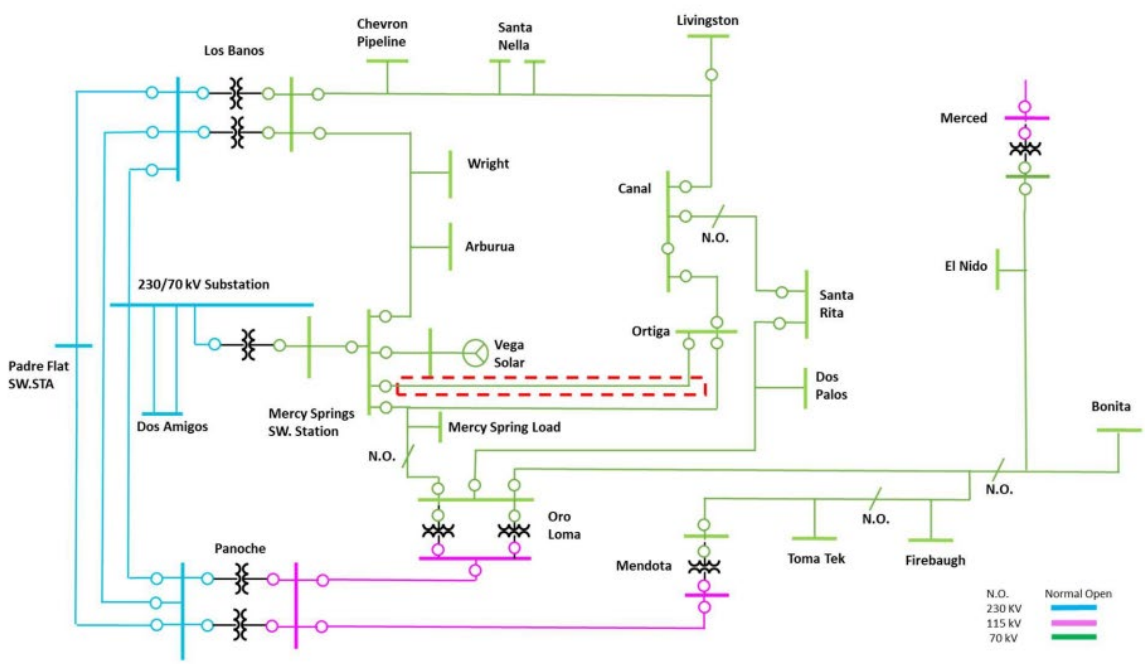
The original project scope had an estimated cost of $35M - 45M.

Proposed re-scope:

The rescoping of Oro Loma 70 kV Area Reinforcement Project will include the following:

- Build a new 70 kV circuit (about 4 miles) from Mercy Springs SW. STA. to Ortiga Substation using the same right-of-way; and
- Expand Mercy Springs SW. STA and Ortiga 70 kV Buses as needed.

Figure 2-1: Proposed project scope



Estimated Cost & In-Service Date

This rescoping of the project will result in an estimated additional cost of $19M - $37.6M and estimated to be in service by May 2032.

Alternatives Considered

Other alternatives considered are as below:

Alternative 1: Reconductoring the Los Banos – Livingston Jct. – Canal 70 kV Line from Santa Nella to Canal Substations and installing additional voltage support at Canal or Ortiga Substations. This alternative is not recommended because it is expected to cost at least $44 M and hence will not be as cost-effective as the proposed scope.

Alternative 2: Energy Storage – This alternative is not feasible because the energy storage charging capability is limited by the existing line capacity and will be further limited by the future load growth. There is also limited space at both Canal and Ortiga Substations.

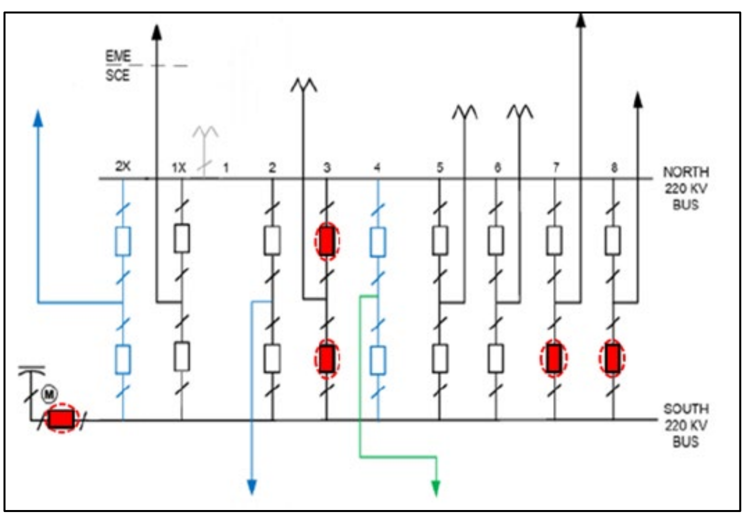
Alternative 3: Grid Enhancing Technologies– The Los Banos – Livingston Jct. -Canal 70 kV Line will be radial following the outage of Mercy Springs SW. STA. – Ortiga 70 kV Line. Flow Control devices will not be able to mitigate the overload and low voltage issues in this case.

2.3.1.2 Walnut 230 kV CB Upgrade Project

Project Need and Background

The project was submitted by Southern California Edison as a reliability need to address the short circuit duty concern at Walnut 230 kV substation. SCE identified that the SCD at the Walnut 230 kV substation is expected to exceed 95% of the interrupting capacity rating of five (5) CBs in near-term by 2030.

Figure 2-2: Walnut 230 kV CB Upgrade Project



Project Details

The scope of this project consists of replacing five CBs currently rated 40 kA with new CBs with higher rating of 63 kA.

Estimated Cost & In-Service Date

The estimated cost range for this project is $11-$15 million with expected in-service date of July 1, 2031.

Alternatives Considered

The proposed solution represents the standard, least-cost, and most effective first step for addressing this type of issue. Other options such as installing TRV or CCVT capacitors and line de-looping were considered, none offered a more effective solution in terms of SCD reduction or cost.

2.3.2 Projects Recommended for approval

2.3.2.1 Ames 115 kV Short Circuit Mitigation

Project Need and Background

Studies show breaker overstress at Ames 115 kV for CB's 112 and 122 starting Year-5 and beyond.

Project Details

The scope is to upgrade 115 kV CB's 112 and 122 to 63 kA.

Estimated Cost & In-Service Date

This project has a cost estimate of $2.5 M - $5 M and an estimated in-service date of Q4 2029.

Alternatives Considered

None

2.3.2.2 De Anza 115 kV Substation[32]

Project Need and Background

The De Anza division has two parallel lines connecting the Monta Vista and Newark substations. These lines serve as a backup transmission connection between these two crucial substations during contingencies. Additionally, along this 115 kV corridor, several

[32] The project was approved but is on hold pending further coordination with Silicon Valley Power.

loads are connected, including Britton, Applied Materials, Phillips, Lawrence, and Lockheed.

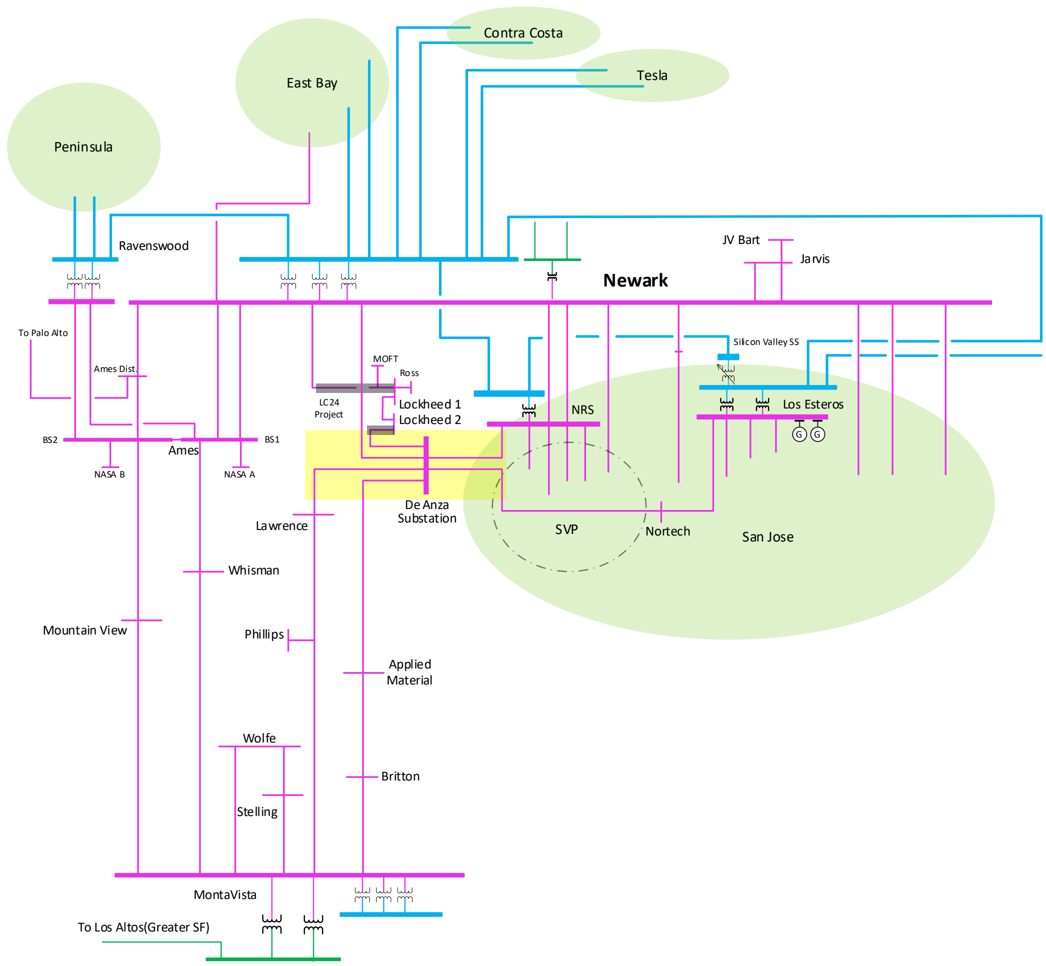
This load pocket has experienced significant growth, with a forecasted load increase of almost 100 MW, or a 50% rise, between years two and five. This growth is primarily driven by increases in existing loads and contributions from new large load interconnections. During the load interconnection process, a reconfiguration project was proposed to eliminate the tap connections at Lockheed and redistribute the load across both circuits connecting Monta Vista and Newark.

With this new configuration, the overloads from Monta Vista to Britton to Applied Materials to Newark will be resolved; however, there are still unresolved overloads that occur during contingencies along the Newark to Lockheed to Lawrence to Phillips to Monta Vista path. This occurs when one of the connections to the source substations, either Monta Vista or Newark, is lost. The lines are rated at 227 MVA during emergencies, but the projected load that needs to be served will exceed 250 MW by 2030.

Project Details

The scope includes constructing a new substation near the Lawrence Substation, which will connect Newark to Monta Vista 115 kV lines with the Nortech to NRS 115 kV line. This new substation and the proposed interconnection will introduce two additional 115 kV lines into the load pocket, enhancing the load-serving capacity in the area. This improvement will allow for an increase in loads across all existing substations along these two 115 kV lines and provide the opportunity to install new distribution transformer banks at the New De Anza substation to accommodate future load growth.

Figure 2-3: De Anza 115 kV Substation Project



Estimated Cost & In-Service Date

The estimated cost of this project is between $130M - $260 M, with an estimated in-service date of December 2031.

Alternatives Considered

Alternatives for alleviating the overload on the 115 kV transmission lines, specifically the Monta Vista – Lawrence and Newark – Lockheed segments, include reconductoring these two 14-mile lines with a higher rating to achieve at least 2,000 A. However, this option is not recommended because it offers less load-serving capability and poses significant construction challenges due to the densely populated urban area surrounding these lines.

Additionally, other grid-enhancement technologies were found to be less effective for this specific situation. An energy storage solution was ruled out due to unavailability of charging window, and alternative solutions, such as power flow control devices, were deemed ineffective because of underlying insufficient capacity of the transmission lines serving this area load demands.

2.3.2.3 Lincoln-Pleasant Grove Line Reconductoring

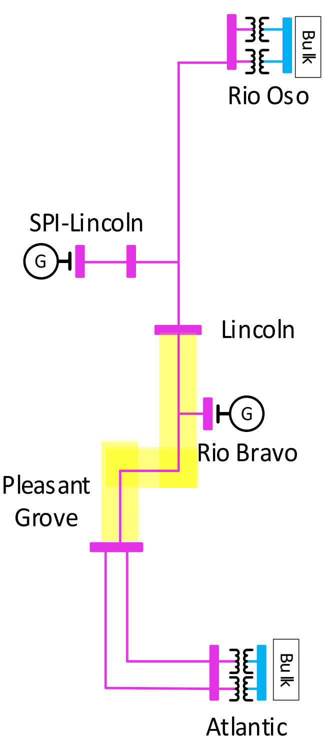
Project Need and Background

Planning analysis identified thermal overloads on the Lincoln - Pleasant Grove 115 kV line under P6 contingency, loss of Rio Oso – Atlantic 230 kV line and the Atlantic – Gold Hill 230 kV line. Projected overloaded are 111% in 2027, 114% in 2030, and 143% in 2035.

Project Details

The ISO is recommending reconductoring Lincoln-Pleasant Grove to a minimum rating of 1517 A for summer emergency.

Figure 2-4: Lincoln – Pleasant Grove line Reconductoring Diagram



Estimated Cost & In-Service Date

The total estimated cost of this project is between $60M- $120M and the expected in-service is 2034.

Alternatives Considered

The ISO has considered the alternatives below:

Alternative 1: Energy Storage - This alternative is not recommended due to charging limitation.

Alternative 2: GETs- Use of Advanced Power Flow Control devices will cause new issues due to overloads observed in underlying low voltage network.

2.3.2.4 Los Esteros 230 kV Short Circuit mitigation

Project Need and Background

Studies show breaker overstress at Los Esteros 230 kV for CB's 252, 352, 262, 362, 342, 442, 812, 822 and 832 starting Year-5 and beyond.

Project Details

The scope is to replace CB's 252, 352, 262, 362, 342, 442, 812, 822 and 832

Estimated Cost & In-Service Date

This project has a cost estimate of $10 M - $20 M and an estimated in-service date of Q4 2029.

Alternatives Considered

Alternatives such as adding reactors to Los Esteros 230/115 kV low-side were considered; however, they will not fully mitigate the 230 kV issues.

2.3.2.5 Mariposa 70 kV Voltage Support

Project Need and Background

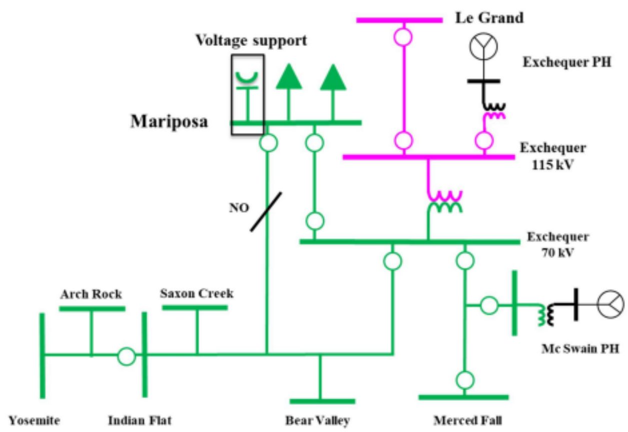
Mariposa Substation, located in Mariposa County, is part of the Exchequer 70 kV pocket which mainly consists of Mariposa, Bear Valley, and Indian Flat Substations. Exchequer PH is the main source for this pocket while Merced Falls-Exchequer 70 kV Line serves as the secondary source. Following an outage of Exchequer 115/70 kV Bank #1, this 70 kV pocket will lose its main source, resulting in severe low voltage issues at Mariposa and other substations. By adding voltage support at Mariposa Substation, this project would mitigate the low-voltage issue mentioned above and protect against the NERC TPL-001-5 Category P1 violation. It will also help increase load-serving capability, improve customer reliability, and reduce losses.

Project Details

Mariposa 70 kV Voltage Support Project consists of the following scope:

- • Install a 20 MVAr voltage support device (STATCOM) at Mariposa Substation
- • Upgrade Mariposa 70 kV bus and associated equipment as needed.

Figure 2-5: Mariposa 70 kV Low Voltage Project Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $31.3M - $62.6M (AACE Level 5) and an estimated in-service date of May 2032

Alternatives Considered

The ISO has considered alternatives below.

Alternative 1: Energy Storage – This alternative is not recommended due to higher cost.

Alternative 2: Grid Enhancing Technologies (GETs) – Use of Advanced Power Flow Control devices will not be able to mitigate the low voltage issue.

2.3.2.6 Metcalf 230 kV Short Circuit Mitigation

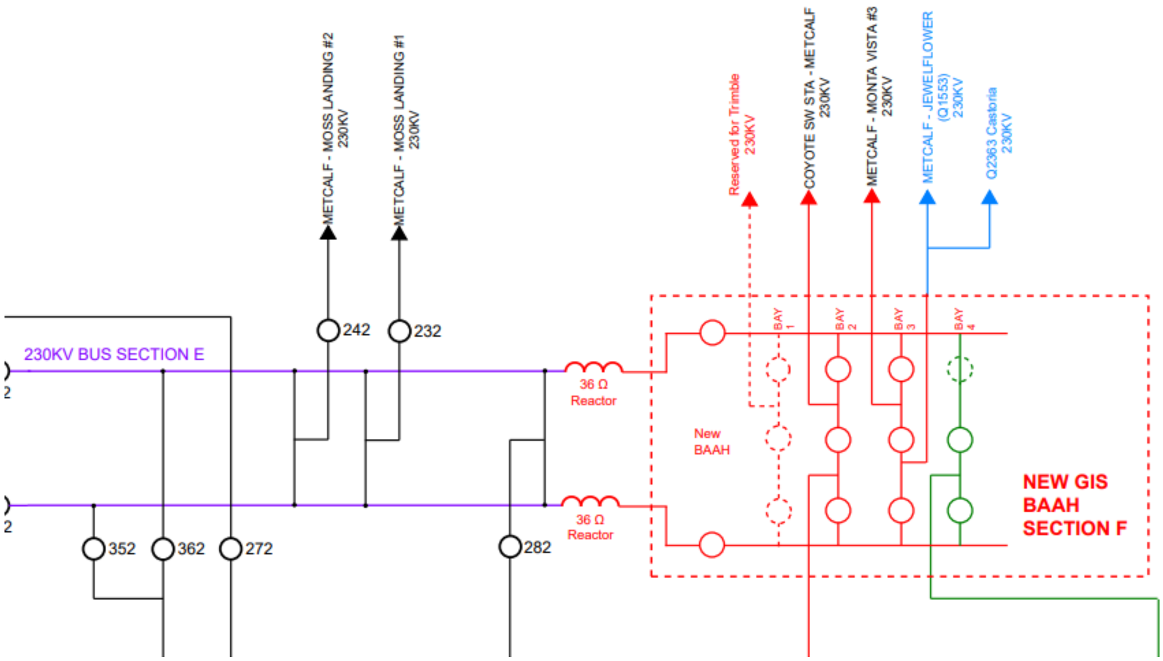
Project Need and Background

Studies show bus and breaker overstress at Metcalf 230 kV CB's 684, 674,664, 654 starting Year-2 and CB's 222, 392, 292, 312, 372, 262, 382, 212, 582, 592, 252, 272, 322, 352, 362, 382, 232 and 242/2 starting in year-10.

Project Details

The scope is to build a new GIS bus section and install two (2) 36-ohm bus reactors between existing Bus E and new GIS bus section.

Figure 2-6: Metcalf 230 kV Short Circuit Mitigation Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $270 M - $405 M and an estimated in-service date of 2034.

Alternatives Considered

Due to the extent of over-stress, replacing all breakers is not cost-effective and will not provide enough margin for future interconnection needs.

2.3.2.7 Midway 115 kV Bus Upgrade

Project Need and Background

Midway 115 kV bus presently serves eight 115 kV lines (with two additional lines planned for generation interconnections), three 230/115 kV transformer banks, and existing distribution transformers. A separate project is converting the 230 kV bus to a breaker-and-a-half configuration. Another major area initiative is the Northeast Kern Reinforcement project, which reconductors several local lines. Earlier study cycles assumed summer operating “open ended” setups on:

- Famoso–Cawelo 115 kV; and
- Wasco–McFarland 70 kV.

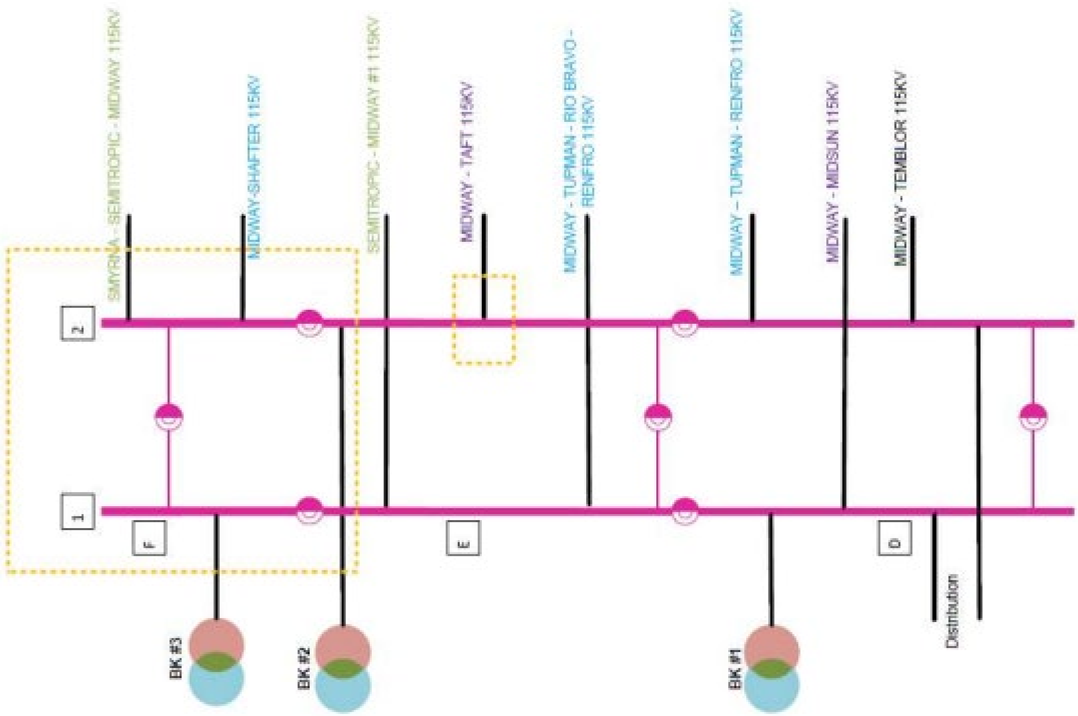
Following recommendations from PG&E System Operations in the most recent assessment cycle (citing reliability concerns with making those open-ended setups permanent), the current studies modeled both line sections closed to determine the mitigation needed for normal closed-position operation after Northeast Kern Reinforcement completes. This change in study assumptions and increased loading result in additional overloads due to P2 contingences at Midway. These P2 contingencies result in the opening of all circuit breakers connected to Section D, Section E, or Bus 2 of the Midway 115 kV bus per the standard protection design to isolate the faulted bus tie breaker. Consequently, all connected elements are tripped for these outages, and simultaneous open-ended outages of the following groups of elements result in criteria violations in the Transmission Planning Horizon.

Project Details

Midway 115 kV Bus Upgrade Project consists of the following components:

- Expand Midway 115 kV double bus single breaker configured bus from two sections (Sections D and E) to three sections (add new Section F) and install two new bus sectionalizing breakers between Section E and new Section F and a new bus parallel breaker on new Section F.
- Relocate 115kV connection of 230/115 kV Transformer #3 from Section E to new Section F.
- Relocate Smyrna-Semitropic-Midway 115 kV line from Section E to new Sec. F.
- Relocate 115kV connection of 230/115 kV Transformer #2 from Section D to Section E.
- Relocate Midway-Shafter 115kV line from Section E to a new position on new Section F.
- Relocate Midway-Taft 115kV line from Section D to Section E.
- Relocate and reuse circuit breakers to accommodate new connections or install new circuit breakers, as appropriate, based on condition, cost, and availability.
- Make protection and control systems upgrade as required.

Figure 2-7: Midway 115 kV Bus Upgrade Project Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $44M - $89M and estimated In-service date of May 2033.

Alternatives Considered

Alternative 1: Status Quo – This alternative is not recommended because it does not mitigate the multiple observed NERC TPL-001-5.1 Category P2 violations.

Alternative 2: Convert Midway 115 kV bus to breaker and a half configuration This alternative provides similar benefits to the proposed project. However, this conversion is not recommended due to higher cost since the existing double bus single breaker configuration meets internal PG&E reliability criteria with these modifications.

Alternative 3: Energy Storage – The addition of energy storage to resolve the observed deficiencies was considered, but to resolve the multiple issues observed for outages of the bus tie breakers, energy storage would need to be added in at least three different locations, rendering this solution impractical for this situation. In addition, the issues identified in the Taft area are complicated because the overloads are observed to switch direction based on system conditions and local area generation dispatch. This likely will require use of a detailed operating nomogram to govern the energy storage charge and discharge cycles that should be avoided due to its operational complexity and need for constant monitoring to avoid detrimental operation of the energy storage resource.

Alternative 4: Advanced Conductors and grid-enhancing technologies Additional advanced technology alternatives were also considered:

- Advanced Conductor – Since multiple overload issues in different areas were observed related to the Midway 115 kV P2 bus tie outages, reconductoring was not considered as an option due to the numerous lines that would need to be upgraded, so advanced conductors were not considered a viable mitigation alternative.
- Advanced Power Flow Control (SmartValve, series reactors, phase shifting) – Since multiple overload issues in different areas were observed related to the Midway 115 kV P2 bus tie outages, installing multiple flow control devices in multiple different local areas was not considered to be a viable alternative from a cost and practicality standpoint.

2.3.2.8 Monta Vista – Loyola – Los Altos 60 kV Line Reconductoring

Project Need and Background

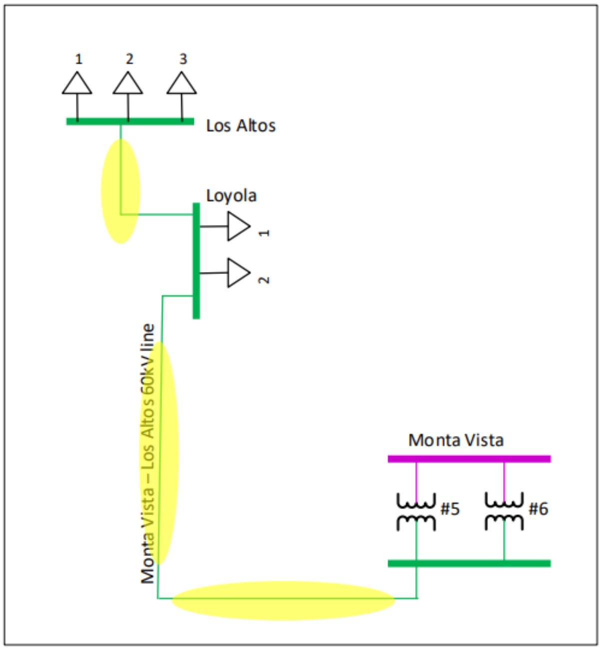
The Monta Vista – Loyola – Los Altos 60 kV line is a radial line that supplies power to the Loyola and Los Altos substations within the De Anza division. These substations serve over 14,800 customers in the communities of Los Altos, Los Altos Hills, and Mountain View. By the summer of 2030, during peak conditions, the forecasted load for the Loyola and Los Altos substations is expected to reach 56 MW. The line rating for the Monta Vista – Loyola 60 kV line is 54.6 MVA, while the rating for the Loyola – Los Altos section is 45.7 MVA, resulting in a 3% overload in normal conditions.

In the longer term, the load at these two substations is projected to increase to 76 MW, aligning with PG&E's distribution planning, which anticipates higher load growth in the area. To address this, there are plans to expand the load-serving capacity by upgrading the distribution banks at the Loyola substation.

Project Details

This project includes the reconductoring of 3.9 circuit miles between the Monta Vista and Loyola substations with a larger conductor to achieve at least 1100 Amps during summer emergency conditions. Additionally, the project plans to reconductor 3.2 circuit miles between the Loyola and Los Altos substations to achieve at least 1100 Amps during summer emergency and upgrade any limiting components as necessary to achieve full conductor capacity.

Figure 2-8: Monta Vista – Loyola – Los Altos 60 kV Line Reconductoring Diagram



Estimated Cost & In-Service Date

The estimated cost of this project is between $32 M - $64 M, with an expected in-service date in 2034 or earlier.

Alternatives Considered

Alternative solutions to address the overload conditions in the 60 kV lines were considered, such as constructing a new circuit to enhance the load-serving capacity of this radial system. However, these options were not economically feasible. Moreover, even with the addition of a new circuit, the issues would still arise under N-1 conditions, where the loss of the new circuit would lead to overloads on the existing lines. These lines do not have sufficient capacity to accommodate the expected load growth in the area. Additionally, other Grid Enhancement Technologies (GETs), such as energy storage or power flow control devices, are not appropriate for this situation due to space constraints and the radial nature of the network.

2.3.2.9 Monta Vista 230/115 kV Transformer bank addition

Project Need and Background

The three existing 230/115 kV transformer banks at the Monta Vista substation primarily supply power to the De Anza 115 kV system. Additional sources for this area include the 230/115 kV transformer banks located at the Newark and Ravenswood substations.

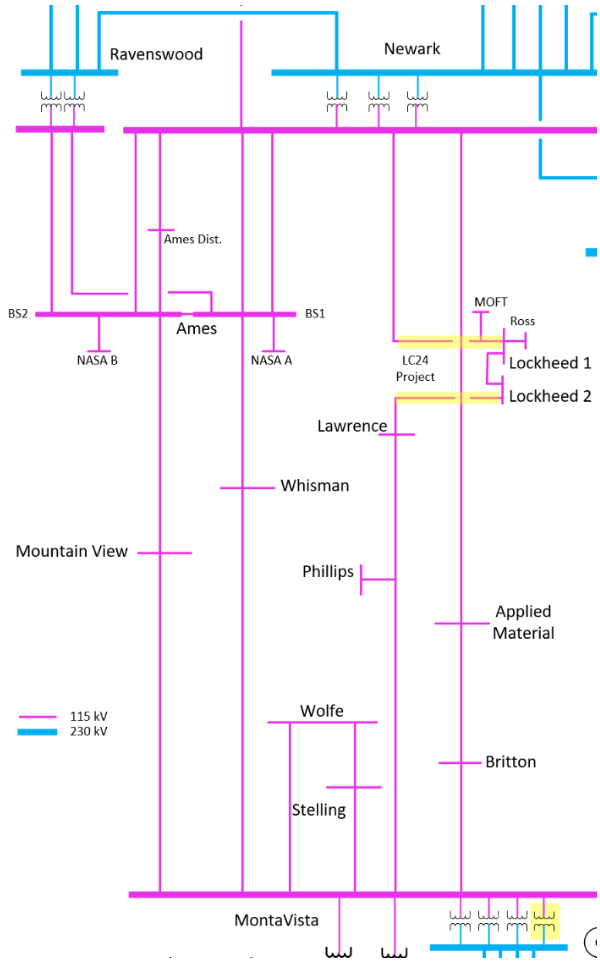
On the 230 kV side, the Monta Vista substation is connected solely to Metcalf via four lines. In the 115 kV network, there are two double circuits that link this substation to Ravenswood and Newark. According to load forecasts for the De Anza division, the area is expected to experience significant load growth, rising from 480 MW in 2027 to 730 MW in 2040, which includes large load interconnections along the 115 kV path from Monta Vista to Newark.

Power flow studies indicate that if any two of the three transformers are out of service, particularly under P6 contingencies, most of the load in the De Anza area would still be supported by the remaining transformers, resulting in its overload by 2035.

Project Details

This project aims to install a new 230/115 kV transformer bank at the Monta Vista substation, which will have a minimum summer normal rating of 420 MVA and a summer emergency rating of 462 MVA.

Figure 2-9 Monta Vista 230/115 kV Transformer Bank Addition Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $52.2M - $104.4 M and an estimated in-service date of 2032.

Alternatives Considered

Other alternatives for alleviating the overload on the Monta Vista 230/115 kV transformer banks were considered. These included expanding nearby substations with additional 230/115 kV banks or constructing a new substation capable of handling sufficient load to prevent the Monta Vista overload. However, these options proved ineffective in relieving the loading on the Monta Vista transformer banks and were not economically viable, particularly when involving the construction of a new substation. Furthermore, other Grid Enhancement Technologies (GETs) were deemed less effective for this issue. The energy storage solution was ruled out because the charging window was not available, and alternative solutions, such as power flow control devices, were considered not cost-effective due to the number of units required to mitigate the overloads on alternative lines.

