California ISO

2023-2024 Transmission Plan

BOARD APPROVED
May 23, 2024

Foreword to Board Approved 2023-2024 Transmission Plan

At the May 23, 2024 ISO Board of Governors meeting, the ISO Board of Governors approved the 2023-2024 Transmission Plan. As discussed at the ISO Board of Governors meeting, the in-service date for the Tejon Area Reinforcement project has been confirmed to be 2029 and updated within the plan.

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Appendices

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Executive Summary

The California Independent System Operator (ISO) has prepared this 2023-2024 Transmission Plan as part of its core responsibility to identify and plan the development of solutions to comprehensively meet the future needs of the ISO-controlled transmission grid. The Plan was prepared through the annual transmission planning process (TPP) that culminates in an ISO Board of Governors (Board) approved, comprehensive transmission plan.

The need for additional generation of electricity over the next 10 years has escalated rapidly in California as it continues transitioning to the carbon-free electrical grid required by the state's clean-energy policies. This in turn has been driving a dramatically accelerated pace for new transmission development in current and future planning cycles. To help ensure we have the transmission in place to achieve this transition reliably and cost-effectively, the ISO's 2023-2024 Transmission Plan builds on the much more strategic and proactive approach adopted in last year's 2022-2023 Transmission Plan to better synchronize power and transmission planning, interconnection queuing and resource procurement. Like last year, the Plan is put forward in close coordination with the state's primary energy planning and regulatory entities, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC).

The more proactive and coordinated strategic direction reflected in this year's transmission plan is set forth in a joint Memorandum of Understanding (MOU)[1] signed by the three parties in December 2022. The MOU tightens the linkages between resource and transmission planning, interconnections, and procurement so California is better equipped to meet its reliability needs and clean-energy policy objectives required by Senate Bill 100.[2]

As set out in the MOU, expectations are that the CPUC[3] will continue to provide resource planning information to the ISO as it did for this transmission planning cycle. The ISO will develop a final transmission plan, initiate the transmission projects and communicate to the electricity industry specific geographic zones that are being targeted for transmission projects along with the capacity made available in those zones. The CPUC will in turn provide clear direction to load-serving entities to focus their energy procurement in those key transmission zones, in alignment with the transmission plan.

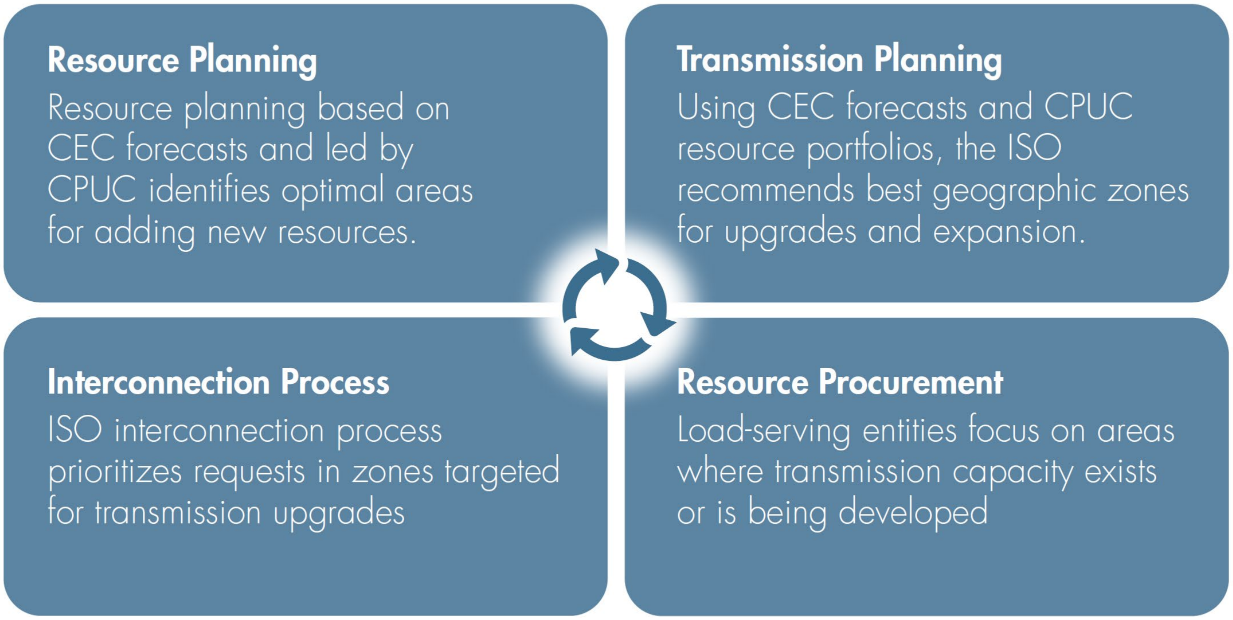
To bring this more coordinated approach full circle, the ISO will also give greater priority to interconnection requests located within those same zones in its generation interconnection process.

[1] http://www.caiso.com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf

[2] 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

[3] In addition to the needs of the jurisdictional load serving entities in the ISO's footprint, the CPUC currently works to include the needs of the publicly-owned utilities and other non-CPUC-jurisdictional utilities in its resource planning efforts for the ISO balancing authority area, and this is an issue that will be receiving additional attention in future planning cycles to ensure the needs of these parties are being addressed.

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



This year's transmission plan is based on state projections[4] provided to the ISO in 2023 that California needs to add more than 85 GW of capacity[5] by 2035 reflecting greenhouse gas reduction goals and load growth including the potential for increased electrification[6] occurring in other sectors of the economy, most notably in transportation and the building industry. This capacity requirement is a significant increase from the base portfolio amounts that were the basis of the 2022-2023 transmission plan. It aligns with the sensitivity case considered in last year's transmission plan, and establishes a solid trajectory to achieving the state's 2045 goals.

This plan, and the projects described on the following page, enable critical resource development, including:

[4] 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.

[5] The CPUC-provided portfolio calls for 85 GW of installed capacity, beyond its baseline of existing resources and resources already contracted for and under development.

[6] The CEC adopted the 2021 IEPR Energy Demand Forecast, 2021-2035 on January 26, 2022 [https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1] The CEC subsequently adopted 2021 IEPR Additional Transportation Electrification Scenario that on July 1, 2022, the CEC and CPUC requested the ISO utilize in the 2022-2023 Transmission Plan. [http://www.caiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf]

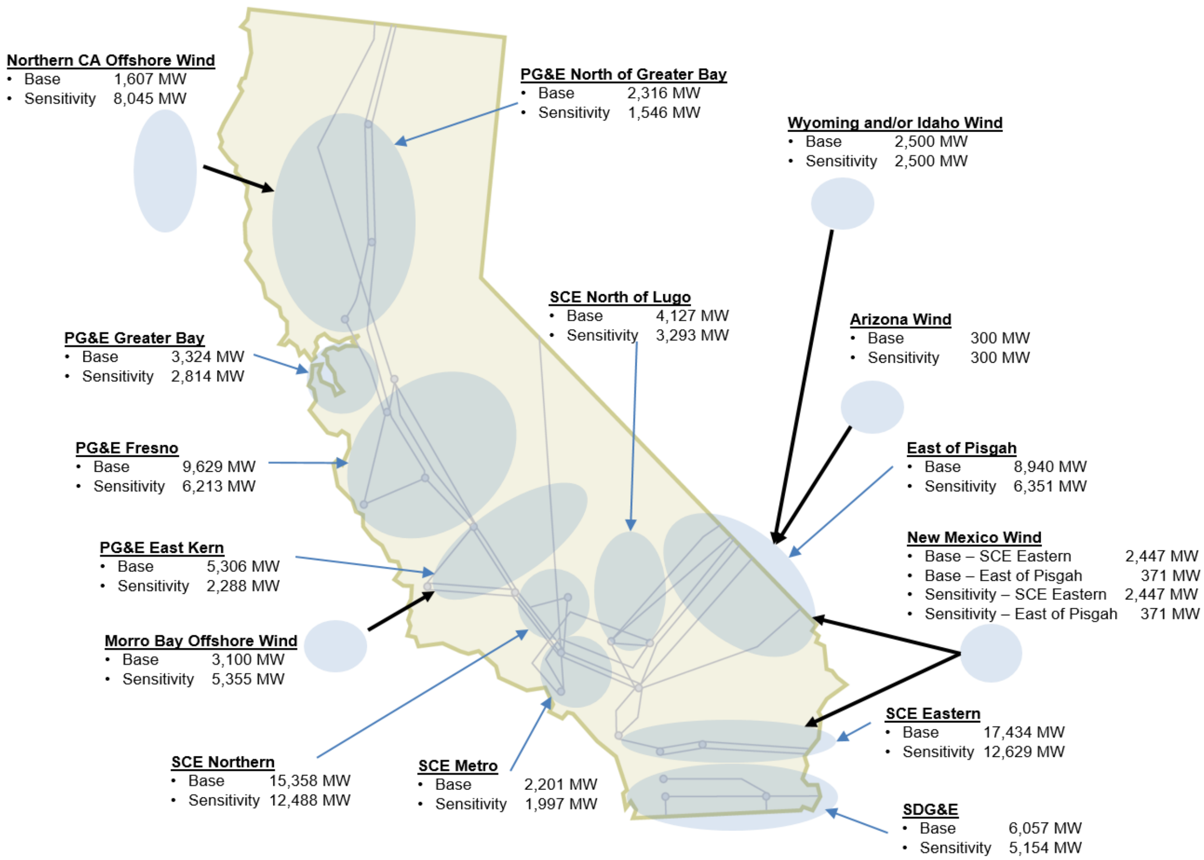
- Over 38 GW of solar generation distributed across the state in solar development regions that include the Westlands area in the Central Valley, Tehachapi, the Kramer area in San Bernardino County, Riverside County, and also in southern Nevada and western Arizona;
- Over 3 GW of in-state wind generation 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 across the state with renewable generation projects, 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 5.6 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 4.7 GW of offshore wind with 3.1 GW in the Central Coast (Morro Bay call area) and 1.6 GW in the North Coast area (Humboldt call area).

To achieve these outcomes, the ISO has found the need for 26 transmission projects, for a total infrastructure investment of an estimated $6.1 billion. 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. The recommended reliability-driven and policy-driven projects, most notably to integrate offshore wind in the North Coast, include:

- A new Humboldt 500 kV substation complete with a 500/115 kV transformer;
- A new HVDC line (approximately 260 miles), initially operated as 500 kV AC line to interconnect the new Humboldt 500 kV substation to the Collinsville 500 kV substation;
- A new 500 kV AC line (approximately 140 miles) to interconnect new Humboldt 500 kV substation to the Fern Road 500 kV substation;
- A 115 kV line from the new Humboldt 500 kV to existing Humboldt 115 kV substation, and a 115 kV/115 kV phase shifting transformer (PST) at Humboldt 115 kV substation; and
- A host of smaller upgrades improving supply of load and access to other smaller resource zones.

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 of the sensitivity portfolio to assess the transmission needs with additional offshore wind in the North Coast area.

Figure ES-2: Transmission Planning Zones and Capacity



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 its dynamic economy and in this year's Plan, significant amounts of new offshore wind generating capacity and the associated 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.

Transmission Projects Recommended for Approval

The 26 new reliability-driven and policy-driven transmission projects found to be needed in the 2023-2024 transmission planning process totaling $6.1 billion 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 19 of the new projects, totaling $1.54 billion. The projects are required to reliably meet the increase in forecasted load related to electrification and electric vehicle transportation loads. The 19 projects are set out in Table ES-1.

Table ES-1: Reliability-Driven Transmission Projects Recommended for Approval

No.	Project Name	PTO Area	Planning Area	Est. Cost ($M)
1	Covelo 60 kV Voltage Support[7]	PG&E	North Coast / North Bay	22
2	Martin-Millbrae 60 kV Area Reinforcement[7]	PG&E	Greater Bay Area	40
3	Atlantic High Voltage Mitigation[7]	PG&E	Central Valley	40
4	Mira Loma 500 kV Bus SCD Mitigation[7]	SCE	SCE Bulk	5
5	Inyo 230 kV Shunt Reactor[7]	SCE	North of Lugo	20
6	Etiwanda 230 kV Bus SCD Mitigation[7]	SCE	SCE Eastern	15
7	Eldorado 230 kV Short Circuit Duty Mitigation[7]	SCE	East of Lugo	48.8
8	Valley Center System Improvement	SDG&E	SDG&E	51
9	Camden 70 kV Reinforcement	PG&E	Greater Fresno	100
10	Gates 230/70 kV Transformer Addition	PG&E	Greater Fresno	72
11	Reedley 70 kV Capacity Increase	PG&E	Greater Fresno	98
12	Diablo Canyon Area 230 kV High Voltage Mitigation	PG&E	Central Coast & Los Padres	70
13	Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring	PG&E	Central Coast & Los Padres	108
14	Vaca-Plainfield 60 kV Line Reconductoring	PG&E	Central Valley	68
15	Rio Oso - W. Sacramento Reconductoring	PG&E	Central Valley	97.4
16	Cortina #1 60 kV Line Reconductoring	PG&E	Central Valley	94.3
17	Salinas Area Reinforcement	PG&E	Central Coast & Los Padres	452.3
18	Tejon Area Reinforcement	PG&E	Kern	56
19	French Camp Reinforcement	PG&E	Central Valley	84.2
			Total	**1,542**

- As a result of increasing load forecast levels in Oakland, a number of overload issues were observed on most of the 115 kV lines serving this pocket, for which the Oakland Clean Energy Initiative (OCEI) approved in 2018 is not sufficient, as shown in the reliability assessment results. This work will be conducted as an extension of the 2023-2024 Transmission Plan, with ISO Board of Governor approval anticipated to be sought in Q2 or Q3 of this year.

[7] 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.

Policy-Driven Projects: The ISO found the need for 7 transmission projects that are policy-driven. These total $4.59 billion and are listed in Table ES-2. They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolio's.

Table ES-2: Policy-Driven Transmission Projects Recommended for Approval

No.	Project Name	PTO Area	Geographic Area	Cost ($M)
1	Sobrante 230/115 kV Transformer Bank Addition	PG&E	GBA	40
2	New Humboldt 500 kV Substation with 500 kV line to Collinsville [HVDC operated as AC]	PG&E	NGBA	2740
3	New Humboldt to Fern Road 500 kV Line	PG&E	NGBA	1400
4	New Humboldt 115/115 kV Phase Shifter with 115 kV line to Humboldt 115kV Substation	PG&E	NGBA	57
5	North Dublin -Vineyard 230 kV Reconductoring	PG&E	NGBA	233
6	Tesla - Newark 230 kV Line No. 2 Reconductoring	PG&E	NGBA	58
7	Collinsville 230 kV Reactor	PG&E	NGBA	58
			Total	**4,586**

- The ISO has included in the above transmission projects (No. 2, 3 and 4 in Table ES-2) its transmission system requirements necessary to interconnect the offshore wind resources in the Humboldt call area as well as the downstream transmission upgrades (No. 5, 6 and 7 in Table ES-2) necessary to facilitate deliverability to the loads.

Economic-Driven Projects: The ISO conducted several economic studies investigating opportunities to reduce total costs to ratepayers through transmission upgrades not otherwise needed for reliably accessing renewables and serving load. No projects driven solely by economic considerations are being recommended in this plan.

Competitive Transmission Procurement: The ISO federal tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the Plan. The following projects – included in Table ES-2 above – are eligible for competitive solicitation, and the ISO will provide a schedule for those processes in May, 2024:

- New Humboldt 500 kV Substation with 500 kV line to Collinsville (HVDC operated as AC); and
- New Humboldt to Fern Road 500 kV Line

Other Findings and Observations

In addition to the key findings listed above, other salient observations include:

- ***Senate Bill 887:*** The Accelerating Renewable Energy Delivery Act, (Becker, 2022) provides state policy direction on a number of resource and transmission planning issues, including direction about requests the CPUC is to make of the ISO in conducting its FERC tariff-based planning processes. The ISO has considered the state policy direction provided by SB 887 in the development of this transmission plan.
  - In calculating the economic benefits of reducing the need for gas-fired generation requirements in local capacity areas, the ISO calculated the economic benefit of reduced gas-fired generation output, and also considered the economic capacity benefit of less generation being needed for local capacity even if it is still required for system capacity. While SB 887 calls for the CPUC to provide to the ISO by March 31, 2024, resource projections expected to reduce the need to rely on non-preferred resources in local capacity areas by 2035, these projections are not yet reflected in the portfolios provided by the CPUC for the 2023-2024 Plan and will be assessed in the ISO's 2024-2025 planning process. The gas-fired generation is being relied upon across the planning horizon for system capacity.
  - The ISO has also reviewed the Pacific Transmission Expansion Project - a multi-terminal HVDC project from Diablo Canyon 500 kV substation to various 230 kV substations in the LA Basin area - that was submitted into the Economic Request window in the 2023-2024 transmission planning process. The ISO has continued discussions with the Los Angeles Department of Water and Power (LADWP) about its potential interest in the project and the possibilities of a joint effort; however, the ISO is not aware of any decisions by LADWP to move forward at this time. The project can provide improved access to future offshore wind development, relieve congestion on Path 26, and reduce gas-fired generation local capacity requirements. However, an ISO recommendation to approve this project will ultimately depend heavily upon the pace and volume of gas-fired generation retirements planned in the LA Basin. The ISO will continue to explore gas-fired generation retirement plans with the CPUC and work with LADWP on potential collaborations in the next planning cycle.
- **FERC *Order No. 1000 Interregional Coordination Process:*** The ISO is required to coordinate its examination of potential interregional projects submitted by stakeholders into the ISO's process and the processes of the ISO's neighboring planning entities in the western interconnection - WestConnect and NorthernGrid. The ISO considered all interregional transmission project (ITP) proposals in its 2022-2023 transmission planning process and did not identify an ISO need for the proposed ITPs. Consistent with the Order No. 1000 Common Interregional Tariff, the ISO was not required to consider the proposed ITPs beyond the ISO's 2022-2023 transmission planning process. Commensurate with this outcome, no further consideration of the submitted ITPs was required in the 2023-2024 transmission planning process. (Please refer to Chapter 5.)

- ***Grid-Enhancing Technologies (GETs):*** GETs encompasses a range of technologies with specific benefits and opportunities that have to be considered on a case-by-case basis and the ISO supports appropriate application and deployment of these technologies. The ISO has also considered several of them – advanced conductors and flow control devices - as potential alternatives in the annual transmission planning process for many years, with particular success in selecting flow controllers in a number of cases in past plans and approving for the first time a policy-driven project employing advanced conductors in the 2022-2023 Transmission Plan. In this plan, a phase-shifting transformer that provides flow control is recommended for approval to increase the resiliency in the Humboldt area. The ISO will continue to explore opportunities for GETS in future planning processes. (Please refer to Section 8.3.)

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.

Conclusions and Recommendations

The 2023-2024 Transmission Plan provides 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 26 transmission projects, estimated to cost a total of $6.1 billion, as needed to maintain the reliability of the ISO transmission system and unlock access to renewable generation resources to meet state energy needs.

Once approved by the ISO Board of Governors at its May, 2023 meeting, the Plan serves to:

- Authorize cost recovery for the 26[8] identified transmission solutions through ISO transmission rates, subject to regulatory approval; and
- Initiate the ISO's competitive solicitation process for the two eligible projects identified above.

As a result of increasing load forecast levels in Oakland, a number of overload issues were observed on most of the 115 kV lines serving this pocket, for which the Oakland Clean Energy Initiative (OCEI) approved in 2018 is not sufficient, as shown in the reliability assessment results. This work will be conducted as an extension of the 2023-2024 Transmission Plan, with ISO Board of Governor approval anticipated to be sought in Q2 or Q3 of this year.

Also, the ISO will continue to monitor progress on the conditions referred to in the conditional approval of the SWIP North project. The ISO will also continue to explore gas-fired generation

[8] As noted earlier, 7 reliability projects have already been approved by Management pursuant to the ISO tariff, and do not require additional approval by the Board of Governors.

retirement plans with the CPUC and work with LADWP on potential collaboration opportunities regarding the Pacific Transmission Expansion Project in future planning cycles.

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Chapter 1

1 Overview of the Transmission Planning Process

1.1 Introduction

The 2023-2024 Transmission Plan continues to build off of the two significant course changes in the 2022-2023 Transmission Plan. The first of these was the proactive zonal transmission planning foundation for transformational changes 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 needs. The projected incremental resource requirements in this year's Plan, for example, climbed fourfold compared to the 2020-2021 Plan prepared only two years ago, and the pace is accelerating in future planning cycles as well.

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 is continuing to employ a much more proactive approach to transmission planning. This proactive, targeted zonal approach is grounded in the policy and reliability needs of the state. Our strategic intent in drafting the Plan in this manner is that it will take into account priority zones identified in resource portfolios to develop the transmission infrastructure required and recommended for approval.

These foundational changes to our planning process build on enhancements and improvements to the ISO's regional transmission planning that have already been moving forward, including introduction in February 2022 of a 20-Year Transmission Outlook framework that is being updated in 2024 outside the tariff-based project approval planning process. This 20-Year Outlook framework was also coordinated with, and supported by the CEC and CPUC, particularly in the development of customized 2040 resource portfolios under the auspices of the CEC's SB 100 activities and responsibilities.

The ISO relies in particular on the CPUC for its lead role in developing resource forecasts for the 10-year planning horizon, with both the ISO and CEC providing input to the CPUC for those resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements. The MOU mentioned in the Executive Summary of this Plan 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 so the three entities are synchronized in working for 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. The ISO understands that the industry is now well into an inflection point marking a significant escalation in the rate of growth in renewable resources and renewable integration resources. To contextualize this increase, it is helpful to compare the resource plans in the past three transmission plans with what is expected next year. The 2020-2021 transmission plan was based on state agency forecasts calling for approximately 1000 megawatts (MW) of additional generating capacity per year over the next 10 years. Just one year later, that 10-year forecast that informed the next Plan was based on a projection calling for adding 2700 MW of generating capacity per year. For this year's plan, the 10-year projection calls for adding approximately 7000 MW per year on average. The 2022-2023 transmission plan was a transitional step, recognizing the ISO and industry at-large was not yet positioned within this single planning cycle to address the full impact of the pivot to these new challenges. In addition to considering significantly larger resource portfolios, the ISO also considered more extensive system upgrades in several areas that were supported by relevant considerations and information beyond the resource portfolios provided by the CPUC. This approach recognized that the requirements expected in the 2023-2024 transmission planning process would call for an even faster pace of resource development. It also allowed several low-risk projects to proceed, providing for a more balanced development workload given that additional projects will also be initiated in this year's planning process. The increased capacity provided by those upgrades, on top of what is called for in the current year's portfolios, has created additional options for load-serving entities conducting procurement to meet mid-term resource requirements.

The accelerating pace of resource development called for over the next 10 years is driven by numerous factors, including:

- The escalating need to decarbonize the electricity grid because of emerging climate change impacts;
- The expected electrification of transportation and other carbon-emitting industries, which is driving higher electricity forecasts;
- Concerns regarding reduced access to opportunity imports as neighboring systems also decarbonize;
- Greater than anticipated impacts of peak loads shifting to later-day hours when solar resources are not available; and
- The need to maintain system reliability while planning for the retirement of gas-fired generation relying on coastal waters for once-through cooling and the Diablo Canyon Power Plant.

These resource requirements, on the path to total decarbonization of the grid and discussed in more detail in Section 1.4, will call for greater volumes of solar photovoltaic resources and battery storage, as well as greater diversity beyond the current focus on those resource types. Geothermal resources, new out-of-state renewable resources and offshore resources all are expected to play greater roles. This will create unique challenges in the planning and interconnection processes. Meeting those challenges requires adaptations and enhancements to existing processes and efforts.

Simultaneous with this shift in planning longer-term resource requirements, the CPUC has made significant strides in authorizing new resource procurement. The CPUC adopted Decision (D.) 19-11-016 on November 7, 2019, which ordered procurement of 3,300 MW of incremental resources, with 50% required to be online by August 2021. As part of a separate proceeding (R.20-05-003), the CPUC adopted D.21-06-035 on June 24, 2021 to address mid-term reliability needs of the electricity system within the ISO's balancing authority area. This decision requires at least 11,500 MW of additional procurement, with 2,000 MW required by August 2023; 6,000 MW by June 2024; 1,500 MW by June 2025; and 2,000 MW of long lead-time resources by June 2026. In that same proceeding, on February 23, 2023, the CPUC adopted Decision (D.) 23-02-040, which ordered supplemental mid-term reliability procurement of an additional 2000 MW in each of 2026 and 2027.

Reacting to previously approved authorizations and numerous signals about the accelerated pace of adding resources, the resource development industry responded with a then record-setting number of new interconnections requests in April, 2021. The ISO received 373 new interconnection requests in its Cluster 14 open window, layered on top of an already heavily populated interconnection queue. Further, after the record-setting number of applications and resulting Cluster Phase I studies, the highest ever percentage of projects proceeded into Phase II; resulting in 205 projects studied in the Cluster 14 Phase II process.

Resource Interconnections:

In parallel with the transmission planning changes being made and reflected in the Plan, the ISO is moving forward with impactful changes in the generation interconnection process. It released an issues paper on March 6, 2023 launching the ISO's 2023 Interconnection Process Enhancements initiative, focusing on making significant and transformative improvements regarding coordination of resource planning, transmission planning, interconnection queuing and power procurement to achieve state reliability and policy needs. The ISO has engaged stakeholders in calls and workgroup meetings in the development of the interconnection process enhancement final proposal that the ISO will being bring to the ISO Board of Governors at its May 2024 meeting. In addition, on September 6, 2023, FERC Issued Order No. 2023 related to generation interconnection with the compliance filing due on April 3, 2024.

In recent years, given California's ambitious decarbonization goals and the large quantities of new clean resources it will take to meet them, the ISO has been receiving hundreds of interconnection requests annually from potential resource developers. Many of these requests are not located in areas considered optimal for additional transmission development, as determined by regulators and load-serving entities. With the ISO's interconnection application queue inundated with applications, current processes need to be re-imagined to ensure resource procurement and queuing are effectively shaped and informed to take advantage of transmission and interconnection capacity that exists or is already planned and under development, and to align with the transmission upgrades necessary for longer-term resource development.

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 quarterly 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 the progress of procurement activities by load-serving entities and assessing the timeliness of those procured resources meeting near and mid-term reliability requirements.

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

1.2 Key Inputs

This Section 1.2 provides background and detail on key load and resource forecast inputs into the 2023-2024 transmission planning process.

1.2.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

1.2.1.1 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.

Further developments related to load electrification due to fuel switching and electric vehicle deployment and goals have led to a significant increase in energy and demand forecasts starting in the year 2028 and beyond, as seen in the2022 IEPR Energy Demand Forecast, 2022-2035 adopted by the CEC on January 25, 2023.[9]

1.2.2 Resource Planning and Portfolio Development

As discussed earlier with regard to 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 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 meeting 2045 renewables portfolio standard goals that were also established in SB 100.

The CPUC, via Decision 23-02-040[10] issued on February 28, 2023, provided the ISO a base portfolio along with a sensitivity[11] portfolio for use in the 2023-2024 TPP. The base portfolio is designed to meet the 30 million metric tons (MMT) greenhouse gas (GHG) emissions target by 2030. The primary focus of the sensitivity study was to study the transmission needs with increased offshore wind in the North Coast area.

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

In developing the base portfolio for the 2023-2024 transmission planning cycle, the CPUC's modeling showed that while no new natural gas-fired power plants are identified in the 2035 new resource mix, existing gas-fired plants – other than those relying on once-through-cooling and scheduled for retirement - are needed in 2035 as operable and operating resources providing a renewable integration service.

The portfolios for the 2024-2025 transmission planning portfolios do consider approximately 2,000 MW of gas-fired generation retirement in the base portfolio and a sensitivity portfolio with approximately 10,000 MW of gas-fired generation retirement by 2039, not including the OTC generation retirements.

1.2.2.2 Offshore Wind Generation

Starting with the 2021-2022 transmission planning process and the 20-Year Transmission Outlook, the ISO began assessing the transmission capabilities for integrating offshore wind in the Central Coast and North Coast areas.

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[9] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2

[10] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF

[11] Sensitivity is to better understand the transmission needs of a portfolio with a large amount of offshore wind by 2035, including 5.3 GW at Morro Bay, 3 GW in Humboldt, and another 5 GW on the north coast.

The analysis indicated there is transmission capability in the Central Coast of approximately 5,300 MW around the Diablo Canyon Power plant that was to be retiring by the end of 2025, and the Morro Bay area where gas-fired generation has retired. It should be noted that the owners of the Diablo Canyon Power Plant retain certain deliverability retention options for repowering that can remain in effect for up to three years following the retirement of the nuclear plant. With Diablo online or deliverability retained, capacity available in the area for the interconnection of offshore wind would be about 3,000 MW. In the North Coast area, the integration of offshore wind will require transmission development for the capacities identified in the CPUC sensitivity portfolios.

In this year's planning cycle, the ISO has continued this assessment with 3,100 MW of offshore wind in the base portfolio in the Morro Bay call area and 1,607 MW in the Humboldt call area. The sensitivity portfolio increased to 5,355 MW in the Central Coast area and 2,600 MW in the Humboldt call area. The ISO has continued to assess transmission alternatives, particularly in the North Coast area in this planning cycle with recommended transmission development for approval in this planning cycle under the base portfolio.

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 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 2023-2024 planning cycle, ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable NERC reliability standards.[12] The ISO performed this analysis across a 12-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

[12] 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.

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 the goals was the renewables portfolio standard (RPS) set out in various legislation; first the trajectory to achieving the 33% renewables portfolio standard set out in the state directive SBX1-2 , and then the 60% renewables portfolio standard by 2030 objective in Senate Bill (SB) 100[13] that became law in September, 2018. More recently, the focus has shifted to the more aggressive 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the CPUC and CEC as directed by SB 350[14] 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

[13] 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

[14] 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.

gas-fired generation in local capacity areas. In this 2023-2024 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 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 allows it to "back out" of previously identified reliability projects inside the planning cycle and count the avoided cost of a separate reliability project as an economic benefit. This is an important distinction, as it is critical to avoid the misconception that a project must be supported by solely reliability benefits, *or* policy benefits, *or* economic benefits exclusively, *i.e.*, the ISO does not approve projects through a siloed approach.

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 Northern Grid, 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 2023-2024 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:

1. Reliability Requirement for Resource Adequacy: Local Capacity Requirements and Resource Adequacy import capability.
2. 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.
3. 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 2023-2024 planning cycle began in January 2023 and concludes in May 2024.

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 those 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 the following major activities:

- Performs technical planning studies described in the Phase 1 study plan and posts the study results;
- Provides a request window for stakeholders to submit reliability project proposals in response to the ISO’s technical studies, demand response, storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- Evaluates and refines the portion of the conceptual statewide plan that applies to the ISO system as part of the process to identify policy-driven transmission elements and other infrastructure needs that will be included in the final comprehensive transmission plan;
- Coordinates transmission planning study work with renewable integration studies performed by the ISO for the CPUC integrated resource planning proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff Section 24.4.6.6(g);
- Reassesses, as needed, significant transmission facilities in 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,[15] which are intended

[15] 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.

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; and
- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the ISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of phase 2.

Board approval of the comprehensive transmission plan at the end of Phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board's approval enables cost recovery through ISO transmission rates of those transmission projects included in the Plan that require Board approval.[16] As indicated above, the ISO solicits and accepts proposals in Phase 3 from all interested project sponsors to build and own the regional transmission solutions that are open to competition.

By definition, category 2 solutions identified in the comprehensive plan are not authorized to proceed after Board approval of the plan, but are instead re-evaluated during the next annual cycle of the planning process. At that time, based on relevant new information about the patterns of expected development, the ISO will determine whether the category 2 solutions should be elevated to category 1 status, remain as category 2 projects for another cycle, or be removed from the transmission plan.

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

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 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 other Western Planning Regions[17] 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 are 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 2023-2024 transmission planning cycle was the second year of the two-year interregional coordination planning process that the ISO conducts with its neighboring planning regions WestConnect and Northern Grid. Accordingly, the Western Planning Regions initiated a new

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

biennial Interregional Transmission coordination cycle beginning in January 2022. The ISO hosted its submission period in the first quarter of 2022 in which proponents were able to request evaluation of an interregional transmission project. The submission period began on January 1 and closed March 31 with one interregional transmission project being submitted to the ISO. The Western Planning Regions held Interregional Coordination Meeting(s) on March 4, 2022, June 13, 2022, and March 9, 2023 to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[18] This process and results of the evaluation conducted with the other relevant planning regions, NorthernGrid and WestConnect, are set out in Chapter 5.

1.4 Other Influences

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 2023-2024 Plan.

1.4.1 SB 887, the Accelerating Renewable Energy Delivery Act

Senate Bill 887, the Accelerating Renewable Energy Delivery Act, was authored by Senator Josh Becker and signed into law by Governor Newsom on September 16, 2022. SB 887 provides state policy direction on a number of resource planning 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.

The ISO has considered the state policy direction provided by SB 887 in the development of this transmission plan and will incorporate the additional input from the CPUC and CEC in future planning cycles as it becomes available.

[18] Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website athttp://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

1.4.2 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
- Topology Optimizations

The ISO leads the transmission expansion planning and interconnection process for systems in its footprint. Transmission owners are responsible for capital maintenance programs on the transmission system – including like for like replacement that may involve incidental capacity increases. They are also responsible for all planning and maintenance on sub-transmission systems that are classed as distribution and are not under ISO operational control.

The California ISO (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.

In the ISO's transmission planning processes, we have considered both advanced conductors and flow controllers in a number of applications. Flow controllers have to date been more successful. Examples include the Imperial Valley phase shifting transformer, HVDC flow control via two projects under development in San Jose, multiple uses of reactors and Smart Wires technology, multiple uses of statcoms, SVCs, synchronous condensers, and series capacitors.

Advanced conductors have been studied in certain applications and the ISO has recently approved the first transmission planning application in the 2022-2023 transmission planning process. While the ISO will continue to consider advanced conductors and seek their appropriate applications, 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.

Advanced conductors have been selected by transmission owners to address particular challenges, such as the use by Southern California Edison (SCE) to address clearance issues – with minimal tower modifications – on the Big Creek-Ventura 220 kV network. (The ISO then approved terminal improvements to access the incidental incremental capacity). Other uses have apparently been made, especially in select urban areas, where the higher tension capabilities and low sag characteristics allowed lower towers to be employed without having to shorten spacing between towers.

The ISO will continue to evaluate and consider opportunities for GETs in the annual transmission planning process. In addition FERC Order No. 2023 requires transmission providers to consider opportunities to deploy GETs in the resource interconnection process.

1.4.3 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 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,[19] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[20] — energy efficiency, demand response, renewable generating resources, and energy storage — that was further advanced and refined through the development of the Moorpark Sub-area Local Capacity Alternative Study released on August 16, 2017.[21] 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. The ISO continued to assess Oakland area needs in the 2023-2024 transmission planning process due to the increasing load forecast in the area, as seen in Section 2.5.4.

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

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

[20] To be precise, the term "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The ISO uses the term more generally here consistent with the preference for certain resources in lieu conventional generation.

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

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 defining need 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 – or other local regulatory authorities as the case may be – 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 procured for system needs to be 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 5 years or less that shall be deemed reasonable and preapproved if certain conditions are met, and can contract for longer than 5 years subject to filing a Tier 3 Advice Letter for approval, as set out in CPUC Decision (D.) 22-03-034. The ISO is not aware of these provisions being used yet to acquire new resources required for transmission needs, however.

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.[22] This work was founded on the analysis of the necessary characteristics for "slow response" demand response programs that was undertaken

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

initially through special study work in the 2016-2017 Transmission Plan, which continued into 2017 through a joint stakeholder process with the CPUC.[23]

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

1.4.4 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 that challenged 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.

1.5 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 discussed above.

1.5.1 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 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

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

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.

1.5.2 Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[24] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

1.5.3 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.[25]

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 is also providing planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities

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[24] 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.

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

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.

Chapter 2

2 Reliability Assessment

2.1 Overview of the ISO Reliability Assessment

The ISO conducts its annual reliability assessment to identify facilities that demonstrate a potential of not meeting the applicable reliability performance requirements and identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards, 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 2023-2024 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 12-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions.

This study is part of the annual transmission planning process and performed in accordance with Section 24 of the ISO tariff and as defined in the Business Process Manual (BPM) for the Transmission Planning Process.

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

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

The 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 Backbone (500 kV and selected 230 kV) System Assessment

Conventional and governor power flow and stability studies were performed for the backbone system assessment to evaluate system performance under normal conditions and following power system contingencies for voltage levels of 230 kV and above. The backbone transmission system studies cover the following areas:

- Northern California — Pacific Gas and Electric (PG&E) system; and
- Southern California — Southern California Edison (SCE) system and San Diego Gas and Electric (SDG&E) system.