2.3.2.10 Newark 115 kV Short Circuit Mitigation

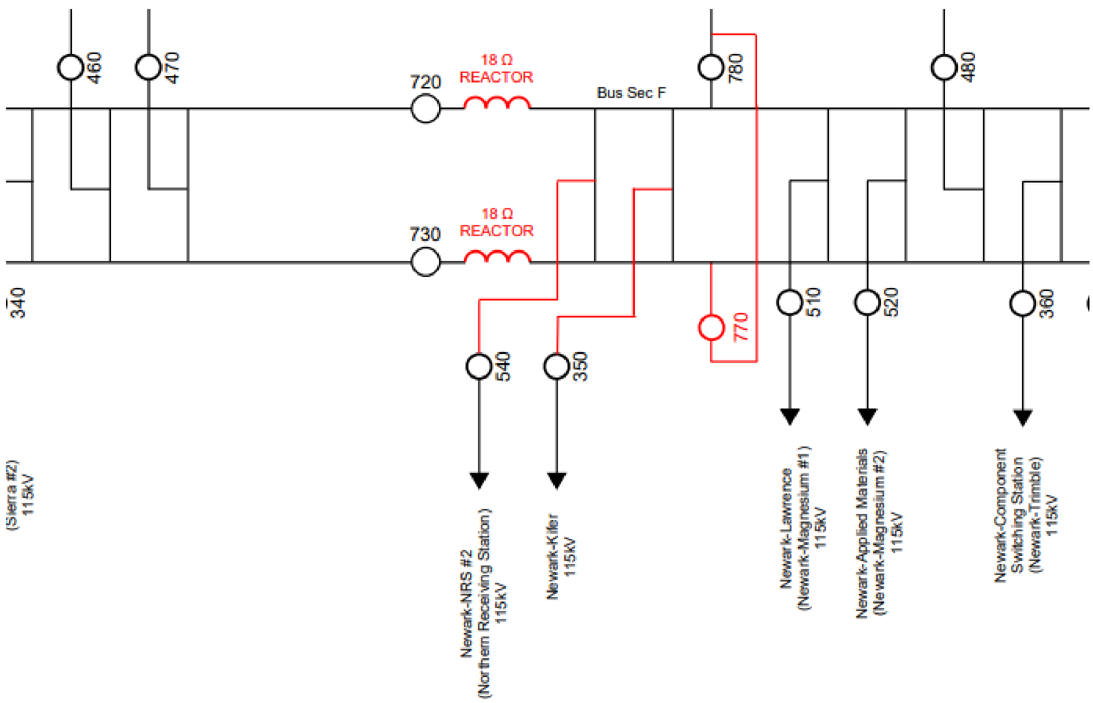
Project Need and Background

Studies show breaker overstress at Newark 115 kV for CB's 130, 140, 170, 310, 320, 330, 340, 350, 360, 370, 380, 420, 430, 460, 470/2, 480, 510, 520, 540, 720, 730, 770, 780 starting year-5 and beyond.

Project Details

The scope for 115 kV is to relocate one to three existing lines to spare bays within Bus F to accommodate installing two (2) 18-ohm bus reactors between Bus E and Bus F.

Figure 2-10: Newark 115 kV Short Circuit Mitigation Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of \$40 M - \$60 M and an estimated in-service date of Q4 2029.

Alternatives Considered

Due to the extent of over-stress, replacing all breakers isn't cost-effective.

2.3.2.11 Newark 230/115 kV Transformer Bank upgrade

Project Need and Background

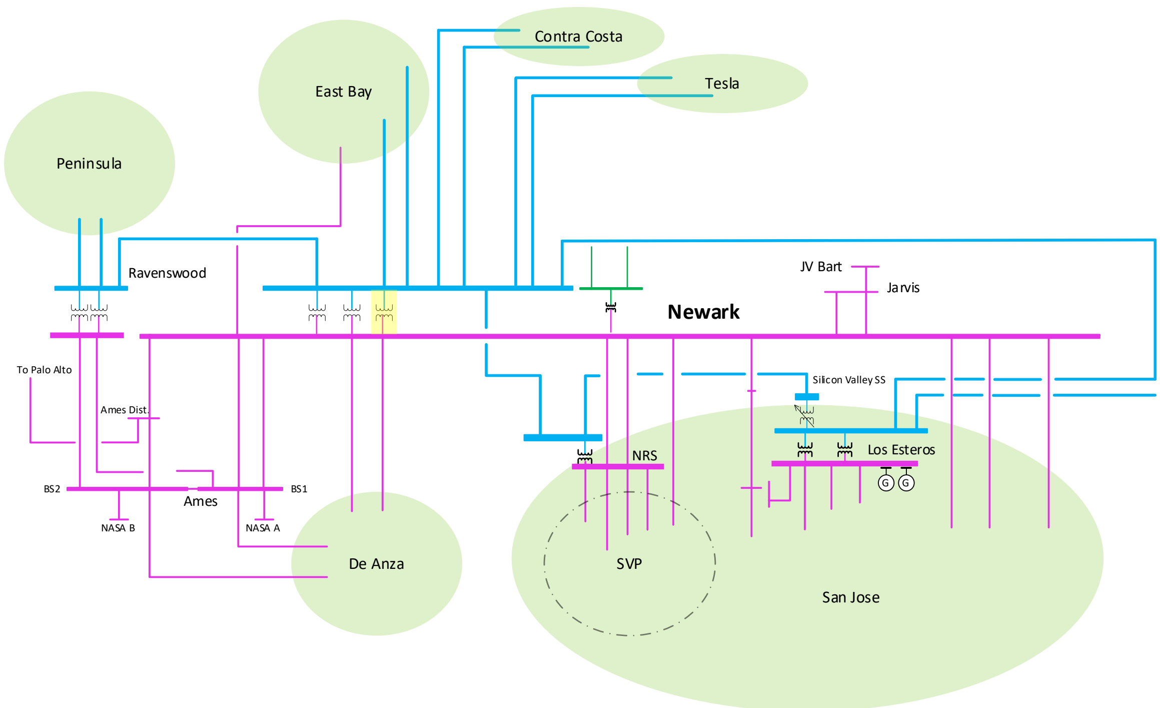
The Newark substation is essential for supplying power to customers in the South Bay area and the SVP system, which includes the cities of San Jose, Santa Clara, and Milpitas. It is equipped with three 230/115 kV transformers, each with different capacities: Transformer #7 has a normal rating of 429 MVA and an emergency rating of 495 MVA; Transformer #9 has a normal rating of 490 MVA and an emergency rating of 579 MVA; and Transformer #11 has a normal rating of 420 MVA and an emergency rating of 462 MVA. This substation connects multiple 230 kV and 115 kV power lines to distribute energy from Tesla, Contra Costa, and the East Bay to Ravenswood and Los Esteros at 230 kV. It also facilitates multiple connections at 115 kV with other major power sources in the South Bay, such as Metcalf, NRS, and Monta Vista. The reliability of this substation is critical for ensuring a stable power supply in this high load density region. Both the 230 kV and 115 kV buses are sectionalized to enhance reliability.

Power flow studies indicate that during P2 and P6 contingencies, most of the load in the San Jose area would continue to be supplied by the remaining transformers. This leads to an overload on Transformer Bank #11 by 2030.

Project Details

This scope is to replace the existing Newark #11 Transformer bank with a new bank that has minimum summer normal rating of 560 MVA and a summer emergency rating of 620 MVA.

Figure 2-11: Newark 230/115 kV Transformer Bank Upgrade Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $31.3 million - $62.6 million and an estimated in-service date of 2032.

Alternatives Considered

Alternative solutions include constructing a new 230 kV bus at nearby 115 kV existing substations to accommodate an additional 230/115 kV transformer bank or building a new substation capable of handling enough load to relieve the Newark overload. However, these alternatives were found to be ineffective in alleviating the load on the Newark transformer bank and were not economical compared to the preferred solution.

Furthermore, other grid-enhancement technologies such as power flow control devices were deemed inefficient, as they would only redirect the flow to other 230 kV substations without addressing the underlying issue. The energy storage solution was eliminated because the charging window was not available.

2.3.2.12 Nortech 115 kV Short Circuit Mitigation

Project Need and Background

Studies show breaker overstress at Nortech 115 kV for CB's 182 and 192 starting Year-5 and beyond.

Project Details

The scope is to upgrade 115 kV CB's 182 and 192 to 63 kA.

Estimated Cost & In-Service Date

This project has a cost estimate of $2.5 million - $5 million and an estimated in-service date of Q4 2029.

Alternatives Considered

None

2.3.2.13 San Jose B 230/115 kV Transformer Bank Addition

Project Need and Background

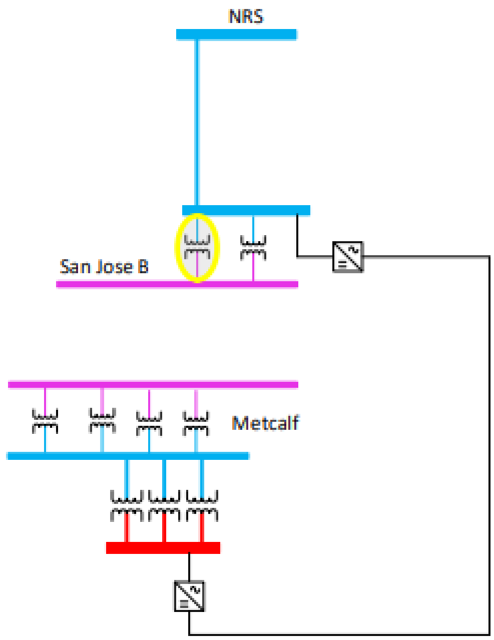
The San Jose B substation is set to become one of the main supply sources in the San Jose area, which includes Silicon Valley. Currently, the substation has only 115 kV connections to San Jose A, FMC, Trimble, and Evergreen. However, with the upcoming San Jose area HVDC line, the substation will be expanded to accommodate a 1,000 MW HVDC line operating at 230 kV, along with a 230/115 kV transformer bank. The power from this HVDC will be delivered through the 230 kV path between the proposed San Jose B to Northern Receiving Station (NRS) and the 230/115 kV bank to the 115 kV system. This expansion will enable it to serve as a primary source for the 115 kV grid that interconnects Newark, Los Esteros, and Metcalf.

The demand in this region is largely driven by distribution customers in the San Jose and Silicon Valley area, particularly with the recent addition of large-load facilities such as data centers. The forecasted load in the four closest substations connected to San Jose B goes from 400 MW in 2027 to 560 MW in 2040. Given the consistent growth in load, power flow studies indicate that the proposed 230/115 kV transformer bank, part of the San Jose area HVDC line, may experience overloading during summer peak loads by the year 2035. This overload is expected to occur under normal operating conditions with a 1,000 MW injection at San Jose B.

Project Details

This project aims to install a parallel 230/115 kV transformer bank at the San Jose B Substation, which will have a minimum summer normal and emergency rating of 560 MVA. Additionally, it will involve upgrading any limiting components as necessary to ensure full transformer capacity is achieved.

Figure 2-12: San Jose B 230/115 kV Transformer Bank Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $34.7 M - $69.4 M and an estimated in-service date of May 2030 or earlier.

Alternatives Considered

Other potential solutions to address the overload on the San Jose B 230/115 kV transformer bank were explored. Options included constructing a new 230 kV bus at nearby 115 kV existing substations to accommodate an additional 230/115 kV transformer bank or building a new substation capable of handling enough load to relieve the San Jose B overload. However, these alternatives were found to be ineffective in alleviating the load on the San Jose transformer bank and were not economically viable.

Other grid-enhancement technologies were deemed less effective for mitigating this constraint. The energy storage solution was eliminated because the charging window was not available. Alternative solutions, such as power flow control devices, were also deemed inefficient, as they would only redirect the flow to other 230 kV substations without addressing the underlying supply issue.

2.3.2.14 Saratoga-Vasona 230 kV Line Reconductoring

Project Need and Background

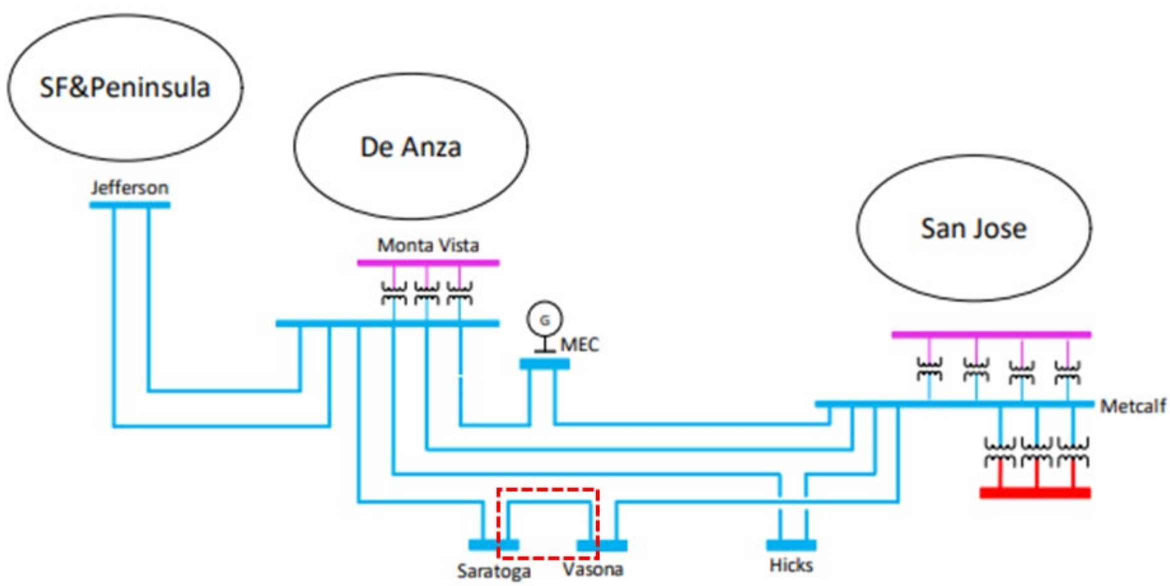
Planning studies indicate that with ongoing load growth in the Bay Area, the lower-rated Saratoga-Vasona circuit between Metcalf-Monta vista corridor is expected to overload under contingency conditions. For a category P6 event involving the loss of two high-capacity circuits, Saratoga-Vasona 230 kV line is overloaded.

The proposed project aims to eliminate these violations and restore adequate contingency margins. By reinforcing the Saratoga-Vasona 230 kV transmission line, the project will enhance transfer capability to the De Anza and Peninsula areas, accommodating future demand growth while providing increased operational flexibility and reliability for customers.

Project Details

The project scope includes the reconductoring of 3.4 miles of 230 kV overhead line between the Saratoga and Vasona substations with a larger conductor to achieve at least 3000 Amps during summer emergency conditions.

Figure 2-13: Saratoga-Vasona 230 kV Line Reconductoring Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $89 M - $178 M and an estimated in-service date of 2034 or earlier.

Alternatives Considered

Alternatives such as adding a new power source in the San Jose area to improve power flow distribution or constructing new circuits parallel to this corridor. However, these options were found to be economically unviable and ineffective in alleviating the loading on the Metcalf-Monta Vista 230 kV path. Additionally, other grid-enhancement technologies were deemed less effective for this specific situation. An energy storage solution was ruled out due to an inadequate charging window, and alternative solutions, such as power flow control devices, were considered not cost-effective because of the number of units required.

2.3.2.15 South Oakland Reinforcement (Phase 2)

Project Need and Background

In the 2024-2025 Transmission Plan, the South Oakland Reinforcement project was approved. This project aims to strengthen the 115 kV lines originating from the Moraga side to San Leandro and Oakland J, which have been found to be overloaded during multiple contingencies. The project addressed most of the overload issues, but some minor overloads persisted and were recommended to be evaluated in future transmission development plans.

Current planning cycle power flow studies indicate that the East Shore-Grant 115 kV lines experience significant overloads when supply from either the Moraga or East Shore side is lost. The primary reason for this overload is increased demand in the area which is expected to rise from approximately 596 MVA in 2027 to 896 MVA by 2040. Furthermore, there are large load interconnection projects planned in the East Shore-Grant region.

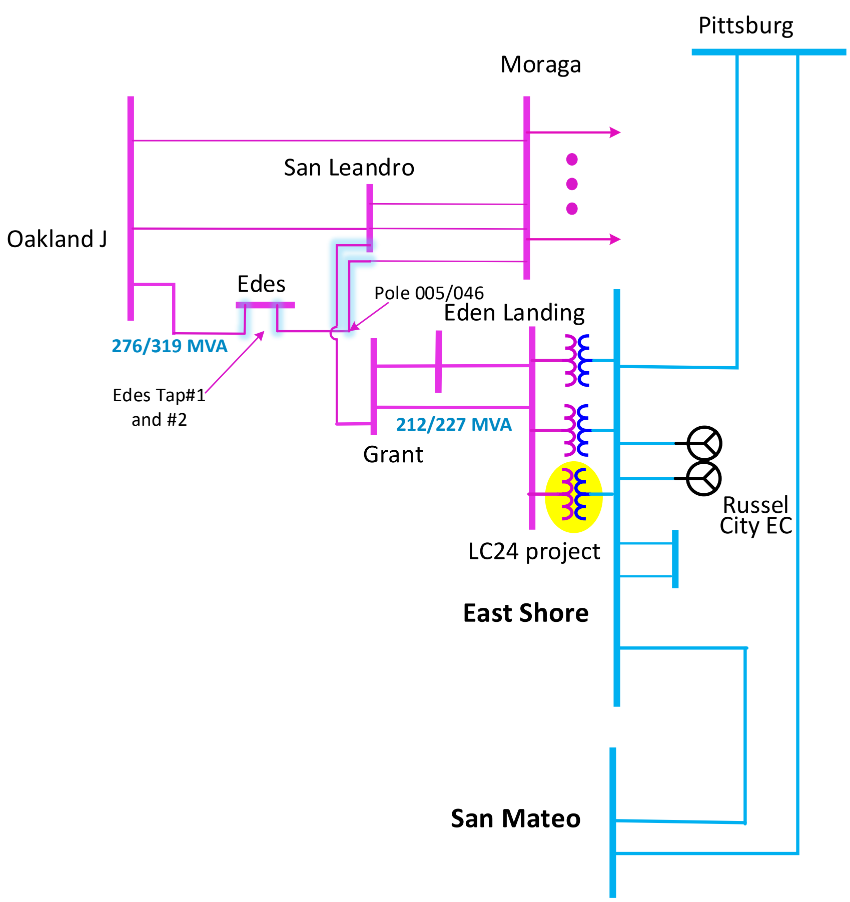
Project Details

The South Oakland Reinforcement Project (Phase 2) aims to address the high demand growth in South Oakland by reconfiguring the 115 kV network and adding a new line section to connect the San Leandro and Grant substations. This new configuration will improve the performance of the South Oakland area by balancing the load between the two sources and ensuring reliability. This alternative builds on the South Oakland Reinforcement Project proposed in the previous planning cycle, increasing transmission capacity for the region while supporting the long-term reliability of the grid and its ability to meet rising demands.

The project scope includes the following components:

- Constructing a new 1.5-mile 115 kV double circuit line from the San Leandro substation to pole 005/046 on the Grant-Oakland J line, with a summer emergency rating of at least 3428 Amps. This double circuit will connect with the San Leandro-Moraga 115 kV line #3 at the San Leandro substation and with the Oakland J-Grant 115 kV line on the opposite side. This new connection will create the Moraga-Grant and San Leandro-Edes 115 kV lines.
- Reconductoring Edes Tap #1 and Edes Tap #2 (approximately 0.05 miles each) to achieve a summer emergency rating of at least 3428 Amps.

Figure 2-14: South Oakland Reinforcement Phase 2 Diagram



Estimated Cost & In-Service Date

This project has a cost estimate of $43 million - $86 million and an estimated in-service date of May 2034.

Alternatives Considered

Alternatives were considered to address the overload issue on the East Shore – Grant, Grant – Edes, and Oakland J lines. These included a new 230 kV supply sourced from East Shore, as well as additional 115 kV reinforcements and the reconductoring of the lines identified with overloads. However, these alternatives would incur higher implementation costs and offer similar performance in resolving the overload issues.

The use of Grid Enhancement Technologies (GETs), including energy storage and power flow control devices, was considered as potential solutions. However, they were ultimately found to be ineffective for mitigating this constraint. Energy storage was not chosen due to unavailability in charging capacity , and alternative solutions, such as power flow control devices, were deemed unfeasible because of the limited transmission capacity in the area.

2.3.2.16 Tesla-Trimble-Metcalf 230 kV Corridor Expansion project

Project Need and Background

The current planning assessment cycle has confirmed that the existing projects are insufficient to meet long-term demand. As a result, some of these projects are being proposed for re-scoping, while others are being submitted for approval in this cycle. Notable new projects in this cycle include the addition of the San Jose B 230/115 transformer bank, the upgrade of the Newark 230/115 kV transformer bank, and the Trimble expansion to 230 kV, which is part of the load interconnection network upgrades and includes two 230/115 kV transformer banks. With significant updates to the transmission development plan, a reassessment was conducted to identify potential new issues within the South Bay 115 kV network. This assessment aimed at finalizing the comprehensive transmission reinforcement project for the area. Findings from this evaluation revealed NERC thermal violations in categories P1, P2, P3, and P6 in specific sections of the 115 kV paths that connect San Jose B with Trimble and Metcalf, as well as the lines serving the load at the SVP system, including Newark - NRS, Kiefer - FMC, and Los Esteros PST. Additionally, in the 230 kV lines serving the South Bay area, specifically the lines from Contra Costa to Newark, Tesla to Newark and Metcalf to Los Esteros were overloaded. These paths overload when major sources to this area are lost, particularly from P1 and P2 contingencies at the Newark substation or P6 contingencies involving the HVDC line and the Trimble - NRS - Newark 230 kV path, or other 230 kV lines connecting to Newark from the Tesla or Contra Costa sides.

Project Details

To address these issues, the ISO is recommending the approval of the "Tesla-Trimble-Metcalf 230 kV Corridor Expansion Project." This project will add two additional 230 kV lines to the center of the San Jose load, alleviating the current burden on the 230 kV lines from the north of Newark and decreasing the load on the Metcalf and Los Esteros 230/115 kV transformer banks and the various 115 kV lines that interconnect the San Jose area. In addition, with the strengthening of the Trimble infrastructure, there will be a more balanced distribution of loads among the various sources supplying power to San Jose, SVP, and the South Bay loads. This will significantly reduce the dependency on the Newark, NRS and Metcalf substations. The project will utilize the existing 230 kV infrastructure to bring two new lines into the Trimble 230 kV substation: Metcalf-Trimble and Tesla-Trimble 230 kV with the following components:

- Move Tesla-LLNL 115 kV to its own pole line and reconductor original line using 1113 ACSS bundled conductor (8 mi).
- Reconductor (both sides) of the Tesla-Newark #2 up to Sunol Jct using 1113 ACSS bundled conductor, or greater and remove cross ties (12.5 mi).
- Reconductor (both sides) of the Los Esteros-Metcalf (from Metcalf to Sunol Jct) using 1113 ACSS bundled conductor, or greater and remove cross ties (26 mi).
- Build two lines from Los Esteros-Metcalf tower line into Trimble establishing the new Tesla-Trimble and Metcalf-Trimble 230 kV lines (8 mi each).

Figure 2-15: Tesla – Trimble – Metcalf 230 kV Corridor Expansion Project

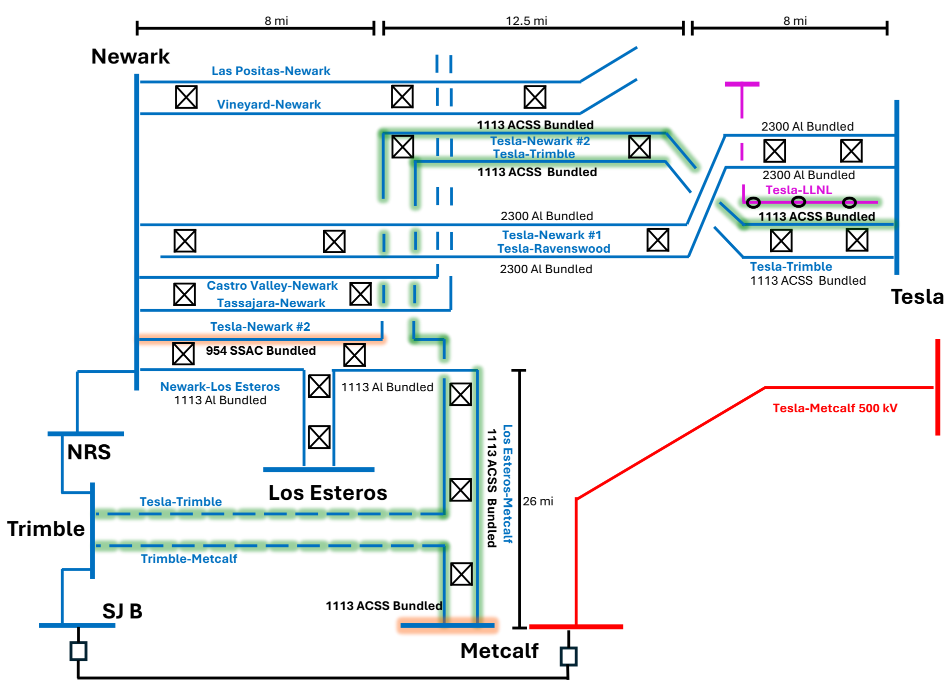


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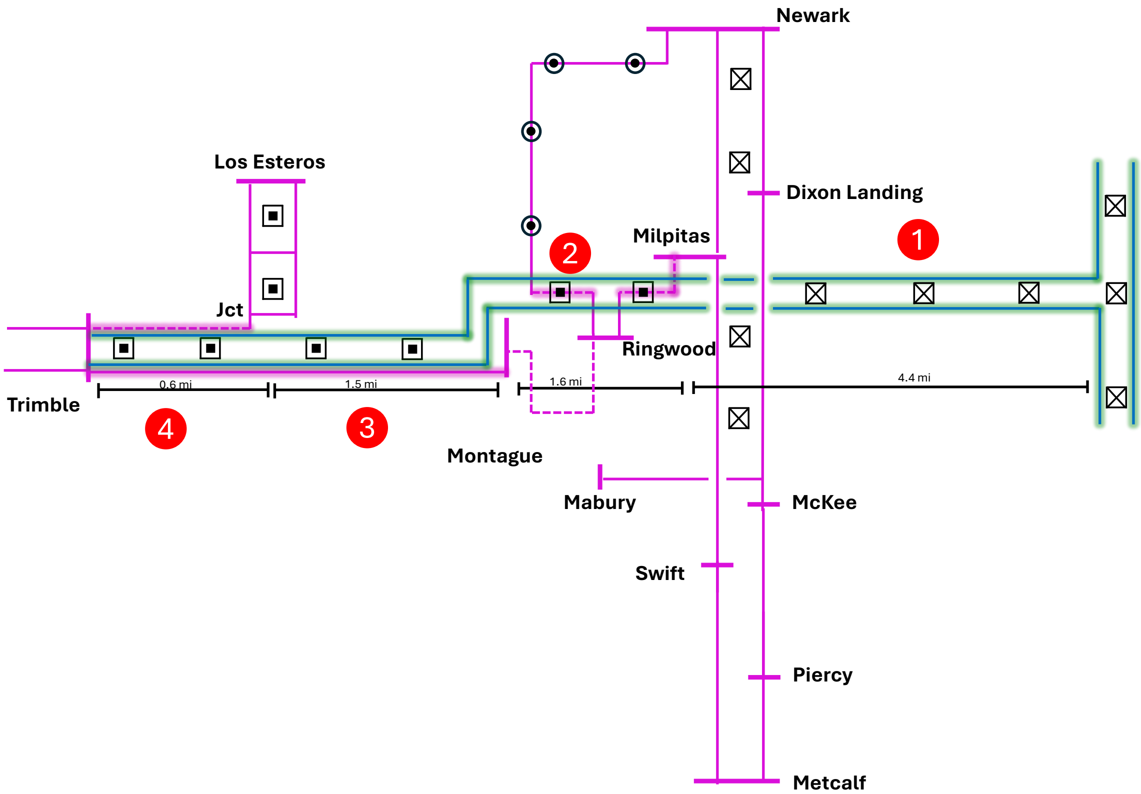
Figure 2-16: Detailed scope for new 230 kV lines



Below is the detailed scope for the new 230 kV lines described in the last bullet:

1. The hills to Milpitas:
   a. Build 230 kV DCTL from Los Esteros-Metcalf tower line near Milpitas Substation using bundled 1113 ACSS (4.4 mi).
2. Milpitas to Montague:
   a. Underground 2.2 mi of the Newark-Ringwood-Milpitas #2 115 kV line.
   b. Build two overhead 230 kV circuits from Milpitas to Montague using bundled 1113 ACSS (1.6 mi).
   c. Build only one 115 kV connection from Montague to Ringwood instead of two (rescope of the "South Bay Reinforcement Project").
3. Montague to Los Esteros Jct:
   a. Remove the last 1.5 mi section of the Los Esteros-Montague 115 kV line from Los Esteros Jct to Montague substation.
   b. Cross-tie the remaining line section from Los Esteros Jct to Los Esteros.
   c. Build two 230 kV circuits using bundled 1113 ACSS and the Montague-Trimble 115 kV circuit on a single structure from Montague to Los Esteros Jct. (1.5 mi).

4. Los Esteros Jct. to Trimble:
   a. Build two 230 kV circuits using bundled 1113 ACSS and the Montague-Trimble 115 kV circuit on a single structure from Los Esteros Jct. to Trimble (0.6 mi).
   b. Underground 0.6 mi of the Los Esteros-Trimble 115 kV line.

Estimated Cost & In-Service Date

This project has a cost estimate of $712 M - $1,424 M and an estimated in-service date of 2034 or earlier.

Alternatives Considered

In the 2024-2025 transmission planning process Hetch Hetchy Water and Power (HHWP) submitted into the Request Window the Warnerville-Newark Transmission Expansion Project (WaNTEP). While assessing the needs within the Greater Bay area in this planning cycle the ISO continued to assess the WaNTEP project as an alternative to address the identified needs. In the review of alternatives, portions of the proposed WaNTEP project were considered. These alternatives involved a transmission line from Tesla to Newark as opposed to from Warnervile to Newark. This new circuit aims to alleviate the load flow in the existing 230 kV lines connecting to Newark and to reduce the loading on other transformer banks in the San Jose area. Two alternatives from Tesla to Newark were considered:

1. 1000 MW HVDC transmission line from Tesla 230 kV to Newark 230 kV
2. 230 kV AC transmission line Tesla to Newark

The AC and HVDC alternatives alleviated some of the identified overloads in the 230 kV paths connecting to Newark. However, the alternatives were not effective in addressing the identified overloads in the 115 kV grid downstream of the Newark substation. With either of the alternatives significant unresolved overloads were observed, as identified in Appendix B.

While the ISO is not recommending the WANTEP proposal in the 2025-2026 transmission plan to meet the reliability needs identified in this planning cycle, the ISO does recognize the potential benefits of upgrading the existing Warnerville-Newark transmission path to a higher capacity. While the existing 115 kV transmission line is not under ISO control, the ISO is interested in working with Hetch Hetchy on projects of mutual interest for the betterment of both systems. As Hetch Hetchy noted in comments submitted in this planning cycle, as well as the project submission in the 2024-2025 planning cycle, the Hetch Hetchy proposal entails utilizing a valuable transmission corridor far more effectively than the current 115 kV asset. The ISO's studies in this planning cycle do demonstrate the effectiveness of the proposal, whether at 230 kV AC or an HVDC option, to provide additional capacity into the 230 kV network at Newark and could potentially enable additional renewable resources in the Newark to Warnerville area. While these capabilities are not called for in the current planning cycle, the steadily increasing load growth being identified in the Greater Bay area suggests additional capacity may be required in future planning cycles.

Hetch Hetchy also stated in the 2024-2025 planning cycle submission that the "existing transmission assets require modernization, either redevelopment, replacement, or improvement over the near-term horizon." This raises the concern that if Hetch Hetchy funds extensive upgrades now to maintain existing 115 kV capabilities, it will be less effective and cost efficient to pursue more significant capacity upgrades in the future. The ISO plans to coordinate with Hetch Hetchy regarding their capital maintenance plans and investigate if a coordinated arrangement could be viable to ensure any upgrades are rightsized to maintain optionality into the future, pursuant to the FERC 2021 policy statement regarding voluntary agreements to plan and pay for transmission facilities.

The recommended project is proposing to use ACSS conductors. Other grid-enhancement technologies, including energy storage and power flow control devices, were explored as potential solutions. However, they were determined to be ineffective in this situation. The energy storage option was not considered due to unavailability of the charging window and the number of batteries at various locations that would be required. Alternative solutions, such as power flow control devices, were deemed ineffective due to the underlying need being the increase in the load and insufficiency of current transmission import capability.

Based on these studies, the most effective solution to enhance transmission capacity and supply the San Jose area is to establish an additional 230 kV loop connecting two major sources in the Greater Bay Area: Tesla and Metcalf, with one of the core substations in this area. This new transmission corridor will deliver much-needed energy directly to the Trimble load center.

2.3.2.17 Trimble 115 kV Short circuit mitigation

Project Need and Background

Studies show breaker overstress at Trimble 115 kV for CB's 312, 322, 332, 372, 382 and 342 starting Year-10.

Project Details

The scope is to replace 115 kV CB's 312, 322, 332, 372, 382 and 342.

Estimated Cost & In-Service Date

This project has a cost estimate of $7.8M - $15.6M and estimated In-Service Date of Q4 2034.