2.1.2 Regional Area Assessments

Conventional and governor power flow studies were performed for the local area non-simultaneous assessments under normal system and contingency conditions for voltage levels 60 kV through 230 kV. The regional planning areas are within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories and are listed below:

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

2.2 Reliability Standards Compliance Criteria

The 2023-2024 transmission plan spans a 12-year planning horizon[26] and, as stated earlier, was conducted to ensure the ISO-controlled grid is in compliance with NERC standards, WECC regional criteria, and ISO planning standards across the 2023-2035 planning horizon. Sections B1.2.1 through B1.2.4 in Appendix B describe how these planning standards were applied for the studies of the 2023-2024 transmission planning process.

2.3 Study Assumptions

In Phase 1 of the ISO annual transmission planning process, the ISO develops the Unified Planning Assumptions and Study Plan[27] for this planning cycle. The study assumptions and methodologies are included in Section B.1.3 of Appendix B. The following sections summarize the study assumptions used for the reliability assessment.

2.3.1 Load and Resource Assumptions

The ISO's annual transmission planning process reliability assessment uses as inputs assumptions developed by the California Energy Commission's (CEC) energy demand forecast and the California Public Utilities Commission's (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 2022 IEPR Additional Transportation Electrification Scenario[28] and the base portfolio provided to the ISO via CPUC Decision (D) 23-02-040[29] issued on February 28, 2023.

Table 2.3-1 provides the non-coincident load for each of the planning areas in the PG&E, SCE, SDG&E and VEA planning areas.

[26] CEC 2022 IEPR forecast and CPUC portfolios go out to 2025

[27] http://www.caiso.com/InitiativeDocuments/Final-Study-Plan-2023-2024-Transmission-Planning-Process.pdf

[28] The CEC adopted the 2022 IEPR Energy Demand Forecast, 2022-2035 on January 23, 2023 [https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2]

[29] Decision 23-02-040 released on February 28, 2023 for ordering supplemental mid-term reliability procurement (2026-2027) and transmitting electric resource portfolio, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF

Table 2.3-1: Non-Coincident Load[30] Forecast for Planning Areas

PTO	Planning Area	2025	2028	2035
PG&E	Humboldt	155	158	234
	North Coast & North Bay	1476	1598	2160
	North Valley	672	892	1111
	Central Valley	3617	4239	4876
	Greater Bay Area	8955	9106	12968
	Greater Fresno	3915	3901	5084
	Kern	1955	2125	2276
	Central Coast & Los Padres	1414	1485	2012
SCE	Tehachapi and Big Creek Corridor	2285	2227	2221
	North of Lugo area	1098	1080	1067
	Eastern	5144	5092	4724
	Main	25461	26253	29700
SDG&E		4976	5217	6022
VEA	VEA	169	177	196

2.3.2 Study Horizon and Years

The studies that comply with TPL-001-5 were conducted for both the near-term[31] (2025-2028) and longer-term[32] (2029-2035) per the requirements of the reliability standards.

Within the identified near and longer term study horizons, the ISO conducted detailed analysis on years 2025, 2028 and 2035. In addition, the ISO conducted a sensitivity study on the year 2035.

2.4 Reliability Studies

In Phase 2 of the annual transmission planning process, the reliability assessment is conducted based upon the Unified Planning Assumptions and Study Plan that were developed as a part of Phase 1 of the planning process. The preliminary reliability results were posted on the ISO webpage and with this posting the Request Window opens for the participating transmission owner to submit potential alternatives to address identified reliability constraints by September 15 and for all other stakeholders to submit their potential mitigation alternatives by October 15. In addition, the ISO held a stakeholder meeting to present the reliability results and for the participating transmission owners to present the potential alternatives that they submitted into the Request Window. The Request Window submissions have been posted on the ISO Market Participant Portal and a list of the submissions is provided in Appendix D. The detailed reliability contingency analysis is provided in Appendix C.

The ISO then conducts its reliability assessment, including technical and economic evaluations of the alternatives identified by the ISO or stakeholders, to select the most effective and efficient

[30] The loads reflect the peak forecast load for the planning area, the load of the area at the time of the PTO area peak load.

[31] 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.

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

recommendation. Details of the reliability studies, request window submission assessments and mitigation assessments are provided in Appendix B.

2.5 Reliability-Projects Needed

The reliability-driven projects that have been identified as needed to mitigate reliability constraints identified in Appendix C are presented below. The comprehensive and detailed technical and economic evaluation of the constraints and the alternatives the ISO considered in selecting the recommended reliability-driven projects are set out in Appendix B.

In total, the reliability assessment has identified 19 new reliability-driven projects required in this transmission planning cycle for a total estimated cost of $1.216 billion.

2.5.1 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 16, 2023 stakeholder meeting. Based on comments received and no objection raised at the following ISO Board of Governors meeting on December 14, 2023, ISO Management approved the transmission projects and informed the respective participating transmission owners of those approvals.

Covelo 60 kV Voltage Support

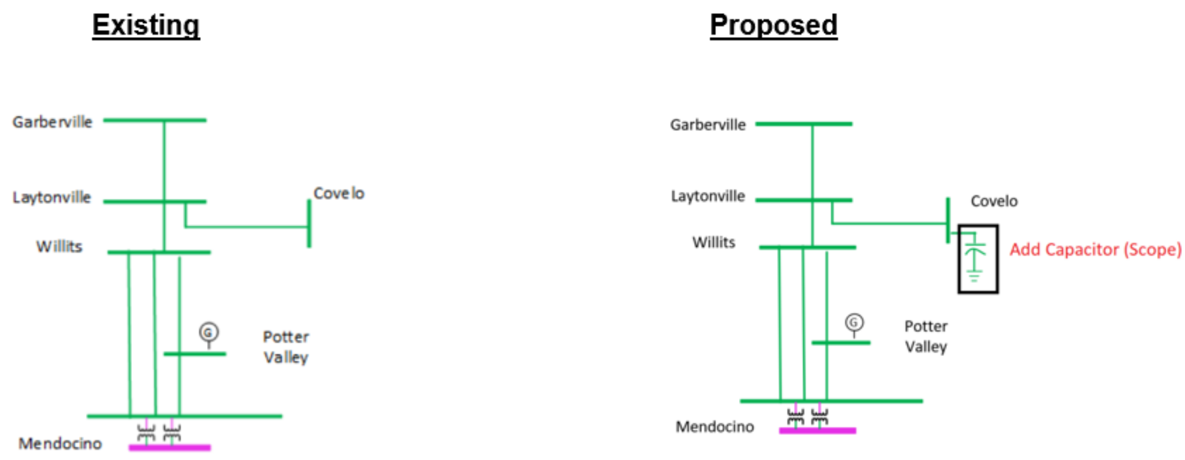
Covelo is located 14 miles east-northeast of Laytonville and is radially served by the 16-mile Laytonville – Covelo 60 kV line. In 2023-2024 TPP assessment studies, low voltages were observed at both Laytonville and Covelo substations for P0, P1 and P2 category contingencies. Furthermore, in terms of contingencies, the Laytonville-Willits 60 kV line outage causes severe low voltage at Laytonville and Covelo substations and installing a shunt capacitor at Covelo would mitigate this issue.

The ISO recommended approval of the “Covelo 60 kV Voltage support project,” which includes the following elements:

- Install a 10 MVAR Shunt Capacitor at Covelo 60 kV Substation.

The total estimated cost of this project is $11M - $22M. Its expected in-service date is May 2030 or earlier.

Figure B.2.5-1: Covelo 60 kV 10 MVAR Shunt Capacitor Install Single Line Diagram



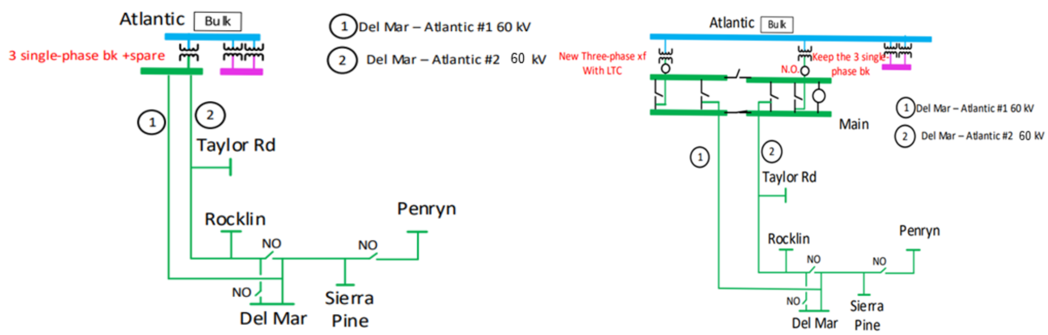
Atlantic High Voltage Mitigation Project (Re-Scope)

The Atlantic 230/60 kV transformer is the main source to serve the City of Rocklin in Placer County. There are four 60 kV substations (Taylor Road, Rocklin, Del Mar and Sierra Pine) in this load pocket which are served by the Del Mar – Atlantic #1 and #2 60 kV lines. The existing 230/60 kV transformer is composed of three single-phase banks without regulator and there was a spare single-phase transformer bank available for serving load during maintenance and potential transformer failure. In the 2021-2022 Transmission Plan, the ISO recommended adding a voltage regulator at the substation to control the voltage on the 60 kV system because of the observation of high voltage at the Atlantic 60 kV pocket in real-time and also in 2026 Spring Off-peak case.

In 2022, one of the single-phase banks failed and the spare single-phase bank was used to replace it. As a result, there is no spare bank for serving the 60 kV system under maintenance and potential transformer failure. In the 2023-2024 TPP assessment, the long-term load forecast of the Atlantic 60 kV load pocket is forecast to be about 125 MW. The failure of any of the existing single-phase banks would cause an outage for load in the area. Also based on the assessment results, there will be a normal overloading (101%) issue on the existing three single-phase banks.

The newly proposed scope is to install a new three-phase transformer with LTC and keep the existing three single-phase banks normally open as the back-up source. Furthermore, the construction to install the new three-phase bank will be possible in a quicker timeframe compared to the original scope due to a shorter outage clearance window requirement. As an additional benefit, maintaining the three single-phase banks as back-up will improve the system reliability to serve customers in the 60 kV load pocket.

Figure B.2.5-2: Existing and Proposed Single Line Diagram of Atlantic 60 kV System



(a) Existing Atlantic 60 kV System (b) Proposed Atlantic 60 kV System

To address these issues, the ISO recommended approval of the “Atlantic High Voltage Mitigation (Re-Scope),” which includes the following:

- Install a 200 MVA 3-phase 230/60 kV transformer with LTC; and
- Associated bus work at Atlantic substation to install the new transformer.

The total estimated cost of this project is \$20M - \$40M. The expected in-service date of this project is May 2029.

Martin-Millbrae 60 kV Area Reinforcement Project

The Martin-Millbrae 60 kV system is located in the Peninsula division of the Greater Bay area and serves approximately 23,000 customers through the Martin, Millbrae, Sneath Lane, Pacifica, San Andreas and Bruno 60 kV substations. Two 115/60 kV transformers banks located in Martin and Millbrae with a capacity of 110 MVA and 100 MVA, respectively, provides service to these areas. The load forecast indicates high load growth in this area due to multiple business load requests resulting in PG&E planning to expand the load serving capacity by upgrading the distribution banks at Sneath Lane substation.

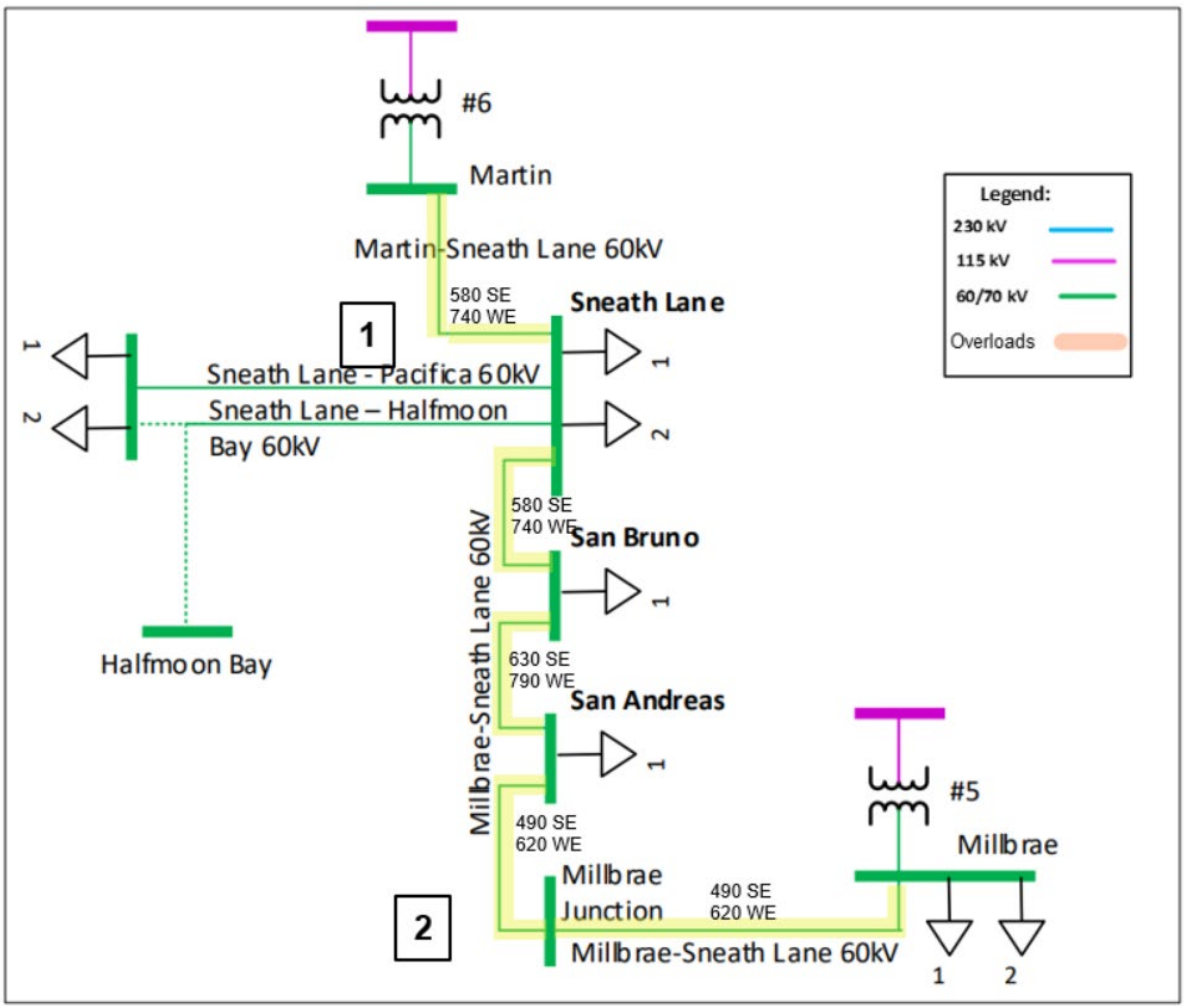
As a result of the increased demand there were overloads observed on the Martin-Sneath Lane and Millbrae-Sneath Lane 60 kV lines upon loss of either the Millbrae or Martin 115/60 kV transformer banks in the 2023-2024 TPP reliability assessment. This project mitigates the NERC TPL-001-5 Category P1 violations. It will also increase the load-serving capability and customer reliability in the area. If the load growth persists at the same rate in this region, considering the electrification trend, it may be necessary to expand the project scope to accommodate long-term load projections in future planning cycles.

The ISO recommended approval of the “Martin-Millbrae 60 kV Area Reinforcement Project” which includes the following elements:

- Reconductor 7.2 circuit miles between the Martin and Sneath Lane Substation with a larger conductor to achieve at least 1100 Amps during summer emergency conditions and 1200 Amps during winter emergency conditions;
- Reconductor 2.5 circuit miles between the Millbrae substation and 012/078, and between 014/093 and Sneath Lane on the Millbrae-Sneath Lane 60 kV line with a larger conductor to achieve at least 1100 Amps during summer emergency conditions and 1200 Amps during winter emergency conditions; and
- Upgrade any limiting components as necessary to achieve the full conductor rating.

The total estimated cost of this project is $20M - $40M. The expected in-service date of this project is May 2030.

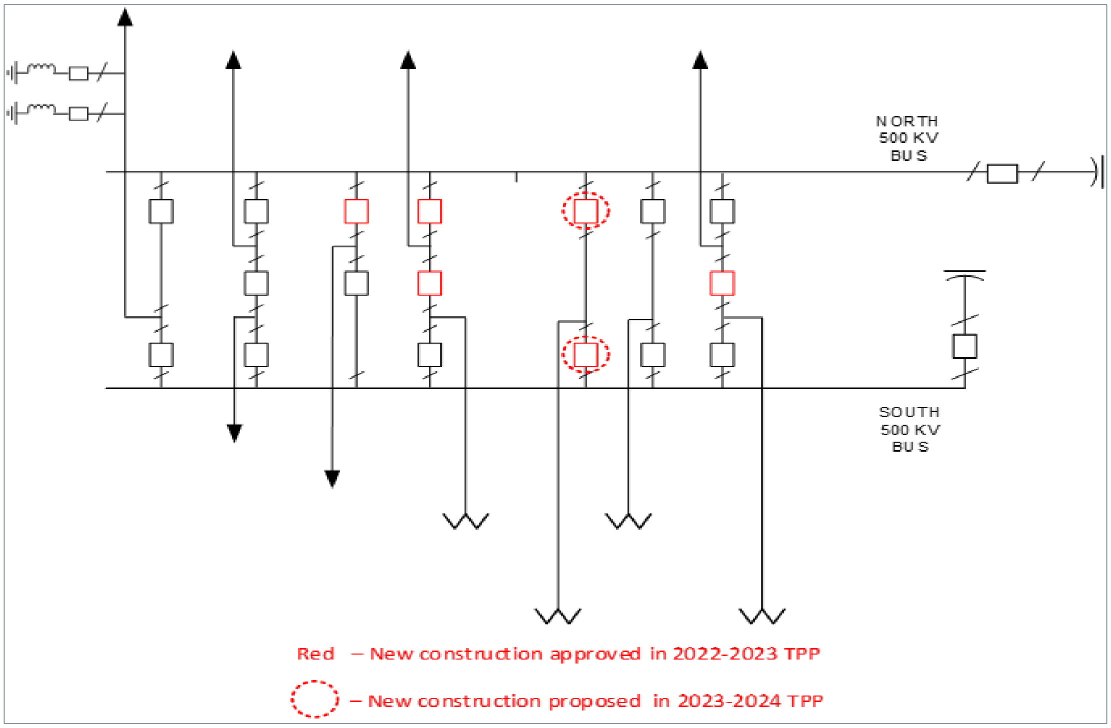
Figure B.2.5-3: Martin-Millbrae 60 kV Area Reinforcement Project Single Line Diagram



Mira Loma 500 kV bus additional SCD mitigation

The project was submitted by Southern California Edison as a reliability need to address the short circuit duty concerns on additional two 500 kV circuit breakers at Mira Loma 500/230 kV substation. After field verification, the two circuit breakers were identified as potentially being loaded to greater than 100% of the rated short circuit duty capability in the near-term and the longer-term planning horizons. The scope of the project recommended is to replace the two circuit breakers with higher rated circuit breakers, as an addition to the four circuit breakers that were already approved to be upgraded in the 2022-2023 Transmission Plan. The project has an estimated cost of $5 million with targeted in-service date of Q2 2027.