Alternatives Considered

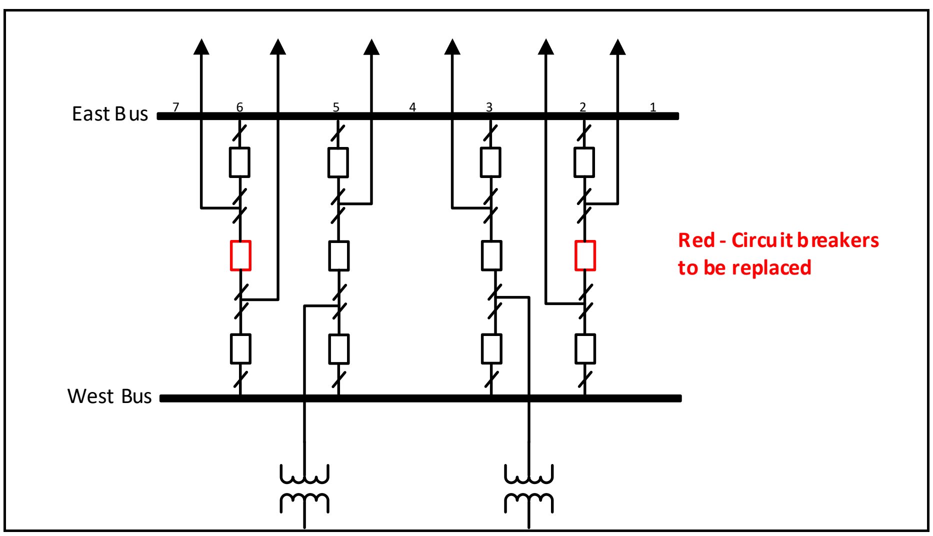
None.

2.3.2.18 Lugo 230 kV CB Upgrade

Project Need and Background

The SCE North of Lugo area assessment indicates that by 2040, two breakers at the Lugo 230 kV substation are projected to exceed their interrupting capacity. To address these Short Circuit Duty (SCD) exceedances, SCE proposes replacing the two affected breakers with higher-rated equipment.

Figure 2-17: Lugo 230 kV CB Upgrade Project



Project Details

The project involves replacing two existing 63 kA breakers (X/R ratio 17) with new breakers rated at 63 kA and a higher X/R ratio of 35.

Estimated Cost & In-Service Date

The project is estimated to cost between $4-5 million, with an estimated in-service date of July 1, 2031.

Alternatives Considered

Alternatives were not evaluated in detail, as the proposed solution represents the standard, least-cost, and most effective first step for addressing the SCD exceedances.

2.3.2.19 Lugo 500 kV Reactive Power Reinforcement

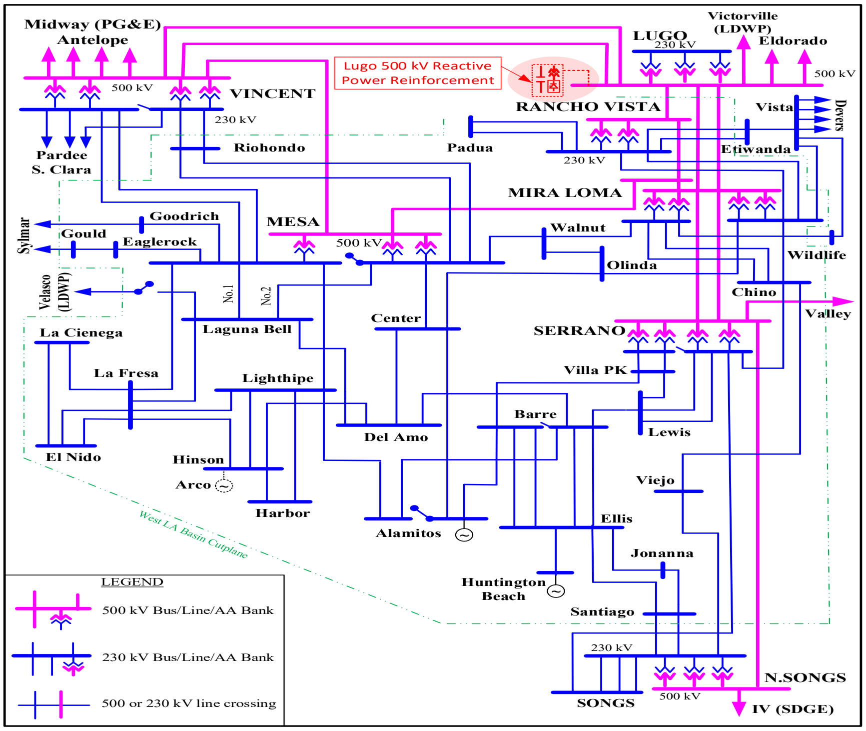
Project Need and Background

The project was submitted by Southern California Edison to address the low-voltage conditions identified on multiple 500 kV buses of the SCE bulk system under Categories P0, P1, and P7 contingencies in the near-term and the long-term planning scenarios. In addition, the P7 contingency of Vincent – Mesa 500 kV and Vincent – Rio Hondo 230 kV lines could potentially result in post-transient voltage instability in the SCE main area in the long term summer off-peak case. These issues are driven by renewable generation development along with limited voltage support from conventional generation resources in the SCE area.

Project Details

The project consists of a ±300 MVAr STATCOM (Static Synchronous Compensator) combined with 3x 200 MVAr switchable capacitor banks located at or near by the Lugo 500 kV substation, providing a total of (+900 to –300) MVAr of steady-state and dynamic reactive power support to the SCE 500 kV bulk system. The scope of this project may need to be revisited in the next planning cycle if the proposed Trout–Canyon–Lugo 500-kV line is approved by the ISO Board during the current cycle.

Figure 2-18: Lugo 500 kV Reactive Power Reinforcement Project



Estimated Cost & In-Service Date

This project has a cost estimate of $370 - $450 M with estimated in-service date of 2032.

Alternatives Considered

The ISO and SCE evaluated several potential locations for installing voltage-support facilities, including steady-state and dynamic reactive power support, at the El Dorado, Mohave, Devers, Lugo, and Vincent 500 kV substations.

2.3.2.20 Devers 230 kV SCD Upgrade Project

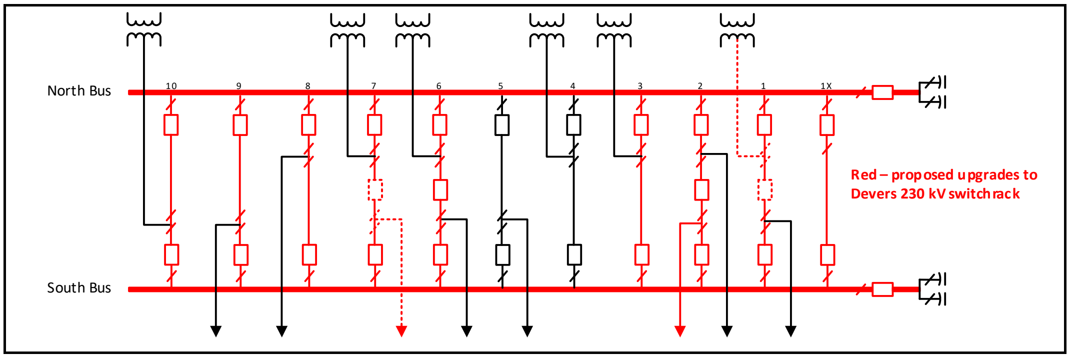
Project Need and Background

The SCE Eastern area assessment identified Short Circuit Duty (SCD) concerns at the Devers 230 kV substation. Studies indicate that by 2027, three circuit breakers will exceed their interrupting capacity, and by 2035, the entire switchrack and all associated breakers are projected to be above their ratings. To maintain system reliability and compliance with applicable standards, SCE proposes upgrading the Devers 230 kV switchrack from 63 kA to 80 kA. This upgrade will ensure adequate interrupting capability for future system conditions and prevent equipment failure under fault scenarios.

Project Details

The project involves upgrading the interrupting capacity rating of 24 circuit breakers at the Devers 230 kV switchrack from 63 kA to 80 kA.

Figure 2-19: Devers 230 kV SCD Upgrade Project



Estimated Cost & In-Service Date

The estimated cost for this project is $124-$186 million with a targeted in-service date of December 31, 2035.

Alternatives Considered

Another proposed alternative evaluated was to split the 230 kV switchrack to reduce short circuit current levels. Based on technical feasibility and outage coordination issues, the ISO does not consider the proposed 230 kV bus split at Devers Substation to be a viable mitigation alternative to address the short circuit duty issues.

2.3.2.21 Mesa–Laguna Bell 230 kV #2 upgrade

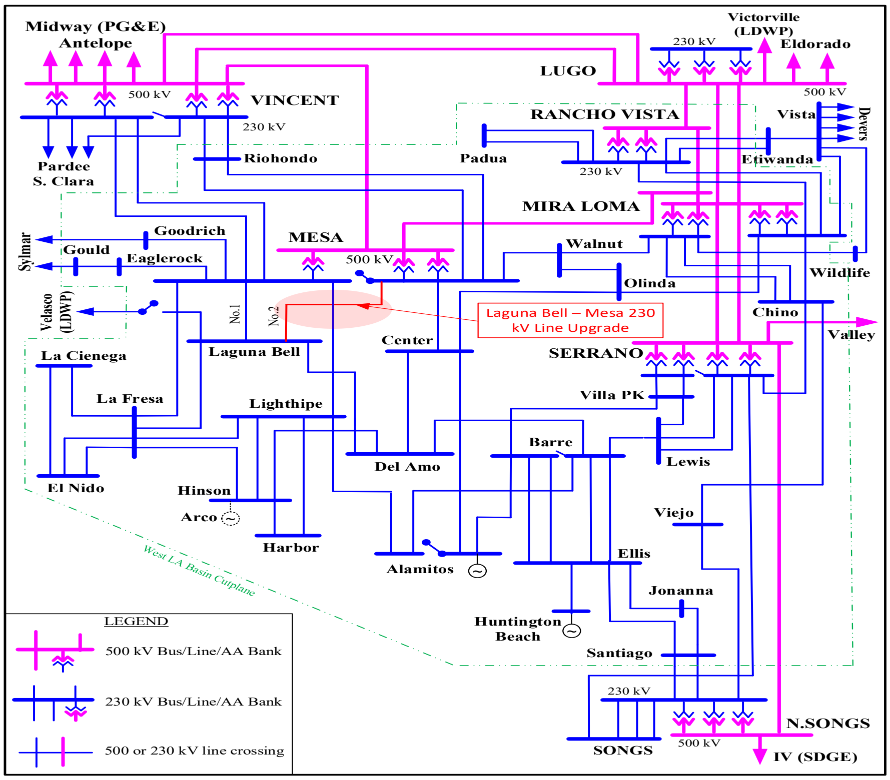
Project Need and Background

The project was submitted by Southern California Edison to eliminate the Mesa–Laguna Bell 230 kV #2 line overloads and increase load serving capability to accommodate additional energy storage resources that can be charged and subsequently deployed to offset local capacity deficiencies through 2035. Prior to completing the Mesa–Laguna Bell 230-kV #2 upgrade, the ISO needs to continue coordinating with the CPUC on energy storage procurement, particularly regarding the appropriate sizing and siting of storage resources, to ensure reliable electric service for the south-of-Mesa load pocket.

Project Details

The project involves reconductoring 4.9 miles of the Mesa–Laguna Bell 230 kV #2 line using advanced conductor technology.

Figure 2-20: Mesa – Laguna Bell 230 kV line #2 Upgrade



Estimated Cost & In-Service Date

The estimated project cost is between $41 million and $56 million, with an expected in-service date of 2032.

Alternatives Considered

The ISO investigated various potential alternatives to address reliability constraints identified in the SCE Metro area in 2035, including reconfiguring the Mesa 230 kV network, building new 230 kV line from Mesa to Del Amo, and adding a new 500 kV transmission switchyard at Lighthipe. The ISO also outlined three potential long-term alternatives including HVDC transmission options to address reliability constraints identified in the LA Basin and Ventura area by the year 2040. These and other potential mitigation solutions that may be provided by stakeholders will be evaluated further in the upcoming 2026-2027 transmission planning process.

2.3.2.22 Etiwanda and Mira Loma 230 kV SCD Upgrade

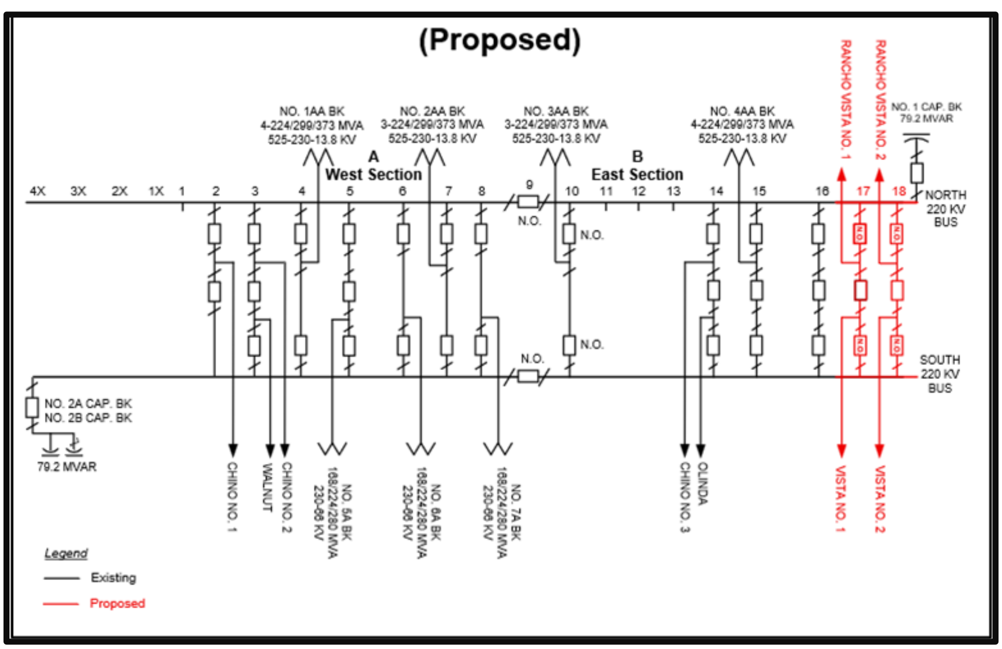
Project Need and Background

This project was submitted by Southern California Edison to address the short circuit duty concern at the neighboring Etiwanda and Mira Loma 230 kV substations which exceed 100% capacity in the long-term planning scenario of 2039. SCE identified that the SCD at Mira Loma 230 kV substation is projected to exceed 95% of the interrupting capacity rating of seven (7) circuit breakers (CBs) at Mira Loma Section A (West) 230 kV and fifteen (15) CBs at Mira Loma Section B (East) 230 kV by 2027. And four (4) of the fifteen CBs at Mira Loma B are expected to exceed 100%. In addition, the entire Etiwanda 230 kV switchrack is anticipated to exceed 100% of its interrupting capability by 2035, even after accounting for the additional margin achieved through the Etiwanda 230 kV Bus SCD Mitigation project approved during the 2023 – 2024 Transmission Plan.

Project Details

The scope of this project is to expand the Mira Loma 230 kV switchrack by extending the 230 kV switchrack, adding two (2) Breaker and a Half (BAAH) positions (No. 17 and No. 18), and relocating the following lines. The two new BAAH positions are needed by SCE as they would provide necessary flexibility and optionality for both grid operations and future generation interconnection.

Figure 2-21: Mira Loma 230 kV Switchrack Proposed Updates



Estimated Cost & In-Service Date

The estimated cost for this project is $40-$55 million, which includes the line relocation, bus extension, and the installation of two BAAH positions. The proposed in-service date is Q3, 2031.

Alternatives Considered

The following alternative mitigations proposed by Electric Power Engineers (EPE) were also considered by SCE:

- Rebuilding the Mira Loma switchrack to 80 kA.
- Opening the Rancho Vista No.1 and No.2 lines at the Mira Loma switchrack.
- EPE's Alternative 1: reconfiguring the Mira Loma 230 kV substation to create a single Rancho Vista–Vista 230 kV transmission line by opening CBs at bay position #17.
- EPE's Alternative 2: reconfigure the Mira Loma 230 kV substation to establish two (2) Rancho Vista–Vista 230 kV lines through the switchrack by swapping Mira Loma–Chino No. 3 and Mira Loma–Vista No. 1 230 kV lines.
- EPS's Alternative 3: reconfigure the substation to create two (2) Rancho Vista–Vista 230 kV lines through the switchrack and relocate the Mira Loma–Walnut 230 kV line from the west section to the east section of the bus.

Both SCE's submitted mitigation and EPE's alternatives provide viable mitigation options with similar technical feasibility to address the SCD issues. SCE's proposed solution avoids the engineering complexities associated with relocating existing and planned transmission structures and creates additional bay positions needed for operational flexibility and support future generation interconnections.

2.3.2.23 Penasquitos – Mira Sorrento 69 kV #2 line

Project Need and Background

The SDG&E study area assessment identified the New Penasquitos – Mira Sorrento 69 kV #2 line project as a reliability transmission solution to address the thermal overload of three 69 kV transmission lines caused by the load growth in the Penasquitos load pocket, starting in 2035.

The Penasquitos load pocket comprises Torrey Pines, University of California Metering, Mira Sorrento, Genesse and Dunhill substations, which serve hospital loads, University of California San Diego (UCSD) and General Atomics. The reliability assessment showed Category P0 and P1 thermal overloads for TL6959 Penasquitos – Mira Sorrento, TL6943 Torrey Pines – University of California Metering and TL666 Penasquitos – Doublet Tap –

Dunhill Tap – Torrey Pines 69 kV lines, requiring additional transmission infrastructure to serve the load growth.

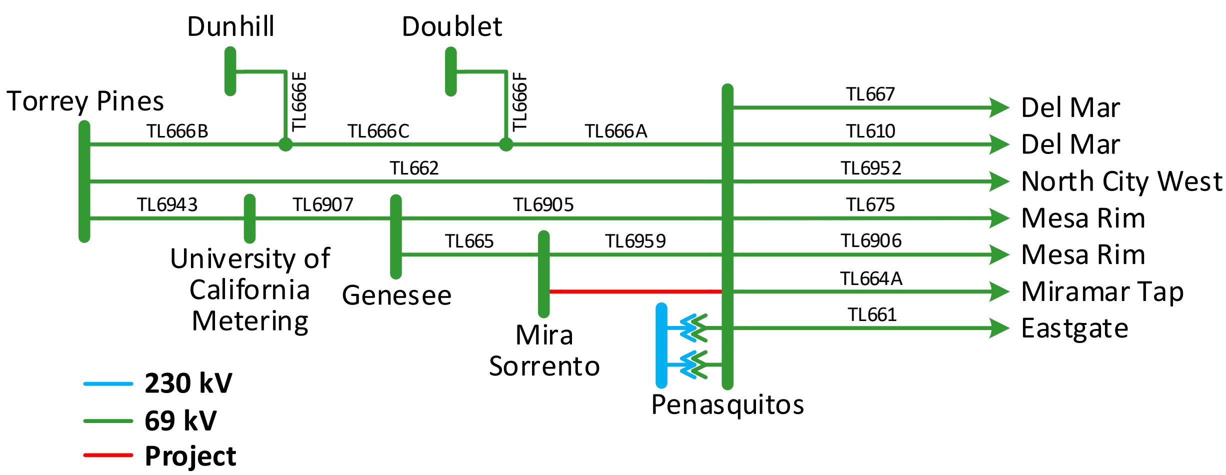
Furthermore, UCSD requested SDG&E to perform an Engineering Study that describes transmission facilities required to accommodate the anticipated electrical load growth at UCSD La Jolla Campus. This request will increase by 28 MVA the load at University of California Metering substation, before the end of 2027. The additional load would directly impact on the reliability of the Penasquitos load pocket, where the in-service date need of the Request Window project would be 2031 instead of 2035.

Project Details

The project involves the following:

- Build a new ~4.5 miles underground 69 kV line between Penasquitos and Mira Sorrento substations with a minimum continuous rating of 136 MVA.

Figure 2-22: New Penasquitos – Mira Sorrento 69 kV #2 line



Estimated Cost & In-Service Date

The estimated cost for this project is $114.8 million with a targeted in-service date of 2031.

Alternatives Considered

Other alternatives explored consist of the following:

- Reconductor TL6959 Penasquitos – Mira Sorrento, TL6943 Torrey Pines – University of California Metering and TL666 Penasquitos – Doublet Tap – Dunhill Tap – Torrey Pines 69 kV line with a continuous rating of 204 MVA and an estimated cost of $121M. This alternative could face construction challenges since the load pocket serves critical loads.

- Advanced flow control devices are not an effective alternative to mitigate the multiple Category P0 and P1 thermal overloads. Additionally, there is no space to expand the substations to add flow control devices.
- Energy storage could solve the thermal overloads identified in the 2035 peak load scenario but not in 2040 due to charging limitations. Moreover, there is no space to expand the substations nor land in the vicinity of them where energy storage could be installed.

2.3.2.24 TL690B Reconductor and TL697 Reconductor

Project Need and Background

The SDG&E study area assessment identified the TL690B Reconductor and TL697 Reconductor project as a reliability transmission solution to address the thermal overload of two 69 kV transmission lines caused by the load growth at Oceanside substation, starting in 2031.

Oceanside substation is served by two 69 kV transmission lines; TL690B Oceanside – Oceanside Tap and TL697 San Luis Rey – Oceanside, which are both currently limited to 54 MVA. Therefore, the Category P1 outage of any of these transmission lines could overload the remaining line. Based on the non-coincident load forecast, Oceanside substation would reach a peak load of 56 MW by 2031.

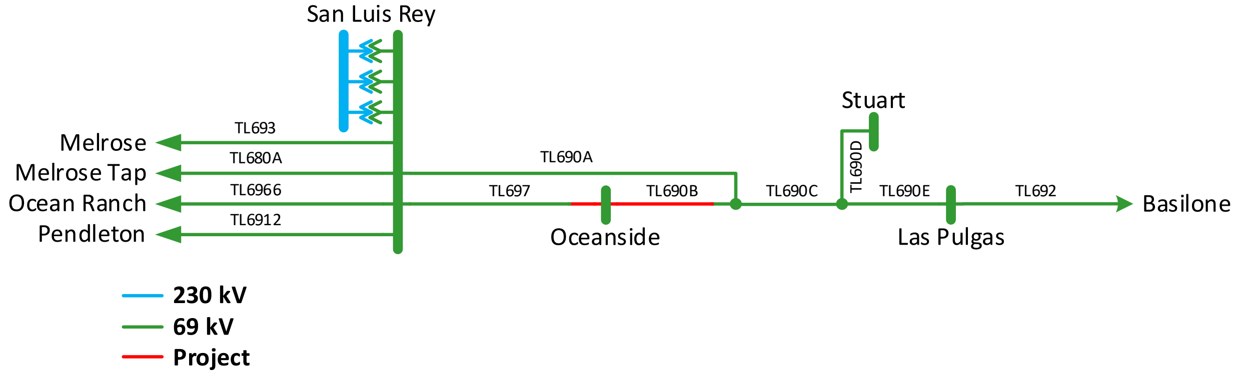
The project submitted in the Request Window considered the full rebuild of these 69 kV transmission lines, but further analysis showed that Oceanside substation distribution bank capacity cannot be expanded beyond 60 MVA. Therefore, it is only necessary to reconductor the underground segments that limit the line rating to 54 MVA.

Project Details

The project involves the following:

- Reconductor ~1.2 miles of TL690B Oceanside – Oceanside Tap and ~0.1 miles of TL697 San Luis Rey – Oceanside 500 Al underground conductor to increase their normal rating to 60 MVA.

Figure 2-23: TL690B Reconductor and TL697 Reconductor



Estimated Cost & In-Service Date

The estimated cost for this project is $33 million with a targeted in-service date of 2031.

Alternatives Considered

Other alternatives explored consist of the following:

- Advanced flow control devices are not applicable since Oceanside substation is only fed from two 69 kV sources. Therefore, the power flow cannot be controlled during a Category P1 contingency.
- Energy storage is not feasible due to charging limitations. Furthermore, there are no bay positions available at Oceanside substation to connect the energy storage nor land in the vicinity of the substation where energy storage could be installed.

2.3.2.25 TL623C Reconductor

Project Need and Background

The SDG&E study area assessment identified the TL623C Reconductor project as a reliability transmission solution to address the thermal overload of one 69 kV transmission line caused by the load growth at San Ysidro substation, starting in 2032.

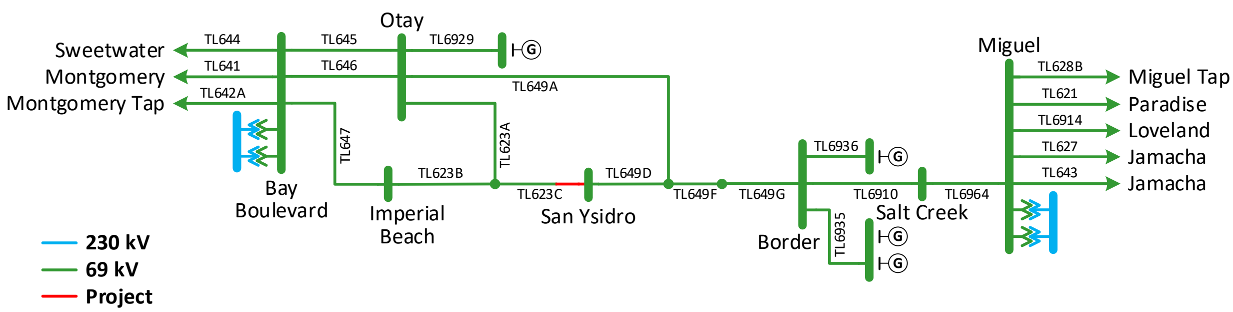
San Ysidro substation is served by two 69 kV transmission lines; TL623C San Ysidro – Otay Tap and TL649D San Ysidro – Otay Lakes Tap, which are currently limited to 50 MVA. Therefore, the Category P1 outage of any of these transmission lines could overload the remaining line. To mitigate this concern, the ISO approved the reconductoring of these transmission lines in the 2017-2018 TPP, increasing the rating of TL623C to 68 MVA and TL649D to 97 MVA. Based on the non-coincident load forecast, San Ysidro substation would reach a peak load of 68 MW by 2032, thus, TL623C rating would be exceeded.

Project Details

The project involves the following:

- Reconductor the remaining limiting underground and overhead segments of TL623C San Ysidro – Otay Tap 69 kV line to increase its normal rating to 136 MVA.

Figure 2-24: TL623C Reconductor



Estimated Cost & In-Service Date

The estimated cost for this project is $5.4 million with a targeted in-service date of 2032.

Alternatives Considered

Other alternatives explored consist of the following:

- Advanced conductors were evaluated for the overhead segments of the 69 kV transmission line. Typically, 69 kV reconductor projects often lie within an aged wood-pole infrastructure that requires a detailed structural analysis to determine if an advanced conductor alternative would be feasible. SDG&E developed an estimated cost range between $3M to $6M, where the lower range assumes that an advanced conductor can be utilized without structure replacements for the sections of the line that appear feasible based on preliminary review and the upper range assumes a full rebuilding utilizing standard conductors. SDG&E will need to provide its analysis of these two alternatives in the next planning cycle and seek approval from the ISO on the final scope of the project.
- Advanced flow control devices are not applicable since San Ysidro substation is only fed from two 69 kV sources. Therefore, the power flow cannot be controlled during a Category P1 contingency.
- Energy storage could solve the thermal overload identified in the 2035 peak load scenario but not in 2040 due to charging limitations. Furthermore, there are no bay positions available at San Ysidro substation to connect the energy storage. The cost

of expanding the substation if land were available would be higher than the proposed project.

2.3.2.26 TL600B Reconductor

Project Need and Background

The SDG&E study area assessment identified the TL600B Reconductor project as a reliability transmission solution to address the thermal overload of one 69 kV transmission line caused by the load growth at Clairemont substation, starting in 2025.

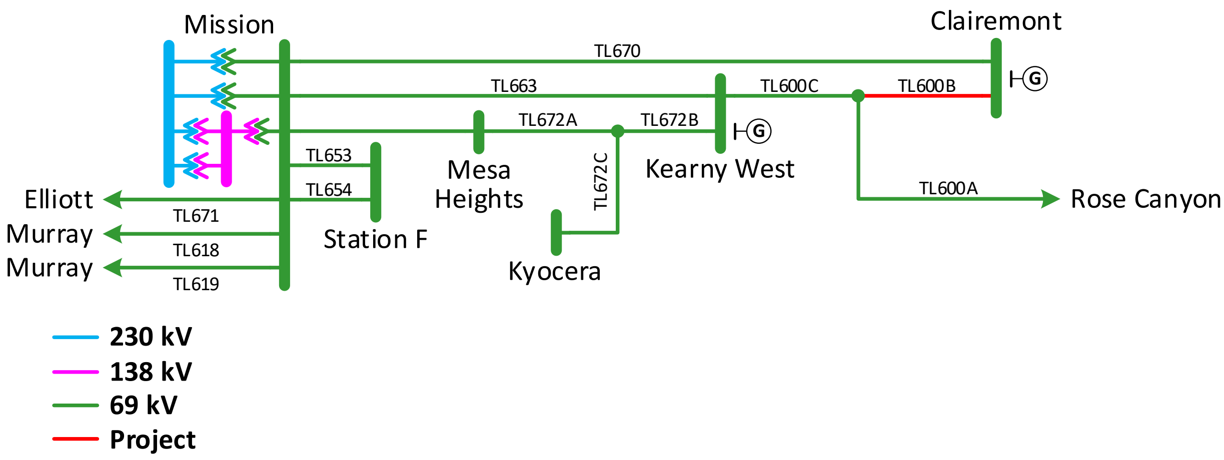
Clairemont substation is served by two 69 kV transmission lines; TL600B Clairemont – Clairemont Tap and TL670 Mission – Clairemont, which are currently limited to 50 MVA and 136 MVA, respectively. Therefore, the Category P1 outage of TL670 could result in an overload of TL600B. A 9 MW WDAT energy storage is installed at this substation which could be relied upon to mitigate the Category P1 reliability concern in the near-term, but this instead would create a Category P3 concern that requires further mitigation. Based on the non-coincident load forecast, Clairemont substation would reach a peak load of 52 MW by 2025.

Project Details

The project involves the following:

- Reconductor ~0.7 miles of TL600B Clairemont – Clairemont Tap 69 kV line to increase its normal rating to 85 MVA.

Figure 2-25: TL600B Reconductor



Estimated Cost & In-Service Date

The estimated cost for this project is $7.5 million with a targeted in-service date of 2031.

Alternatives Considered

Other alternatives explored consist of the following:

- Advanced conductors were evaluated for the overhead segment of the 69 kV transmission line. Typically, 69 kV reconductor projects often lie within an aged wood-pole infrastructure that requires a detailed structural analysis to determine if an advanced conductor alternative would be feasible. SDG&E developed an estimated cost range between $4M to $8M, where the lower range assumes that an advanced conductor can be utilized without structure replacements for the sections of the line that appear feasible based on preliminary review and the upper range assumes a full rebuild utilizing standard conductors. SDG&E will need to provide its analysis of these two alternatives in the next planning cycle and seek approval from the ISO on the final scope of the project.
- Advanced flow control devices are not applicable since Clairemont substation is only fed from two 69 kV sources. Therefore, the power flow cannot be controlled during a Category P1 contingency.
- Energy storage is not feasible as there is no available land in the vicinity that could be used to install additional energy storage.

2.3.3 Previously Approved Project Re-scopes

2.3.3.1 Ames Distribution – Palo Alto 115 kV line

This project was proposed in the previous 2024–2025 Transmission Plan to address two main concerns in the Santa Clara region: preventing overloads in the Ravenswood–Palo Alto 115 kV line and adding a new connection to the Palo Alto substation. This connection aims to improve system reliability by diversifying the sources that supply power to the City of Palo Alto, including the connection to the Ames Distribution substation in the De Anza division, thereby reducing dependence on the Ravenswood side.

However, due to significant increases in the load forecast, the initially proposed reconductor capacity for these lines is insufficient to prevent overloads in longer-term scenarios. As a result, the project scope has been revised, leading to changes in both the scope of work and cost estimations as follows:

Original Scope

The original project scope included the construction of a new Ames Distribution–Palo Alto 115 kV line using existing vacant tower positions and idle lines, with a minimum capacity requirement of 1,500 A. Additionally, the expansion of the Ames Distribution and Palo Alto

Switching Station buses to allow for one additional 115 kV connection at each location. The estimated cost for this original scope ranged from $42 million to $84 million.

Revised Scope

The revised scope still includes the construction of the Ames Distribution–Palo Alto 115 kV line, but it now utilizes advanced conductors to achieve a summer emergency rating of 3,000 A or higher. Furthermore, to leverage the proposed higher capacity from the new link connecting to the De Anza and Peninsula areas, the revised scope also incorporates the reconductoring of 0.1 miles of the Ames Distribution 115 kV line to ensure it achieves at least 3000 A.

The estimated additional cost for the changes in scope is between $26 million and $52 million, with an expected in-service date in the first quarter of 2034.

2.3.3.2 Morgan Hill Area Reinforcement project

The Morgan Hill Area Reinforcement Project, as redefined in the 2017 transmission planning process, aims to address several P6 issues in the Morgan Hill and Llagas areas. Studies indicate that by looping the Metcalf-Llagas 115 kV transmission line into the Morgan Hill substation (which is being converted to a Breaker-and-a-Half configuration), the Morgan Hill Area Reinforcement Project can achieve additional benefits and mitigate some P6 issues.