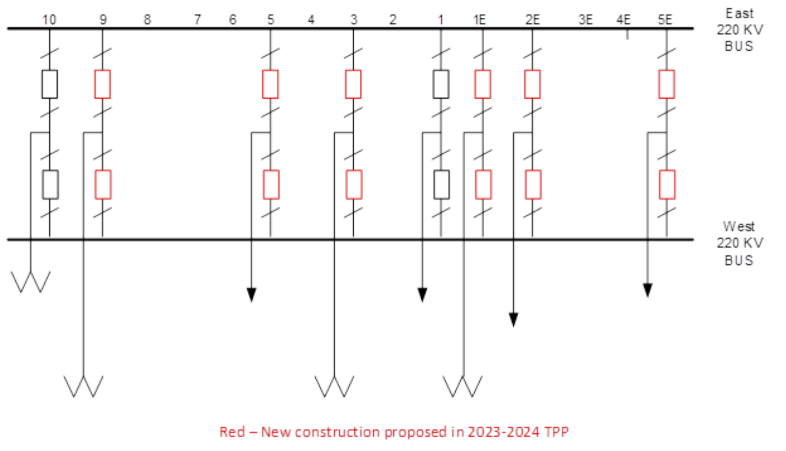
Figure B.2.5-4: Mira Loma 500 kV Bus SCD Mitigation Project One Line Diagram



Etiwanda 230 kV Bus SCD Mitigation Project

This project was submitted by Southern California Edison as a reliability need to address the short circuit duty concerns on the 230 kV circuit breakers at the Etiwanda substation. The recommended scope of this project considered the replacement of twelve (12) circuit breakers, at Etiwanda, currently rated 63 kA, tested at X/R ratio of 17; with new 63 kA rated circuit breakers, tested at X/R ratio of 35. The short-circuit duty (SCD) studies indicated that the twelve 230 kV circuit breakers are expected to be loaded to greater than 95% of their rated three-phase SCD capability in the near-term (2025) and to 100% in the long-term (2035). The project has an estimated cost of $15 million, with a targeted in-service date of Q4 2027.

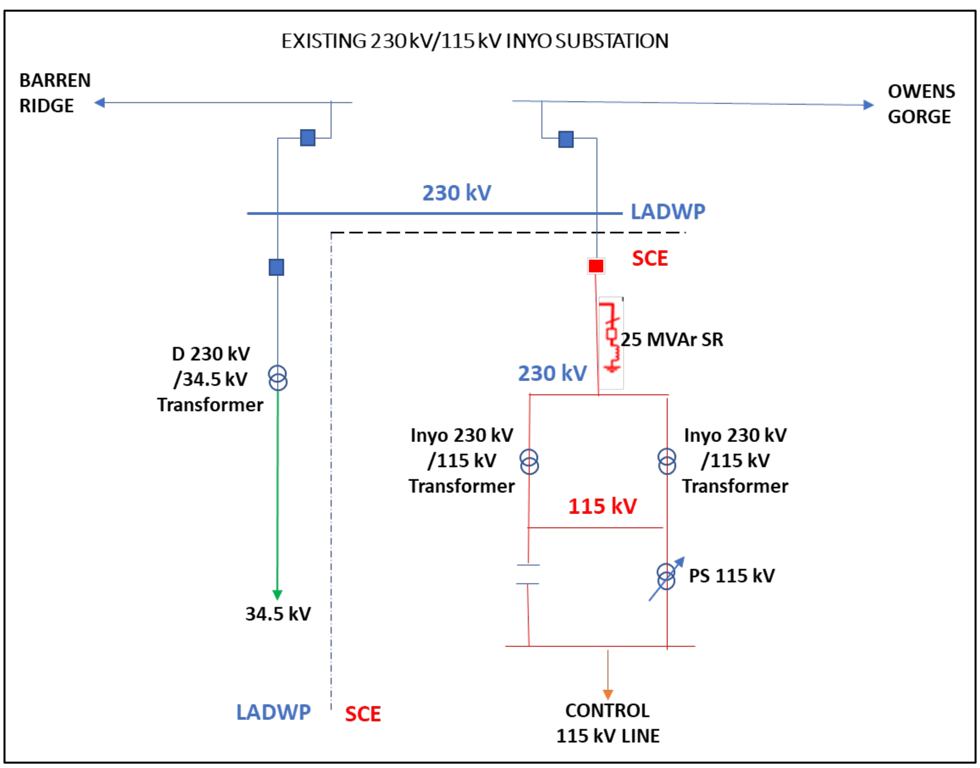
Figure B.2.5-5: Etiwanda 230 kV Bus SCD Mitigation Single Line Diagram



Inyo 230 kV Shunt Reactor Project

This project was submitted by Southern California Edison as a reliability need to address the high voltage concerns in the Inyo area. The recommended scope of this project consisted of installing a 25 MVAR shunt reactor at Inyo 230 kV substation (SCE side). The project has an estimated cost of $20 million, with a targeted in-service date of Q4 2027. The project will supersede the previously approved Control 115 kV Shunt Reactor Project.

Figure B.2.5-6: Inyo 230 kV Shunt Reactor Project One Line Diagram



Eldorado 230 kV Short Circuit Duty Mitigation Project

This project was submitted by Southern California Edison as a reliability need to address the short circuit duty concerns at the joint-owned Eldorado 230 kV bus. The recommended scope of this project included splitting the Eldorado joint-owned 230 kV bus into two sections using sectionalizing breakers and associated equipment, extending the bus with two new positions to the east of the current structure and relocating 230 kV lines and other equipment to balance the short circuit contribution.

The increased short circuit levels are due to the addition of renewable generation in the area, along with associated transmission upgrades, interconnecting to NV Energy, Los Angeles Water and Power, and ISO controlled SCE facilities. The short circuit levels are expected to exceed the breaker ratings by 2024. The proposed project will reduce the short circuit current levels at the Eldorado joint-owned 230 kV bus by about 21.4 kA to about 53.9 kA, well below the 63 kA breaker ratings.

The estimated cost of this project is $67 Million with $48.8 Million funded by SCE, and $18.2 Million being allocated to LADWP and NVE. The proposed in-service date of the project is Q4 2029.

The ISO portion of the project is less than $50 Million. There was an urgent need for the project and a high degree of certainty that the project will not conflict with other solutions that were considered in the 2023-2024 transmission planning process. Thus the project met the requirements set out in the ISO tariff for expedited management approval. A stakeholder meeting was held on June 28, 2023 and ISO management approved the project in July 2023.

Figure B.2.5-7: Eldorado 230 kV SCE Project One Line Diagram before Project

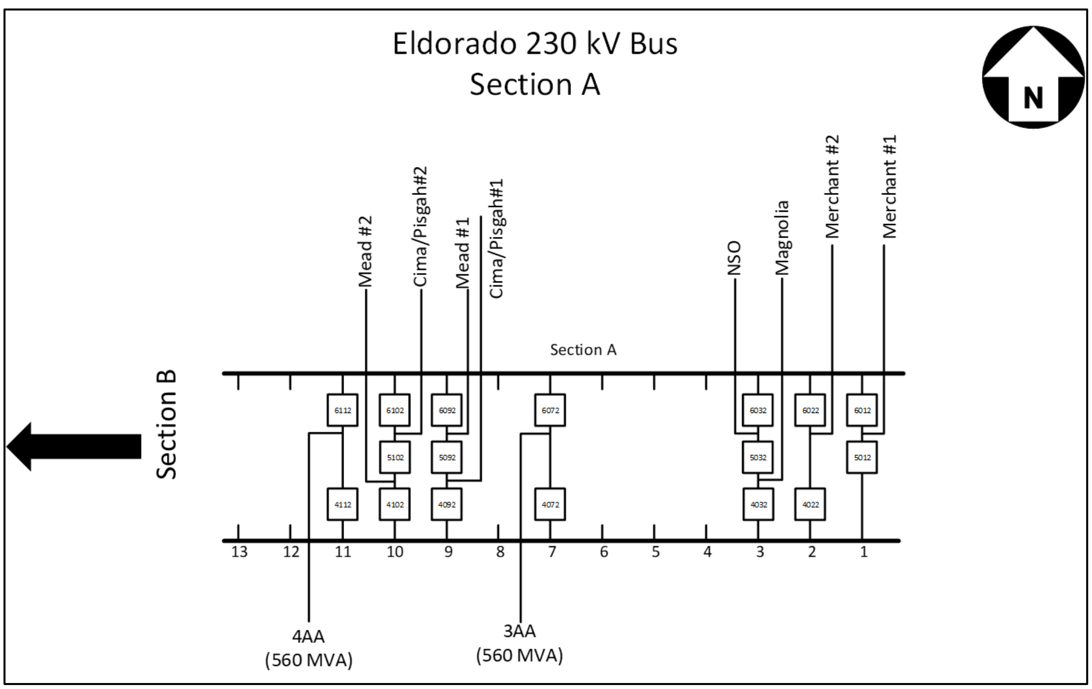
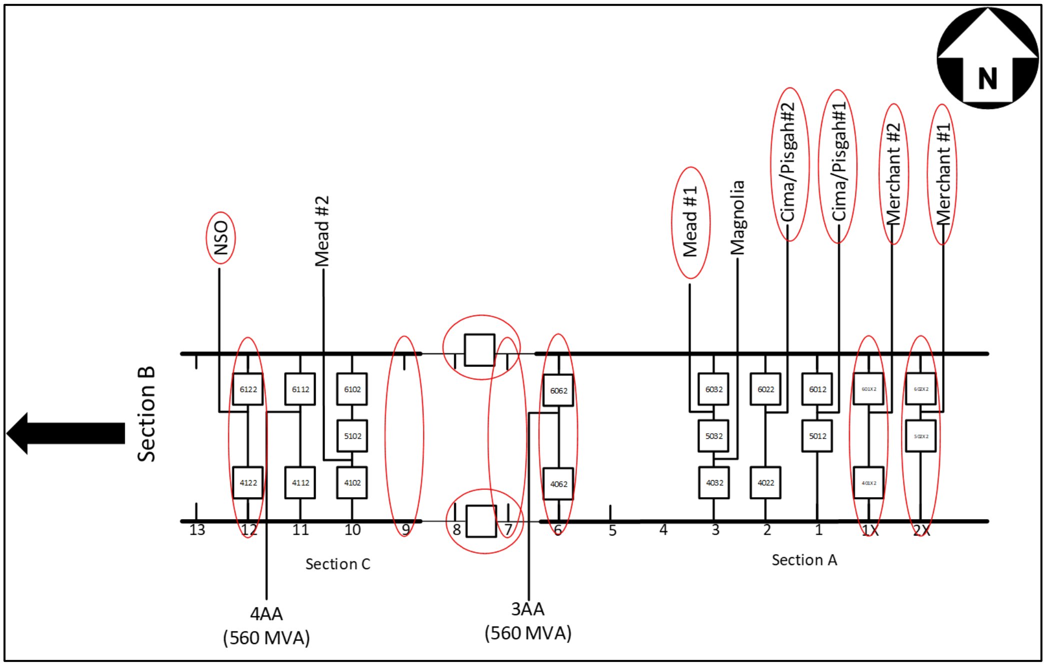


Figure B.2.5-8: Eldorado 230 kV SCD Project One Line Diagram post Project



2.5.2 Projects Recommended for Approval

Camden 70 kV Reinforcement Project

This project was submitted by PG&E to address 70 kV line overloads and low voltages at Camden substation that is radially served from Camden-Kingsburg 70 kV line. Operations has observed low voltages at Camden substation and over 90% loading on Camden-Kingsburg 70 kV line during peak conditions due to the local load growth. The recent PG&E distribution load forecast indicates additional loads will need to be transferred from nearby overloaded distribution feeders to the Camden substation. As a result of the increased demand, low voltages were observed at Camden substation in all near-term and long-term summer peak scenarios. In addition, thermal overloads were observed on the Camden-Kingsburg 70 kV line under normal system conditions. This mitigates the NERC TPL-001-5 Category P0 violations.

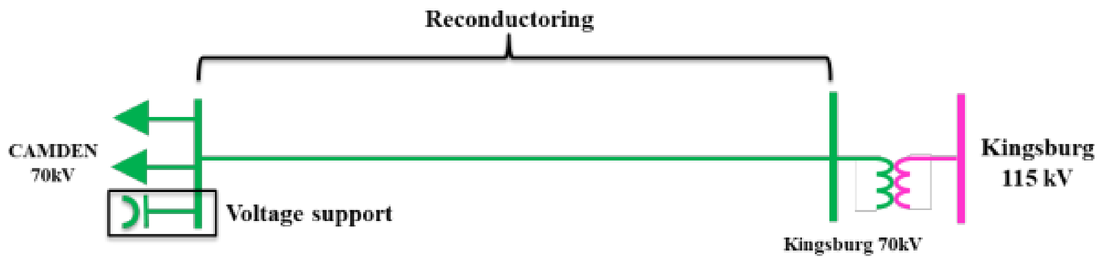
The project scope includes:

- Install 30 MVAR voltage support at Camden substation;
- Reconductoring of the Camden-Kingsburg 70 kV line to achieve minimum required rating of 800 Amps under summer normal conditions; and
- Upgrading limiting component(s) as necessary to achieve full conductor rating.

In addition to mitigating the low voltage and normal overload issues mentioned above, this project will also increase load-serving capability, improve customer reliability, and reduce losses. This project has a cost estimate of $50M - $100M and expected in-service date of May 2030 or earlier.

Figure 2.5-6: Camden 70 kV Reconductoring and Voltage Support

Existing single line diagram



Proposed single line diagram

Gates 230/70 kV Transformer Addition Project

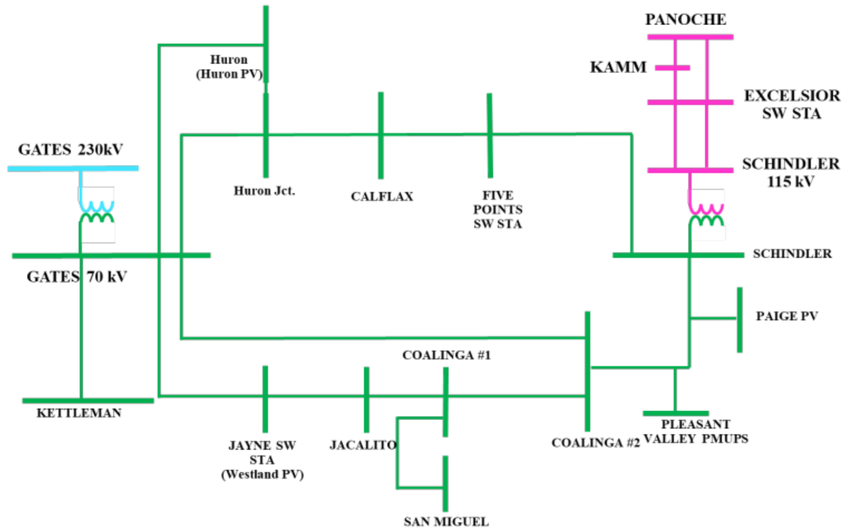
This project was submitted by PG&E to address 70 kV and 115 kV line overloads in Gates area. The Gates 230/70 kV transformer bank #5 serves as the main source feeding the local 70 kV sub-area. Besides Gates 230/70 kV transformer bank #5, the other two sources feeding the load pocket include the Schindler 115/70 kV transformer bank #1 and the Coalinga #1- San Miguel 70 kV line. The load in this area is mainly driven by the distribution customers at Calflax, Coalinga #1, Coalinga #2, Huron, and Schindler substations. This project mitigates the NERC TPL-001-5 Category P1 and P3 violations. For an outage of Gates 230/70 kV transformer bank #5, all the loads in this area will be served through Schindler 115/70 kV transformer bank #1 and the Coalinga #1- San Miguel 70 kV line resulting in overloads on multiple transmission elements, such as Schindler-Five Points SW STA 70 kV line, Schindler-Coalinga #2 70 kV line, Five Points SW STA–Huron-Gates 70 kV line and Schindler 115/70 kV transformer bank #1. Widespread low voltages were also observed in the long-term scenario. In addition there were category P3 contingencies involving Gates 230/70 kV transformer bank #5 resulting in thermal and voltage violations.

The project scope includes:

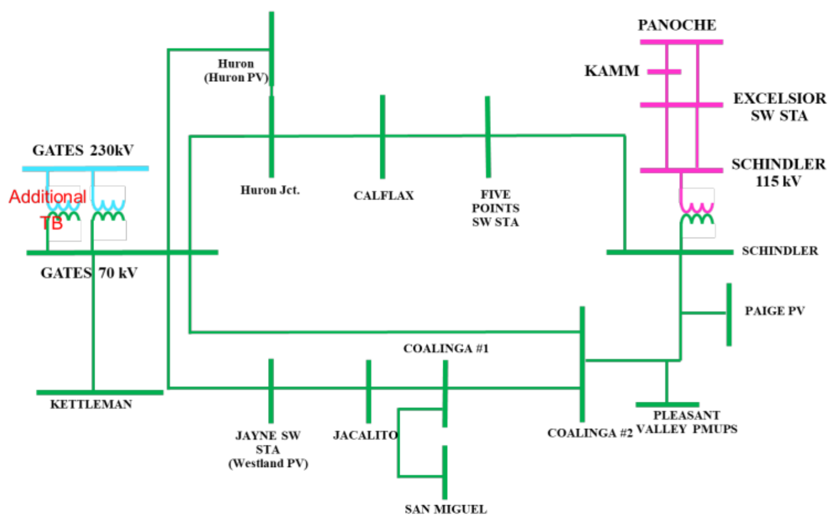
- Installing an additional 230/70 kV transformer bank at Gates substation;
- Gates 70 kV bus conversion; and
- Upgrade limiting elements to achieve full bank capacity.

This project will establish Gates substation as a stronger source for the local 70 kV area. This project has a cost estimate of $36M - $72M and expected in-service date of May 2030 or earlier.