As a result, the project scope has been revised, leading to changes in both the scope of work and cost estimations as follows:

Original scope

- - Rebuild the Metcalf-Green Valley 115 kV line into the Green Valley-Morgan Hill 115 kV line (all new structures; 15 miles).
- - Rebuild the Morgan Hill 115 kV substation into a breaker-and-a-half configuration.

The estimated cost for this scope in the 2017-2018 TPP was between $72 million and $104 million. The current cost estimate has increased to between $93 million and $134 million.

Revised Scope

- - Rebuild the Metcalf-Green Valley 115 kV line into the Green Valley-Morgan Hill 115 kV line (all new structures; 15 miles).
- - Rebuild the Morgan Hill 115 kV substation into a breaker-and-a-half configuration.
- - Loop the Metcalf-Llagas 115 kV transmission line into the Morgan Hill substation.

The estimated additional cost for the changes in scope is between $28 million and $47 million, with an expected in-service date of December 2028. In the interim, the system will rely on operating solutions.

2.3.3.3 South Bay Area reinforcement project[33]

This project was included in the previous 2024-2025 Transmission Plan and involves several reinforcements to the 115 kV lines in the San Jose and De Anza divisions. However, following the latest reliability assessment in this planning cycle, particularly the findings from the evaluation of the newly proposed "Tesla-Trimble-Metcalf 230 kV Corridor Expansion Project" as part of the 2025-2026 Transmission Plan, there are two changes to both the project scope and cost estimates for the South Bay Reinforcement Project:

Original scope

A. Reconductor the line drop at San Jose A and at El Patio between the El Patio and San Jose A Substation on the El Patio – San Jose A 115kV line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions.
B. Reconductor the Trimble – San Jose B 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions.
C. Reconductor the Mountain View – Monta Vista 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions.
D. Reconductor the Whisman – Monta Vista 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions.
E. Remove the limiting elements at the Metcalf Substation on the Los Esteros – Metcalf 230kV line to achieve at least 725 MVA during summer emergency conditions.
F. Reconductor the Ringwood – Milpitas 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions.
G. Reconductor the Kiefer – FMC 115 kV Line with a larger conductor to achieve at least 1400 Amps during summer emergency conditions.
H. Ringwood loop: Loop Ringwood onto the Los Esteros-Montague 115 kV line by extending Los Esteros-Montague via two new line sections to Ringwood to terminate the new Los Esteros – Ringwood and Ringwood – Montague 115kV lines. The looping conductor must achieve at least 2000 Amp during summer emergency conditions, and 3000 Amp during summer emergency conditions is preferred.

[33] The project was approved but part G of the rescoping of the project is on hold for further coordination with Silicon Valley Power.

The estimated cost for this scope in the 2024-2025 Transmission Plan was between $217 million and $434 million.

Revised Scope

The scope for items A to E remains unchanged. However, items F, G, and H have the following revised scope:

F. Not required. This line will be rebuilt as UG in the Tesla – Trimble – Metcalf 230 kV corridor expansion project.
G. Swap the connections of the Newark-Trimble and Trimble-FMC 115 kV lines at the tower line. Additionally, rebuild the KRS-Trimble section using double 795 ACSS conductors over a length of approximately 3 miles.
H. Construct an underground (UG) line from Ringwood to Montague. The conductor must be capable of handling at least 1500 Amps during summer emergency conditions. Disconnect the Los Esteros-Montague 115 kV line and use the available connection point at Montague to connect the new Ringwood-Montague 115 kV line. Additionally, a new 115 kV connection will be required at the Ringwood substation.

The estimated cost for the revised scope remains unchanged, ranging from $217 million to $434 million, with the expected in-service date still set for May 2032.

2.3.3.4 Oro loma 70 kV Area Reinforcement (Re-scope)

Please refer to section 2.3.1.1 for more details on this project's original scope and re-scope.

2.3.3.5 East Marysville 115/60 kV project

This project was proposed as an LCR reduction project in TPP 2018-2019 TPP to address P6 contingencies.

Original Scope:

The original project scope was to loop the Pease-Marysville 60 kV line into the East Marysville 115 kV substation, install a 115/60 kV transformer at East Marysville, and add 25 MVAr of voltage support. The estimated cost for the original scope was $26 to $32 million.

Revised Scope:

The East Marysville project scope is revised to remove 25 MVAr of voltage support at Pease due to implementation challenges. Study results for this year indicate no short-term violations with the revised scope. Long-term analysis indicates marginal voltage magnitude violations may be possible. The area will continue to be monitored to determine whether additional voltage support is needed in coming cycles. The total estimated cost of this project is $50.6- $101 million and the expected in-service date is January 2030.

2.3.3.6 Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers Project

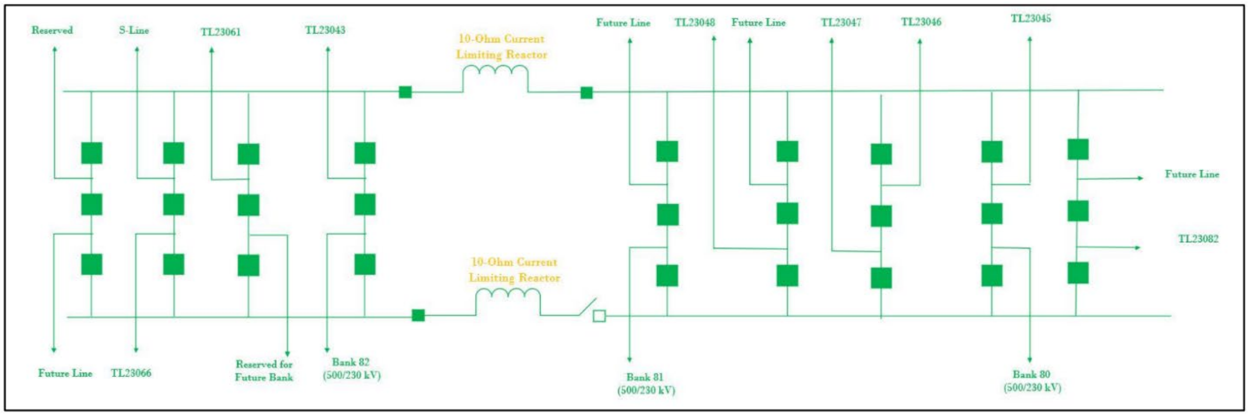
This project was approved in the 2023-2024 Transmission Plan as a reliability transmission solution to address the Short Circuit Duty (SCD) concerns since all of the 63 kA Circuit Breakers (CBs) at Imperial Valley 230 kV substation will overstress considering the previously approved projects and the CPUC's base portfolio. However, during the 2025-2026 TPP reliability assessment, the ISO observed excessive thermal overload, low voltages and divergence in some scenarios that would require developing an operational procedure that will connect the normally open Current Limiting Reactor (CLR) when Imperial Valley 500/230 kV Bank #82 or the normally closed CLR are out-of-service to protect the system against subsequent outages. The reliability concerns and operational complexity can be mitigated by increasing the CLRs size from 10-Ohms to 20-Ohms and operating both CLRs normally closed while maintaining the same short-circuit current levels.

Furthermore, the policy assessment identified the overload Imperial Valley 500/230 kV Bank #82 in the 2040 On-peak SSN scenario in Category P0 conditions due to high solar generation output driven by the 230 kV line rearrangement included in the approved scope. To avoid this deliverability concern, the ISO proposed a different 230 kV line rearrangement that would better distribute the power flow between the three 500/230 kV banks.

Original scope

- Install two sets of 10-Ohm CLRs in series with the 230 kV buses, one on each side of the bus.
- One CLR will be operated normally open.
- Rearrange 230 kV transmission lines and move TL23043 Imperial Valley – Westside Canal, TL23066 Imperial Valley – Drew, and IID owned S-Line Imperial Valley – Wixom SS to the west bus.
- Preserve the 63 kA Circuit Breakers.

Figure 2-26: Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers Project – Original Scope

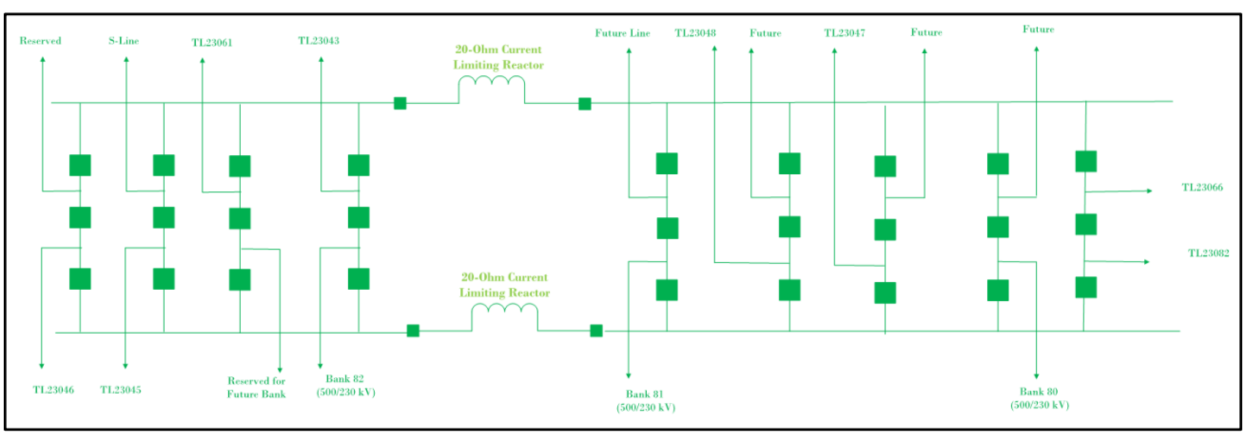


The estimated cost for the approved scope, in the 2023-2024 Transmission Plan, was $97 million and has increased to $110 million for the 2025-2026 TPP.

Revised Scope

- Install two sets of 20-Ohm CLRs in series with the 230 kV buses, one on each side of the bus
- Both CLRs will be operated normally closed
- Rearrange 230 kV transmission lines and move TL23043 Imperial Valley – Westside Canal, TL23045 and TL23046 Imperial Valley – Central La Rosita II lines 1 and 2, and IID owned S-Line Imperial Valley – Wixom SS to the west bus
- Preserve the 63 kA Circuit Breakers

Figure 2-27 : Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers Project – Revised Scope



The estimated cost for the revised scope is $130 million, with an expected in-service date of June 2035.

2.3.4 Previously Approved Projects on Hold

2.3.4.1 Alamitos 230 kV SCD upgrade

This project was originally approved in the 2024–2025 TPP to mitigate short-circuit duty concerns at the Alamitos 230 kV substation. This project is under re-evaluation because its need depended on the Del Amo–Mesa–Serrano 500 kV transmission reinforcement, which is currently on hold in this planning cycle.

The ISO considered normally closing the Alamitos 230-kV sectionalizing circuit breakers to relieve reliability concerns south of Mesa substation. However, additional coordination with SCE is required to confirm whether this upgrade is sufficient to support normally closing the sectionalizing breakers without creating new SCD concern in the area. Therefore, the ISO recommends placing the Alamitos 230-kV SCD upgrade project on hold at this time and will reevaluate the project in the 2026–2027 transmission planning process.

2.3.4.2 Lone Tree – Cayetano – Newark Corridor Series Compensation

This project was approved in the 2022-2023 Transmission Plan as a mitigation measure for several NERC contingency categories that caused overloads on the 230 kV path from the Contra Costa substation to Newark. This issue was particularly evident on the Cayetano–Lone Tree and Las Positas–Newark 230 kV lines.

The project, "Lone Tree–Cayetano–Newark Corridor Series Compensation," involves the installation of series compensation (reactance) devices with a value of 6 to 8 ohms on the Contra Costa–Lone Tree and Contra Costa–Las Positas 230 kV lines. These devices are intended to be activated only under system conditions that could potentially overload the Cayetano–Lone Tree and Las Positas–Newark 230 kV lines.

Power flow studies conducted in this cycle indicate that the overload conditions no longer exist in the near term when the project is not modeled, and only a few minor overloads remain in the long-term scenarios. Therefore, it is proposed that the project be placed on hold during this cycle.

2.3.4.3 Coolwater 115 kV Line Looping into Tortilla 115 kV Substation

The project was approved in the 2024-2025 TPP to address thermal overloads and case divergence issues due to load growth projects at the Tortilla and Accelerate substations. The project would add support to Tortilla from the Coolwater side, as the Coolwater-SEGS-Tortilla 115 kV line is the only available path for power flow into the Coolwater A-Bank(s).

The scope of the project is to use the existing Kramer-Coolwater 115 kV transmission line to loop in the Tortilla 115/33 kV substation via an approximate 11.5-mile double circuit line extension and switchrack expansion at Tortilla 115/33 kV substation.

At the time of approval, the estimated cost for this project was $37 million. SCE has informed the ISO that the estimated cost of this project is now $105 million. In addition, the load forecast in the area has been materially reduced, particularly at Tortilla. Based on the ISO's reassessment of the need for this project with the latest load forecast, the project was not found to be needed. However, SCE anticipates that the IEPR load modeling in the NOL area in the 2026-2027 transmission planning process will yield higher load values and the number of highly confident known load growth projects continue to increase within the area. Therefore, this project will be placed on hold.

2.3.4.4 Julian Hind-Mirage 230 kV Line Upgrade Project

The project was approved in the 2024-2025 Transmission Plan to address the thermally constrained Julian Hinds-Mirage 230 kV line, which has been subject to the Blythe Energy Remedial Action Scheme (RAS). Increasing the power transfer capability of this line would reduce the frequency of RAS operations.

The scope of this project is reconductoring approximately 47 miles of the Julian Hinds-Mirage 230 kV Line with high-temperature, low-sag advanced conductors.

At the time of approval, the estimated cost for this project was $76 million. These upgrade costs were expected to be partially subsidized by the U.S. Department of Energy GRIP grant funding awarded through the CHARGE 2T project.

SCE has informed the ISO that the estimated cost of this project is now $178 million, and the status and amount of the DOE subsidization is still being evaluated. Therefore, this project has been put on hold.

2.3.5 Previously Approved Projects Cancellations

2.3.5.1 East Shore bus re-configuration

This project was originally approved during the 2019-2020 TPP. It aimed to address the overload of East Shore 230/115 kV Transformer #1, which occurred due to a P2 contingency in the East Shore 230 kV bus. This contingency involved the simultaneous loss of the San Mateo - East Shore 230 kV line and the parallel 230/115 kV Transformer #2.

However, the topology of the East Shore 230 kV bus has changed due to the interconnection project at the new Clawiter 230 kV substation, which added two additional lines to the East Shore bus. Given the current bus arrangement and the forecasted load for this area, there are no P2 contingencies that can be resolved with a bus terminal configuration project. As a result, the East Shore 230 kV Bus Terminals Reconfiguration project is no longer necessary and will be cancelled.

2.3.5.2 Metcalf 230/115 kV Transformers CB Addition Project

This project was originally approved during 2022-2023 TPP. It aimed to reduce NERC category P2 and P6 violations and scope was to add parallel breakers to each of 230/115 kV banks 1,2 and 3. With newly approved Metcalf 230 kV short circuit mitigation project, this project is no longer necessary and will be cancelled.

2.3.5.3 Moraga-Sobrante 115 kV line re-conductor

This project was originally approved during 2018-2019 TPP. It aimed to reduce NERC category P2 violations and scope was to reconductor "Moraga-Sobrante 115 kV line". With newly approved projects in Oakland, this project is no longer necessary and will be cancelled.

2.3.6 Projects concurred for large load interconnections

Pacific Gas and Electric Company (PG&E) is seeing large growth for data center and other large load interconnections specifically in the Greater Bay area.

Large Load interconnection studies are facilitated under PG&E's tariff [34]for load interconnection. PG&E's large load study process includes a Preliminary Engineering Study (PES) and requires Interconnection Customers to sign the PES study agreement before proceeding to the Reassessment Study, where the capacity upgrades are re-evaluated following a withdrawal window.

In 2024, PG&E performed a Large Load Cluster Study (Load Cluster 2024 or Data Center Pilot Cluster) which currently has 11 active data center projects, a total of 840 MW, in Santa Clara County and Alameda County. There are three additional data center requests in San Jose following a serial study process.

Table 2-1: Large load interconnection projects currently reviewed by the ISO

	Load Cluster 2024		Total
Planning Area	**Application MWs**	**Projects**	
De Anza	49	1	49 MW
San Jose	494	6	494 MW
Gilroy	99	2	99 MW
Mission	198	2	198 MW

[34] https://elibrary.ferc.gov/eLibrary/# or https://www.pge.com/assets/pge/docs/regulation/wholesale-transmission-service/tariff-wdt4.pdf

The load interconnection studies identified multiple capacity network upgrades to support these interconnections. The ISO reviewed and concurred with below local network upgrades to move forward as part of the load interconnection. Area supply network upgrades are reviewed within the ISO TPP process and recommended for approval as needed.

Table 2-2: Identified network upgrades project scope, estimated ISD and costs.

Project	Interconnection Scope and Capacity Upgrade	Estimated In-service date	Estimated cost of Network upgrade
LC24-2: 49 MW	**Interconnection:** • Add (1) 115 kV circuit breaker at Lockheed #1 Substation and associated 115 kV service line	2027	$69 M- 138 M
	Capacity Upgrade: Lockheed loop project • Convert Lockheed 115 kV double tap to Lockheed loop configuration • Reconductor Lockheed #1 and #2 115 kV taps • Remove substation limiting elements and upgrade protection	2031	
LC24-13: 99 MW **LC24-14: 99 MW**	**Interconnection:** • Build a new 115 kV switching station, Hellyer, to loop both Metcalf-Evergreen #1 and #2 115 kV Lines and associated service lines	2030	$223 M- 446 M
	Capacity Upgrade: • Hellyer-Metcalf #1 and #2 115 kV Lines reconductoring (5 miles from Metcalf) • San Jose B-Stone-Evergreen 115 kV Line reconductoring	2030	

Project	Interconnection Scope and Capacity Upgrade	Estimated In-service date	Estimated cost of Network upgrade
LC24-26: 99 MW **LC24-27: 49 MW** **LC24-28: 49 MW**	**Interconnection:** • Add 115 kV breakers at San Jose A and build associated 115 kV service lines from San Jose A to customer sites	2028	$112 M-224 M
	Capacity Upgrade: • Rebuild San Jose A – San Jose B 115 kV Line to double circuit transmission lines San Jose A-San Jose B #1 and #2 115 kV Lines	2028	
LC24-3: 99 MW **LC24-26: 99MW** **LC24-27:49MW** **LC24-28:49MW** **LC24-13: 99MW** **LC24-14:99MW**	**Interconnection:** • Build new 115 kV switching station, Charcot, near Trimble 115 kV and associated service lines • Build (2) 0.8-mile 115 kV transmission line to connect Charcot to Trimble 115 kV	2030	$276 M-552 M
	Capacity Upgrade: • Trimble 230 kV/115 kV Substation expansion looping onto NRS-San Jose B 230 kV Line • Trimble-Montague 115 kV line upgrade	2031	
LC24-1: 49.5 MW, **LC24-24: 49.5 MW**	**Interconnection:** • Build a new BAAH bay at the Garlic 115 kV Switching Station and associated service lines for LC24-1	2028	$ 78 M-155 M
	Capacity Upgrade: • Reconductor Morgan Hill-Llagas 115 kV DCTL	2031	
LC24-6:99 MW	**Interconnection:** • Build a new 115 kV BAAH bus at Eastshore substation and associated service lines	2031	$ 185 M-371 M

Project	Interconnection Scope and Capacity Upgrade	Estimated In-service date	Estimated cost of Network upgrade
LC24-18: 99 MW	**Capacity Upgrade:** • Partial 230 kV BAAH bay at Eastshore 230 kV and a third 230 kV/115 kV transformer	2031	

Above concurred network upgrades will be modelled in the upcoming 2026-2027 TPP cycle, along with the CEC forecasted data center load values. Regarding the CEC forecast of the data center loads, starting in 2024 IEPR, data center load forecast has been moved from other adjustment and is included as a separate load modifier at bus-bar level. The forecast considers 67% utilization factor, which is a difference between requested capacity versus maximum demand. It also considers the confidence level of project completion that varies from 70% ,50% and 10% for Group 1, 2 and 3 projects respectively. Linear ramping assumptions were considered for modelling in different TPP years.

2.4 Reliability Assessment Summary and Recommendations

The 33 new reliability-driven projects are required in this transmission planning cycle for a total estimated cost of $4.2 billion are listed below. Table 2-3 includes the two projects that were approved by ISO management in this planning cycle for an estimated total cost of $53 million.

Table 2-3: Reliability-Driven Projects Management Approved

#	ID	Project Name	PTO	Area	Est. Cost ($M)
1	1011-R-16	Oro Loma 70 kV Area Reinforcement (Re-scope)	PG&E	GFA	38
2	2526-R-01	Walnut 230 kV CB Upgrade[5]	SCE	Metro	15
				Total	53

Table 2-4 lists the 26 projects recommended for approval in this planning cycle for an estimated cost of $3.944 billion.

Table 2-4: Reliability-Driven Projects Recommended for Approval

#	ID	Project Name	PTO	Area	Est. Cost ($M)
3	2526-R-02	Ames 115 kV Short Circuit Mitigation	PG&E	GBA	5
4	2526-R-03	DeAnza 115 kV Substation[35]	PG&E	GBA	260
5	2526-R-04	Lincoln - Pleasant Grove Line Reconductoring	PG&E	CVLY	120
6	2526-R-05	Los Esteros 230 kV Short Circuit Mitigation	PG&E	GBA	20
7	2526-R-06	Mariposa 70 kV Voltage Support	PG&E	GFA	63
8	2526-R-07	Metcalf 230 kV Short Circuit Mitigation	PG&E	GBA	405
9	2526-R-08	Midway 115 kV Bus Upgrade	PG&E	Kern	89
10	2526-R-09	Monta Vista – Loyola – Los Altos 60 kV Line Reconductoring	PG&E	GBA	64
11	2526-R-10	Monta Vista 230/115 kV Transformer Bank Addition	PG&E	GBA	104
12	2526-R-11	Newark 115 kV Short Circuit Mitigation	PG&E	GBA	60
13	2526-R-12	Newark 230/115 kV Bank Upgrade	PG&E	GBA	63
14	2526-R-13	Nortech 115 kV Short Circuit Mitigation	PG&E	GBA	5
15	2526-R-14	San Jose B 230/115 kV Transformer Bank Addition	PG&E	GBA	69
16	2526-R-15	Saratoga-Vasona 230 kV Line Reconductoring	PG&E	GBA	178
17	2526-R-16	South Oakland Reinforcement (Phase 2)	PG&E	GBA	86
18	2526-R-17	Tesla – Trimble – Metcalf 230 kV Corridor Expansion	PG&E	GBA	1424
19	2526-R-18	Trimble 115 kV Short Circuit Mitigation	PG&E	GBA	16
20	2526-R-19	Lugo 230 kV CB Upgrade	SCE	NOL	5
21	2526-R-20	Devers 230 kV SCD Upgrade	SCE	Eastern	186
22	2526-R-21	Lugo 500 kV Reactive Power Reinforcement	SCE	Bulk	450
23	2526-R-22	Mesa - Laguna Bell 230 kV #2 Upgrade	SCE	Metro	56
24	2526-R-23	Etiwanda and Mira Loma 230 kV SCD Upgrade	SCE	Metro	55
25	2526-R-24	Penasquitos- Mira Sorrento 69 KV #2 line	SDG&E	SDG&E	115
26	2526-R-25	TL600B Reconductor	SDG&E	SDG&E	8
27	2526-R-26	TL623C Reconductor	SDG&E	SDG&E	5
28	2526-R-27	TL690B & TL 697 Reconductor	SDG&E	SDG&E	33
				Total	3,944

[35] The project was approved but is on hold pending further coordination with Silicon Valley Power.

Table 2-5 lists the five previously approved reliability-driven projects scope changes recommended for approval in this planning cycle for an estimated cost of $182 million.

Table 2-5: Previously Approved Reliability Driven Projects Scope Changes Recommended for Approval

#	ID	Project Name	PTO	Area	Est. Cost ($M)
29	2425-R-02	Ames Distribution – Palo Alto 115 kV line (Re-scope)	PG&E	GBA	52
30	1314-R-17	Morgan Hill Area Reinforcement project (Re-scope)[7]	PG&E	GBA	28
31	2425-R-25	South Bay Reinforcement Project (Re-scope)[36]	PG&E	GBA	0
32	1819-E-01	East Marysville 115/60 kV Project (Re-scope)	PG&E	CVLY	69
33	2324-R-20	Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers (Re-scope)	SDG&E	SDG&E	33
				TOTAL	182

The ISO recommends that the following four previously approved transmission projects be on hold pending further assessment in the next planning cycle:

- Alamitos 230 kV SCD upgrade;
- Lone Tree – Cayetano – Newark Corridor Series Compensation;
- Coolwater 115 kV Line Looping into Tortilla 115 kV Substation; and
- Julian Hind-Mirage 230 kV Line Upgrade Project.

The ISO recommends that the following three previously approved transmission projects be cancelled:

- East Shore bus re-configuration;
- Metcalf 230/115 kV Transformers CB Addition Project; and
- Moraga-Sobrante 115 kV line re-conductor.

[36] The project was approved but part G of the rescoping of the project is on hold pending further coordination with Silicon Valley Power.

3 Policy Assessment

3.1 Overview of the ISO Policy Assessment

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 while maintaining reliability. For 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 during all hours of the year.

The CPUC issued a Decision[37] 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 the 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.

As mentioned earlier, the more coordinated and proactive approach taken in the ISO's current annual transmission planning process is part of a larger set of interrelated and coordinated planning and resource development activities being undertaken between the state energy agencies and the ISO.

The CPUC issued Decision 25-02-026 [38] on February 20, 2025 adopting a base case portfolio and a sensitivity portfolio with greater volume of long lead-time (LLT) resources for use in the 2025-2026 transmission planning process. The base case portfolio is based on the 25 million metric tons greenhouse gas target by 2035 and the CEC's 2023 Integrated Energy Policy Report demand forecast. The base case portfolio is used to identify reliability and policy-driven transmission needs for approval in the ISO 2025-2026 TPP. The sensitivity portfolio is designed to help study the transmission implications of a portfolio with a greater volume of long lead-time (LLT) resources as called for in Decision 24-08-064. The Decision is accompanied by a document entitled Modeling Assumptions for the 2025-2026 transmission planning process[39], which provides the methodology and results of the resources-to-busbar mapping[40] process as well as other assumptions for use in the ISO

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37 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

38 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879249.PDF

39 https://files.cpuc.ca.gov/energy/modeling/LTPP/Modeling_Assumptions_25-26TPP_Final_2025-02-20.pdf

40 The busbar is the electrical connection within the ISO planning models where the generator is connected to the electrical system.

TPP. This detailed information establishing resource types and locations is pivotal to the zonal approach to transmission planning, which is used to shape and guide interconnection and resource procurement processes.

3.1.1 Objectives of the 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;
- Gain further insights to inform future portfolio development;
- Set out the zonal capacities that are being established through coordinated transmission planning and resource planning, to shape and guide interconnection and resource procurement; and
- Policy Assessment Assumptions.

3.1.2 Resource Portfolios

3.1.2.1 CPUC Portfolio

As mentioned in Section 3.1, the base case portfolio and sensitivity portfolio with greater volume of LLT resources were transmitted by the CPUC for study in the ISO 2025-2026 transmission planning process. The detailed portfolios are available on the CPUC website.[41]

Table 3.2-1 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO). The numbers also include any portfolio adjustments based on CPUC guidance, including unaccounted for TPD, additional in-development resources modeled by PTOs based on projects status and non-CPUC jurisdictional portfolios. The portfolios are comprised of solar, wind (in-state, out-of-state and offshore), battery storage (4-hour and 8-hour), geothermal, long-duration energy storage, biomass/biogas and distributed solar resources and net dependable gas generation capacity not retained. All portfolio resources are

41 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp

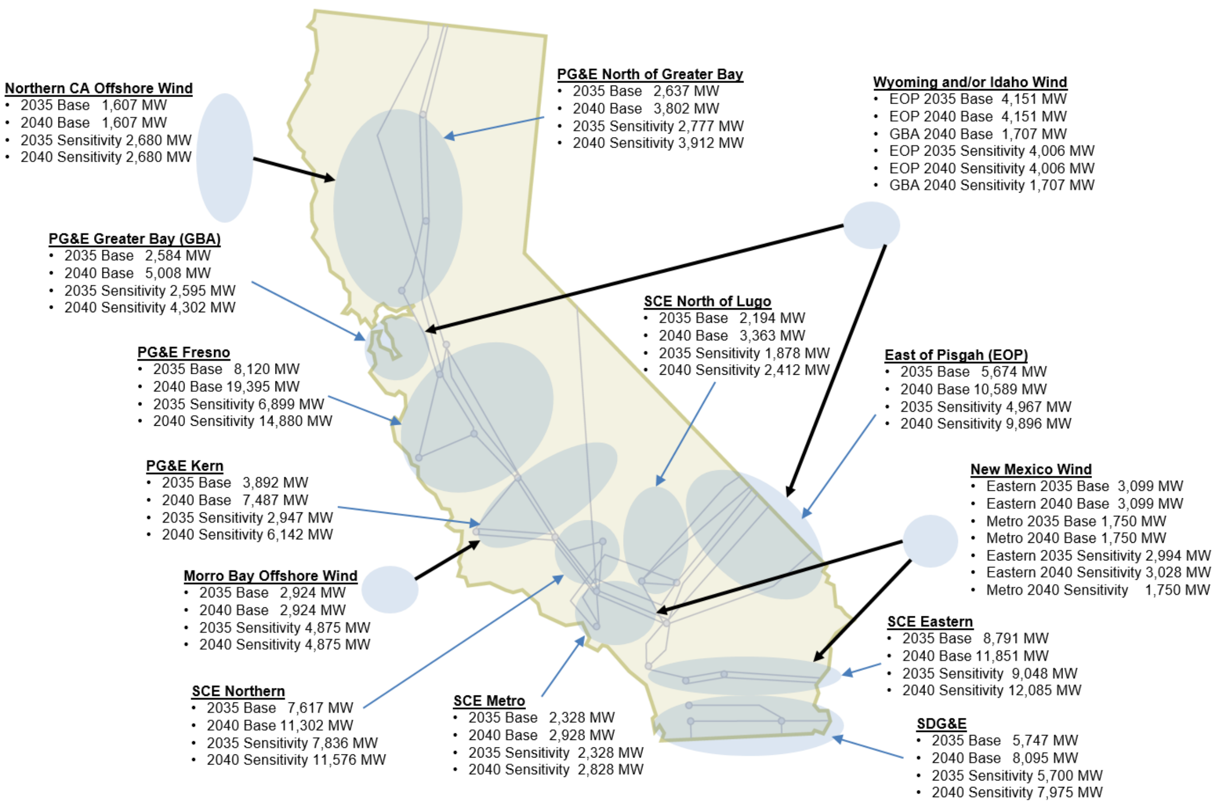
modeled in policy-driven assessments based on the study plan and deliverability methodology.

Table 3-1:Base and Sensitivity Portfolios by Resource Type and Deliverability Status

Resource Type	2035 Baseline Portfolio			2040 Base Portfolio			2035 Sensitivity Portfolio		
	FCDS (MW)	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**
Solar	6,611	13,266	**19,876**	14,728	29,890	**44,619**	6,379	11,435	**17,814**
Wind – In State	6,750	1,157	**7,908**	6,750	1,157	**7,908**	5,981	954	**6,936**
Wind – Out-of-State	9,000	0	**9,000**	10,707	0	**10,707**	7,000	0	**7,000**
Wind - Offshore	4,531	0	**4,531**	4,531	0	**4,531**	7,555	0	**7,555**
Li Battery – 4 hr	26,463	0	**26,463**	24,432	0	**24,432**	27,002	0	**27,002**
Li Battery – 8 hr	2,913	0	**2,913**	11,440	0	**11,440**	1,341	0	**1,341**
Long Duration Energy Storage (LDES)	1,197	0	**1,197**	1,197	0	**1,197**	2,582	0	**2,582**
Geothermal	1,649	0	**1,649**	1,659	0	**1,659**	2,150	0	**2,150**
Biomass/Biogas	166	0	**166**	166	0	**166**	166	0	**166**
Distributed Solar	0	304	**304**	0	304	**304**	0	290	**290**
Net Dependable Gas Capacity not Retained	0	0	**0**	0	0	**0**	0	0	**0**
Total	**59,280**	**14,727**	**74,007**	**75,610**	**31,351**	**106,963**	**60,156**	**12,679**	**72,836**

Figure 3-1 illustrates the interconnection planning areas along with total base and sensitivity portfolio resource amounts in each area for year 2035 and 2040 based on the CPUC busbar mapping results.

Figure 3-1: 2035 and 2040 Base and Sensitivity Portfolios by Area



3.1.2.2 Non-CPUC Jurisdictional Portfolios

As a continued effort to coordinate with the non-CPUC jurisdictional entities to incorporate their approved IRP into the ISO transmission planning process, the ISO sent a non-CPUC jurisdictional IRP resource mapping workbook to the entities to gather their integrated resource planning information on October 30, 2024. By January 15, 2025, the ISO received data submittal and approved IRP documents from the following publicly owned utilities (POUs): Anaheim Public Utilities (APU), Riverside Public Utilities (RPU), Pasadena Water and Power (PWP), Vernon Public Utilities (VPU), Northern California Power Agency (NCPA), Silicon Valley Power (SVP), Colton Electric Utility (CEU) and Valley Electric Association (VEA).

Table 3.2-2 presents a summary of the submitted non-CPUC IRP resources that were evaluated in this TPP.

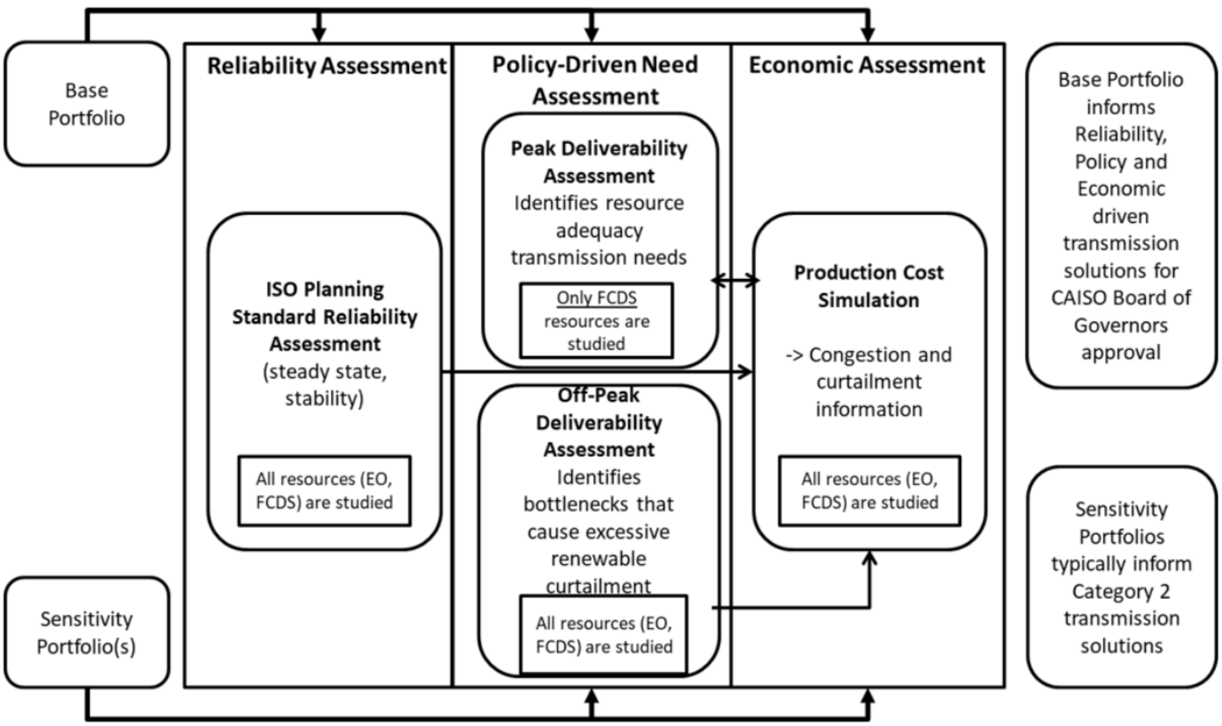
Table 3.1-2: Non-CPUC jurisdictional portfolio resources evaluated in the study

Transmission Area	Substation	Voltage	Resource Type	2035 Baseline Portfolio			2040 Baseline Portfolio			2035 Sensitivity Portfolio		
				FCDS (MW)	EODS (MW)	Total (MW)	FCDS (MW)	EODS (MW)	Total (MW)	FCDS (MW)	EODS (MW)	Total (MW)
SCE Eastern	Palo Verde	500	OOS Wind	125	0	125	125	0	125	125	0	125
SCE Eastern	Red Bluff	230	Solar	39	39	78	39	39	78	39	39	78
SCE Eastern	Red Bluff	230	Li_Battery	40	0	40	40	0	40	40	0	40
SCE Eastern	Colorado River	230	Solar	0	170	170	0	170	170	0	170	170
SCE Eastern	Unknown		Li_Battery	36	0	36	18	0	18	36	0	36
SCE NOL	Roadway	115	Li_Battery	50	0	50	50	0	50	50	0	50
SCE NOL	Coso	115	Geothermal	10	0	10	20	0	20	10	0	10
SCE Northern	Rector	230	Li_Battery	80	0	80	80	0	80	80	0	80
SCE Metro	Goodrich	230	Li_Battery	25	0	25	25	0	25	25	0	25
SCE Metro	Mira Loma	230	Li_Battery	300	0	300	300	0	300	300	0	300
EOP	Vista	138	Li_Battery	35	0	35	35	0	35	35	0	35
EOP	Innovation	230	Solar	0	105	105	0	105	105	0	105	105
EOP	Innovation	230	Li_Battery	55	0	55	55	0	55	55	0	55
SDG&E	East County	230	Onshore Wind	300	0	300	300	0	300	300	0	300
PG&E NGBA	Geysers	115	Geothermal	25	0	25	25	0	25	25	0	25
PG&E GBA	KEN-OKJ	60	Li_Battery	50	0	50	50	0	50	50	0	50
PG&E GBA	Bellota	230	Li_Battery	200	0	200	200	0	200	200	0	200
PG&E Kern	Arco	230	Li_Battery	11	0	11	11	0	11	11	0	11
PG&E Kern	Arco	230	Solar	11	0	11	11	0	11	11	0	11
PG&E Fresno	Los Banos-Midway 500kV #2 line	500	Li_Battery	150	0	150	150	0	150	150	0	150
PG&E Fresno	Los Banos-Midway 500kV #2 line	500	Solar	150	0	150	150	0	150	150	0	150
Unknown			Geothermal	50	0	50	50	0	50	50	0	50
Unknown			Solar	160	0	160	455	0	455	160	0	160
Unknown			Onshore Wind	50	0	50	60	0	60	50	0	50
Unknown			OSW	0	0	0	10	0	10	0	0	0
Unknown			Li_Battery	110	0	110	590	0	590	110	0	110

3.2 Policy Assessment Methodology

The policy-driven assessment is an iterative process comprised of three types of technical studies as illustrated in Figure 3-2. These studies are geared towards capturing the impact of the resource buildout on transmission infrastructure, identifying any required upgrades and generating transmission-related input for use by the CPUC in the next cycle of portfolio development.

Figure 3-2: Policy-Driven Assessment Technical Studies



Reliability assessment

The CPUC's base resource portfolio is a key input in the ISO's long-term reliability assessment. The reliability assessment is used to assess transmission needs in accordance with NERC, WECC and the ISO transmission planning standards and criteria. It is also used to identify constraints and potential solutions that may be modeled in production cost simulations to assess the impact of the constraints on congestion and renewable curtailment, which may lead to identification of economic transmission projects. The reliability assessment is presented in Chapter 2 and Appendix B.

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 area to the aggregate of the ISO control-area load when the generation is needed most. The ISO performs the assessment in accordance with its On-peak Deliverability Assessment Methodology.[42]

Off-peak deliverability assessment

The off-peak deliverability assessment is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. Like the reliability assessment, the off-peak assessment is also used to identify constraints and transmission solutions as candidates for detailed production cost simulation studies and economic assessment. The ISO performs the assessment in accordance with its Off-Peak Deliverability Assessment Methodology.[43]

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 and sensitivity portfolios are used mainly in the economic assessment covered in Chapter 4 and Appendix G. The PCM cases are developed based on study assumptions for the ISO-controlled grid outlined in the 2025-2026 transmission planning process study plan. Details of PCM modeling assumptions and approaches are provided in Appendix G.

42 https://www.caiso.com/documents/on-peak-deliverability-assessment-methodology.pdf

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

3.3 Policy Projects

Overview of needed projects is provided below, detailed results and information is available in Appendix F.

3.3.1 Policy Projects Recommended for Approval

3.3.1.1 Drum – Higgins 115kV Line Reconductoring

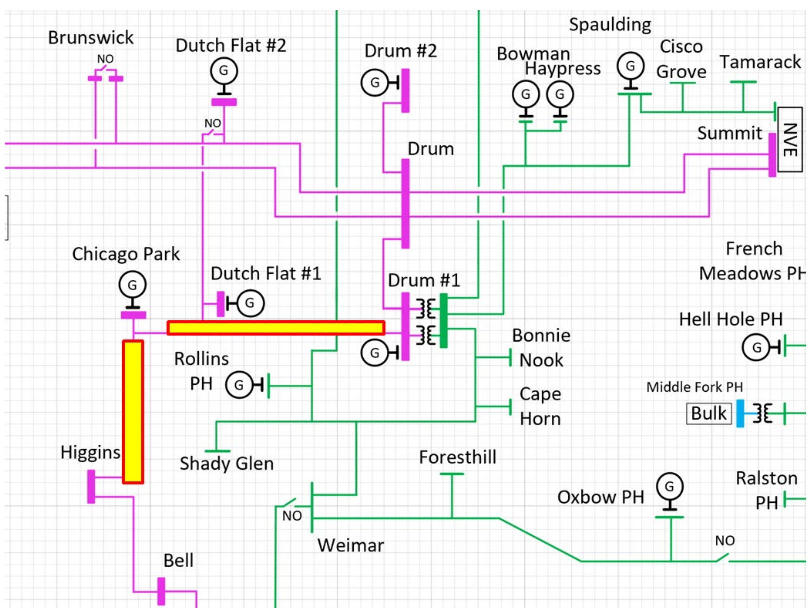
Project Need and Background

Drum – Higgins 115kV line sees overloads in the on-peak deliverability assessment for 2035 baseline, sensitivity and 2040 baseline portfolios. These overloads are caused by NERC category P1 & P7 contingencies.

Project Details

The scope includes reconductoring the entire Drum – Higgins 115kV line (approximately 30 mile) to a minimum SN rating of 1714 Amps (341 MVA, 954ACSS). The project scope also includes updating the limiting components at the substations if necessary

Figure 3-3: Drum – Higgins 115kV Line Reconductoring Project



Estimated Cost & In-Service Date

The estimated project cost range is $154.19-$308.37 M, with an expected in-service date of 2034.

Alternatives Considered

- <u>Remapping portfolio energy storage resources</u>
  Most of the resources behind the Drum – Higgins 115kV line are geothermal resources and cannot be remapped to other substations. Hence this alternative is not feasible.

3.3.1.2 East Shore 230kV Area Reinforcement

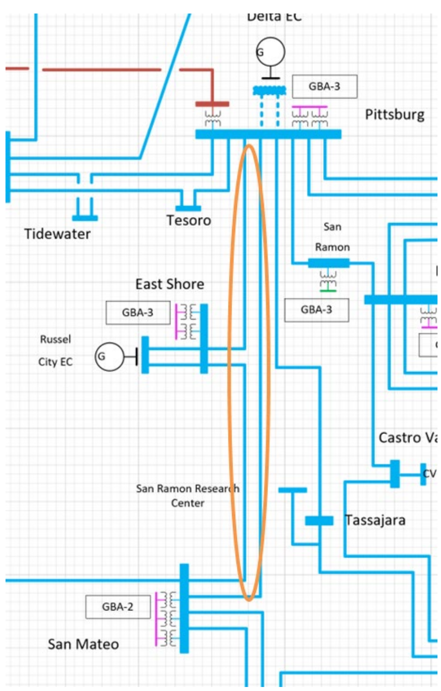
Project Need and Background

Pittsburg – San Mateo 230 kV and Pittsburg – Eastshore 230 kV lines see overloads for multiple contingencies in the on-peak deliverability assessment for 2035 baseline, sensitivity and 2040 baseline portfolios. These overloads are caused by NERC category P0, P1 and P7 contingencies.

Project Details

The project scope includes looping the Pittsburg-San Mateo 230kV Line into East Shore 230 kV substation and then reconductoring the remaining sections of the Pittsburg-East Shore 230kV Lines #1 and #2 (13.12 and 23.34 miles). The project scope also includes updating the limiting components at the substations if necessary.

Figure 3-4: East Shore 230kV Area Reinforcement Project



Estimated Cost & In-Service Date

The estimated project cost range is $128.45M - $256.9M, with an expected in-service date of 2030.

Alternatives Considered

- Remapping portfolio energy storage resources
  Most of the energy storage resources behind the Pittsburg-San Mateo 230 kV line and Pittsburg-East Shore 230 kV line are in-development resources and cannot be remapped to other substations. Hence this alternative is not feasible.

3.3.1.3 Oleum Area Reinforcement

Project Need and Background

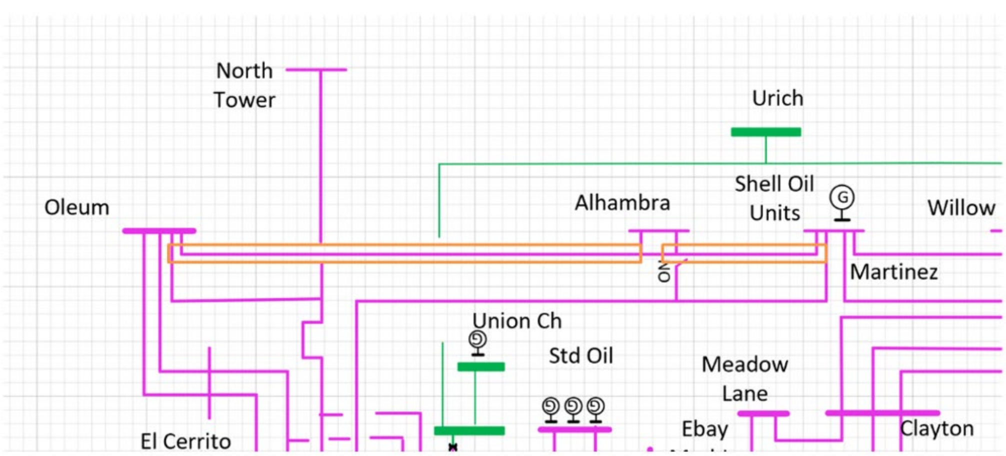
Oleum-Martinez 115 kV line and Martinez-Noth Tower 115 kV (North Tower to Alham Tap 1 115 kV) line see overloads in the on-peak deliverability assessment for 2035 baseline, sensitivity and 2040 baseline portfolios. These overloads are caused by NERC category P7 contingencies.

Project Details

The project scope includes the following:

1. Reconductoring the entire Oleum-Martinez 115 kV line (approximately 10.49 mile) with minimum SN rating of 1714 Amps (341 MVA, 954ACSS).
2. Reconductoring the Martinez-Sobrante 115 kV line from Martinez PP-Alhambra (approximately 2.42 mile) with minimum SN rating of 1714 Amps (341 MVA, 954ACSS).
3. Upgrade the limiting elements to achieve the line conductor ratings.

Figure 3-5: Oleum Area Reinforcement Project



Estimated Cost & In-Service Date

The estimated project cost range is $82.78-$144.29M, with an expected in-service date of 2033.

Alternatives Considered

- Remapping portfolio energy storage resources
  Most of the energy storage resources behind the Oleum-Martinez 115kV line and Martinez-Noth Tower 115kv (North Tower to Alham Tap 1 115kV) line are in-development resources and cannot be remapped to other substations. Hence this alternative is not feasible.

3.3.1.4 Trout Canyon – Lugo 500 kV Line

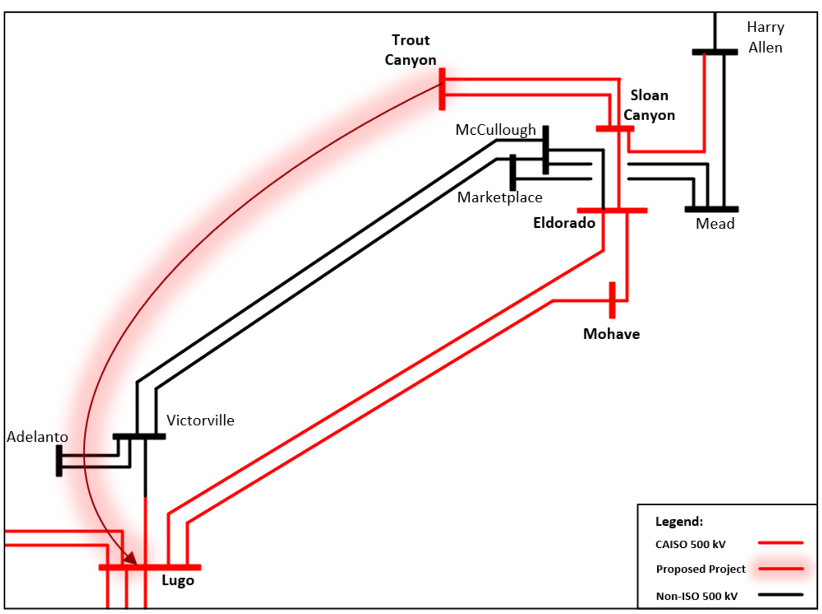
Project Need and Background

The EOP area policy-driven transmission assessment identified severe portfolio resource deliverability limitations due to the GLW-VEA area constraint, Lugo – Victorville 500 kV constraint, Eldorado – McCullough 500 kV constraint, Victorville – McCullough 500 kV constraint and Sloan Canyon – Eldorado 500 kV constraint associated with the 2035 baseline and sensitivity portfolios and 2040 baseline portfolio under peak and off-peak scenarios.

Project Details

The project includes building a new 500 kV line from Trout Canyon 500 kV substation to Lugo 500 kV substation, approximately 180 miles, with 70% series compensation.

Figure 3-6: Trout Canyon – Lugo 500 kV Line



Estimated Cost & In-Service Date

The project is estimated to cost between $1,270-$1,800 million, with an estimated in-service date of 2035.

Alternatives Considered

- The alternative considered comprises of the Sagebrush interconnection project, Marketplace – Adelanto AC-DC conversion project and Sloan Canyon – Eldorado 500 kV No.2 line. This alternative was found to not be effective at mitigating the Victorville – McCullough 500 kV line constraint. Additional major transmission upgrades would need to be added to this alternative to mitigate this constraint, and as a result, the cost of this alternative would be much higher than the cost of the recommended alternative.

3.3.2 Previously Approved Projects

There was a significant increase in the estimated cost of the Lugo-Victor-Kramer 230 kV upgrades, San Bernardino-Etiwanda No.1, San Bernardino-Vista No.1, Vista-Etiwanda No.1, Colorado River-Red Bluff No.1 500 kV line upgrades and Mira Loma-Mesa 500kV Underground Cable Addition. However, after reviewing alternative projects, these previously approved projects were confirmed to be the most cost-effective solutions to the identified transmission needs. There are also changes in the project scope for the Eagle Rock-Fulton-Silverado 115 kV Line reconductoring project and the Tesla –Newark #2 230 kV Line reconductoring project. More details of these assessments are included in section F.3 of Appendix F.

3.3.3 Previously Approved Projects Cancellations

3.3.3.1 Helm 230/70 kV bank project

This project was originally approved as a policy project during the 2024-2025 TPP. It was chosen as a low-cost alternative for the overloads seen on the Crescent-Helm 70 kV line. However, there is a network upgrade recommended through the generator interconnection process track that reconductors the Crescent-Helm 70 kV line. As a result, the ISO is recommending cancellation of the Helm 230/70 kV bank project.

3.3.3.2 Del Amo - Mesa - Serrano 500 kV project

This project was approved in the 2022-2023 TPP to address south of Mesa corridor constraints affecting the deliverability of capacity resources due to thermal overloading of the Mesa–Lighthipe and Mesa–Laguna Bell 230 kV lines and the Mesa 500/230 kV transformers. The project also addressed Serrano–Barre corridor constraints affecting deliverability of capacity resources due to thermal overloading of the Serrano 500/230 kV transformer and the 230 kV transmission lines between Serrano and Barre substations.

- At the time of approval this alternative had a total cost estimate of $1.125 billion and consisted of the following developments:
- A new Mesa-Serrano 500 kV line created by extending one of the existing box-looped segments of the Mesa–Mira Loma 500 kV line to Serrano;
- Build 500 kV facilities at Del Amo Substation complete with three 500/230 banks; construct two 500 kV lines to loop the new Mesa–Serrano 500 kV line into Del Amo Substation; and
- Loop Alamitos–Barre No. 1 and No. 2 230 kV lines into Del Amo Substation.

SCE has informed the ISO that the estimated cost of this project is now $5.0 billion, with the significantly higher cost estimates resulting from increased requirements identified in the detailed engineering phase. The ISO removed this project from the study model in this planning cycle to reevaluate the need for the project and to identify potential alternatives. In the Policy studies with the latest resource portfolios, the ISO determined that the project is not needed to ensure deliverability of resources. This is because the latest resource portfolios have approximately 2,000 MW of additional battery storage downstream from the previously identified line overloads that were driving the policy-driven need for this project. However, because of updated load forecasts showing higher load growth, the removal of this project from the ISO transmission system models did cause reliability concerns. As a result, the Mesa - Laguna Bell 230 kV #2 Upgrade reliability-driven project has been recommended to meet the reliability needs anticipated in the 10-year planning horizon for the LA Basin area that previously were planned to be met by the Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement project. These reliability concerns are addressed in Appendix B and Chapter 2.

3.4 Out-of-State Wind Resource Integration

The resource portfolio for the 2025-2026 TPP has a significant amount of OOS wind on new transmission in both the 2035 and 2040 study years (9,000 MW and 10,707 MW, respectively). Presently, there are no known transmission projects in the public domain that can directly support additional OOS resource integration beyond the in-development or operational transmission projects such as SWIP-North, TransWest Express (TWE) and SunZia.

Transmission projects currently in development or operational include SWIP-North, TransWest Express (TWE) and SunZia. TWE and SunZia are the two ISO Board-approved subscriber transmission developments that help integrate out-of-state wind resources from Wyoming and New Mexico respectively for the amounts specified in the CPUC submitted portfolios. Specifically, TWE will help integrate 1,500 MW from Wyoming and SunZia will help integrate 3,099 MW from New Mexico.

SWIP-North is the in-development transmission project supporting the integration of 1,100 MW of Idaho wind resources consistent with the CPUC TPP resource portfolios. In addition to SWIP-North receiving necessary FERC approvals, the Idaho Public Utilities Commission (IPUC) approved an Idaho Power application that requested a Certificate of Public Convenience and Necessity (CPCN) and approval of a capacity entitlement agreement related to SWIP-North on December 12, 2025.[44] The SWIP-North project is expected to be online in 2028.

The ISO continues to monitor transmission developments in the Western Interconnection such as PacifiCorp's Gateway projects and the Blueprint South transmission project[45], NV Energy's GreenLink projects, TransCanyon's CrossTie transmission project, Grid United's Southline transmission project and the RioSol transmission project. Various segments of the Gateway project are either in service or currently in development. The Greenlink West transmission project (Harry Allen – Ft. Churchill) is expected to be in service in May 2027 and the Greenlink North transmission project (Robinson – Ft. Churchill) is expected to be in service by the end of 2028.[46] The RioSol transmission project connects New Mexico and Arizona and will generally follow the same route as SunZia serving as an AC transmission line as compared to SunZia which is HVDC Bipole. Based on the completion of SunZia, RioSol's construction is expected to commence in 2026 and is expected to be in-service by 2028.[47] Grid United and Black Forest Partners are co-developing the Southline Transmission Project, a 278-mile, double-circuit, high voltage transmission line and associated substation facilities. This project will enable wind and solar resources from the Desert Southwest to reach key markets.

These transmission projects provide access to renewable resources in the region and could potentially serve interregional needs including those of California. The ISO will be considering these projects and engaging with the project proponents as appropriate to study any options that may be available to leverage these transmission projects to integrate additional amount of out-of-state wind resources from New Mexico and Wyoming. Additional details in Appendix F.

[44] puc.idaho.gov/case/Details/7510.

[45] https://www.pacificorp.com/transmission/transmission-projects/blueprint-south.html

[46] https://www.nvenergy.com/cleanenergy/greenlink-nevada

[47] https://nmreta.com/riosol-transmission-project/

3.4.1 ISO Participation in the Western Transmission Expansion Coalition (WestTEC) Initiative

The ISO is a participating member of the WestTEC initiative. WestTEC is a first of its kind initiative at transmission planning for the entire western interconnection, consistent with the principles of the ISO's planning processes, with the objective of developing actionable transmission solutions to address resource and demand requirements in the western interconnection by 2035 (10-year study) and 2045 (20-year study). WestTEC is a collaborative industry effort jointly facilitated by the Western Power Pool and WECC. The initiative involves most of the utilities and transmission providers in the western interconnection with a committee-based governance consisting of a broad array of Western regional partners including transmission providers, utilities, tribes, state regulators, policy makers, and other interested parties.

Transmission solutions developed are based on load forecasts, integrated resource plans, capacity expansion results, reliability, economic, and inter-area deliverability studies. The 10-year study was released on February 04, 2026 and the 20-year study is expected to be released towards the end of 2026. In addition to the 8,900 miles of transmission currently in development in the western interconnection totaling $40 billion, the 10-year study identified an additional 3,400 miles of transmission solutions totaling around $14 billion. [48]

For the ISO, the 10-year WestTEC study results were consistent with the ISO's transmission planning studies and stakeholder engagement.

3.5 Policy Assessment Summary and Recommendations

The ISO found the need for four transmission projects that are policy driven, totaling $2.4 billion and listed in Table ES-2. They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios.

Table 3-2: Policy Driven Projects Recommended for Approval

ID	Project Name	PTO	Area	Est. Cost ($M)
2526-P-01	Drum - Higgins 115 kV Line Reconductoring	PG&E	CVLY	308
2526-P-02	East Shore 230 kV Area Reinforcement	PG&E	GBA	257
2526-P-03	Oleum Area Reinforcement	PG&E	GBA	144
2526-P-04	Trout Canyon - Lugo 500 kV Line	SCE	EOP	1685
			TOTAL	2395

[48] WestTEC_10-year_Full_Report.pdf

As well, the ISO recommends canceling both the previously approved Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement project and the Helm 230/70 kV Bank project.

4 Economic Assessment

4.1 Overview of the ISO Economic Assessment

4.1.1 Objectives of the Economic Driven Assessment

The ISO's economic planning study is an integral part of its 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. Economic studies can also lead to replacing or upscaling a solution initially identified at the reliability or policy stage. The analysis focuses on reducing costs to ISO ratepayers; the potential economic benefits are quantified as reductions of ratepayer costs based on the ISO's documented Transmission Economic Analysis Methodology (TEAM).[49]

The studies used 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. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all hours for each study year.

The production cost modeling simulations 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 power flow analysis.

4.1.2 Interrelationship of Transmission Planning Studies

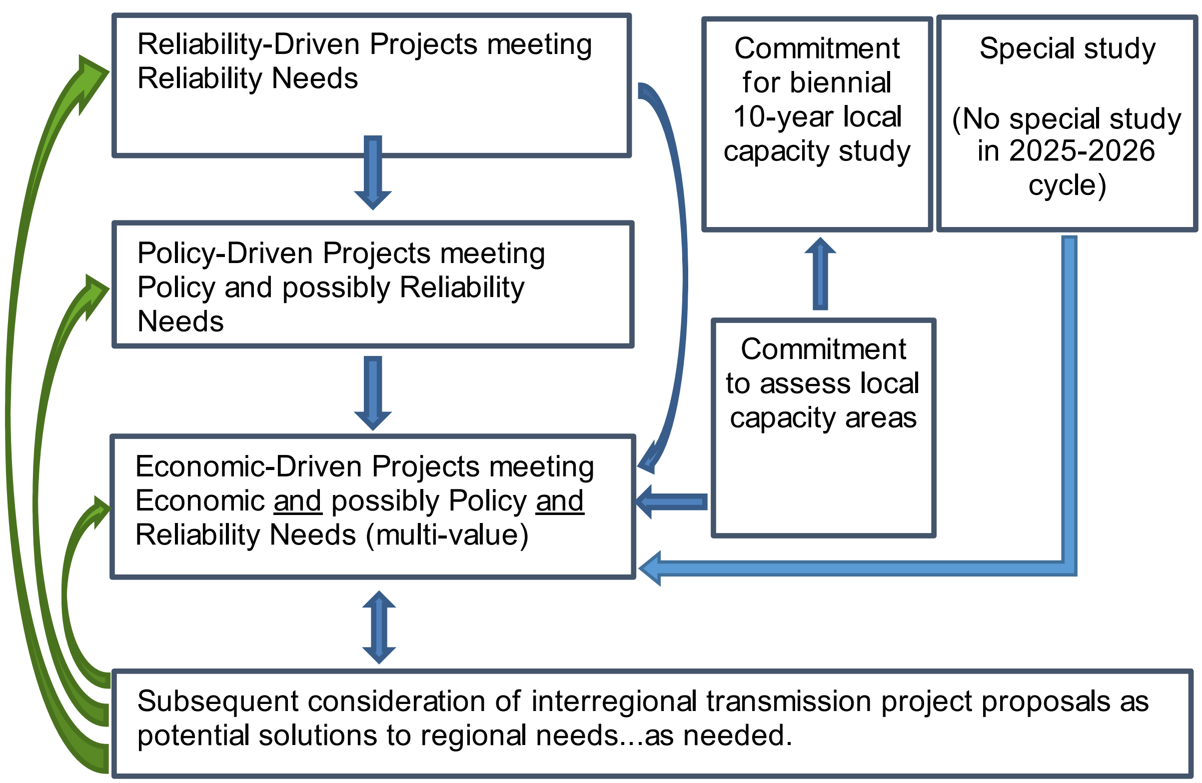
Economic studies are being driven from a growing number of sources and needs, including:

[49] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

- 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.

The above issues led to requiring a broader view of economic study methodologies and developing stronger interrelationships between studies conducted under different aspects of the transmission planning process. These interrelationships are illustrated in Figure 4-1.

Figure 4-1: Interrelationship of Transmission Planning Studies



4.2 Economic Assessment Methodology

4.2.1 Technical Study Approach and Process

Different components of ISO ratepayer benefits are assessed and quantified under the economic planning study.

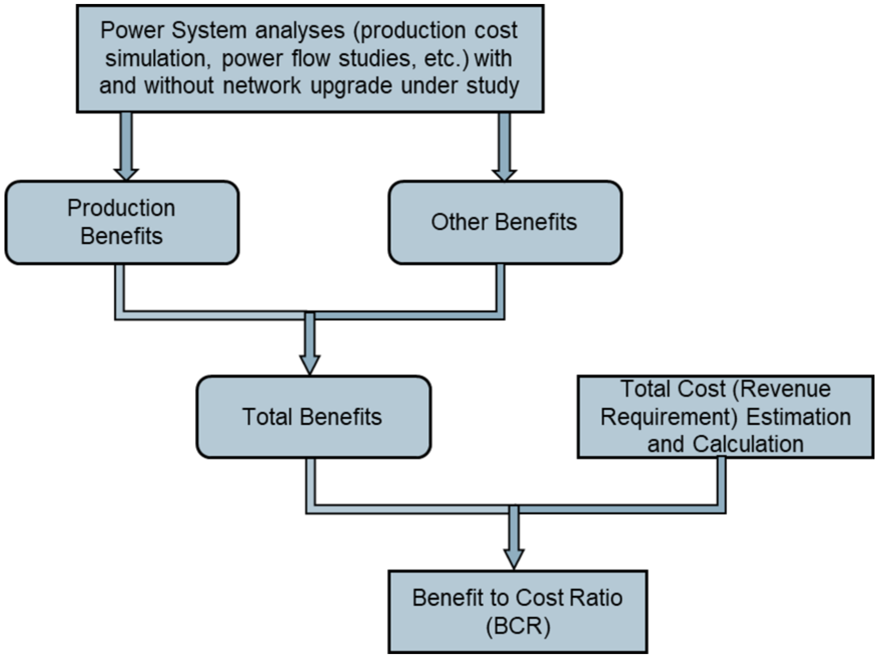
First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and 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. These include: consumer energy cost decreases; increased load-serving entity-owned generation revenues; and increased transmission congestion revenues. This analysis also includes assessment of the effectiveness of different projects for congestion mitigation.

Additionally, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings, assessed through power flow analysis. 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.

Once the total economic benefit is calculated, it is weighed against the cost, which is the total revenue requirement of the project under study.

The technical approach of the economic planning study is depicted in Figure 4-2

Figure 4-2: Technical approach of economic planning study



4.2.2 Congestion revenue allocation in production cost benefit calculation

In the current TEAM methodology, congestion revenue is allocated based on transmission ownership as discussed in section G.2.2. This congestion revenue allocation approach has been used in the ISO's transmission economic assessment since the TEAM methodology was adopted by the ISO in 2005. The market operation evolved in many ways in the past two decades and power market footprints experienced significant expansion in the Western Interconnection. The resulting changing flow patterns triggered the consideration of potential revisions to the congestion revenue allocation approach in the stakeholder meeting on November 19, 2025. The proposed potential changes were:

- Congestion revenue is allocated to areas that have net positive flow contribution to constraints;
- Allocation is based on net generation distribution factors of area to constraint; and
- This approach can be applied to congestion within the ISO or the entire WECC system.

With the revised flow contribution-based approach, congestion revenue on ISO internal constraints is only partially allocated to ISO's ratepayers, even though ISO's PTOs may have 100% ownership on the transmission lines.

In this planning cycle, production cost benefit calculations were performed on the current ownership-based congestion revenue allocation approach and the revised approach. The ISO considered these results on a case-by-case basis to understand the implications on the viability of economic-driven projects. The ISO will update the congestion cost revenue allocation in TEAM in 2026.

4.2.3 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 2024 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net-present values.

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, operation and maintenance expenses and other relevant costs, using the financial parameters and assumptions set out in Appendix G. 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.

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 determine annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. For screening purposes, the multiplier of 1.3 is used in this study to estimate the present value of the annual revenue requirement stemming from a capital investment, reflective of a 7% real discount rate and based on 40 to 50-year lifespans.