Figure 2.5-7: Gates 70 kV existing and proposed single line diagrams



Existing single line diagram



Proposed single line diagram

Valley Center System Improvement

This project was proposed by SDG&E as a reliability transmission solution to address several thermal overloads in the 69 kV transmission system due to the charging/discharging of Valley Center energy storage. The reliability assessment of the SDG&E planning area in Section B.6 of Appendix B identified contingencies (P0, P1, P3, and P6) in the near-term and long-term planning assessments that resulted in thermal overloads on the TL682 Warners – Rincon, TL683 Rincon – Lilac, TL6926 Rincon – Valley Center, TL681B Valley Center – Ash Tap, and TL681A Ash – Ash Tap 69 kV transmission lines.

Additionally, this project will allow the retirement of the Valley Center RAS in P0 conditions which contradicts the ISO S-RAS2 standard.

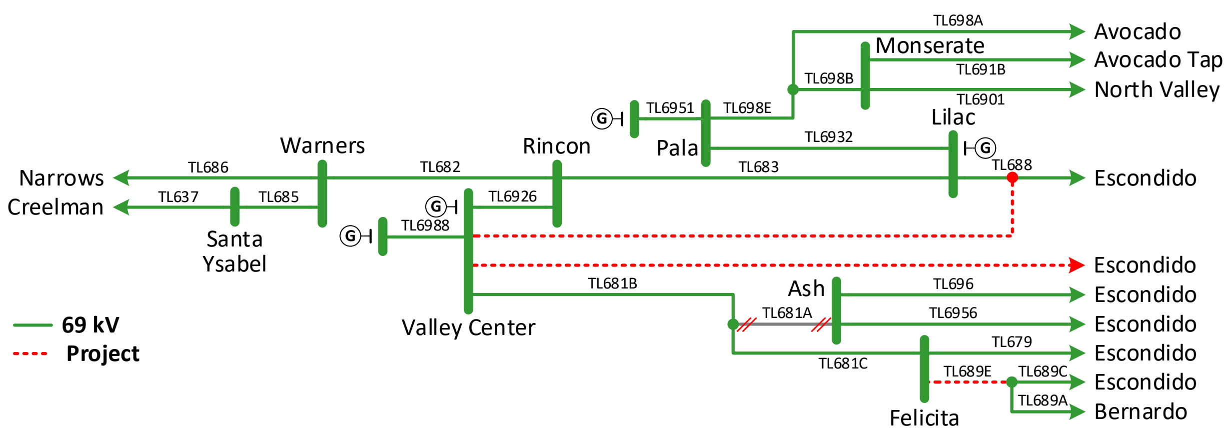
The scope of the project to mitigate the identified reliability concerns consists of the following:

- New 5-mile double circuit 69 kV line (one pole structure) to create two new lines that will connect to Valley Center substation;
    - One circuit will connect to a de-energized line TL99901 to form a new Valley Center – Escondido 69 kV line; and
    - One circuit will tap into TL688 to create Valley Center – Escondido – Lilac 3-terminal 69 kV line;
- De-energize TL681A Ash – Ash Tap;
- Reconductor 0.1 miles of TL689E Felicita – Felicita Tap; and
- Reconductor the underground section of the existing TL99901.

The estimated cost for this project is $51 million with a targeted in-service date of 2028.

In the interim, the area will continue relying on the existing Valley Center RAS and operational actions to restrict the charging/discharging of Valley Center energy storage.

Figure 2.5-8: Valley Center System Improvement



Crazy Horse Canyon (CHCSS)-Salinas-Soledad #1 and #2 115 kV Line Reconductoring Project

As a result of the increased demand, thermal overloads were observed on CHCSS-Natividad and Natividad-Salinas line sections of CHCSS-Salinas-Soledad 115 kV line #1 and line #2 during peak loading conditions under P7 contingencies starting near-term and P2 contingency in long term. PG&E proposed a reconductor project to address these overloads.

The ISO is recommending approval of the “Crazy Horse Canyon-Salinas-Soledad #1 and #2 115 kV line reconductoring” project which includes the following:

- Reconductor CHCSS-Natividad section of the CHCSS-Salinas-Soledad #1 and #2 115 kV lines to achieve at least 1200 Amps under summer emergency conditions;
- Reconductor Natividad-Salinas section of the CHCSS-Salinas-Soledad #1 and #2 115 kV lines to achieve at least 1200 Amps under summer emergency conditions; and
- Upgrade any limiting element(s) on these line sections and associated bus connections to achieve full conductor rating.

Alternatives considered were status quo and looping in the Moss Landing – Del Monte #1 and #2 115 kV double circuit line in Salinas 115 kV but was not recommended due to reliability concerns and space constraint at Salinas substation respectively. In addition, RAS was considered as an alternative, however, the RAS is not feasible due to the number of contingencies and facilities that would need to be monitored.

The project has a cost estimate of $54M - $108M and expected in-service date of May 2030.

Figure 2.5-9 and Figure 2.5-10 represent system configuration of Crazy Horse Canyon – Salinas – Soledad 115 kV, Crazy Horse Canyon – Moss Landing 115 kV, Moss Landing – Salinas 115 kV, and Moss Landing – Del Monte 115 kV before and after “Crazy Horse Canyon-Salinas-Soledad #1 and #2 115 kV Line Reconductoring” the project is complete.

Figure 2.5-9: Existing System Configuration

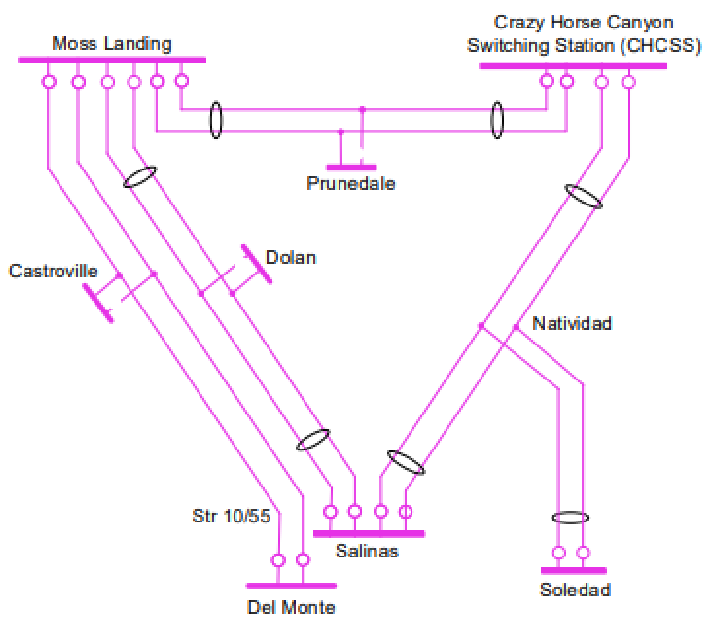
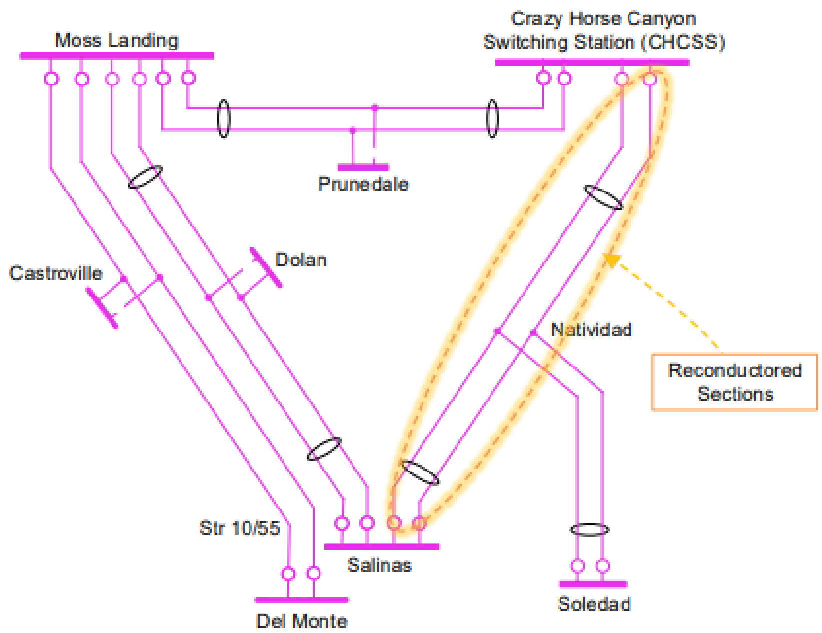


Figure 2.5-10: Proposed System Configuration



Diablo Canyon Area 230 kV High Voltage Mitigation Project

High voltages above acceptable operating limit of 242 kV have been observed at Diablo Canyon 230 kV substation in real-time operation around or right after midnight when the overall area load was low, the local Los Padres load was low, the local solar farms had zero output, and the transfer on bulk system with SCE was also low.

The ISO is recommending approval of the "Diablo Canyon Area 230 kV High Voltage Mitigation Project," which includes the following:

- Install a total of 120 MVAR shunt reactor along with the existing shunt capacitors at Mesa Substation 115 kV bus. The number and size of reactor units will be either 3X40 MVAR or 4X30 MVAR. This will be determined based on power quality requirements (i.e. flicker) as well as in coordination of the LTCs on Mesa 230/115kV transformer banks #2 and #3. The shunt devices will regulate the voltage at Mesa 230 kV bus; and
- Remove one or two of the existing 25 MVAR shunt capacitor steps.

Alternatives considered were STATCOM installations at Mesa 230 kV, Morro Bay 230 kV, Diablo Canyon 230 kV, or Mesa 115 kV substation, but not recommended due to high costs compared to recommended alternative.

The project has the estimated cost of $35M - $70M and the expected in-service date of May 2027.

Figure 2.5-11 represents current system configuration at Diablo Canyon 230 kV and Figure 2.5-12 and Figure 2.5-13 represent system configuration of with proposed recommended alternatives.

Figure 2.5-11: Diablo Canyon 230 kV Existing System Configuration

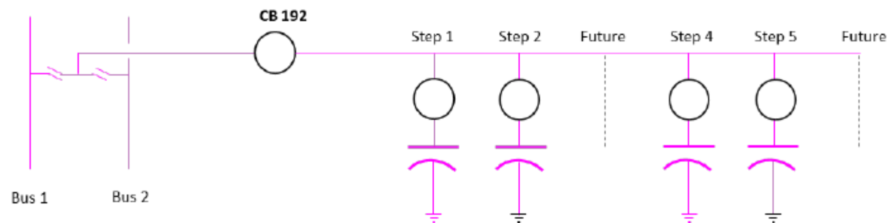


Figure 2.5-12: Diablo Canyon 230 kV Proposed Configuration (3x40 MVAr Shunt Reactors)

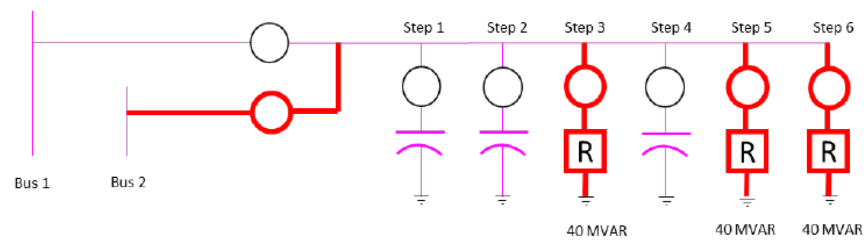
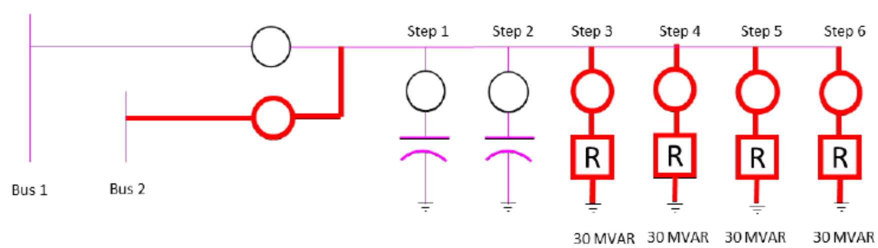


Figure 2.5-13: Diablo Canyon 230 kV Proposed Configuration (4x30 MVAr Shunt Reactors)



Salinas Area Reinforcement Project

The Salinas-Spence 60 kV system located in Monterey County is supplied from the Salinas 115 kV bus via two stepdown transformers that also feed other lines out of Salinas substation. The Salinas-Spence 60 kV system consists of two 60 kV paths. One is the Salinas-Firestone 60 kV and Firestone-Spence 60 kV lines. The second path is the Salinas-Spence 60 kV line that passes through Sanborn junction and serves the Industrial Acres Substation. Buena Vista, Industrial Acres, and Spence are three PG&E distribution substations supplied from the Salinas-Spence 60 kV system along with two small transmission load substations, Fresh Express and Firestone. South of Spence substation, the 60 kV lines Soledad #1 and Soledad #2 extend toward Gonzales and eventually Soledad and are normally open at Spence. PG&E Distribution Planning has received a large number of load interconnection applications near Spence. The major load growth has been modelled at Spence substation, which is forecasted at 23.3 MW in 2023, 50.8 MW in 2025, and 84.6 MW in 2035. However, due to space limitations, Spence substation is limited to two 30 MVA distribution transformers and capable of serving only up to 60 MVA load. A limited amount of projected load can be supplied out of Gonzales, however, this would warrant potential upgrades at Gonzales in near future.

Category P0, P1, P2, and P7 contingencies resulted in reliability constraints on the Salinas-Firestone #1 60 kV and Salinas-Firestone #2 60 kV lines. Additionally, low voltage concerns were identified at multiple 60 kV substations fed from Salinas 60 kV system at Spence 60 kV and Firestone 60 kV and Gonzales 60 kV substations. Due to load growth in the area, the previously approved Salinas-Firestone #1 and #2 reconductor project that is currently expected to be in-service in Q4 of 2026 is insufficient to address these overloads. To address reliability-driven thermal and voltage concerns identified, the ISO is recommending approval of Salinas Area Reinforcement Project which includes following:

- Build a new Chaular 115 kV substation with two distribution banks to carry load from Gonzales 60 kV substation. The Gonzales 60 kV substation is to be decommissioned.
- Rebuild the existing 60 kV lines Salinas-Spence, Salinas-Firestone and Firestone-Spence to 115 kV to achieve minimum rating of:
    - 1400 A for the Salinas-Buena Vista and Salinas-Sanborn Jct sections; and
    - 800 A for the Buena Vista-Firestone-Spence and Sanborn Jct-Spence Jct-Spence;
- Maintain the existing bus configuration at Spence after 115 kV conversion. Supply Chaular 115 kV from Spence with both 115 kV lines normally closed. Normally close Buena Vista – Industrial Acres and loop-in the existing line into Industrial Acres:
    - Spence-Chaular and Spence Jct-Chaular Jct-Chaular sections to achieve minimum rating of 500 A; and
    - Sanborn Jct-Industrial Acres-Buena Vista sections to achieve minimum rating of 950 A;
- Replace the transformer and other high voltage side equipment at the following substations to allow 115 kV operation:
    - Distribution stations: Industrial Acres, Spence, and Buena Vista; and
    - Transmission stations: Fresh Express and Firestone;
- Terminate two lines (Salinas-Spence, Salinas-Firestone) at Salinas 115 kV to convert and operate the Salinas to Chaular system at 115 kV.

The project has the estimated cost of $226.1M - $452.3M and the expected in-service date of December 2035. Other alternatives were considered but are not recommended. Please refer to Appendix B for more details.

Refer to Figure 2.5-14 for existing system configuration of Salinas 60 kV area network and Figure 2.5-15 for recommended system configuration of Salinas 60 kV area.

Figure 2.5-14: Salinas 60 kV area - Existing System Configuration

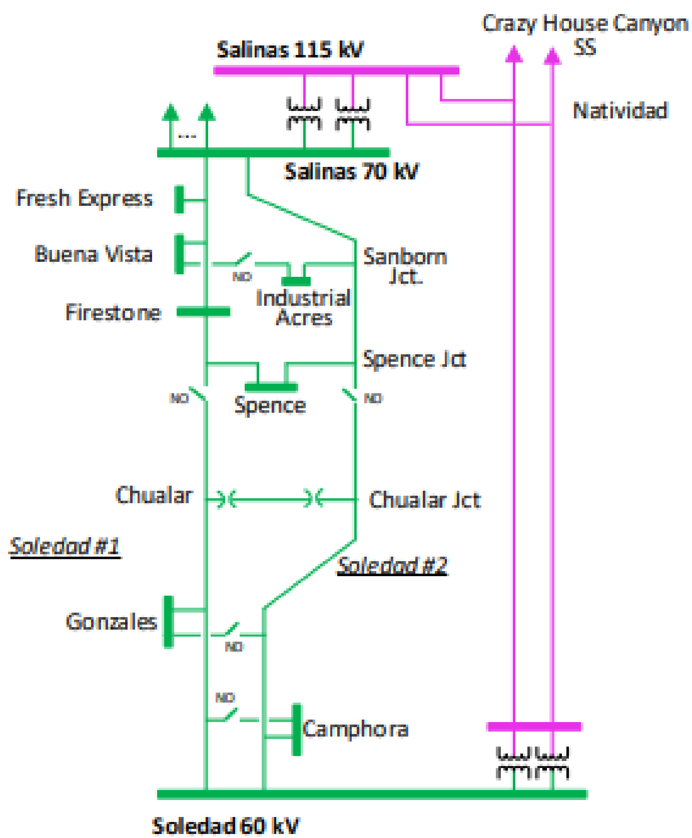
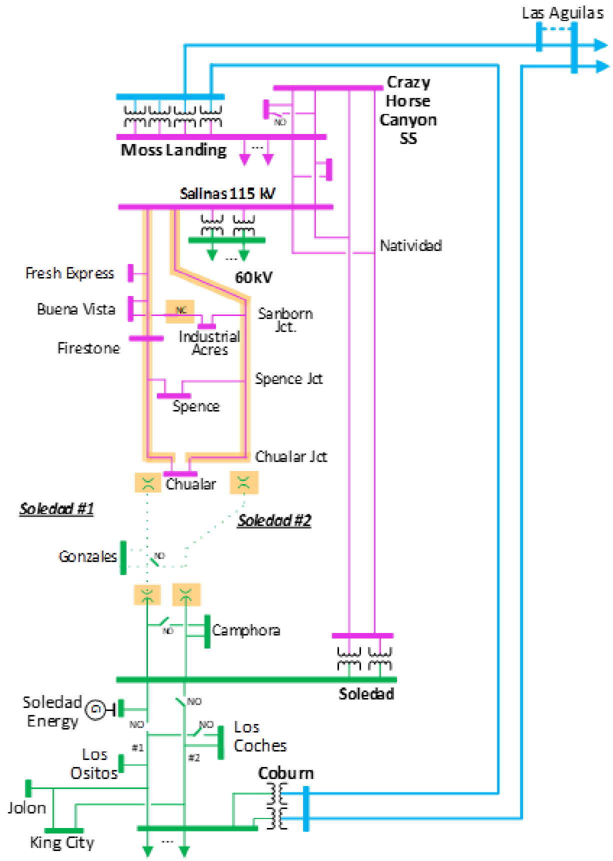


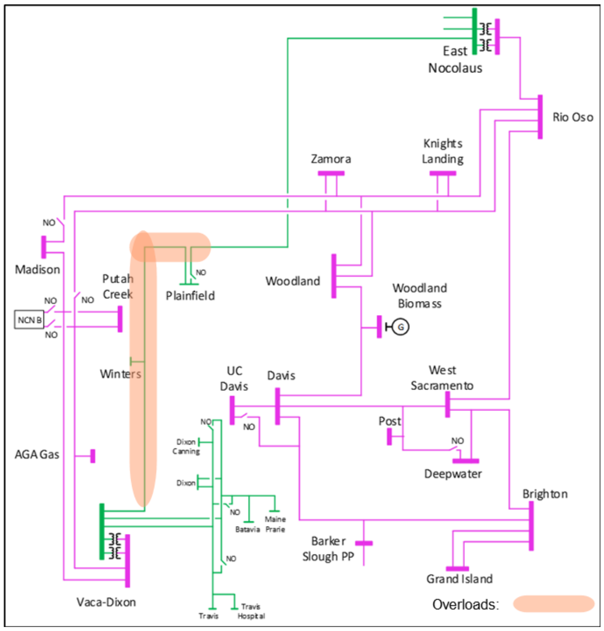
Figure 2.5-15: Salinas 60 kV Area - Proposed Configuration – Alternative 1



Vaca-Plainfield 60 kV Line Reconductoring Project

Vaca-Plainfield 60 kV line serves load within the city of Winters and Plainfield in the Sacramento area. The Plainfield substation is currently radially served from the Vaca - Plainfield 60 kV line while the source from Nicolaus-Plainfield 60 kV line is normally open. The load serving capability in this area has been limited due to capacity constraint on transmission lines and the radial setup. A P0 contingency overload was observed on the Vaca-Plainfield 60 kV line in the near term. Reconductoring the Vaca-Plainfield 60 kV (about 30 miles) line to achieve minimum conductor rating of 635 amps for summer normal and 741 amps for summer emergency rating mitigate these constraints.