4.2.4 Production cost simulation tool

The ISO primarily uses the Hitachi GridView™ software for the economic planning study.

4.3 Economic Assessment Assumptions

4.3.1 Study years and generator portfolios

In the 2025-2026 planning cycle, the CPUC provided the 2035 and 2040 IRP portfolios to the ISO for transmission planning study. Therefore, the 10-year and the 15-year production cost simulation cases were developed. The CPUC 2035 base portfolio and sensitivity portfolio were used to develop the generator model in the 2035 base and sensitivity PCM cases, respectively. The CPUC 2040 base portfolio was used to develop the generator models in the 2040 base PCM case, which was also used for detailed economic assessment in this planning cycle. Generator locations and installed capacities in the PCM are consistent with the policy assessment power flow cases, including both conventional and renewable generators. Chapter 3 provides more details about the renewable portfolios.

4.3.2 Network model

The 2025-2026 transmission planning process PCM development started from the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) 2034 PCM case.

The ISO then modified the network model for the ISO system to exactly match the 2025-2026 cycle's policy 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 policy assessment power flow cases.

The major assumptions of system modeling used in PCM development for the economic planning study are set out in Appendix G.

Appendix G also highlights the major ISO enhancements and modifications to the 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 for the rest of the Western Interconnection in this document, but the final PCM is posted on the ISO's market participant portal once the study is final.

4.3.3 Load model

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 system. Specifically in the 2025-2026 cycle, the CEC California Energy Demand Updated Forecast for 2035 and 2040, consistent with the reliability assessment as described in Chapter 2, were used to develop the 2035 and 2040 PCM cases, respectively.

4.4 Production cost simulation results

4.4.1 Summary of congestion results in 2035 and 2040 base portfolio PCM

High-level assessments were conducted in this section on the constraints that have a large impact on the bulk system, or the heavily congested areas, or the areas with recurring congestion. The assessment results are shown in Table 4-1. The aggregated congestion cost and aggregated congestion hours shown in this table are the summation of congestion cost and hours respectively of individual transmission constraints in the same area or on the same corridor. As the occurrences of different congestion may overlap at the same hours, the aggregated congestion hours can be greater than the total hours of a calendar year. Similarly, the summation of congestion costs can also reflect multiple representations of the amount of economic congestion that is occurring. As a result, these two aggregated values are calculated only for sorting transmission constraints and helping prioritize areas to receive detailed assessments. They do not reflect the specific economic benefit resulting from mitigating the constraints in the area or corridor; that benefit can only be assessed by actually modeling and assessing alternatives.

Table 4-1: Summary of congestion results in 2035 and 2040 base portfolio PCM

Area or Branch Group	Aggregated Congestion Cost ($M) 2035B	Aggregated Congestion Hours 2035B	Aggregated Congestion Cost ($M) 2040B	Aggregated Congestion Hours 2040B	Overview of investigation
Path 15 Corridor	1,779.96	9,899	1,818.11	10,345	Path 15 corridor congestion was mainly observed on the south of Manning 500 kV lines of Path 15 when the flow was from south to north, under normal or contingency conditions. Some of the underneath 230 kV lines of the Path 15 corridor were also congested. Renewable generators in the PG&E Fresno/Kern areas and offshore wind modeled at Diablo Canyon contributed to the Path 15 corridor congestion. Path 26 flow from south to north also contributed to the Path 15 corridor congestion. The Path 15 corridor was selected to receive detailed analysis in this planning cycle.
Path 26 Corridor	392.81	4,677	328.88	4,557	Path 26 corridor congestion was mostly attributed to: • Path 26 path rating binding • The Midway - Vincent 500 kV line 4-hour rating binding under the Midway - Vincent N-1 • The Midway - Whirlwind 500 kV line congestion under normal and the Midway - Vincent N-2 conditions The path rating binding and the Midway – Whirlwind congestion was mainly observed when the Path 26 flow was from south to north, but the Midway - Vincent congestion occurred mainly when flow was from north to south. The Path 26 corridor was selected to receive detailed analysis in this planning cycle.
SCE Northern	14.98	1,052	237.67	4,930	SCE Northern area congestion was mainly observed on the Vincent transformers from 500 kV to 230 kV and the Vincent - Pardee 230 kV line from Vincent to Pardee. Upgrades to mitigate the Path 26 corridor and Western LA Basin congestion would impact the SCE Northen area congestion. This area will be assessed in future planning cycles when there is clarity on the Path 26 and Western LA Basin upgrades.
Path 65 PDCI	164.07	4,737	153.2	4,300	PDCI congestion was observed when flow is from south to north. The LADWP's operation limit of PDCI was the binding constraint of the PDCI congestion.
SCE Metro	33.58	577	148.55	4,425	SCE Metro area congestion was mainly observed on some 230 kV lines in the Western LA Basin load pocket when flow was coming into the pocket. The worst congestions were on the La Fresa – La Cienega 230 kV line under the La Fresa – El Nido 230 kV lines N-2 and on the Barre – Lewis 230 kV line. The SCE Western LA Basin area was selected to receive detailed analysis in this planning cycle.

Area or Branch Group	Aggregated Congestion Cost ($M) 2035B	Aggregated Congestion Hours 2035B	Aggregated Congestion Cost ($M) 2040B	Aggregated Congestion Hours 2040B	Overview of investigation
East of Pisgah-GLW/VEA	32.94	3,517	120.88	6,945	Congestion in the GLW/VEA area was mainly observed in the VEA's 138 kV system, which was caused largely by the loop flow between the 138 kV and the 230 kV systems under contingency. Opening the 138 kV loop at the Gamebird substation when contingency occurs can mitigate most of the 138 kV congestion
PG&E GBA	4.81	453	109.8	4,512	With the reliability upgrade (the Trimble project) in the Greater Bay area modeled in the PCM cases, the remaining congestion was mainly observed on some 230/115 kV transformers, such as NRS and San Jose. There was also congestion on the 230 kV lines in the Contra Costa, Los Positas, and Cayetano areas. The congestion in this area will be monitored and further assessed in coordination with the reliability and policy assessments in future planning cycles.
PG&E Las Aguilas - Moss Landing 230 kV	0	0	67.98	1,777	The previously approved series reactor of the Las Aguilas - Moss Landing 230 kV line was not adequate to mitigate congestion of the line in 2040 due to the increase in renewable generation in the Fresno/Kern areas. Path 15 flow has impact on the flow and congestion of this 230 kV line. Reconductoring the line can help to mitigate the congestion, and further assessment is needed in coordination with the Path 15 corridor assessment.

4.4.2 Summary of curtailment results in 2035 and 2040 base portfolio PCM

Table 4-2 shows wind and solar generation curtailment in the ISO system in the base portfolio PCM cases. 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 to the same direction, or based on geographic locations if there were no direct transmission constraints nearby. Renewable curtailment in this planning cycle's PCM results was mainly observed in the areas where transmission congestion occurred. The overall renewable curtailment remained at similar level as in the previous planning cycle.

Table 4-2: Wind and solar curtailment summary in the base portfolio PCM

	2035 Base Portfolio				2040 Base Portfolio			
Zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Ratio
PG&E Fresno	20,773	843	21,616	3.90%	39,586	6,658	46,244	14.40%
SCE Northern	33,596	1,021	34,616	2.95%	39,848	2,003	41,852	4.79%
SCE Eastern	25,171	172	25,343	0.68%	30,756	1,135	31,891	3.56%
NM	27,853	239	28,093	0.85%	27,939	469	28,408	1.65%
SCE EOP, GLW/VEA	13,899	68	13,967	0.49%	21,953	1,888	23,841	7.92%
PG&E Kern	13,108	494	13,602	3.63%	17,436	2,239	19,676	11.38%
SDGE East of Miguel	14,834	28	14,861	0.19%	18,887	261	19,148	1.36%
WY	11,530	86	11,615	0.74%	17,868	346	18,214	1.90%
OSW-Diablo Canyon	12,819	1,315	14,134	9.30%	12,273	1,861	14,134	13.17%

	2035 Base Portfolio				2040 Base Portfolio			
Zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Ratio
SCE NOL	9,398	276	9,675	2.86%	11,219	1,142	12,361	9.24%
OSW-Humboldt	8,203	0	8,203	0.00%	8,198	5	8,203	0.06%
PG&E Greater Bay Area	6,674	0	6,674	0.00%	7,552	12	7,564	0.16%
PG&E Central Valley	2,385	0	2,385	0.00%	5,623	5	5,628	0.09%
PG&E N. Valley	1,884	0	1,884	0.00%	4,508	35	4,543	0.77%
NW	4,194	0	4,194	0.00%	4,190	4	4,194	0.09%
AZ	3,078	44	3,122	1.41%	3,063	59	3,122	1.91%
ID	3,043	7	3,050	0.23%	3,025	25	3,050	0.82%
IID	1,719	16	1,735	0.91%	1,717	18	1,735	1.07%
BANC	408	0	408	0.00%	408	0	408	0.00%
PG&E N. Coast	379	0	379	0.00%	379	0	379	0.02%
NV	667	24	692	3.52%	372	5	376	1.24%
San Diego	279	0	279	0.00%	278	0	279	0.13%
SCE Metro	265	0	265	0.10%	260	5	265	1.92%
PG&E North Bay	67	0	67	0.00%	67	0	67	0.00%
Total	**216,228**	**4,634**	**220,862**	**2.10%**	**277,408**	**18,177**	**295,585**	**6.15%**

4.5 Detailed economic assessments

4.5.1 Transmission lines or areas selected for detailed economic assessment

Areas or transmission facilities that were selected to receive detailed economic assessments were summarized in Table 4-3. The selection was based on the detailed production cost simulation results as set out in Appendix G section G.7, with taking into account the economic study requests as evaluated in Appendix G section G.8. Detailed economic assessments can also be found in Appendix G.

Table 4-3: Areas receiving detailed economic assessment

Area	Alternative	Reason for receiving detailed assessment
Path 26 corridor and Western LA Basin	10 alternatives were studied as set out in Appendix G section G.9.2	Path 26 congestion is recurring congestion with large congestion cost. Large congestion cost on the La Fresa – La Cienega 230 kV line was also observed. The mitigation alternatives are expected to help to mitigate the congestions, and to reduce local capacity requirements.
Path 15 corridor	19 alternatives were studied as set out in Appendix G section G.9.3	Path 15 corridor congestion showed significant increase in this planning cycle compared with the results in previous planning cycles, as the resource assumption changed in the CPUC IRP portfolio.
Las Aguilas-Moss Landing 230 kV line	One alternative was studied as set out in Appendix G section G.9.4	As the portfolio resource capacity increased in the PG&E's Fresno and Kern areas and the load increased in the south Bay area, the existing Las Aguilas – Moss Landing 230 kV line congestion increased.

4.5.2 Path 26 corridor and Western LA Basin area

Ten alternatives for mitigating Path 26 corridor and Western LA Basin area congestion were assessed. Alternatives 1, 2, 3, and 4 either have zero capital cost or only need small capital cost for system or operating procedure modifications.

- Alternative 1: Bypass series capacitor on the Midway – Whirlwind 500 kV line.
- Alternative 2: Eliminate the Midway – Vincent N-2 contingency in the PCM by considering it as conditional P7 or expanding the RAS for Path 26. The Path 26 path rating is assumed to be 5000 MW north to south and 4400 MW south to north according the WECC Path rating study.
- Alternative 3: Alternative 2 plus restoring to use 30-minute emergency rating for the Midway – Vincent 500 kV lines under Midway – Vincent N-1.
- Alternative 4: Combination of Alternative 1 and Alternative 3, i.e. eliminating Midway – Vincent N-2, using 30-minute rating for Midway – Vincent lines, and bypassing the series compensation on the Midway – Whirlwind 500 kV line.
- Alternative 5: Reconductoring the Midway – Vincent #1 and #2 500 kV lines and the Midway – Whirlwind 500 kV line to be able to carry 4000 Amps flow. The Path 26 path rating was assumed to increase by 800 MW based on preliminary assessment with the reconductoring.
- Alternative 6: Build a new Midway – Windhub 500 kV line, which not only provides a parallel line to the existing Midway – Whirlwind 500 kV line, but also helps to relief generation deliverability issue at the Windhub 500 kV substation.
- Alternative 7: The PTEP project - a 2000 MW offshore HVDC line from Diablo Canyon to El Segundo, and four 230 kV underground HVAC cables from El Segundo to El Nido and Redondo, respectively.
- Alternative 8: The K-SEL project - a 2000 MW HVDC line from Midway to El Nido.
- Alternative 9: Alternative 7 (PTEP) plus Alternative 4.
- Alternative 10: Alternative 8 (K-SEL) plus Alternative 4.

The results showed that Alternative 1 alone did not have sufficient economic benefit for ISO's ratepayers. The other three zero-cost or low-cost alternatives, Alternative 2, 3, and 4, showed positive benefit to the ISO's ratepayers and were effective to mitigate the Path 26 corridor congestion. Other alternatives, reconductoring or adding new AC or DC lines, were not as effective to mitigate the Path 26 corridor congestion as the zero-cost or low-cost alternatives. Their benefit to cost ratios were also less than 1.0, especially if the Path 26 corridor congestion was mitigated by the zero-cost or low-cost alternatives first.

Based on the economic assessment results in this planning cycle, it was recommended to:

- Evaluate the Midway – Vincent 500 kV N-2 contingency to determine if it can be categorized as conditional P7, or if the current RAS for Path 26 can be expanded;
- Evaluate and restore the Midway – Vincent #1 and # 2 500 kV lines 30-minute emergency ratings under the Midway – Vincent 500 kV line N-1 contingency;
- Consider bypassing the series capacitor of the Midway – Whirlwind 500 kV line when the Midway – Vincent 500 kV lines 30-minute ratings were restored; and
- Assess and identify any potential system modification associated with the above mitigations

Table 4-4 showed the production benefits, cost, and the benefit to cost ratio of the recommended alternatives for mitigating Path 26 corridor congestion. Three approaches were used to calculate congestion revenue for ISO's ratepayers, as discussed in Section 4.2.2:

- S0: The current TEAM approach, i.e. allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's ownership of transmission lines and paths.
- S1: Allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.
- S2: Allocate congestion revenue of entire WECC's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.

Table 4-4: Production Benefits, cost and BCR of recommended Path 26 corridor congestion mitigation alternatives

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0- Current Team	S1-Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue	WECC Saving		S0 - Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue
A2 (Remove N-2)	26	21	22	26	39	8.74	7.29	7.36
A3 (A2 + 30 min. rating)	62	61	59	48	39	21.26	20.73	20.11
A4 (A1 + A3)	59	66	65	55	40	19.80	22.05	21.75

It was noted that the Path 26 corridor may still have some congestion with the above recommended mitigations being modeled, even though not significant. The ISO will continue to monitor the Path 26 corridor and assess if incremental mitigation is needed.

4.5.3 Path 15 Corridor

The Path 15 Corridor is a critically located transmission path pivotal to north/south transfers inside and outside California as well as renewable generation development in the greater Fresno and Kern areas in the San Joaquin valley. While Path 15 itself is defined as the electrical cut-plane south of Los Banos, encompassing the three 500 kV lines running south to Gates and Midway, it is best to think of reinforcements addressing the congestion on the cut-plane in terms of the overall corridor encompassing Path 15 in the San Joaquin valley as well as extending north to Tesla, and south to Midway and Whirlwind.

As set out in Chapter 3 and in Appendix F, the analysis of transmission needs to address deliverability for resources developing in the greater Fresno and Kern areas did not find the need for policy-driven transmission. However, the additional economic analysis considering congestion from increased resource development as well as additional path utilization more broadly found the need for both more immediate needs recommended for approval in this plan, as well as additional needs driving major reinforcements that require additional engineering details to be resolved before those reinforcements can be approved.

Given the complexity of the issues driving potential reinforcements, very few standalone alternatives could reasonably be expected to meet the needs in the corridor over the planning horizon, and many needed to be considered in a sequenced approach to determine the best overall path forward.

As a result, nineteen transmission configurations and alternatives for mitigating Path 15 corridor congestion were assessed in this planning cycle. Some alternatives include upgrades for the Path 26 corridor since the Path 26 and Path 15 flows are highly correlated with each other. All proposed new 500 kV lines were modeled with 70% compensation in PCM studies.

- Alternative 1: Add 70% series compensation on the Gates – Los Banos #3 500 kV line. This alternative is to balance the impedances between all three 500 kV lines between the Gates and Los Banos substations.
- Alternative 2: Alternative 1 plus loop the Gates – Los Banos #3 line in the Manning substation and loop the Midway – Manning #2 line in the Gates substation.
- Alternative 3: Alternative 1 plus reconductoring the Gates – Los Banos #3 line, the Midway – Gates #1 and Gates – Manning #1 line, and the Midway – Manning #2 line. The ratings of the reconductored lines are 3464/3880 MVA and 3291/3817 MVA for the conductor and series compensation, respectively.
- Alternative 4: Alternative 1 plus adding a new Midway – Tesla 500 kV line.
- Alternative 5: Alternative 4 plus adding a new Windhub – Midway 500 kV.

- Alternative 6: Alternative 5 plus tying the new Midway – Tesla 500 kV line to the Gates substation.
- Alternative 7: Alternative 2 plus reconductoring the Gates – Los Banos #3 line, the Midway – Gates #1 and Gates – Manning #1 line, and the Midway – Manning #2 line. The ratings of the reconductored lines are 3464/3880 MVA and 3291/3817 MVA for the conductor and series compensation, respectively.
- Alternative 8: Alternative 2 plus adding a new Midway – Tesla 500 kV line.
- Alternative 9: Alternative 8 plus adding a new Windhub – Midway 500 kV line.
- Alternative 10: Alternative 3 plus adding a new Midway – Tesla 500 kV line.
- Alternative 11: Alternative 10 plus adding a new Windhub – Midway 500 kV line.
- Alternative 12: Alternative 1 plus reconductoring the Gates – Los Banos # 3 line.
- Alternative 13: Alternative 12 plus adding a new Midway – Tesla 500 kV line.
- Alternative 14: Alternative 13 plus adding a new Windhub – Midway 500 kV line.
- Alternative 15: Alternative 14 plus the new Midway – Tesla line ties to Gates.
- Alternative 16: Alternative 3 plus adding a new Manning – Tesla 500 kV line.
- Alternative 17: Alternative 7 plus adding a new Manning – Tesla 500 kV line.
- Alternative 18: Alternative 12 plus adding a new Midway – Gates 500 kV line.
- Alternative 19: Alternative 18 plus adding a new tie line from the Manning substation to the existing Gates – Los Banos #3 500 kV line.

Some of the alternatives mitigated some of the congestion but still resulted in significant congestion on the Path 15 corridor. Many of the alternatives can help to mitigate congestion of some segments of the Path 15 corridor but aggravate congestion of other segments. Congestion on downstream lines may be aggravated as well. Given the scope of issues discussed, it is necessary to consider shorter term and longer-term implications.

In the shorter term, adding 70% series compensation on the Gates – Los Banos #3 line helped to balance flow among the three 500 kV lines of the Path 15 corridor, even though congestion along the Path 15 corridor still existed. Among all transmission alternatives in this section, only Alternative 1, which is to add 70% series compensation on the Gates – Los Banos #3 500 kV line, had benefit to cost ratio greater than 1.0 when the current TEAM congestion revenue allocation approach was used as well as when the revised congestion revenue allocation approaches were considered.

Accordingly, Alternative 1 that adds 70% series compensation on the Gates – Los Banos #3 500 kV line is recommended for approval as an economic-driven upgrade. Alternative 1 is a least-regret upgrade and its approval provides some certainty for the already sophisticated Path 15 corridor assessment in considering what additional mitigations are also needed.

In the longer term, all alternatives, except for Alternative 2, showed benefit to cost ratios greater than 1.0 when the revised congestion revenue allocation approaches were used. These results demonstrate conclusively that the Path 15 corridor now requires substantial reinforcement to alleviate congestion on this corridor.

Alternative 6, which is Alternative 1 plus adding a new Windhub – Tesla 500 kV line with tying the Midway and Gates 500 kV substations, had the highest benefit to cost ratios among all remaining alternatives and is considered the most economically favorable alternative in longer term. The ISO is planning to recommend this alternative for approval in the next planning cycle after conducting bulk system reliability assessment by modeling this alternative to confirm if there is any impact on the bulk system.

Table 4-5 showed the production benefits, cost, and the benefit to cost ratio of Alternative 1 and Alternative 6 for mitigating Path 15 corridor congestion. Three approaches were used to calculate congestion revenue for ISO's ratepayers, as discussed in Section 4.2.2:

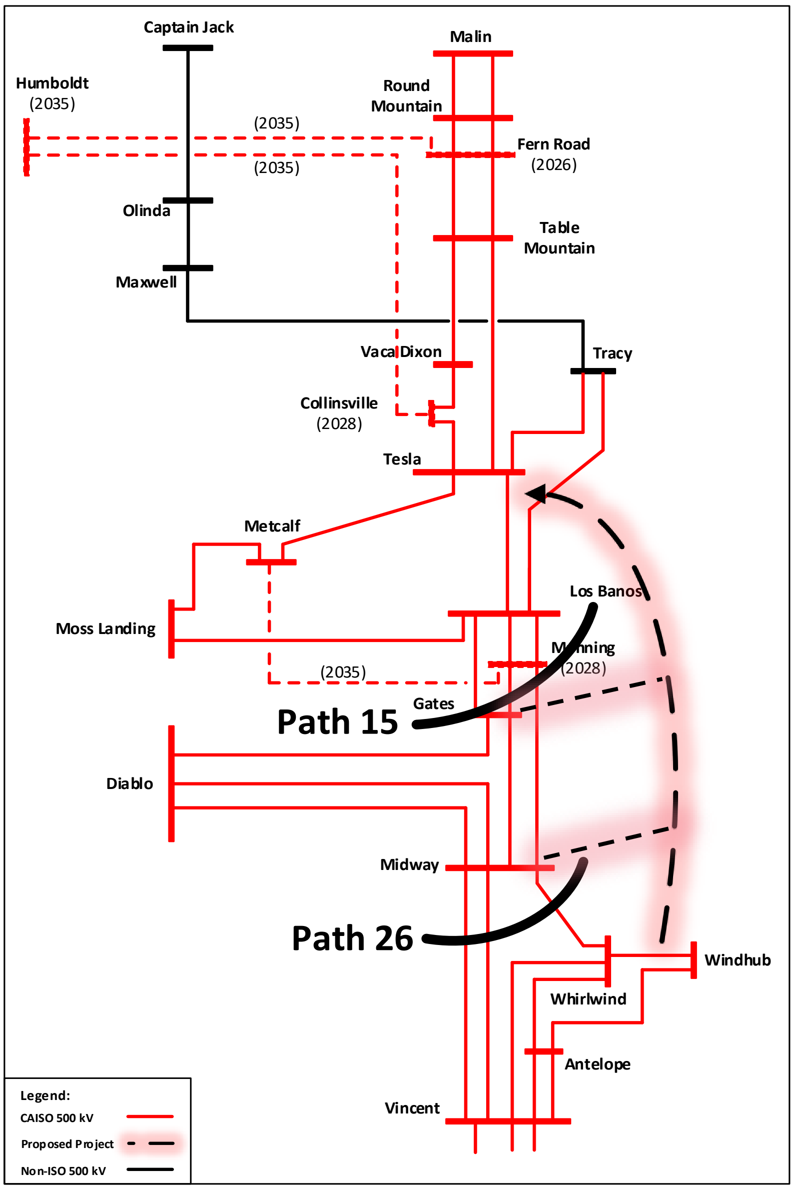
- S0: The current TEAM approach, i.e. allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's ownership of transmission lines and paths.
- S1: Allocate congestion revenue of ISO's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.
- S2: Allocate congestion revenue of entire WECC's transmission lines and paths to ISO's ratepayers based on ISO's load areas positive flow contribution to the congestion.

Table 4-5: Production Benefits, cost and BCR of recommended or favorable Path 15 corridor congestion mitigation alternatives

Case	Production cost saving ($M/year)				Total Cost ($M)	Benefit to Cost Ratio		
	S0- Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue	WECC Saving		S0- Current Team	S1- Allocating ISO Congestion Revenue	S2- Allocating WECC Congestion Revenue
A1 (Gates - Los Banos #3 70pst comp.)	24	174	161	111	195	1.66	11.91	11.02
A6 (A1 plus a new Windhub – Tesla 500 kV line with tying to Midway and Gates)	191	768	740	383	3,271	0.81	3.24	3.12

Figure 4-3 showed the 500 kV lines in northern California and Path 26. Path 15 and Path 26 were labeled on the diagram. The black dash line illustrated the transmission alternatives of adding a new Windhub – Tesla 500 kV line through a different right of way. Tying the new line to Midway and Gates that is a part of the scope of Alternative 6 was also shown in the diagram.

Figure 4-3: Diagram of Path 15 and Path 26



While a longer-term solution is identified, the ISO recognizes the need for comprehensive bulk system impact studies and detailed engineering studies for the Path 15 corridor and the upstream and downstream systems, including the Path 26 corridor and the Manning to

Metcalf corridor. Such studies may include power flow and stability studies to identify new path ratings or transmission capacity, short circuit duty study to assess the need of substation expansion, and deliverability study to evaluate the impact on generation interconnection in the adjacent areas. Remedy action schemes (RAS) associated with the Path 26 and Path 15 corridors would be also revisited in the comprehensive study. With taking into account all of new study results, the scope of the longer term solution may need to be fine-tuned. It is worth noting that additional upgrades may need to be considered beyond the identified longer term solution if Path 15 corridor congestion remains significant with the new load forecast and resource assumption in the next planning cycle.

The ISO has also been informed of the Valley Clean Infrastructure Project being advanced by Golden State Clean Energy and the Westlands Water District, and the ISO will monitor the progress as it advances the engineering detail in the 2026-2027 planning process.

4.5.4 Las Aguilas – Moss Landing 230 kV

One alternative for mitigating Las Aguilas – Moss Landing 230 kV congestion was assessed:

- Alternative 1: Reconductoring the Las Aguilas – Moss Landing 230 kV line.

This alternative was effective to mitigate the congestion but did not show sufficient benefit to ISO's ratepayers. Therefore, this alternative was not recommended as economic-driven upgrade in this planning cycle. It is worth noting that the flow on this corridor is highly correlated with the flow on Path 15 corridor. Further assessment of this corridor will be conducted in future planning cycles in coordination with Path 15 corridor assessments.

4.6 Economic Assessment Summary and Recommendations

The ISO conducted production cost modeling simulations in this economic planning study. Grid congestion was identified and evaluated; the congestion studies helped guide the specific study areas that were considered for further detailed analysis. Other factors, including the ISO's commitment to consider potential options for reducing the requirements for local gas-fired generation capacity and prior commitments to continuing 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, including: request window submissions that cited economic benefits, economic study requests, and comments in various stakeholder sessions.

Total 30 transmission alternatives for the Path 26 corridor, LA Basin area, Path 15 corridor, and Las Aguilas – Moss Landing 230 kV line congestion were assessed, respectively.

Three mitigations for the Path 26 corridor congestion, which have either zero or low capital cost, were recommended to implement:

- Evaluate the Midway – Vincent 500 kV N-2 contingency to determine if it can be categorized as conditional P7, or if the current RAS for Path 26 can be expanded, so that there is no need to enforce this N-2 contingency in PCM and the Path 26 path rating can be increased;
- Evaluate the Midway – Vincent #1 and # 2 500 kV line emergency ratings under Midway – Vincent 500 kV line N-1 contingency, and restoring the 30-minute emergency ratings for these lines; and
- Consider bypassing the series capacitor of the Midway – Whirlwind 500 kV line when the Midway – Vincent 500 kV lines 30-minute ratings were restored.

The ISO is recommending for approval one transmission project that is economic-driven, totaling $150 million and listed in Table 4-6. This project is needed to address congestion on Path 15 to accommodate the renewable generation requirements established in the CPUC-developed renewable generation portfolios and the increasing load in the CEC forecast.

Table 4-6: Economic Driven Projects Recommended for Approval

ID	Project Name	PTO	Area	Est. Cost ($M)
2026-E-01	Gates – Los Banos #3 500 kV Line Series Compensation	WAPA	Fresno	150

While the Gates – Los Banos #3 500 kV Line Series Compensation project is the sole economic-driven project being recommended in this planning cycle, this transmission plan has identified and confirmed the need for new additional transmission on the 500 kV corridor in the San Joaquin Valley, encompassing the Path 15 corridor and portions of Path 26. The ISO has identified a preferred option to meet these needs, extending as far north as Tesla and south to Midway and Windhub. Given the magnitude and impact on the 500 kV backbone grid, the ISO has identified the need for additional engineering details to be completed before a functional specification can be completed and a competitive process launched, so the ISO plans to seek Board of Governors approval and move forward with this transmission reinforcement in the 2026-2027 transmission planning cycle[50].

[50] The ISO has also been informed of the Valley Clean Infrastructure Project being advanced by Golden State Clean Energy and the Westlands Water District, and the ISO will monitor the progress as it advances the engineering detail in the 2026-2027 planning process.

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5 Interregional Transmission Assessment

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 started its 2024-2026 Interregional Transmission Project (ITP) cycle in the first quarter of 2024 in which proponents were able to submit ITP proposals to the ISO and request their initial evaluation within the 2024-2025 transmission planning process and then subsequently in the 2025-2026 transmission planning process for detailed evaluation if required as well as coordinate with the other western planning regions (WPRs). During the submission period, five projects were submitted by their project sponsors for consideration by the ISO in its 2024-2026 ITP cycle.

5.1 Interregional Transmission Coordination

FERC Order No. 1000 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.

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. Like past interregional transmission coordination cycles, the ISO continues to engage and coordinate with the other WPRs on submitted ITP projects in addition to representing and supporting interregional coordination concepts and processes in public forums such as WECC.

5.1.1 Procedure to Coordinate and Share ISO Results with other WPRs

During each planning cycle the ISO 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. The annual coordination meetings are generally held in February/March 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. NorthernGrid hosted the 2024 meeting and the ISO hosted the 2025 meeting on March 24, 2025. The 2026 annual coordination meeting is hosted by WestConnect on March 26.

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 process are conducted annually 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.

5.1.2 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 No. 1000 planning regions;
- While an ITP may connect two Order No. 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; and
- When a sponsor submits an ITP into the regional process of an Order No. 1000 planning region, it must indicate whether it is seeking cost allocation from that Order No. 1000 planning region. When a properly submitted ITP is successfully validated, the two or more Order No. 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 planning process.

5.1.3 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.