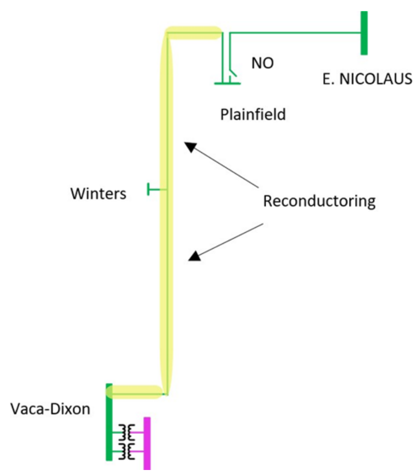
Figure 2.5-16: Vaca-Plainfield 60 kV Line Overload Single Line Diagram



The ISO recommends approval of the Vaca-Plainfield 60 kV Line Reconductoring Project which includes the following scope:

- Reconductor Vaca-Plainfield 60 kV (about 30 miles) to achieve minimum conductor rating of 635 amps for summer normal and 741 amps for summer emergency rating; and
- Upgrade limiting components as necessary to achieve full conductor capacity.

Figure 2.5-17: Proposed Single Line Diagram for the project

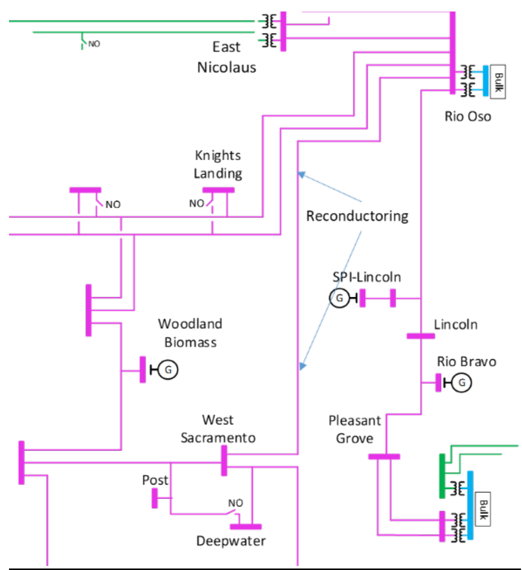


The total estimated cost of this project is \$34M - \$68M with an expected in-service date of May 2030 or earlier. Operating solutions will be relied upon in the interim.

<u>Rio Oso-W. Sacramento Reconductoring Project</u>

Thermal overloads and voltage criteria violations were observed in the 115 kV and 60 kV transmission system between Vaca Dixon, Davis, Rio Oso, and Brighton substations. The overloads were on the Woodlan-Davis 115 kV line, Brighton-Davis 115 kV line, Rio Oso-West Sacramento 115 kV lines and the Vaca Dixon 115/60 kV transformer bank 5 under category P1-P7 contingency conditions. The Vaca Dixon Reinforcement Project was approved in the 2017-2018 TPP to address these issues in the area. However, due to aging infrastructure, the re-rate of the Rio Oso-West Sacramento 115 kV line (as a part of Vaca-Dixon Reinforcement project) is no longer viable. In addition, substantial distribution load interconnections have been requested in this area. Altering the scope from rerating the Rio Oso-West Sacramento 115 kV line to reconductoring approximately 26 miles of this Rio Oso-West Sacramento line would effectively mitigate these issues.

Figure 2.5-18: Proposed Rio Oso-W. Sacramento 115 kV Line Reconductoring for the project



The ISO recommends approval of the “Rio Oso-West Sacramento Reconductoring Project” with the following scope:

- Reconductoring of the Rio Oso – West Sacramento 115 kV line from 040/291 to 013/095A (about 26 miles).

The total estimated cost of this project is $48.7M -$97.4M, with an expected in-service date of 5 years from its start. Operating solutions will be relied upon in the interim.

French Camp Reinforcement Project

Weber 60 kV substation is in San Joaquin County. The Weber-French Camp #1 and #2 60 kV lines serve customers through French Camp, JM Manufacturing, Cargill and Dana substations. Weber substation has been the main source for serving the load in this pocket. In 2023-2024 TPP assessment studies, P1 contingencies overloads were observed on Weber 60 kV line #2 (Weber – French Camp) starting in the near-term. Significant distribution load interconnections have been requested in this area. Weber substation has already been serving at its maximum capacity. Looping French Camp substation into Bellota-Tesla #2 230 kV line and adding a new 230 kV bus at French Camp and distribution banks connected to the 230 kV bus would mitigate these issues.

Figure 2.5-19: Overloads observed at Weber 60 kV line

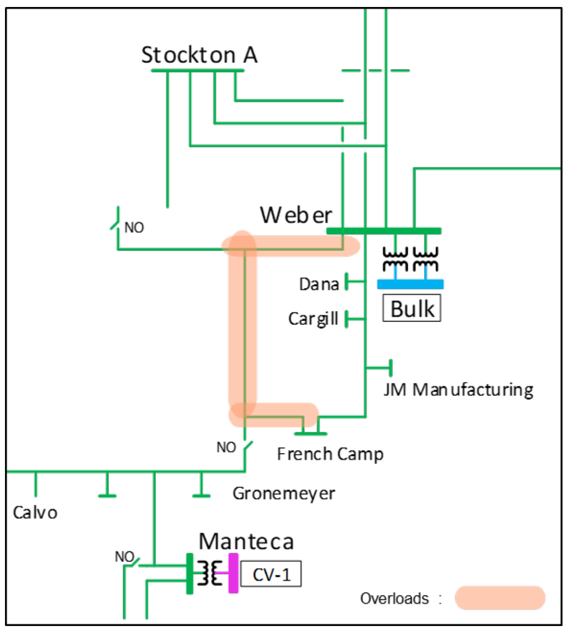
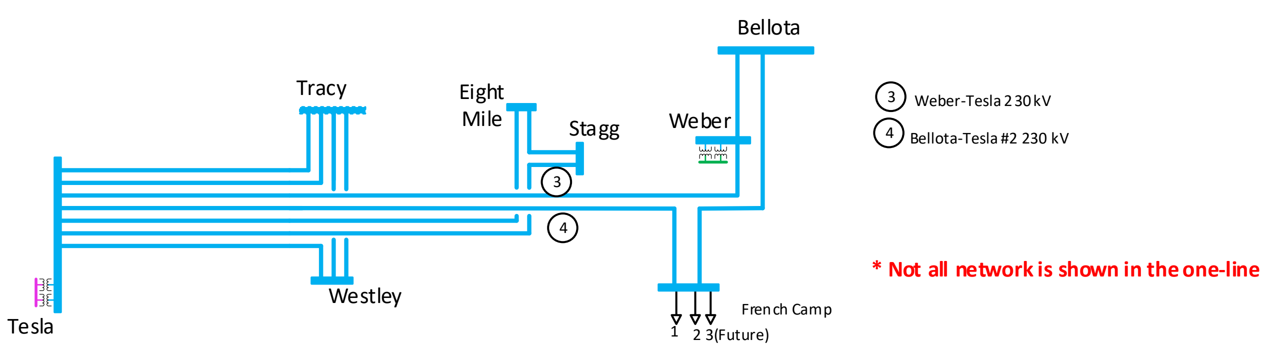


Figure 2.5-20: Proposed looping French Camp Substation into Bellota-Tesla #2 230 kV line



The ISO recommends approval of the "French Camp Reinforcement Project" with the following scope

- Loop French Camp substation into Bellota-Tesla #2 230 kV line to add a new 230 kV bus at French Camp. The total length of transmission circuit is about 4.4 miles.

The total estimated cost of this project is $42.1M - $84.2M. The expected in-service date of this project is May 2030 or earlier. Operating solutions will be relied upon in the interim.

Cortina #1 60 kV Line Reconductoring Project

The Cortina #1 60 kV line, situated in Yolo County, serves Dunnigan and Arbuckle substations in a radial manner. PG&E anticipates a significant increase in load at these substations, especially at Dunnigan due to its proximity to the I-5 transportation corridor.

Both the Dunnigan and Arbuckle substations are operating at full capacity. PG&E has received a near-term 10 MW load interconnection request at the Dunnigan substation, scheduled for phased operation and connection to the transmission system. Currently, 0.7 MW of load has been online since 2023, with an additional 4.2 MW in queue to be energized in early 2024. Moreover, a 0.5 MW agricultural pump load and a 0.4 MW EV charging station submitted their applications in 2023. These new loads have raised concerns about potential overload and low voltage issues along the Cortina #1 60 kV line.

PG&E Planning conducted load interconnection system impact study for this load increase and identified normal overloads on multiple sections of the Cortina #1 60 kV line, with several buses along the line potentially experiencing low voltage issues. The most severe of these issues may lead to overloading the Arbuckle-Dunnigan 60 kV section up to 140% of its summer normal rating and a voltage level as low as 0.87 p.u. at the Dunnigan bus in 2024. Even considering only normal distribution load growth, power flow results for the year 2035 also show P0 thermal overload at 113% of the line rating. The ISO concurs with PG&E's findings and recommendation. As such, the ISO recommends approval of the "Cortina #1 60 kV Line Reconductoring Project" with the following scope:

- Reconductor ~15.4 circuit miles between the Cortina substation and Arbuckle substation (From Cortina to 015/259) on the Cortina #1 60 kV line with a larger conductor to achieve at least 818 Amps during normal conditions.
- Reconductor ~10.8 circuit miles between the Arbuckle Substation and Dunnigan substation (From 015/260 to Dunnigan) on the Cortina #1 60 kV line with a larger conductor to achieve at least 818 Amps during normal conditions.
- Remove any limiting components as necessary to achieve full conductor capacity.

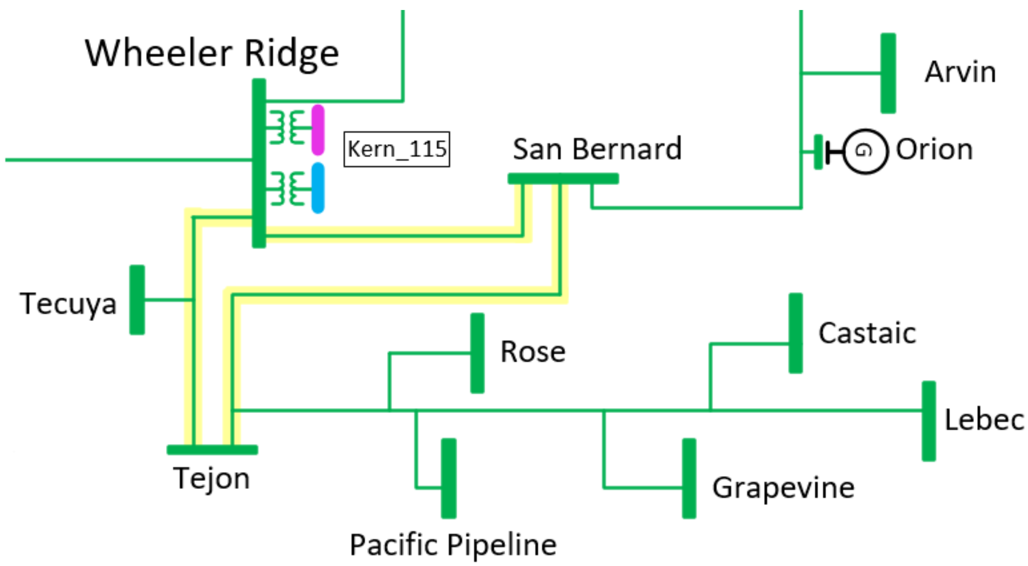
The total estimated cost of this project is $47.1 to $94.3 million. The expected in-service date of this project is May 2028. In the interim, the load ramp will be limited to the available capacity. Operating solutions will also be relied upon in the interim if needed.

Tejon Area Reinforcement Project

The Tejon area is served by three 70kV lines. The projected local load growth, including an additional 50 MW load at San Bernard substation and 45.5 MW load at Tejon 70kV substation, as indicated in section B3.7.5 of Appendix B, results in thermal overloads observed on the Wheeler Ridge – Tejon, Wheeler Ridge – San Bernard and San Bernard – Tejon 70kV lines in all near-term and long-term Summer Peak scenarios under P3 contingency conditions. This project mitigates the NERC TPL-001-5 Category P3 violations along with increasing the load serving capability and improves customer reliability in the area. This project will add an estimated 104 MW of load-serving capacity to the Tejon area.

Thermal overloads seen with the updated load projection are shown in Figure 2.5-21 below:

Figure 2.5-21: Tejon Area Configuration and Overloads



The ISO recommends approval of the “Tejon Area Reinforcement Project” which includes the following:

- Reconductor of the Wheeler Ridge – Tejon 70kV line;
- Reconductor of the Wheeler Ridge – San Bernard 70kV line; and
- Reconductor of the San Bernard – Tejon 70kV line and replace the limiting disconnect switches.

The estimated to cost of the project is $28 - $56 million with an estimated completion date of 2029.

Reedley 70 kV Capacity Increase Project

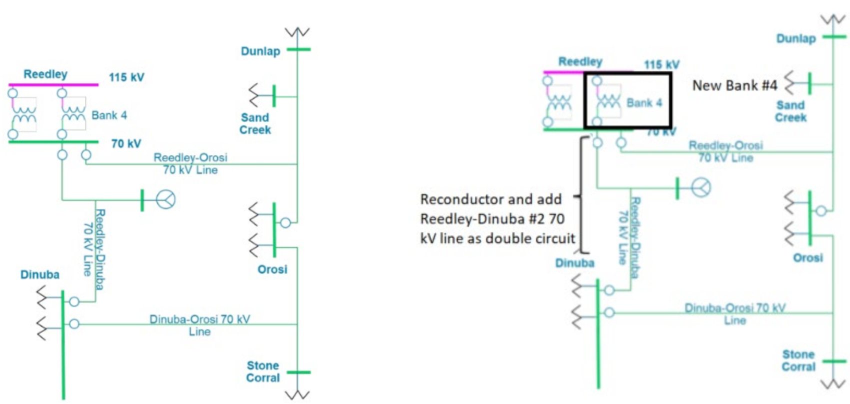
This project was submitted by PG&E to address 70 kV line and 115/70 kV bank overloads in Reedley area. The two 115/70 kV transformer banks (#2 and #4) at Reedley substation supply the load in this 70 kV area through the Reedley-TIVY Valley, Reedley-Dinuba #1, Reedley-Orosi, and Dinuba-Orosi 70 kV lines. In both near-term and long-term Summer Peak scenarios the P1 contingencies of the Reedley-Dinuba #1 and the Reedley-Orosi 70 kV lines result in thermal overloads. Also in the 2028 and 2035 Summer Peak scenarios, the loss of the Reedley 115/70 kV transformer bank #2 will result in the overload of Reedley 115/70 kV transformer bank #4. The ISO previously approved Reedley 70 kV Reinforcement project that included installing a 12 MW energy storage at Dinuba substation as a transmission asset does not mitigate these constraints and further network upgrades are required to mitigate these NERC Category P1 violations.

The ISO is recommending approval of Reedley 70 kV Capacity Increase project with the following scope:

- Reconductoring the Reedley-Dinuba #1 70 kV line to achieve minimum required rating of 800 Amps and 1000 Amps under summer normal and summer emergency conditions respectively and replace any limiting element(s) as needed;
- Adding a double circuit line Reedley-Dinuba #2 70 kV line to achieve minimum required rating of 800 Amps and 1000 Amps under summer normal and summer emergency conditions respectively and replace any limiting element(s) as needed; and
- Upgrading Reedley 115/70 kV transformer bank #4 to achieve the summer normal rating of 200 MVA.

With this recommended project, the previously approved Reedley 70 kV Reinforcement project will no longer be needed and can be cancelled. The estimate cost of the project is $49 -$98 million with an estimated in-service date of May 2030 or earlier.