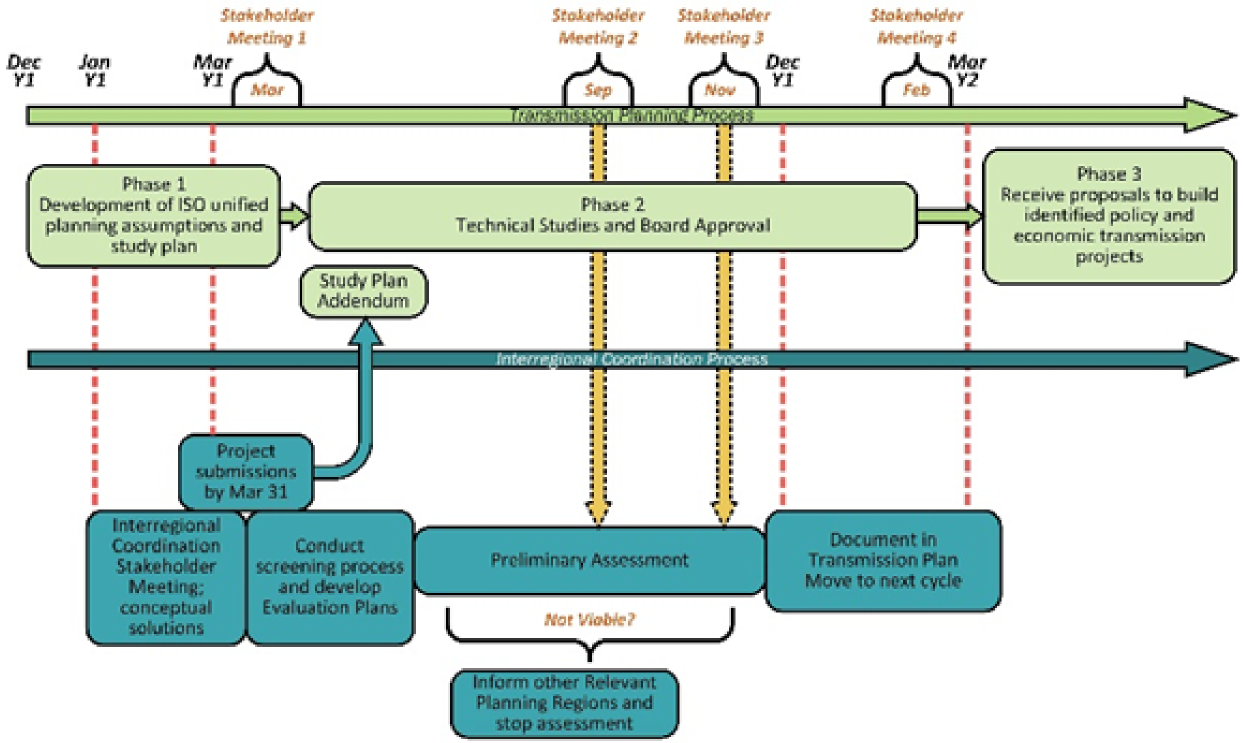
5.1.3.1 Year One (Even Year) Assessment

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 and 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 5-1: Even Year Interregional Coordination Process

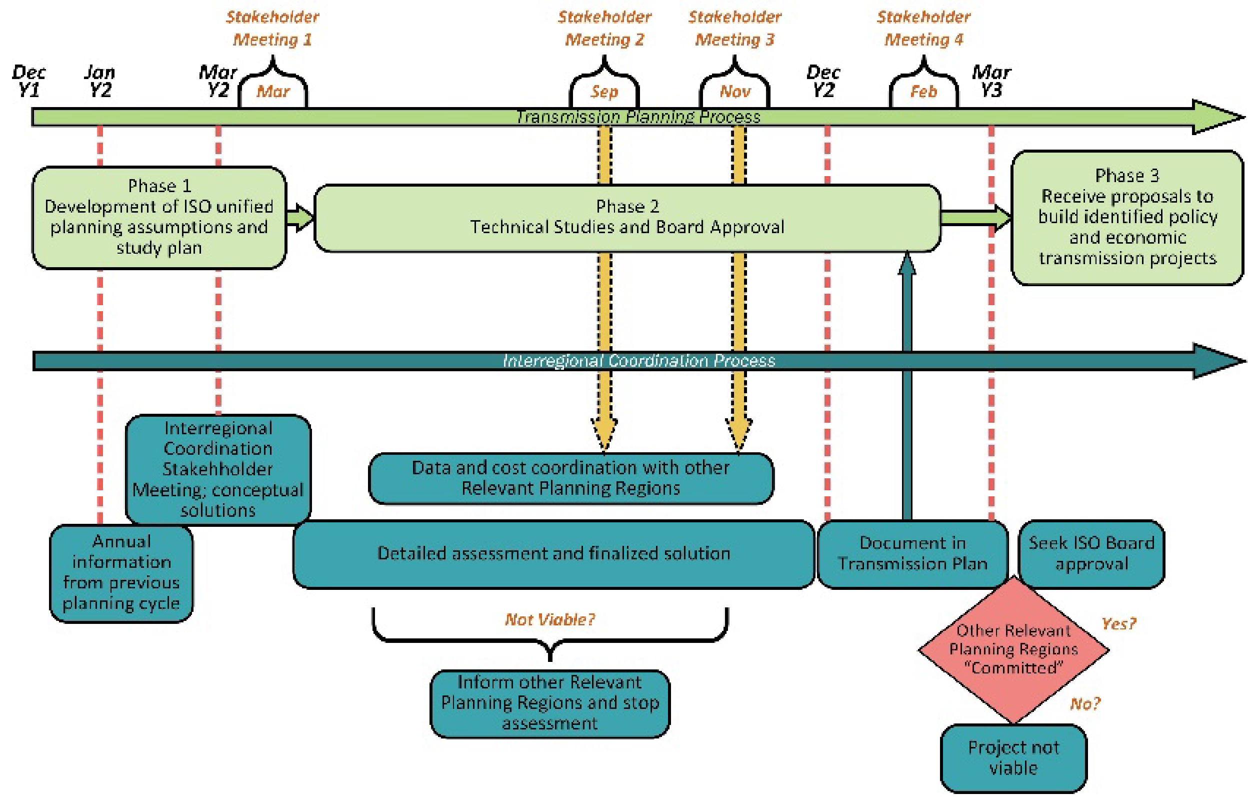


The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation on whether to continue assessment of the ITP in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission plan.

5.1.3.2 Year Two (Odd Year) 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 5-1, the ISO will follow the odd-year interregional coordination process shown in Figure 5-2.

Figure 5-2: Odd Year Interregional Coordination Process



During the odd-year planning cycle, the ISO will conduct a more in-depth analysis of the project proposal, including consideration of the timing for when 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 in 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.

5.2 2024-2026 Interregional Transmission Project Assessment

The ISO opened its 2024-2026 ITP submission window in the first quarter of 2024, when proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2024-2025 transmission planning process. The submission period began on January 1 and closed on March 31, 2024. The ITP projects submitted for evaluation in the first quarter of 2024 are listed in Table 5-1. The initial screening occurred during the 2024-2025 Transmission Planning process, and the final assessment results of the submitted projects are detailed below.

Table 5-1: ITP's submitted to the 2024-2026 Submission Window

Project Name	Company	Project Submitted to	Description	In-Service Date
Sloan Canyon – Mead 230 kV Ckt 2	GridLiance West LLC	ISO, WC	An 890 MVA, AC circuit to be added to the existing GLW Sloan Canyon to WAPA Mead double-circuit capable 230 kV towers	2028
Mead – Mohave	GridLiance West LLC	ISO, WC	Rebuilding the existing Mead to Davis 230 kV line to 500 kV and building a 5-mile Davis to Mohave extension	2030
GLW Upsize to Sagebrush	GridLiance West LLC	ISO, NG	Upgrade to sections of the ISO 2022-2023 TPP approved GridLiance West (GLW)/ Valley Electric Association (VEA) Area Upgrades and Beatty 230 kV Upgrade projects	2028
GLW Upsize to Esmeralda	GridLiance West LLC	ISO, NG	The project upgrades existing double circuit 230 kV configuration to 500 kV-capable towers to sections of GLW's approved Core and Beatty upgrades	2030
Western Bounty Transmission System	Western Bounty LLC	ISO, NG, WC	A three-segment 500- to 800-kilovolt (kV) HVDC transmission system connecting renewable energy resources produced near Western Bounty's Hub in Esmeralda County, NV to termini in Southern California, central Oregon, and southwestern Idaho	2033

Following the submission and screening of the ITP submittals for need determination, and in coordination with the other Western planning regions, it was determined that the submitted ITPs did not meet a regional need in any of the western planning regions and as such would not be evaluated.

- <u>Western Planning Regions:</u> WestConnect will not evaluate the submitted ITPs to determine if they meet any regional transmission needs because WestConnect has determined that there are no regional transmission needs in its 2024-26 regional planning cycle.[51] NorthernGrid arrived at a similar conclusion regarding the lack of a regional need for the submitted ITPs.[52]
- <u>GridLiance West (GLW) ITP Submissions:</u> The ISO identified only some minor congestion within the GridLiance/VEA system in the 138 kV system and hence none of the GridLiance/VEA ITP study requests were selected for detailed economic assessments.
- <u>Western Bounty Transmission System:</u> The ISO performed a sensitivity study to evaluate different alternatives to import additional 1,500 MW Wyoming wind beyond TransWest Express capacity and to mitigate area constraints including the Lugo – Victorville constraint. This transmission project addresses the Lugo – Victorville constraint but does not address GLW area constraints. Apart from its reduced effectiveness in addressing constraints, this is an HVDC project and the cost of this project would likely be higher than alternatives considered.

[51] https://doc.westconnect.com/Documents.aspx?NID=21545&dl=1

[52] https://www.northerngrid.net/private-media/documents/2024-2025_NorthernGrid_RTP.pdf

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6 Additional Studies and Assessments

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan. These studies are either set out in the ISO tariff or form part of the ongoing collaborative study efforts taken on by the ISO to assist the CPUC with state regulatory needs. The studies 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. This section also includes additional analysis supporting long-term planning processes, 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 2026. 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 2025. A short-term analysis was conducted for the 2026 system configuration to determine the minimum local capacity requirements for the 2026 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 in a transparent stakeholder process with a final report published on April 30, 2025. For detailed information on the 2026 LCT Study Report please visit:

https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2026-Local-Capacity-Technical-Report.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2030 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years. The 2030 LCT Study Report was published on April 30, 2025. For detailed information please visit:

https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2030-Long-Term-Local-Capacity-Technical-Report.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. 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 2024-2025 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.

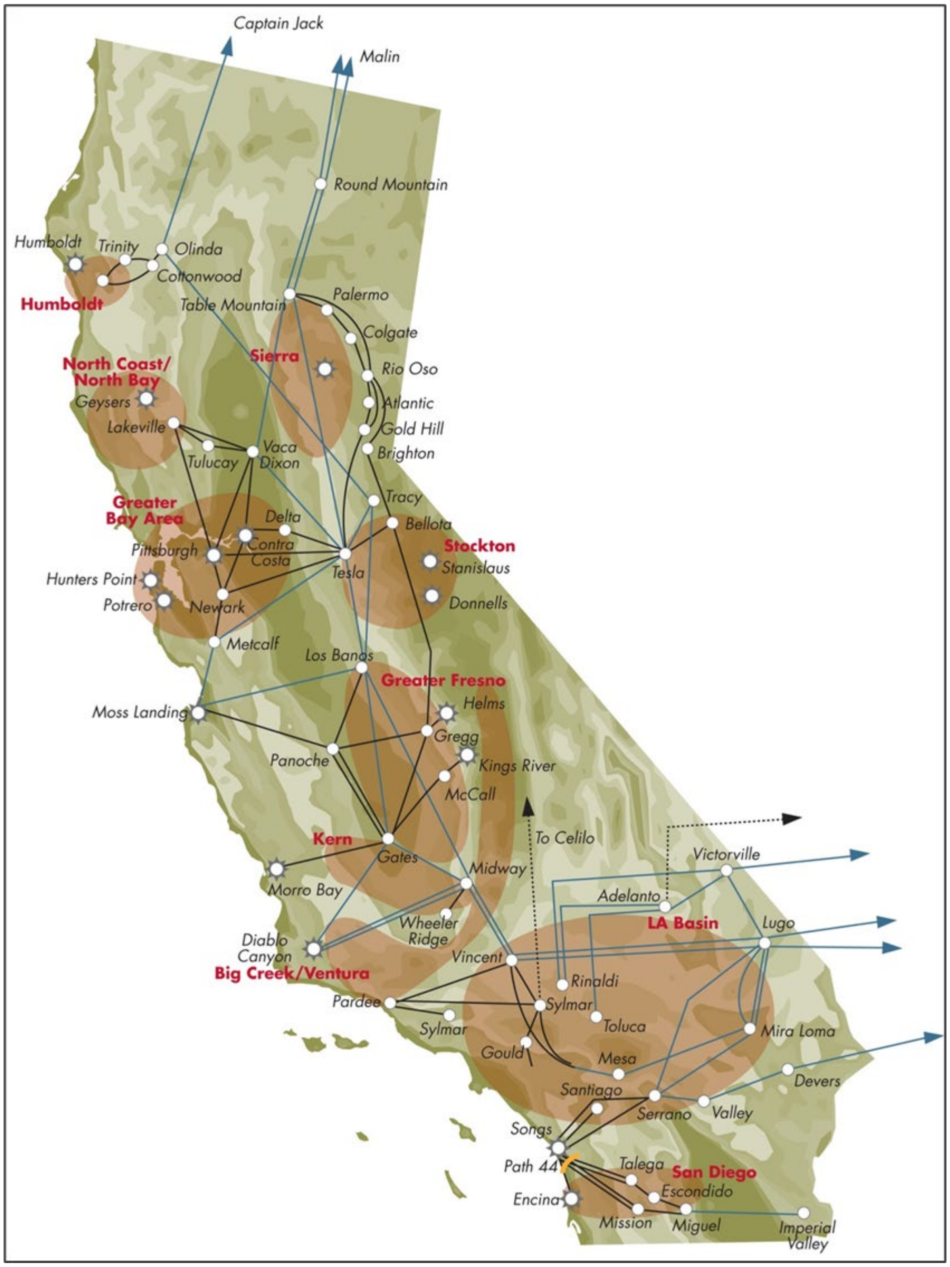
For detailed information about the 2034 and selected 2039 long-term LCT study results, please refer to the stand-alone report in Appendix J of the 2024-2025 transmission planning process.

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; however only 10 of them have local capacity area requirements as illustrated in Table 6-1.

Table 6-1: 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: 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 170 MW. In contrast, the requirements of the Bay Area are approximately 7,500 MW. The short-term and long-term LCR needs from this year's studies are shown in Table 6-2.

Table 6-2: Local capacity areas and requirements for 2026, 2030 and 2034

LCR Area	LCR Capacity Need (MW)		
	2026	2030	2034
Humboldt	136	174	178
North Coast/North Bay	848	606	812
Sierra	1,354	1,911	1,865
Stockton	756	780	864
Bay Area	7,558	8,308	8,554
Fresno	2,100	2,603	2,695
Kern	452	346	121
Big Creek/Ventura	1,369	1,381	1,462
Los Angeles Basin	5,812	7,269	4,900
San Diego/Imperial Valley	2,631	3,305	1,902
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	23,016	26,683	23,353

Notes:
For more information about the LCR criteria, methodology and assumptions, please refer to the ISO LCR manual.[53]
For more information about the 2026 LCT study results, please refer to the report posted on the ISO website.
For more information about the 2030 LCT study results, please refer to the report posted on the ISO website.

6.1.2 Resource Adequacy Import Capability

6.1.2.1 Maximum Import Capability for Resource Adequacy and Future Outlook

The ISO has established the maximum resource adequacy (RA) import capability to be used in year 2026 in accordance with the ISO tariff Section 40.4.6.2.1. This data can be found on the ISO website[54]. The entire import allocation process is posted on the ISO website[55].

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[53] "Final Manual 2026 Local Capacity Area Technical Study," December 2, 2024, https://stakeholdercenter.caiso.com/InitiativeDocuments/FinalStudyManual-2026LocalCapacityRequirements.pdf .

[54] California ISO Maximum RA Import Capability for year 2026," available on the ISO's website at https://www.caiso.com/documents/iso-maximum-resource-adequacy-import-capability-for-year-2026.pdf

[55] See general the Reliability Requirements page on the ISO website https://www.caiso.com/generation-transmission/resource-adequacy

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

https://www.caiso.com/documents/advisory-estimates-of-future-resource-adequacy-import-capability.pdf

The maximum import capability (MIC) from the Imperial Irrigation District (IID) was increased to 702 MW starting in 2024 to accommodate renewable resources development in this area that the 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_ITC and the IID-SDGE_ITC intertie.

The following are base portfolio and MIC expansion requests fully approved increases, which passed both the TPP deliverability and the GIP deliverability studies.

Table 6-3: Maximum Import Capability fully approved increases

Orig. Year	Driver	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	QC MWs	Waiting for:	First RA year
2015	Portfolio	IID-SDGE_ITC (IVLY2) and IID-SCE_ITC (DEVERS230 & MIR2)	240	Geothermal & Solar/Battery	240	All projects are in-service.	2024 (implemented)

6.1.2.2 Maximum Import Capability expansions driven by the Portfolio

Per the ISO Tariff, the Base Portfolio drives approval of new transmission in order to assure all import resources are deliverable to the aggregate of load.

Yearly NQC deliverability study:

Only three scheduling points had a MIC expansion driven by the Base Portfolio that triggered an increase applicable to the 2026 RA year.

Table 6-4: 2026 NQC deliverability study results regarding MIC expansion for Base Portfolio

No.	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	2025 QC MWs	Status	Comments:
1	IPPCADLN_ITC (IPP & IPPUTAH)	20	Geothermal	20	N/A	There is no need for expansion since there is enough Remaining Import Capability available.
2	BLYTHE_ITC (BLYTHE161)	145	Hybrid (solar/battery)	145	Failed	Behind the Devers-Red Bluff constraints.
3	MEAD_ITC (MEAD 230)	350 45	Wind Geothermal	122.61 45	Failed	Behind the Lugo-Victorville constraint.

The appropriate amount of MWs to the scheduling points that passed the test of the 2026 NQC deliverability study were given to the LSEs as a temporary MIC increase for RA year 2026.

Permanent expansion of MIC depends on the TPP and GIP deliverability study results.

TPP deliverability study:

The following are the previous cycle's portfolio increase requests that passed the TPP deliverability study and are awaiting results of the GIP deliverability studies.

Table 6-5: Base portfolio driven MIC increase (per TPP) that awaits GIP deliverability studies

Orig. Year	Deliverability Reservation	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	2025 QC MWs	Waiting for:	First RA year[56]
2022	Yes	IID-SDGE_ITC (IVLY2) & IID-SCE_ITC (DEVERS230 & MIR2)	655	Geothermal	655	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2022	Yes	MEAD_ITC (MEAD 230)	300	Wind	97	Lugo-Victorville line upgrade.	2030
2022	Yes	PALOVRDE_ITC (PVWEST)	438	Wind	228	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2023	Yes	HA500_ISL (HA500)	2500	Wind	1096	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	No	HA500_ISL (HA500)	72	Geothermal	72	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	No	MEAD_ITC (MEAD230)	45	Geothermal	45	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Yes	MEAD_ITC (MEAD230)	45	Geothermal	45	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Yes	IPPUTAH_ITC (IPP & IPPUTAH)	70	Geothermal	70	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	No	GONDIPPDC_ITC (GONIPP)	23	Geothermal	23	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Yes	PALOVRDE_ITC (PVWEST)	1890	Wind	983	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2023	Yes	SUMMIT_ITC (SUMMIT120)	39	Geothermal	39	Humboldt-Fern Road 500 kV, Humboldt-Collinsville 500 kV and Drum-Higgins 115 kV Reconductoring	2035
2024	Yes	HA500_ISL (HA500)	60	Wind	26	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2024	Yes	MEAD_ITC (MEAD 230)	50	Wind	26	Lugo-Victorville line upgrade.	2030
2024	Yes	PALOVRDE_ITC (PVWEST)	771	Wind	401	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2024	Yes	IPPCADLN_ITC (IPP & IPPUTAH)	20	Geothermal	20	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2024	No	MCCULLGH_ITC (ELDORADO500)	1500	Wind	658	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS. Plus, Trout Canyon-Lugo 500 kV	2036
2024	No	New TESLA500_ITC (TBD)	1500	Wind	658	Tesla Expansion and assumes new line from Wyoming to Tesla.	TBD
2025	No	New TESLA500_ITC (TBD)	207	Wind	91	Tesla Expansion and assumes new line from Wyoming to Tesla.	TBD
2025	Yes	HA500_ISL (HA500)	40	Wind	18	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS. Plus, Trout Canyon-Lugo 500 kV	2036
2025	No	New LUGO500_ITC (TBD)	1750	Wind	910	Assumes new line from New Mexico to Lugo.	TBD

56 First RA year must be at least 1 year out after the GIP deliverability study is complete, or the year after the last transmission element is in-service.

The ISO confirms that not 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 2025 submitted base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2035 and 2040.

Based on the TPP deliverability studies (and potentially GIP deliverability studies) some scheduling points (branch groups) currently do not have enough deliverability available to make the main CPUC portfolio deliverable without transmission reinforcements. Transmission reinforcements are studied and if necessary, will be approved through the TPP.

Table 6-6: Base portfolio MIC increases awaiting new TPP upgrades and GIP deliverability studies

Orig. Year	Deliverability Reservation	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	2025 QC MWs	Status	Comments:
2025	No	BLYTHE_ITC (BLYTHE161)	145	Hybrid (Solar/Battery)	145	Failed	Mitigation under investigation

For scheduling points where the CPUC main portfolio has failed the TPP deliverability test, the long-term MIC expansion is not possible without new transmission reinforcements. Please follow the potential mitigations for specific constraints as listed in the table above.

GIP deliverability study:

The GIP deliverability study includes all resources with deliverability included in the TPP deliverability study, (including MIC expansion due to base portfolio and requests) plus additional resources that have received TPD and DGD allocation prior to this study cycle.

The interrelation between the target expanded MIC and the generation interconnection process can be found in RR BPM Section 6.1.3.6, "Modeling Expended MIC Values in GIP".

The ISO has not yet conducted a complete and comprehensive GIP deliverability studies vis-a-vis all MIC expansions because certain areas, without new allocations, were not studied in GIP, certain MIC expansions driven by the base portfolio don't yet have deliverability reservations and because the TPP deliverability study modeled most, but not all, the unaccounted for TPD. The ISO plans on running a complete and comprehensive GIP deliverability study in the next TPP cycle.

6.1.2.3 Maximum Import Capability Expansion Requests

Per Section 3.2.2.3 of the transmission planning process Business Practice Manual (TPP BPM), requests to perform deliverability studies to expand the maximum import capability have been submitted to the ISO within two weeks after the first stakeholder meeting and not later than when study plan comments were due. The valid maximum import capability expansion requests have identified the intertie(s) (branch group(s)) that require expansion.

The ISO has evaluated each maximum import capability expansion request to establish if the submitting entity meets the criteria listed in the Tariff Section 24.3.5. The table below includes the valid Maximum Import Capability expansion requests that were submitted for this planning cycle.

Table 6-7: Valid 2025 Maximum Import Capability Expansion Requests

<table>
<tr><th>No.</th><th>Requestor Name</th><th>Intertie Name (Scheduling Point)</th><th>QC MW quantity</th><th>Resource Type</th></tr>
<tr><td>1</td><td>Sunzia</td><td>PALOVRDE_ITC (PVWEST)</td><td>1898.1</td><td>Wind</td></tr>
<tr><td>2</td><td>Peninsula Clean Energy Authority</td><td>PALOVRDE_ITC (PVWEST)</td><td>114.4</td><td>Wind</td></tr>
<tr><td>3-4</td><td rowspan="2">Valley Electric Association</td><td rowspan="2">MEAD_ITC (MEAD230)</td><td>24</td><td>Hydro</td></tr>
<tr><td>5</td><td>90</td><td>Solar/Battery</td></tr>
</table>

The ISO has received three submittals with six requests for MIC expansion. They contained 5 distinct requests (one was duplicate – the LSE provided the request and the supplier provided a request for the same resource).

Based on the ISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) four distinct requests qualify as valid requests based on the following factors:

- Power Purchase Agreements between ISO LSEs and import suppliers, not fully accounted for as Pre-RA Import Commitment or New Use Import Commitment.
- Submittal by transmission owner with newly built transmission near the ISO BAA boundary in an adjacent BAA.

For the following reasons, one distinct request does not qualify at this time:

- Power Purchase Agreements between ISO LSEs and import suppliers, fully accounted for as Pre-RA Import Commitment or New Use Import Commitment.

The ISO has coordinated the valid MIC expansion requests with the policy-driven MIC expansion and the total of the two (after elimination of duplicates) was used to identify all branch groups that do not have sufficient Remaining Import Capability to cover both the valid MIC expansion requests and the policy-driven MIC expansion.

The exact calculation of the target expanded MIC can be found in Reliability Requirements Business Practice Manual (RR BPM) Section 6.1.3.5, “Deliverability of Imports”.

Table 6-8: Assessment of valid 2025 Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	QC MW quantity	Triggers Expansion	Comments
1	Sunzia	PALOVRDE_ITC (PVWEST)	1898.1	Yes	Partially included in the CPUC base portfolio
2	Peninsula Clean Energy Authority	PALOVRDE_ITC (PVWEST)	114.4	No	Included in the CPUC base portfolio and duplicate of above.
3-4	Valley Electric Association	MEAD_ITC (MEAD230)	24	Yes	Full.
5			90		

After the elimination of duplicate entries (vis-à-vis the base CPUC portfolio), requests for increases at branch groups that do not require a MIC increase and obsolete data from previous year's requests, the following MIC expansion requests are being modeled and explored.

Table 6-9: Maximum Import Capability Expansion requests currently being assessed

No.	Year	Requestor Name	Intertie Name (Scheduling Point)	MW quantity (QC)	Resource Type
1	2024	California Community Power	SUMMIT_ITC (SUMMIT120) [57]	18	Geothermal
2		San Diego Community Power	IID-SDGE_ITC (IVLY2)	35	Hybrid (Solar/Battery)
3	2025	Sunzia	PALOVRDE_ITC (PVWEST)	936.53 (2026) 286.62 (2035-40)	Wind
4-5		Valley Electric Association	MEAD_ITC (MEAD 230)	24	Hydro
6				90	Hybrid (Solar/Battery)

For the above branch groups where MIC expansion was triggered, the increase in MIC was modeled and tested through deliverability studies: the NQC deliverability study (if applicable in year one), the TPP deliverability study and the GIP deliverability study. One or multiple of these studies can limit the deliverability and therefore the MIC expansion.

Yearly NQC deliverability study:

Three scheduling points had a MIC expansion request that triggered an increase applicable to the 2026 RA year.

Table 6-10: 2026 NQC deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	IID-SDGE_ITC (IVLY2)	N/A	There is no need for expansion since there is enough Remaining Import Capability available.
2	PALOVRDE_ITC (PVWEST)	Fail	For the part that is beyond the CPUC base portfolio. Behind the Lugo-Victorville and Devers-Red Bluff constraints.
3	MEAD_ITC (MEAD 230)	Fail	For the part that is beyond the CPUC base portfolio. Behind the Lugo-Victorville constraint.

57 As back-up locations only – main delivery point included as MEAD_ITC (MEAD 230) and part of the CPUC portfolio.

The appropriate amount of MWs to the scheduling points that passed the test of the 2026 NQC deliverability study were given to the LSEs as a temporary MIC increase for RA year 2026.
Permanent expansion of MIC depends on the TPP and GIP deliverability study results.

TPP deliverability study

The TPP deliverability study includes all existing resources with deliverability, new resources with deliverability as dictated by the TPP study plan, all new resources provided in the main policy portfolio provided by the CPUC and the MIC expansion requests submitted to the ISO.

Table 6-11: TPP Deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	SUMMIT_ITC (SUMMIT120)	Failed/ Pass with upgrade/ Move forward	Used as back-up only – main in the CPUC portfolio. Waiting for Humboldt-Fern Road 500 kV, Humboldt-Collinsville 500 kV and Drum-Higgins 115 kV Reconductoring. First expected RA year 2035.
2	IID-SDGE_ITC (IVLY2)	Ineligible/ Denied	This MIC expansion request is not longer valid since it achieved NUIC status for its entire quantity and is therefore denied.
3	PALOVRDE_ITC (PVWEST)	Failed/ Denied	Part not in the CPUC portfolio. Additional mitigation for Devers-Red Bluff and Serrano-Alberhill-Valley constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
4	MEAD_ITC (MEAD 230)	Failed/ Pass with upgrade/ Move forward	Part not in the CPUC portfolio. Waiting for Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS. Plus, Trout Canyon-Lugo 500 kV. First expected RA year 2036.

The MIC expansion requests that have failed the TPP deliverability test are denied because long-term MIC expansion is not possible without new transmission reinforcements. MIC expansion requests on their own cannot trigger transmission expansion, however, some of the MIC expansion requests may end up passing as long as mitigations move forward for reliability, economic or policy need.

For those MIC expansion requests that passed, please follow the potential mitigations for specific constraints as listed in the table above.

GIP deliverability study

The GIP deliverability study includes all resources with deliverability included in the TPP deliverability study, (including MIC expansion due to base portfolio and requests) plus additional resources that have received TPD and DGD allocation prior to this study cycle.

The interrelation between the target expanded MIC and the generation interconnection process can be found in RR BPM Section 6.1.3.6, “Modeling Expended MIC Values in GIP”.

The ISO has not yet conducted a complete and comprehensive GIP deliverability studies vis-a-vis all MIC expansions because certain areas, without new allocations, were not studied in GIP, certain MIC expansions driven by the base portfolio don't have yet deliverability reservation and because the TPP deliverability study modeled most, but not all the unaccounted for TPD. The ISO plans on running a complete and comprehensive GIP deliverability study in the next TPP cycle. While the ISO has not yet conducted a complete and comprehensive cycle of GIP deliverability studies, it is reasonably assumed, since the GIP deliverability study includes additional new resources with prior TPD and DGD allocation beyond those modeled in the TPP deliverability study, that if they failed the TPP deliverability study then they would fail the GIP deliverability studies.

Table 6-12: GIP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	SUMMIT_ITC (SUMMIT120)	TBD	Used as back-up only – main in the CPUC portfolio. Waiting for Humboldt-Fern Road 500 kV, Humboldt-Collinsville 500 kV and Drum-Higgins 115 kV Reconductoring. First expected RA year 2035.
2	IID-SDGE_ITC (IVLY2)	Ineligible/ Denied	This MIC expansion request is not longer valid since it achieved NUIC status for its entire quantity and is therefore denied.
3	PALOVRDE_ITC (PVWEST)	Failed/ Denied	Part not in the CPUC portfolio. Additional mitigation for Devers-Red Bluff and Serrano-Alberhill-Valley constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
4	MEAD_ITC (MEAD 230)	TBD	Part not in the CPUC portfolio. Waiting for Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS. Plus, Trout Canyon-Lugo 500 kV. First expected RA year 2036.

MIC expansion requests that failed the TPP deliverability study will likely fail the GIP deliverability test and therefore long-term MIC expansion is not possible without new transmission reinforcements. The mitigations proposed in the TPP must allow the internal resources with prior TPD and DGD allocation to remain deliverable before MIC is allowed to permanently increase to account for import resources included in the CPUC portfolio and if possible, to allow for further MIC increase due to MIC expansion requests.

For MIC expansion requests that passed the GIP deliverability study, please follow the potential mitigations for specific constraints as listed in the table above.

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 2025 LT congestion revenue rights (CRR) study leveraged the base case network topology used for the annual 2026 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 2025-2026 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 1 being January through March and season 3 July through September) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as saved 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 and 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 January 2026 that there were no existing released LT CRRs “at-risk” that require further analysis. Thus, the transmission projects and elements approved in the 2025-2026 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

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 several 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 have been summarized, as well as the background setting the context for these efforts and the study results.

6.3.1 Frequency Response Methodology & Metrics

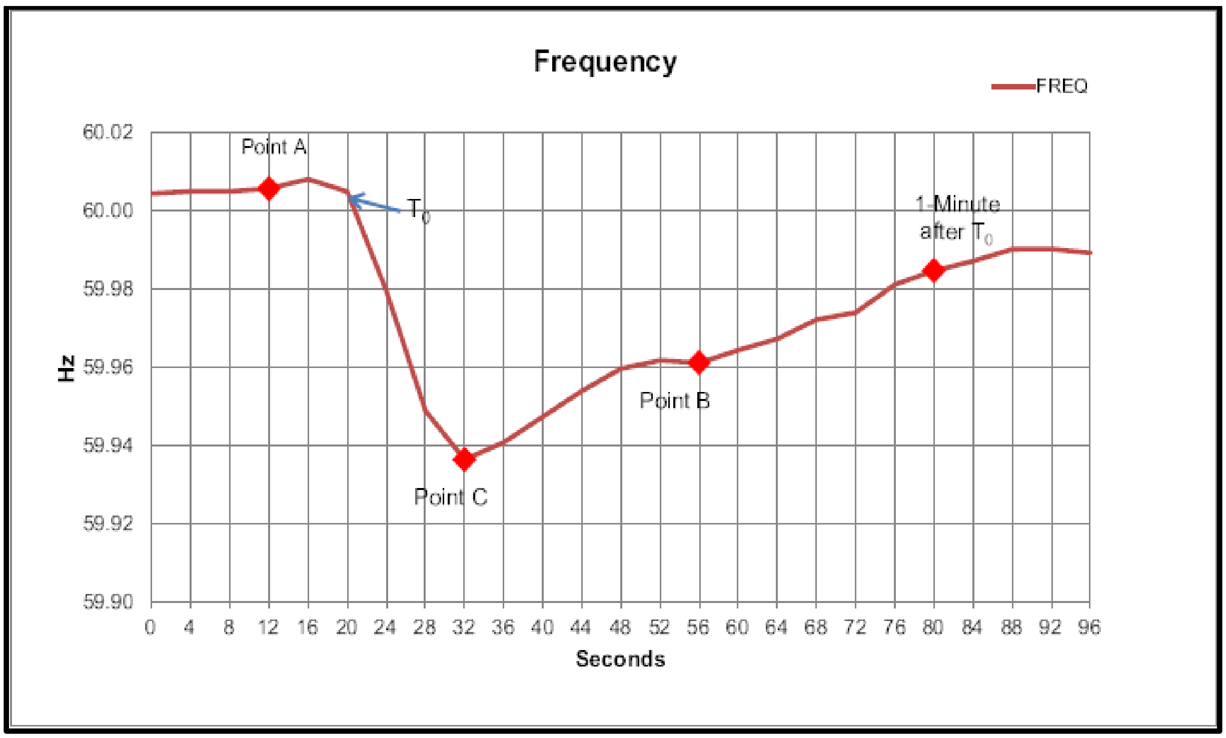
The ISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued in subsequent years, using the latest dynamic stability models. In this planning cycle, the potential impact of inverter-based resources (IBR), 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 the loss of a large generating facility, is illustrated in Figure 6-2. 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 6-2: 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 the share allocated to the ISO is -236.3 MW/0.1Hz.

More conventional synchronous 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 synchronous generation with governor controls, inverter-based renewable resources must specifically have a dedicated 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 large amounts 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[58]; 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 in positive-sequence dynamic simulations due to model inaccuracies and large timestep durations. Also, 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 frequency event in real-time. 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. Per that Order, all generators including wind, solar and BESS generators that execute an LGIA on or after May 15, 2018 are required to provide frequency response.

6.3.3 2024-2025 Transmission Plan Study

In the 2024-2025 transmission planning cycle, the frequency response was assessed and it was determined that the Frequency Response Obligation (FRO) required from ISO was

[58] Undrill, J. (2010). Power and Frequency Control as it Relates to Wind-Powered Generation. LBNL-4143E. Berkeley, CA: Lawrence Berkeley National Laboratory

being met. Particular focus was centered on IBR contribution to that response. The IBR units with frequency regulation turned on with available headroom all cause a higher increase in response than would otherwise be provided.

6.3.4 2025-2026 Transmission Plan Study

As in the 2024-2025 transmission planning process, this study was to re-assess the frequency response of the ISO system to a dual Palo Verde unit outage. Once again an emphasis was being placed on the frequency response provided by IBR resources.