Figure 2.5-22: Reedley 70 kV capacity increase single line diagrams- recommended



(a) Existing single line diagram (b) Proposed single line diagram

2.5.3 Previously Approved Projects on Hold

Moraga-Sobrante 115 kV Line Reconductor Project

The ISO recommends the Moraga-Sobrante remain on hold for this planning cycle. The reliability assessment of the PG&E Greater Bay planning area in Section 3.5 of Appendix B identified contingencies (P2 and P5) which resulted in overloads on the Moraga-Sobrante 115 kV line only in the longer-term planning horizon. The ISO will continue to assess the need in future planning cycles.

2.5.4 Projects under Review for Potential Approval in 2023-2024 Transmission Planning Process

Oakland Area Reinforcement Project

As a result of increases in the load forecast in the Oakland area, a number of overloads were observed on most of the 115 kV lines serving this area. The previously approved OCEI project is not sufficient to mitigate the overloads. This has led to the need for additional transmission upgrades in the area. The aim of this project will be to supply the anticipated increased load in Oakland without relying on the local aging Oakland thermal units. The ISO recommends the previously approved OCEI project to move forward as designed, which will help reduce reliance on the local thermal units while the additional transmission upgrades are being developed and implemented.

The Oakland area, being a densely populated urban area, poses challenges in assessing the potential alternatives to mitigate the overloads. Based on the power flow simulations, the forecast load growth, and the Oakland grid topology, the addition of a new 230/115 kV substation in the southwest part of Oakland providing a new supply point to the 115 kV in the area, as indicated in Alternative 1 below, is the preferred alternative. The feasibility of potential locations for a new substation and the preferred 230 kV transmission line(s) to interconnect a new Oakland 230/115 kV substation are still being assessed.

Alternative 1: New 230/115 kV substation

The scope of this alternative requires to build a new 230/115 kV substation in the Oakland west area (nearby the Oakland C, Oakland L, and Oakland D substations), as follows:

- Equipment in the 230/115 kV substation:
  - Two or thre 230 kV connections (one bank and one or two lines)
  - Five 115 kV connections (one bank and four lines/cables)
  - 1x230/115 kV transformers (420 MVA)

- 230 kV lines options to interconnect the new substation:
    - **Option 1.** Moraga-New Oakland 230 kV substation (requires one connection in Moraga);
    - **Option 2.** Sobrante-New Oakland 230 kV substation (requires one connection in Moraga);
    - **Option 3.** Loop-in the Moraga – Parkway 230 kV line in the New Oakland 230 kV substation; or
    - **Option 4.** Embarcadero-New Oakland 230 kV substation (requires one connection in Embarcadero and possibly a power flow control device); and
- 115 kV lines from the new substation:
    - One 115 kV lines to Oakland C (requires one connection in 115 kV at Oakland C);
    - Two 115 kV lines to Oakland L; and
    - One 115 kV line to Oakland D (requires one connection in 115 kV at Oakland D)

Alternative 2: Oakland 115 kV lines reinforcement

This alternative upgrades the current transmission lines and cables in Oakland by reconductoring to the highest feasible capacity.

The scope for this alternative is as follows:

- Increase capacity of the Moraga-Claremont #1 and #2 115 kV lines from 111 MVA up to 140 MVA;
- Increase capacity of the Claremont-D #1 and #2 115 kV lines from 204 up to 225 MVA;
- Increase capacity of the Oakland C-X #2 115 kV line from 157 MVA up to 240 MVA; and
- Increase capacity of the D-L line from 157 MVA up to 280 MVA;
- Increase capacity of the L-C line from 157 MVA up to 280 MVA

Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers

This project was proposed by SDG&E 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.

The project involves the following:

- Install two sets of 10 Ohm current limiting reactors (CLRs) in series with the 230 kV buses, one on each side
- 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 bus section 2
- Preserve the 63 kA Circuit Breakers

The estimated cost for this project is $97 million with a targeted in-service date of 2035.

Short Circuit Mitigation for Miguel 230 kV Circuit Breakers

This project was proposed by SDG&E as a reliability transmission solution to address the SCD concerns since all of the 63 kA CBs at Miguel 230 kV substation will overstress considering the previously approved projects and the CPUC's base portfolio.

The project involves the following:

- Open Miguel 230 kV CB 6X
- Operate TL23042C Miguel – Miguel 6X Tap normally open
- Modify TL 23041 / TL 23042 RAS to consider Miguel CB 6X status
- Install a CLR in series with TL23026 Silvergate – Bay Boulevard 230 kV line

The alternative assessment will be conducted as an extension of the 2023-2024 Transmission Plan, with ISO Board of Governor approval anticipated to be sought in Q2 or Q3 of this year.

2.6 Conclusion

The 19 new reliability-driven projects required in this transmission planning cycle for a total estimated cost of $1.54 billion are listed below. Table 2.6-1 includes the 7 projects that were approved by ISO management in this planning cycle.

Table 2.6-1: Management Approved Transmission Projects

No.	Project Name	PTO Area	Planning Area	Est. Cost ($M)
1	Covelo 60 kV Voltage Support[33]	PG&E	North Coast / North Bay	22
2	Martin-Millbrae 60 kV Area Reinforcement[33]	PG&E	Greater Bay Area	40
3	Atlantic High Voltage Mitigation[33]	PG&E	Central Valley	40
4	Mira Loma 500 kV Bus SCD Mitigation[33]	SCE	SCE Bulk	5
5	Inyo 230 kV Shunt Reactor[33]	SCE	North of Lugo	20
6	Etiwanda 230 kV Bus SCD Mitigation[33]	SCE	SCE Eastern	15
7	Eldorado 230 kV Short Circuit Duty Mitigation[33]	SCE	East of Lugo	48.8
8	Valley Center System Improvement	SDG&E	SDG&E	51
9	Camden 70 kV Reinforcement	PG&E	Greater Fresno	100
10	Gates 230/70 kV Transformer Addition	PG&E	Greater Fresno	72
11	Reedley 70 kV Capacity Increase	PG&E	Greater Fresno	98
12	Diablo Canyon Area 230 kV High Voltage Mitigation	PG&E	Central Coast & Los Padres	70
13	Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring	PG&E	Central Coast & Los Padres	108
14	Vaca-Plainfield 60 kV Line Reconductoring	PG&E	Central Valley	68
15	Rio Oso - W. Sacramento Reconductoring	PG&E	Central Valley	97.4
16	Cortina #1 60 kV Line Reconductoring	PG&E	Central Valley	94.3
17	Salinas Area Reinforcement	PG&E	Central Coast & Los Padres	452.3
18	Tejon Area Reinforcement	PG&E	Kern	56
19	French Camp Reinforcement	PG&E	Central Valley	84.2
			Total	**1,542**

Also, the alternative assessment for the Oakland Area Reinforcement Project will be conducted as an extension of the 2023-2024 Transmission Plan, with ISO Board of Governor approval anticipated to be sought in Q2 or Q3 of this year.

[33] These projects have already been approved by ISO Management, ahead of the rest of the Plan being approved 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.

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Chapter 3

3 Policy-Driven Need Assessment

3.1 Background and Objective

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[34] on February 8, 2018, which adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the state achieve its 2030 GHG reduction target, at least cost, while maintaining electric service reliability and meeting other state goals. In subsequent years, the CPUC has been developing integrated resource plans and transmitting them to the ISO for use in the annual transmission planning process.

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 23-02-040 [35] on February 28, 2023 adopting a base and a sensitivity portfolio for use in the 2023-2024 Transmission Planning Process (TPP). The portfolios are based on the 30-million metric ton (MMT) greenhouse gas (GHG) target by 2030 and the 2021 Integrated Energy Policy Report demand forecast utilizing the additional transportation electrification (ATE) scenario. The base portfolio is used to identify reliability and policy-driven transmission needs for approval in the ISO 2023-2024 TPP. The sensitivity portfolio is intended to test the transmission needs associated with 13.4 GW of offshore wind (OSW). The Decision is accompanied by a document entitled Modeling Assumptions for the 2023-2024 Transmission Planning Process[36], which provides the methodology and results of the resources-to-busbar mapping[37] process as well as other assumptions for use in the ISO 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.

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

[35] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF

[36] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/modeling_assumptions_2023-24tpp_v02-23-23.pdf

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

3.2 Objectives of policy-driven assessment

Key objectives of the policy-driven assessment are to:

- Assess the transmission impacts of portfolio resources using:
    - Reliability assessment,
    - Peak and Off-peak deliverability assessment, and
    - Production cost simulation;
- Identify transmission upgrades or other solutions needed to ensure reliability, deliverability or alleviate excessive curtailment;
- Gain further insights to inform future portfolio development; and
- Set out the zonal capacities that are being established through coordinated transmission planning and resource planning, to shape and guide interconnection and resource procurement.

3.3 Study methodology and components

The policy assessment is geared towards capturing the impact of resource build-out on transmission infrastructure, identifying any required upgrades, and generating transmission input for use by the CPUC in the next cycle of portfolio development. The following provides a description of the assessments the ISO undertakes under the umbrella of the overall policy-driven transmission analysis to integrate the resources identified in the CPUC portfolios to meet the state's greenhouse gas goals.

Policy-driven reliability assessment

The policy-driven reliability assessment is used to identify transmission constraints that need to be modeled in production cost simulations to capture the impact on renewable curtailment of the constraints caused by transmission congestion. The reliability assessment component of the overall policy-driven analysis is addressed in the reliability assessment 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 sub-area to the aggregate of the ISO control-area load when the generation is needed most. The ISO performs the assessment in accordance with the On-peak Deliverability Assessment Methodology.[38]

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

Off-peak deliverability assessment

The off-peak deliverability assessment is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The ISO performs the assessment in accordance with the Off-Peak Deliverability Assessment Methodology.[39]

Production cost model (PCM) simulation

Production cost models for the base and sensitivity portfolios are used to identify renewable curtailment and transmission congestion in the ISO Balancing Authority Area. The PCM for the base portfolio is used in the policy-driven assessment covered in this section as well as the economic assessment discussed in Chapter 4 and Appendix G. The PCM with the sensitivity portfolios is used only in the policy-driven assessment. Details of PCM modeling assumptions and approaches are provided in Chapter 4 and Appendix G.

3.4 Resource Portfolios

As mentioned in Section 3.1, a base portfolio and a sensitivity portfolio were transmitted by the CPUC for study in the ISO 2023-2024 transmission planning process. The detailed portfolios are available at the CPUC website.[40]

Table 3.4-1 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 portfolios are comprised of solar, wind (in-state, out-of-state and offshore), battery storage, geothermal, long-duration energy storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.4-1: Base and Sensitivity Portfolios by Resource Type and Deliverability Status (2035)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	15,636	23,311	38,947	11,442	14,304	25,746
Wind – In State	2,511	564	3,074	2,511	564	3,074
Wind – Out-of-State (Existing TX)	690	100	790	690	100	790
Wind – Out-of-State (New TX)	4,828	-	4,828	4,828	-	4,828
Wind - Offshore	4,546	161	4,707	13,239	161	13,400
Li Battery	28,374	-	28,374	23,545	-	23,545
Geothermal	2,037	-	2,037	1,149	-	1,149
Long-duration Energy Storage (LDES)	2,000	-	2,000	1,000	-	1,000
Biomass/Biogas	134	-	134	134	-	134
Distributed Solar	125	-	125	125	-	125
Total	**60,880**	**24,135**	**85,015**	**58,663**	**15,129**	**73,791**

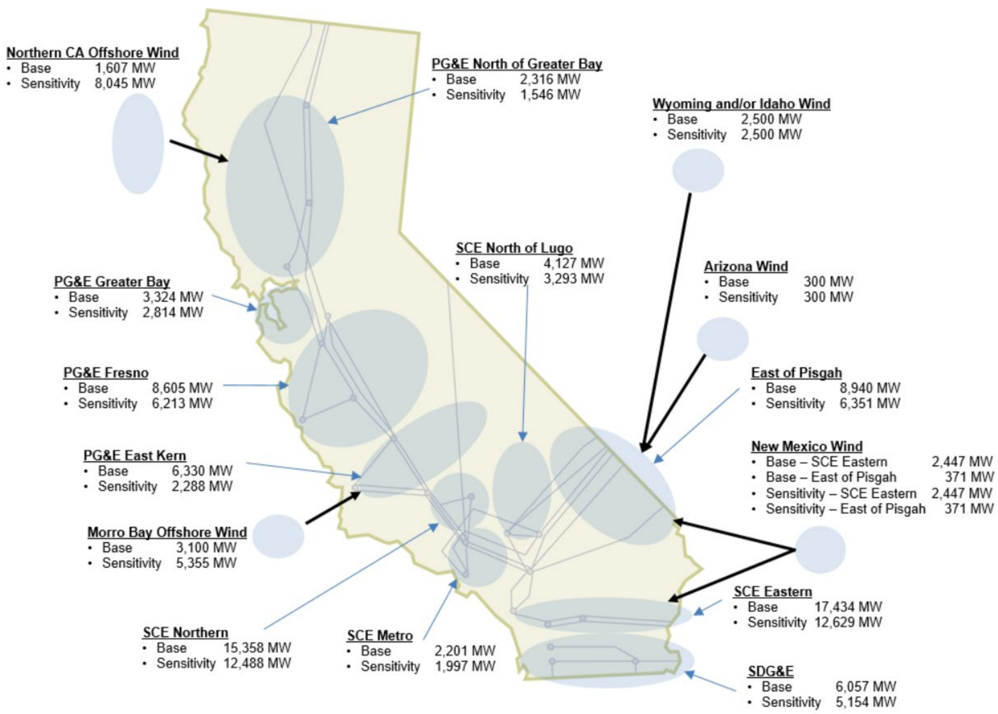
39 http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

40 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

3.4.1 Mapping of portfolio resources to transmission substations

The portfolios that RESOLVE[41] generates are at the zonal level. As a result, the portfolios have to be mapped to the busbar level for use in the ISO transmission planning process. The resource-to-busbar mapping process is documented in the CPUC report entitled *Methodology for Resource-to-Busbar Mapping & Assumptions for the Annual TPP*[42] with further refinements as described in the CPUC staff report entitled *Modeling Assumptions for the 2023-2024 Transmission Planning Process.*[43] Workbooks containing the busbar mapping results are provided for years 2033[44] and 2035[45] for the base portfolio and year 2035[46] for the sensitivity portfolio. The policy-driven assessment is primarily performed for year 2035. Figure 3.4-1 illustrates the interconnection planning areas along with total base and sensitivity portfolio resource amounts in each area for year 2035 based on the CPUC busbar mapping results.

Figure 3.4-1: Base and Sensitivity Portfolios Total MW in Each Interconnection Area for Year 2035



41 RESOLVE is the resource optimization model that the CPUC uses to develop resource portfolios

42 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/busbarmethodologyfortppv20230109.pdf

43 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/modeling_assumptions_2023-24tpp_v02-23-23.pdf

44 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/busbardashboard2033_30mmt_hebase_vd_02-22-23.xlsx

45 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/busbardashboard2035_30mmt_hebase_vd_02-22-23.xlsx

46 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/busbardashboard2035_oswsens_vd_02-23-23.xlsx

3.5 Transmission Interconnection Zone Assessments

On-peak and off-peak deliverability assessments were conducted for each of the transmission interconnection zones to determine where constraints are on the transmission system that limit deliverability of portfolio resources. The assessment for the sensitivity portfolio was performed only for the PG&E area because the portfolio is intended to test the transmission needs associated with 13.4 GW of offshore wind and contains less resources in southern California than the base portfolio.

Transmission mitigation is identified to address the constraints after considering other solutions so resources in the portfolio can be deliverable. The ISO then conducts its technical and economic evaluations of the transmission alternatives identified by the ISO or by stakeholders to select the most effective and efficient solution. Details of the technical assessments and comparisons of alternatives are provided in Appendix F.

The following section identifies the policy-driven projects that are recommended for approval. In total, the policy assessment has identified 7 new policy-driven projects required in this transmission planning cycle for a total estimated cost of $3.931 billion.

3.5.1 PG&E North of Greater Bay Interconnection Area

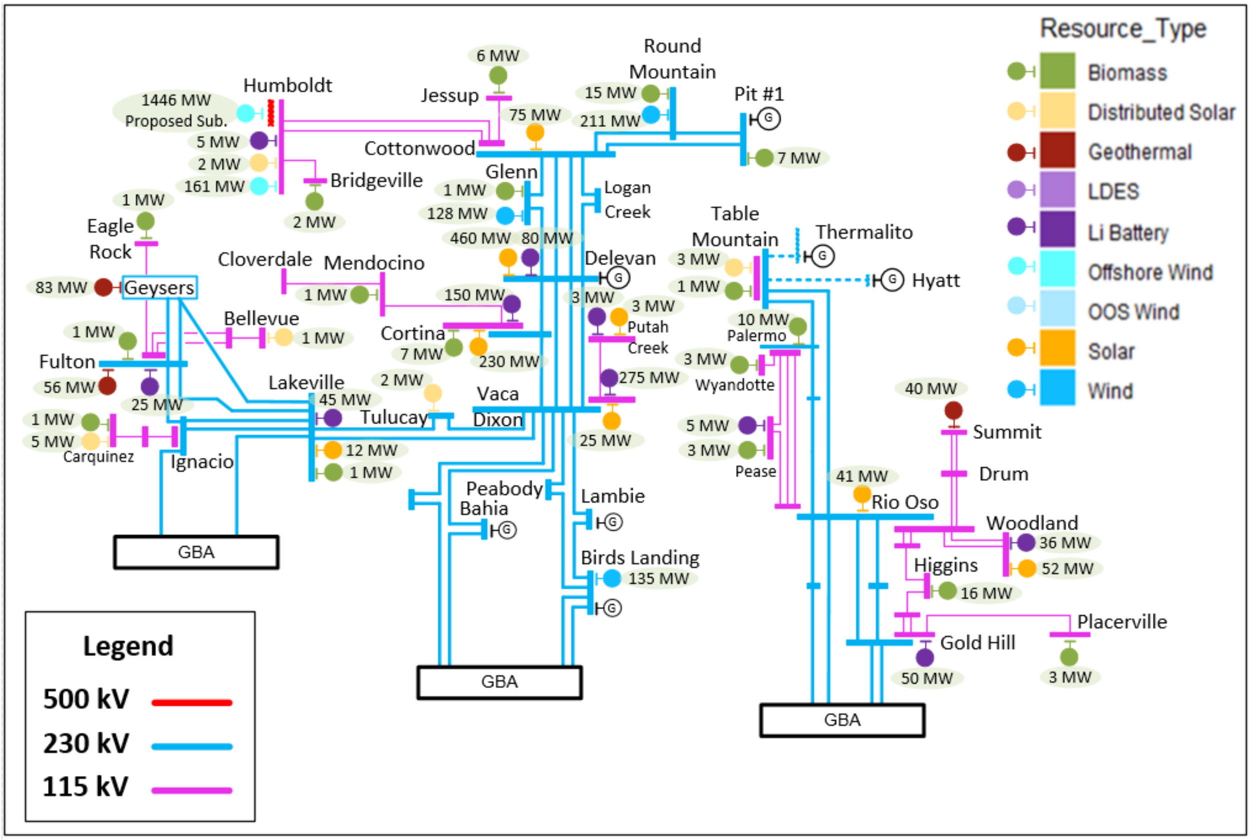
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E and North of Greater Bay interconnection area are listed in Table 3.5-1. The portfolios in the interconnection area are comprised of solar, wind (in-state and offshore), battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-1: PG&E North of Greater Bay Interconnection Area –
Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	185	713	898	5	277	282
Wind – In State	320	154	474	320	154	474
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	1,446	161	1,607	7,884	161	8,045
Li Battery	674	-	674	565	-	565
Geothermal	179	-	179	135	-	135
Long-duration Energy Storage (LDES)	-	-	-	-	-	-
Biomass/Biogas	79	-	79	79	-	79
Distributed Solar	13	-	13	13	-	13
Total	**2,895**	**1,027**	**3,923**	**9,000**	**591**	**9,591**

The resources as identified in the CPUC busbar mapping for the PG&E North of Greater Bay interconnection area are illustrated on the single-line diagram in Figure 3.5-1.