Solar and wind plants are IBR but are typically operated so that all energy captured from the wind and the sun is converted to electrical energy and fed into the power system. These units typically do not operate at sub-optimal capability and thus have no headroom available for when a frequency response event occurs.

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 with most BESS plants operating in charging mode at full negative maximum plant capacity. IBR plants are those with ‘reec_c’ and ‘repc_a’ dynamic models. Turning off frequency control for these units consists of changing the up and down frequency gains to zero.

Typically for these studies, spring off-peak cases for year 5 and 10 are chosen. This year no year 5 spring-off-peak case was created so year 2 (2027) is being used instead.

The study scenarios are summarized in Table 6-13. The study results are illustrated in Figures 6.3-2 through 6.3-6.

Table 6-13: Study Scenarios for Frequency Response Study in the 2024-2025 TPP

	Study Scenarios				
	SC1	SC2	SC3	SC4	SC5
PFR enabled for existing IBRs?	No	Yes	Yes	Yes	Yes
Headroom	Existing	Existing	Min BESS units	Min ISO spinning reserve	Min ISO spinning reserve with 10% BESS
Existing IBRs and other gens droop	5%	5%	5%	5%	5%
Existing IBRs and other gens deadband (Hz)	±0.036	±0.036	±0.036	±0.036	±0.036

Scenario 1 is the reference against which to compare all others, where all BESS IBR plants have frequency regulation shut off in the dynamic plant controller model.

Scenario 2 has all IBR plant frequency regulation turned on. This scenario is identical to that of the normal 2027 and 2035 base cases and with unmodified dynamic models.

Figure 6.3-2 shows the resultant 2027 system frequency event result with both IBR frequency regulation turned on (SC2) and off (SC1). The trace with IBR turned on shows an improvement over that with it off. A similar plot for 2035 is shown in Figure 6.3-3. Again there is a marked improvement when frequency regulation is enabled.

For scenario 3, all new BESS plants were adjusted to as minimal a headroom as possible. The original target was for 10%, but this is only achievable for the 2027 base case. In both original Spring Peak cases, the BESS units are in charging mode close to or at their minimum power limit (negative pmax) which represents the IBR being in full charging mode. For this scenario, all BESS units were re-dispatched using the remaining available ISO generation to achieve the lowest attainable headroom. The net result is that there is a similar response profile for both scenarios 3 and scenario 1 (Figure 6.3-4). A minimal headroom shows a reduction in frequency response.

Scenarios 4 and 5 are with the ISO system at a minimum level of spinning reserve, one with modification of BESS output to a minimal headroom and the other with BESS output at 10% headroom. Scenarios 4 and 5 are difficult cases to establish partially since most BESS are in full charging mode. Also, given the significant proportion of BESS generation, the latter redispatch requires both additional generation and path flow changes that significantly alter the character of the original Spring-Off Peak cases. Only Scenario 5 was created in this TPP cycle and comparative results between 2029 and 2034 are presented in Figure 6.3-6. The results shows a higher nadir in 2034 which is, in part, due to the higher proportion of BESS in the latter year.

These results indicate that by enabling the frequency response of the new IBR units coming on-line, particularly in 2035, the system recovers from frequency events faster and settles at higher frequencies. There is a higher proportion of IBR plants in 2035 which significantly aids the system frequency response when enabled. Also the Palo Verde outage drops a lesser proportion of the overall system generation in 2035 than it does in the 2027 base case.

Figure 6-3: 2027 Scenarios 1 & 2: System Frequency Response for All IBR Frequency Control On and Off

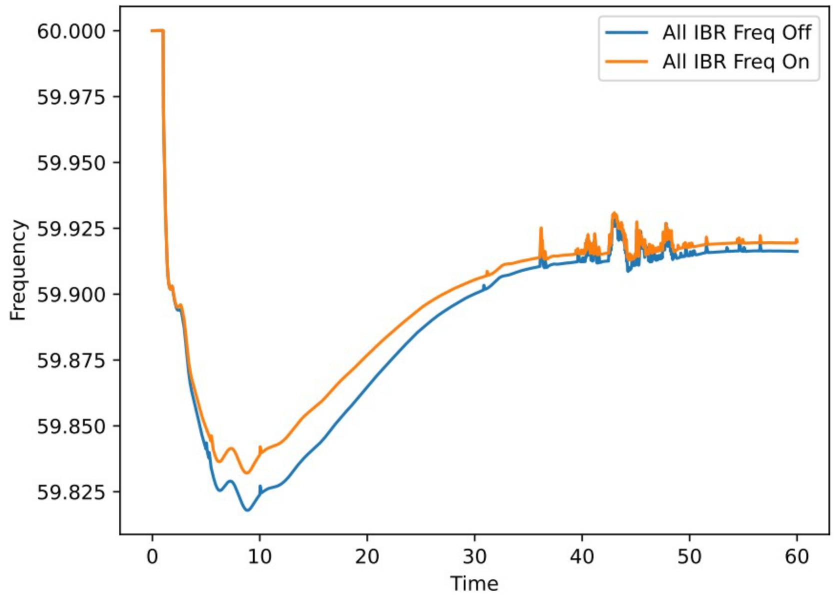
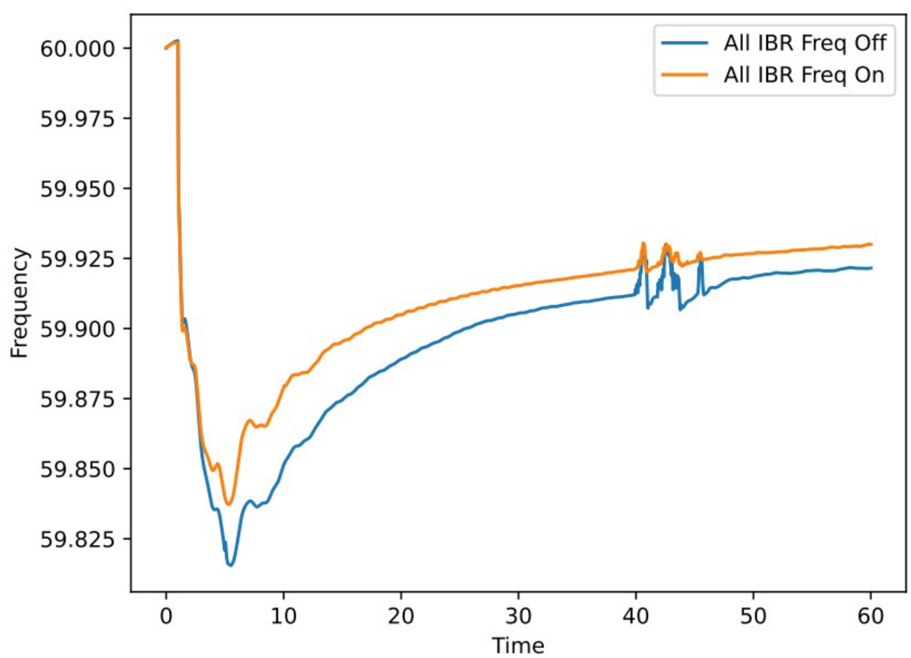


Figure 6-4:2035 Scenarios 1 & 2: System Frequency Response for all IBR Frequency Control On and Off



7 Supplementary Planning Information and Considerations

In addition to the key study plan inputs described above, the ISO must address a range of considerations in its planning process that shift in content and priority over the years to ensure overall safe, reliable, and efficient operation and develop effective solutions to emerging challenges.

This section discusses a number of the issues and other actions that the ISO took into account in preparing the 2025-2026 Transmission Plan.

7.1 Grid Enhancing Technologies (GETs)

GETs encompass a range of technologies with specific benefits and opportunities. Currently, the term is used to describe:

- Advanced conductors – high temperature, low sag characteristics;
- Dynamic line ratings;
- Power Flow Controllers; and
- Topology Optimizations.

The ISO supports appropriate application and deployment of these technologies, and has considered them on a case-by-case basis as potential alternatives in past annual transmission planning processes.

The ISO typically considers advanced conductors and power flow controllers as planning tools providing an alternative to other capital expenditures. We also consider dynamic thermal line ratings and topology optimizations in accessing operational benefits through additional capacity providing economic or emergency measure uses.

The ISO has considered and approved both advanced conductors and flow controllers in previous transmission planning processes. The ISO will continue to consider advanced conductors and seek their appropriate applications, and it is important to highlight some considerations in addition to costs:

- Reconductoring often requires taking circuits out of service to conduct the work. This presents additional challenges when transmission constraints already exist or suggests live-line work.
- While some conductors show lower line loss savings when run at the same level of loading as the existing ACSR, the losses climb exponentially as the loading continues to increase.

The ISO seeks opportunities to enhance flexibility and optimize the transmission system through Grid-enhancing Technologies and will continue to evaluate and consider them in the annual transmission planning process.[59]

7.1.1 Senate Bill 1006 Submittals from PG&E, SCE and SDG&E

Senate Bill (SB) 1006 required three investor-owned utilities to submit the reports to the ISO, and post publicly, by January 1, 2026, with components of the reports to be updated every two years and others every four years going forward.

The ISO received the following reports from PG&E, SCE and SDG&E as set out in Senate Bill (SB) 1006:

- PG&E - SB1006 Compliance Report[60];
- SCE - A Study of the Feasibility of Projects using Grid Enhancing Technologies and Reconductoring with Advanced Conductors[61]; and
- SDG&E - A Study of the Feasibility of Projects Using Grid Enhancing Technologies and Reconductoring with Advanced Conductors[62].

In assessing mitigation alternatives for the needs identified in the reliability, policy and economic assessments conducted in this year's transmission planning cycle, the ISO coordinated with the transmission owners on the feasibility of GETs as an alternative, particularly application of advance conductors and flow control devices with the projects recommended using GETs identified in the section below, along with those approved in previous planning cycles.

Dynamic Line Rating (DLR) refers to transmission line rating varying based on local conditions, such as ambient air temperature, wind speed, cloud cover, solar heating, and precipitation, etc., rather than a static rating assumption. DLR can provide additional capacity for a transmission line. FERC Order No. 1920[63] requires transmission providers to consider more fully the alternative transmission technologies of dynamic line ratings in long-term transmission planning.

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[59] FERC Orders No. 1920 and 1920-A require consideration of GETs. In addition, FERC Order No. 2023 requires transmission providers to consider opportunities to deploy GETs in the resource interconnection process.

[60] http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=858547

[61] https://www.sce.com/sites/default/files/Regulatory/SB1006-FinalStudiesFor2025-PublicVersion.pdf

[62] https://www.sdge.com/sites/default/files/documents/2025-12/SDGE_SB-1006_12292025_Clean.pdf

[63] https://www.ferc.gov/media/e1-rm21-17-000

In the ISO's production cost simulation, many congestions were observed happening in the evening time or in the months when temperature is not high. Such congestion can be potentially mitigated or reduced by adopting dynamic line ratings for the lines.

In this planning cycle, dynamic line ratings were not modeled in PCM cases, since it not only requires operational history data of weather conditions and line ratings, but also requires software and modeling enhancement to accommodate the data in PCM. The ISO will coordinate with the ISO's PTOs, WECC, and the software vendor of GridView, to explore the feasibility and possibility of implementing dynamic line rating in PCM model in future planning cycles.

7.1.2 Grid-Enhancing Technologies (GETs) Projects

- In the 2025-2026 transmission plan, the following projects are being proposed that are categorized as GETs solutions:
    - Mesa – Laguna Bell 230 kV #2 Upgrade;
    - Lugo 500 kV Reactive Power Reinforcement; and
    - Ames Distribution – Palo Alto 115 kV Line (Re-scope).

The below Table 7-1 provides a historical list of GETs projects approved in previous Transmission Plans.

Table 7-1: Flow Control, Advanced Conductor and Dynamic Reactive Support Approved Projects

Projects	**Transmission Plan approved**	**In-Service Date (planned or achieved)**
Flow Control		
Series Reactor on Warnerville-Wilson 230 kV	2012-2013	2018
Series compensation on Eldorado-Lugo-Mohave	2012-2013	2024
Imperial Valley phase shifters	2013-2014	2017
Wilson 115 kV SVC/Statcom	2015-2016	2021
San Jose-Trible 115 kV Series Reactors	2017-2018	2019
Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	2017-2018	2026
Series Compensation on Los Esteros-Nortech 115 kV Line	2021-2022	2025
San Jose HVDC project - Metcalf-San Jose B	2021-2022	2028
Lone Tree – Cayetano – Newark Corridor Series Compensation	2022-2023	2027
Humboldt Phase Shifting Transformer (Part of New Humboldt 500 kV Substation with 500 kV line to Collinsville)	2023-2024	2034

Projects	Transmission Plan approved	In-Service Date (planned or achieved)
Advanced Conductors		
Big Creek Rating Increase Project	2016-2017	2020
Moorpark-Pardee No. 4 230 kV Line[64]	2017-2018	2022
Laguna Bell – Mesa No. 1 Line Rating Increase Project[69]	2021-2022	2024
San Bernardino-Vista 230 kV 1 Line Upgrade[69]	2022-2023	2028
San Bernardino-Etiwanda 230 kV 1 Line Upgrade[69]	2022-2023	2031
Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines	2022-2023	2032
Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	2024-2025	2027
Julian Hinds-Mirage 230 kV Advanced Reconductor	2024-2025	2030
Dynamic Voltage Control		
Rio Oso SVC	2011-2012	2025
SVC at Suncrest	2013-2014	2017
Synchronous condensers in LA/San Diego area (loss of SONGS)		
Round Mountain 500 kV Dynamic Voltage Support (Fern Road Substation)	2018-2019	2026
Gates 500 kV Dynamic Voltage Support (Orchard Substation)	2018-2019	2025

7.2 Non-Transmission Alternatives and Storage

Since implementing the current comprehensive 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 market-based energy storage solutions as a means to meet local transmission system needs. As stated earlier, the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan but 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. As the volumes of renewable generation and storage required to meet system needs have escalated rapidly in recent years, the challenge has shifted from seeking to support resources that may not otherwise develop, to testing the effectiveness

[64] Selection of advanced conductor was done by the PTO in their conductor optimization to meet the ISO requirements.

of preferred resources to meeting the local needs and encouraging system capacity resources be procured in optimal locations.

The methodology used for assessing the effectiveness of local preferred resources is based on the initial methodology issued on September 4, 2013, as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources — energy efficiency, demand response, renewable generating resources, and energy storage — that was further advanced and refined through the development of the Moorpark Sub-area Local Capacity Alternative Study released on August 16, 2017. Storage also played a major role in consideration of preferred resource alternatives in LA Basin studies as well as the Oakland Clean-Energy Initiative approved in the 2017-2018 Transmission Plan and modified in the 2018-2019 Plan. These efforts help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs.

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 plan also identifies areas where future reinforcement may be necessary but immediate action is not required. The ISO has also expanded the scope of the biennial 10-year local capacity technical requirements study to provide additional information on the characteristics which define needs in the areas and sub-areas. 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.

Once preferred resources – and storage in particular – have been identified as the best solution taking into account overall cost effectiveness and technical requirements, coordination with the CPUC and other local regulatory authorities is needed to achieve procurement of the resources.

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 which have been procured for system needs targeted in specific areas to also meet local needs. It appears the Central Procurement Entities (CPEs) may play a larger role in acquiring these resources. Further, the CPEs can now contract with resources for five years or less that shall be deemed reasonable and preapproved if certain conditions are met, and can contract for longer than five years subject to filing a Tier 3 Advice Letter for approval, as set out in CPUC Decision (D.) 22-03-034.

Accordingly, the ISO is continuing to follow its current approach to meet local needs with storage where possible but is concerned with the progress made on resources being acquired to meet previously identified needs.

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 due to their ability to also participate in the electricity market.

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.

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

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.

7.3 System Modeling, Performance, and Assessments

The grid is 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 constant managing of thermal, stability, and voltage limits across a broader range of operating conditions.

This has in turn led to the need for greater accuracy in planning studies at the same time the challenges are compounded by the complexity of the settings in Inverter Based Resource models. The ISO's study work, built off the initial special study initiative undertaken in the 2016-2017 planning cycle, found and reaffirmed year after year the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. The ISO has made significant progress in establishing and implementing a more comprehensive framework for the collection of accurate generator model data through the process developed and set out in Section 10 of the ISO's transmission planning process – Business Practice Manual. This established a schedule for validating models, and the ISO will be continuing with its efforts, in coordination with Participating Transmission Owners, to collect this important information and ensure generation owners provide validated models.

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8 Transmission Projects

8.1 Previously Approved Transmission Plan Projects Update

Table 8-1 lists the projects that were closed out during the 2025-2026 TPP. Table 8-2 and Table 8-3 provide an update on expected in-service dates of previously approved transmission projects categorized as having a cost of below and above $50 million respectively. 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: Projects closed out during the 2025-2026 TPP Cycle

Project ID	Project Name	PTO	Final ISD
2122-R-04	Cooley Landing 60 kV Substation Circuit Breaker No #62 Upgrade	PG&E	Apr-25
2122-P-02	Laguna Bell - Mesa No. 1 230 kV Line Rating Increase Project	SCE	Apr-25
1920-R-07	Salinas-Firestone #1 and #2 60 kV Lines	PG&E	Dec-25
1819-R-03	Gates 500 kV Dynamic Voltage Support (Orchard Substation)	PG&E	Mar-25
1011-R-13	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Apr-25
07-R-04	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Apr-25
1920-R-02	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	Cancelled
2223-R-12	Metcalf 230/115 kV Transformers Circuit Breaker Addition	PG&E	Cancelled
1819-R-06	Moraga-Sobrante 115 kV Line Reconductor	PG&E	Cancelled
2425-P-02	New Helm 230/70 kV Bank #2	PG&E	Cancelled
2223-P-18	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE	Cancelled

Table 8-2: Status of Previously Approved Projects with Cost < $50 Million

Project ID[65]	Project Name	PTO	Current ISD[66]
2425-R-27	Tortilla 115 kV Capacitor Replacement	SCE	Jun-29
2425-R-24	Sobrante 230 kV Bus Upgrade	PG&E	May-33
2425-R-23	Sloan Canyon Tertiary Reactors	GLW	Dec-27
2425-R-21	Serrano 230 kV SCD GIS Bus Split	SCE	Oct-33
2425-R-20	San Miguel New 70 kV Line	PG&E	May-32
2425-R-17	Pittsburg-Kirker 115 kV Line Section Limiting Elements Upgrade	PG&E	May-28
2425-R-15	Moraga 230/115 kV Transformer Bank Addition	PG&E	May-31

[65] Additional detail for the projects including cost information and scope can be found in the Transmission Plan in which they were approved. Library | Transmission plans and studies | California ISO https://www.caiso.com/library/transmission-plans-and-studies

[66] Draft Transmission Plan in-service dates are based on the January 2026 Transmission Development Forum

Project ID[65]	Project Name	PTO	Current ISD[66]
2425-R-12	Kramer-Coolwater 115 kV Line Looping into Tortilla 115 kV Substation	SCE	On Hold
2425-R-09	Jefferson-Stanford 60 kV Recabling	PG&E	May-29
2425-R-03	Coronado Island Reliability Reinforcement Phase I	SDG&E	Sep-27
2425-R-01	Alamitos 230 kV SCD Upgrade	SCE	On Hold
2324-R-01	Atlantic High Voltage Mitigation	PG&E	Dec-28
2324-R-04	Covelo 60 kV Voltage Support	PG&E	May-30
2324-R-07	Eldorado 230 kV Short Circuit Duty Mitigation Project	SCE	Dec-29
2324-R-08	Etiwanda 230 kV Bus SCD Mitigation	SCE	Dec-27
2324-R-12	Martin-Millbrae 60 kV Area Reinforcement	PG&E	May-30
2324-R-13	Mira Loma 500 kV Bus SCD Mitigation	SCE	Sep-27
2324-P-06	Sobrante 230/115 kV Transformer Bank Addition	PG&E	May-34
2223-P-01	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	Jul-27
2223-R-01	Antelope-Whirlwind 500 kV Line Upgrade	SCE	Jan-26
2223-R-02	Banta 60 kV Bus Voltage Conversion	PG&E	Jan-28
2223-R-03	Barre 230 kV Switchrack Conversion to BAAH Project	SCE	Dec-27
2223-P-03	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Jan-30
2223-P-04	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	Apr-27
2223-R-04	Control 115 kV Shunt Reactor	SCE	Dec-26
2223-P-06	Devers-Valley 500 kV 1 Line Upgrade	SCE	Dec-28
2223-P-07	Henrietta 230/115 kV Bank 3 Replacement	PG&E	Jun-29
2223-R-08	Lone Tree – Cayetano – Newark Corridor Series Compensation	PG&E	Aug-28
2223-R-11	Mesa Spare Transformer Installation	PG&E	Dec-29
2223-R-14	Mira Loma 500 kV Circuit Breaker Upgrade	SCE	Aug-28
2223-R-08	Lone Tree – Cayetano – Newark Corridor Series Compensation	PG&E	On Hold
2223-R-05	New Coolwater A 230/115 kV Bank	SCE	On Hold
2223-R-17	Pittsburg 115 kV Bus Reactor project	PG&E	May-28
2223-P-13	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	Aug-31
2223-P-14	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	Sep-31
2223-P-16	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	Dec-31
2223-R-21	South Bay Area Limiting Elements Upgrade	PG&E	Jul-26
2223-R-22	Sylmar Transformer Replacement	SCE	Jan-28
2223-R-24	Tulucay-Napa #2 60 kV line Reconductoring Project	PG&E	Dec-26
2223-P-19	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	May-32
2223-P-21	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	Jun-27
2122-R-16	Weber-Mormon Jct 60 kV Line Section Reconductoring Project	PG&E	Jul-27
2122-R-15	Victor 230 kV Switchrack Reconfiguration	SCE	Jun-27
2122-R-14	Vasona-Metcalf 230 kV Line Limiting Elements Removal Project	PG&E	Apr-27
2122-R-12	Series Compensation on Los Esteros-Nortech 115 kV Line	PG&E	Apr-26
2122-R-09	Metcalf 230 kV Substation Circuit Breaker #No 292 Upgrade	PG&E	Apr-26
2122-R-08	Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project	PG&E	Sep-27
2122-R-06	Cortina 230/115/60 kV Transformer Bank No. 1 Replacement Project	PG&E	Dec-28
2122-R-05	Coppermine 70 kV Reinforcement Project	PG&E	Apr-30
2122-R-03	Contra Costa PP 230 kV Line Terminals Reconfiguration Project	PG&E	Feb-26

Project ID[65]	Project Name	PTO	Current ISD[66]
2122-P-06	Reconductor Rio Oso–SPI Jct–Lincoln 115kV line	PG&E	Feb-30
2122-P-05	Reconductor Delevan-Cortina 230kV line	PG&E	Feb-28
2122-E-01	Moss Landing – Las Aguilas 230 kV Series Reactor Project	PG&E	Aug-27
1920-R-09	Wilson-Oro Loma 115kV Line Reconductoring	PG&E	Jul-28
1920-R-06	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	Jun-29
1920-R-05	Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition	PG&E	Jul-27
1920-R-04	Moraga 230 kV Bus Upgrade	PG&E	May-29
1920-R-01	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	Mar-29
1819-R-11	Tyler 60 kV Shunt Capacitor	PG&E	Mar-28
1819-R-05	Jefferson 230 kV Bus Upgrade	PG&E	Jun-28
1819-R-04	Gold Hill 230/115 kV Transformer Addition Project	PG&E	Jan-30
1819-R-02	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	Aug-28
1819-R-01	Christie-Sobrante 115 kV Line Reconductor	PG&E	Dec-29
1819-E-01	East Marysville 115/60 kV Project	PG&E	Jan-30
1718-R-13	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	Nov-27
1718-R-11	Tie line Phasor Measurement Units	PG&E, SCE, VEA	Dec-27
1718-R-09	San Ysidro 69 kV Reconductoring (TL623C)	SDG&E	Mar-27
1718-R-07	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	Dec-26
1718-R-04	Lakeville 60 kV Area Reinforcement	PG&E	Dec-28
1718-R-03	Herndon-Bullard 115 kV Reconductoring Project	PG&E	Feb-28
1415-R-07	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Feb-27
1314-R-24	TL690A San Luis Rey-Oceanside Tap 69 kV Sections Re-Conductor	SDG&E	Jul-29
1314-R-24	TL690E Stuart Tap-Las Pulgas 69 kV Sections Re-Conductor	SDG&E	Jul-29
1314-R-18	Mosher Transmission Project	PG&E	Nov-28
1314-R-06	Estrella Substation Project	PG&E	Mar-29
1213-R-32	Sweetwater Reliability Enhancement	SDG&E	Mar-27
1213-R-21	Monte Vista 230 kV Bus Upgrade	PG&E	Jun-28
1213-R-19	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	Feb-29
1112-R-27	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	May-28
1112-R-21	Rio Oso Area 230 kV Voltage Support	PG&E	Oct-26
1112-R-15	North Tower 115 kV Looping Project	PG&E	Nov-29
1011-R-32	Wilson 115 kV Area Reinforcement	PG&E	May-30
1011-R-30	Vierra 115 kV Looping Project	PG&E	Jun-26
1011-R-16	Oro Loma 70 kV Area Reinforcement	PG&E	May-28
1011-R-12	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Kern PP 230 kV Area Reinforcement Project)	PG&E	Feb-29
1011-R-01	Cascade 115/60 kV No.2 Transformer Project and Cascade - Benton 60 kV Line Project	PG&E	Apr-26
09-R-02	Maple Creek Reactive Support	PG&E	Mar-28
09-R-01	Clear Lake 60 kV System Reinforcement	PG&E	Oct-30
08-R-01	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Jun-31
07-R-02	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	Jan-29
07-R-01	South of San Mateo Capacity Increase	PG&E	Dec-31

Table 8-3: Status of Previously Approved Projects with Cost > $50 Million

Project ID	Project Name	PTO	Current ISD
2425-R-28	West Fresno 115 kV Voltage Support	PG&E	May-31
2425-R-26	South Oakland Reinforcement Project	PG&E	May-32
2425-R-25	South Bay Reinforcement Project	PG&E	May-34
2425-R-22	Serrano 500 kV SCD Mitigation	SCE	Aug-33
2425-R-19	San Mateo 230/115 kV Transformer Bank Addition Project	PG&E	May-32
2425-R-18	San Jose B – NRS 230 kV line	PG&E	May-30
2425-R-16	North Oakland Reinforcement Project	PG&E	May-32
2425-R-14	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Re-scope	PG&E	Dec-30
2425-R-13	Metcalf Substation 500/230 kV Transformer Bank Addition	PG&E	May-34
2425-R-10	Julian Hinds-Mirage 230 kV Advanced Reconductor	SCE	On Hold
2425-R-08	Greater Bay Area 500 kV Transmission Reinforcement	PG&E	May-34
2425-R-07	Gold Hill-El Dorado Reinforcement	PG&E	May-32
2425-R-06	Downtown Reliability Reinforcement	SDG&E	Dec-37
2425-R-05	Cortina #3 60 kV Reconductoring	PG&E	Dec-31
2425-R-04	Coronado Island Reliability Reinforcement Phase II	SDG&E	Dec-28
2425-R-02	Ames Distribution – Palo Alto 115 kV transmission line	PG&E	May-34
2425-P-03	Reconductor of GWF – Kingsburg 115 kV line	PG&E	May-34
2425-P-01	Eagle Rock- Fulton- Silverado 115 kV Line Reconductor	PG&E	Aug-29
2324-R-02	Camden 70 kV Reinforcement	PG&E	Mar-30
2324-P-01	Collinsville 230kV Reactor Project	PG&E	May-28
2324-R-03	Cortina #1 60 kV Line Reconductoring	PG&E	May-28
2324-R-05	Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring	PG&E	Apr-30
2324-R-06	Diablo Canyon Area 230 kV High Voltage Mitigation	PG&E	Apr-30
2324-R-09	French Camp Reinforcement	PG&E	May-30
2324-R-10	Gates 230/70 kV Transformer Addition	PG&E	May-30
2324-P-02	New Humboldt 115/115 kV Phase Shifter with 115 kV line to Humboldt 115kV Substation	PG&E	May-34
2324-P-03	New Humboldt 500 kV Substation with 500 kV line to Collinsville [HVDC operated as AC]	PG&E	May-34
2324-P-04	New Humboldt to Fern Road 500 kV Line	PG&E	May-34
2324-P-05	North Dublin -Vineyard 230 kV Reconductoring	PG&E	May-34
2324-R-14	Reedley 70 kV Capacity Increase	PG&E	May-30
2324-R-15	Rio Oso - W. Sacramento Reconductoring	PG&E	Sep-29
2324-R-16	Salinas Area Reinforcement	PG&E	Dec-32
2324-R-17	Tejon Area Reinforcement	PG&E	Apr-29
2324-P-07	Tesla - Newark 230 kV Line No. 2 Reconductoring	PG&E	Dec-34
2324-R-18	Vaca-Plainfield 60 kV Line Reconductoring	PG&E	May-30
2324-R-19	Valley Center System Improvement	SDG&E	Jan-31
2223-P-02	Beatty 230 kV Project	VEA/GLW	May-28

Project ID	Project Name	PTO	Current ISD
2223-P-03	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Jan-30
2223-P-04	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	Apr-27
2223-P-05	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	Dec-30
2223-R-07	Garberville Area Reinforcement	PG&E	Dec-28
2223-P-08	IV-North of Songs 500 kV line and North of Songs Substation	SDG&E	Jan-32
2223-R-09	Los Banos 230 kV Circuit Breaker Replacement	PG&E	Dec-28
2223-R-10	Los Banos 70 kV Area Reinforcement Project	PG&E	Jan-31
2223-P-09	Lugo–Victor–Kramer 230 kV Upgrade	SCE	Jun-29
2223-R-13	Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest	SDG&E	Dec-32
2223-R-15	North East Kern 115 kV Line Reconductoring	PG&E	Mar-32
2223-P-11	North Gila–Imperial Valley 500 kV line	SDG&E	Dec-31
2223-P-12	North of Songs-Sorreno 500 kV Line	SDG&E / SCE	Jan-32
2223-R-16	Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	Apr-28
2223-R-18	Redwood City Area 115 kV System Reinforcement	PG&E	Feb-30
2223-P-15	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	Dec-31
2223-R-19	Santa Rosa 115 kV lines reconductoring project	PG&E	May-32
2223-R-20	Serrano 4AA 500/230 kV Transformer Bank Addition	SCE	May-33
2223-P-17	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	Aug-31
2223-R-23	Tesla 115 kV Bus Reconfiguration Project	PG&E	Jun-28
2223-P-20	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	Sep-31
2122-R-13	Table Mountain Second 500/230 kV Transformer	PG&E	May-29
2122-R-11	San Jose Area HVDC 230 kV Line (Newark - NRS)	PG&E	Apr-28
2122-R-10	San Jose Area HVDC 500 kV Line (Metcalf – San Jose)	PG&E	May-28
2122-R-01	Antelope 66 kV Short Circuit Duty Mitigation Project	SCE	Dec-26
2122-P-04	Manning 500/230 kV Substation Project	PG&E	Apr-28
2122-P-03	Collinsville 500/230 kV Substation Project	PG&E	May-28
2122-P-01	GLW/VEA Area Upgrades	GLW/VEA	Jun-28
1819-R-09	South of Mesa Upgrade	PG&E	Jun-29
1819-R-08	Round Mountain 500 kV Dynamic Voltage Support (Fern Road Substation)	PG&E	May-26
1415-R-03	Martin 230 kV Bus Extension	PG&E	Oct-28
1314-R-27	Wheeler Ridge Junction Substation	PG&E	May-34
1314-R-13	Midway-Kern PP #2 230 kV Line	PG&E	Dec-28
1314-P-01	Lugo-Mohave series capacitor upgrade	SCE	Jun-26
1213-R-14	Lockeford-Lodi Area 230 kV Development	PG&E	Jun-31
1213-P-02	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	Jun-26
1112-R-10	Kern PP 115 kV Area Reinforcement	PG&E	Aug-29
09-R-03	Alberhill 500 kV Method of Service	SCE	Dec-29

8.2 Competitive Solicitation for 2025-2026 Recommended Projects

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 categories, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner if that solution 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.

The ISO has identified the following regional transmission solution recommended for approval in this 2025-2026 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

- Trout Canyon-Lugo 500 kV Line.

The descriptions and functional specifications for the facilities eligible for competitive solicitation can be found in Appendix I.

8.3 Capital Program Impacts on Transmission High-Voltage Access Charge

8.3.1 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 some of the stakeholder comments. 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, it 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 so the relative impacts of different decisions can be reasonably estimated.

The tool is based on the fundamental cost-of-service models employed by participating transmission owners, with a level of detail necessary to adequately estimate the impacts of changes in capital spending, operating costs, and other financial factors or considerations. 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.

8.3.2 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. The 2026 model uses the average annual 2.3% energy growth rate based on the CEC 2024 IEPR 2025-2041 California Energy Demand baseline forecast, which is also used in the 2025-2026 TPP.

The projection also includes capital projects in this year's plan and all other transmission plan projects not already energized. 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 8-1, the trend of the 2026 TAC value for the 2026 projection is higher than the 2025 projection for all years. This is in part due to the increase of $1.19 from last year's projection for January 1, 2026, to this year's actuals, reflecting an increase in TRR and TRBAA above the historical projections. The higher Gross Load Growth rate reduces the impact of the TAC Rates, with the projected rate reaching $26.18 for 2035.

Figure 8-1: Forecast of ISO High Voltage Transmission Access Charge Trending from First Year of Transmission Plan