Figure 3.5-1: North of Greater Bay Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the North of Greater Bay interconnection areas along with the recommended mitigation plans are identified in Table 3.5-2.

Table 3.5-2: North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Hopland 115/60 kV transformer bank	Base	2	0	0	62	Maintenance Project
	Sensitivity	1	22	0	466	
Geyser56-MPE Tap 115 kV	Base	1	0	0	119	This constraint is a local constraint and therefore will be addressed in the GIP.
	Sensitivity	0	0	0	0	
Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115kv to Hopland Jct 115kv)	Base	1	0	0	217	This constraint is a local constraint and therefore will be addressed in the GIP.
	Sensitivity	206	432	614	34	
Cascade-Deschutes 60 kV Line	Base	6	5	0	28	This constraint is a local constraint and therefore will be addressed in the GIP.
	Sensitivity	1	22	0	29	
Fulton - Hopland 60 kV (Hopland Jct 60 kV to Cloverdale Jct 60 kV to Geysers Jct 60 kV)	Base	2	232	84	151	Existing LDNU
	Sensitivity	206	432	614	34	

Based on the constraints identified in Table 3.5-2, there are no policy-driven upgrades identified in the North of Greater Bay interconnection planning areas. There is an existing maintenance project for the Hopland 115/60 kV bank. There is an existing LDNU that will address the Fulton-Hopland 60 kV line.

Off-Shore Wind Deliverability Baseline Assessment

In the Humboldt area, the base portfolio included 1,607 MW (1,446 MW FCDS and 161 MW EO) and the sensitivity portfolio included 8,045 MW of offshore wind. There is no existing bulk substation in the vicinity of Humboldt offshore wind. Eight options in the baseline and sensitivity portfolios were considered to interconnect Humboldt offshore wind to the rest of the system (Figure 3.5-2). These options along with the study results are detailed in the following sections.

Figure 3.5-2: Interconnection options considered for Humboldt Bay Offshore Wind

Concept/ Alternative	500 kV AC	Onshore HVDC	Offshore HVDC
Base_A	2 Fern Road	0	0
Base_B	0	1 Collinsville	0
Base_C	0	0	1 Moss Landing
Base_D	0	0	1 Bay Hub

Concept/ Alternative	500 kV AC	Onshore HVDC	Offshore HVDC
Sen _A_1	1 Fern Road	1 Collinsville	1 Bay Hub
Sen _A_2	1 Fern Road	1 Collinsville	1 Moss Landing
Sen_B	1 Fern Road	2 Collinsville	0
Sen_C	2 Fern Road	0	1 Bay Hub

Table 3.5-3: Humboldt Offshore Wind related On-Peak Deliverability Constraints in Base Portfolio

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Table Mountain – Vaca Dixon 500kV line	Base Case	122%	<100%	103%	101%
	TABLE MTN-TESLA 500KV	129%	103%	106%	105%
Fern Rd – Table Mountain 500 kV line #1	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	106%	<100%	<100%	<100%
Fern Rd – Table Mountain 500 kV line #2	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	107%	<100%	<100%	<100%
Table Mountain – Tesla 500 kV line	TABLE MTN-VACA 500KV	114%	<100%	<100%	<100%
Vaca – Collinsville 500 kV line	TABLE MTN-TESLA 500KV	106%	<100%	<100%	<100%
Collinsville – PittsburgE 230kV line	Base Case	106%	112%	<100%	<100%
Collinsville – PittsburgF 230kV line	Base Case	<100%	110%	<100%	<100%
	COLLINSVILLE-PITTSBURG-E #1 230KV	124%	130%	<100%	106%
North Dublin -Vineyard 230 kV	CONTRA COSTA-LAS POSITAS 230KV	<100%	103%	100%	<100%
Cayetano-Lone Tree (USWP-Cayetano) 230kV Line	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	100%	<100%	<100%	<100%
Tesla - Newark 230 kV Line No. 2	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	<100%	107%	104%	<100%
Henrietta-GWF 115 kV Line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	<100%	<100%	<100%	103%
Eastshore 230/115kV Transformer #1	E. SHORE 230/115KV TB 2	<100%	<100%	<100%	107%
Eastshore 230/115kV Transformer #2	E. SHORE 230/115KV TB 1	<100%	<100%	<100%	108%
Cortina - Mendocino 115 kV Line (Indian Valley – Lucern)	EAGLE ROCK-CORTINA & EAGLE ROCK-REDBUD LINES (2)	<100%	<100%	101%	<100%
Eagle Rock - Cortina 115 kV (Cortina to Highland)	CORTINA-MENDOCINO #1 115KV	<100%	<100%	100%	<100%
Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	<100%	<100%	104%	100%

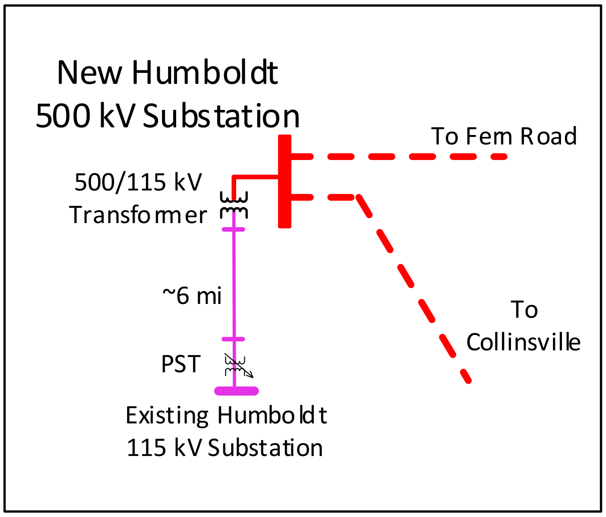
Table 3.5-4: Summary of potential mitigations and cost estimates

Potential Mitigation	Base A	Base B/E	Base C	Base D	Base E
Interconnection	**$2.1B-$3.0B**	**$3.2B-$4.6B**	**$4.5B-$6.6B**	**$4.9B-$7.0B**	**$2.9B-$4.2B**
North Dublin -Vineyard 230 kV Reconductor		$116M-$233M	$116M-$233M		$116M-$233M
Tesla - Newark 230 kV Line No. 2 Reconductor		$29M-$58M	$29M-$58M		$29M-$58M
Henrietta-GWF 115 kV Line Reconductor				$107M-$215M	
New Fern Road- Tesla 500 kV Line	$1.4B-2.0B				
Reinstate 500 kV Line Rerates		PG&E maintenance	PG&E maintenance	PG&E maintenance	PG&E maintenance
New Eastshore 230/115kV Transformer #3				$120M-$240M	
Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap) Reconductor			existing LDNU	existing LDNU	
Collinsville 230 kV Reactor	$39-58M	$39-58M		$39-58M	$39-58M
Total Mitigation Cost	**$1.4B- $2.1B**	**$184M-$349M**	**$145M-$291M**	**$266M-$513M**	**$184M-$349M**
Total Mitigation and Interconnection Costs	**$3.5B – $5.1B**	**$3.3B- $4.9B**	**$4.6B- $6.9B**	**$5.1B- $7.5B**	**$3.1B - $4.5B**

Interconnection to Humboldt 115 kV System

Humboldt area is currently supplied by local gas generation and through two 115 kV lines from Cottonwood substation around 120 miles away. To enhance the resiliency of the Humboldt 115 kV system and allow for the retirement of gas generation in the long term, in all alternatives the ISO is proposing to provide another supply to the area from the Humboldt 500 kV substation. The interconnection includes a 500/115 kV transformer at Humboldt 500 kV substation, a 115 kV line from Humboldt 500 kV to existing Humboldt 115 kV substation, and a 115kV/115 kV phase shifting transformer (PST) at Humboldt 115 kV substation. The PST will help to control the flow and prevent overload as the amount of offshore wind generation varies in real time operation. The schematic diagram of the interconnection is provided in Figure 3.5-2

Figure 3.5-2: Interconnecting Humboldt 500 kV substation to Humboldt 115 kV substation



In addition to Alternatives A, B, C and D, the ISO also considered a fifth alternative E, see Figure 3.5-3, that the ISO is recommending for approval that provides more flexibility for implementation in the short term and for expansion in the long term. This option has all of the same downstream mitigation needs as for option B and:

- Will provide more flexibility as offshore wind development progresses;
- Ensure transmission will not be stranded in the event that offshore wind does not get developed as quickly as anticipated or if it shifts to a different call area;
- Provides a parallel path to the existing 500 kV lines from Round Mountain to Tesla which provides an opportunity in the long term to reconductor/rebuild the existing lines rather than building new lines in new right of ways; and
- Has the lowest cost estimate compared to other combinations of interconnection and associated mitigations.

Given the overall cost estimates for the interconnection and associated mitigation solutions, the ISO is recommending Option E for approval, which includes:

- New Humboldt 500 kV substation, with a 500/115 kV transformer; and building approximately 260 mile HVDC line, initially operated as 500 kV AC line to interconnect Humboldt 500 kV to the Collinsville substation;
    - Estimated cost of $1,913 – $2,740 million;
- Building approximately 140 mile, 500 kV AC line to interconnect Humboldt 500 kV to the Fern Road substation;
    - Estimated cost of $980 – $1,400 million; and
- A 115 kV/115 kV phase shifting transformer (PST) and a 115 kV line from Humboldt 500 kV to existing Humboldt 115 kV substation.
    - Estimated at $40 – $57 million.

The total estimated cost of Alternative E is \$3.1B to \$4.5 B with and estimated in-service date of 2034[47].

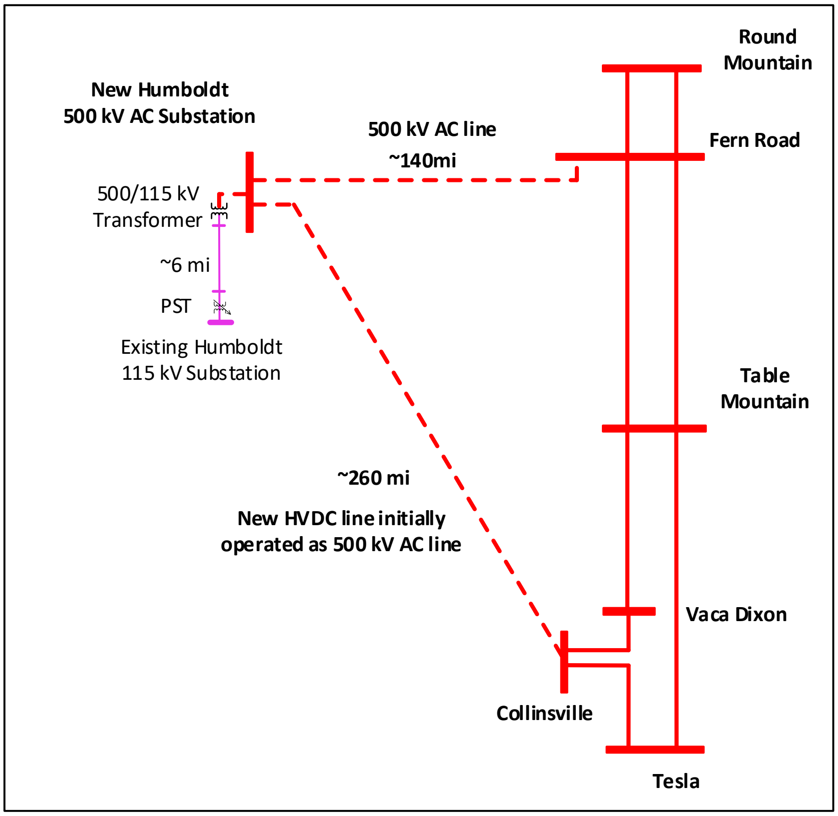
The ISO acknowledges and appreciates stakeholder concerns expressed through the transmission planning stakeholder process regarding the inherent uncertainty with the development of new technologies such as floating offshore wind off the California coast. In balancing the need to engage promptly on long lead time transmission yet remain in step with the numerous other parallel development paths needed to enable offshore wind to develop, the ISO is committed to both seeking to prudently manage expenditures that could be the subject of cost recovery processes, as well as providing industry transparency on the pace of transmission development activities and associated cost exposure. Accordingly, the functional specifications for these projects set out additional informational expectations to facilitate these efforts, and the ISO will explore how best provide industry transparency once a project sponsor has been selected through the ISO's competitive process.

The CEC has posted under its AB525 Reports webpage[48] a high-level corridor assessment related to the development of potential electric transmission infrastructure needed to access wind energy in federal waters offshore Humboldt County.

[47] The CPUC base portfolio for 2023-2024 transmission planning process indicated 2035; however the CPUC has indicated 2034 for 900 MW of offshore wind in the Humboldt area in the base portfolio for the 2024-2025 transmission planning process.

[48] https://www.energy.ca.gov/data-reports/reports/ab-525-reports-offshore-renewable-energy

Figure 3.5-3: Overall Recommended Alternative to Interconnect Humboldt to Fern Road and Collinsville

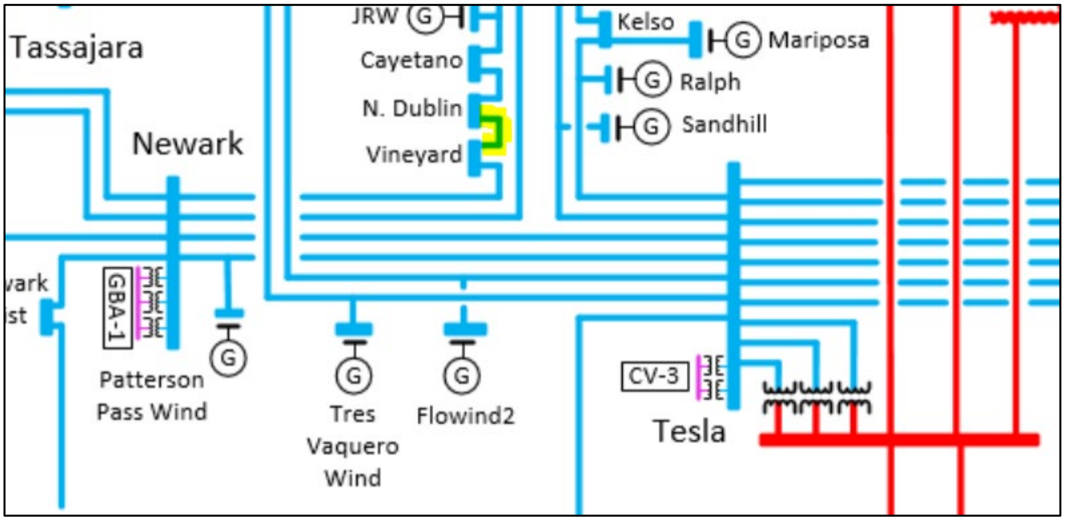


Recommended additional downstream mitigations needed for the Alternative E are identified below.

North Dublin -Vineyard 230 kV Reconductor

To mitigate P1 overloads identified as part of Interconnection Alternative E, the ISO is recommending approval of the North Dublin – Vineyard 230 kV reconductoring project. This project will cost $116M - $232M and take an estimated 24 months to complete. The scope includes reconductor the North Dublin-Vineyard 230 kV line with minimum summer emergency rating of 1350 AMPS or highest conductor feasible with existing structure and will include any other limiting elements upgraded to achieve the new line rating.

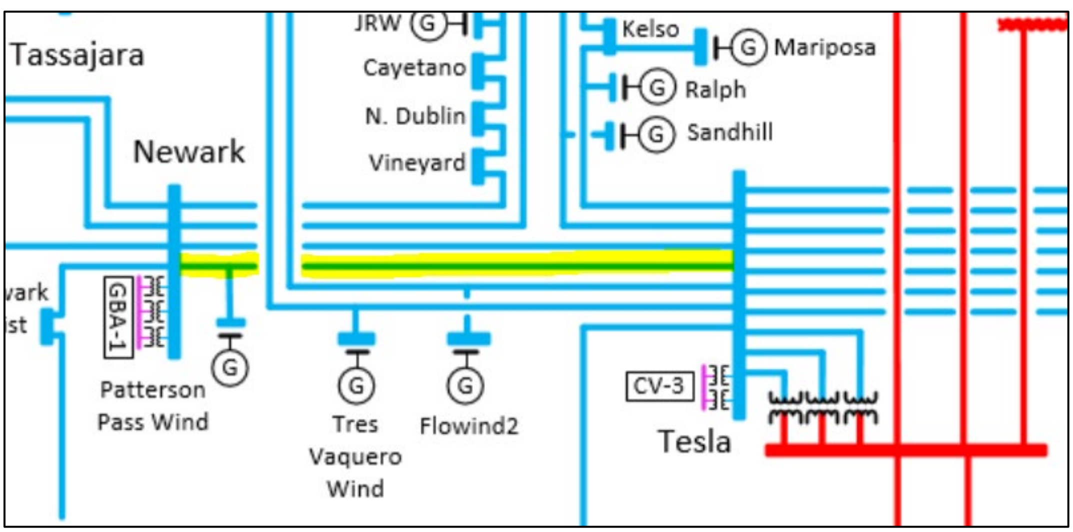
Figure 3.5-4: Recommended North Dublin – Vineyard 230 kV Reconductor



Tesla - Newark 230 kV Line No. 2 Reconductor

To mitigate overloads identified as part of Interconnection Alternative E, the ISO is recommending approval of the Telsa - Newark 230 kV line No 2 reconductoring project. The project will cost $29M - $58M and take an estimated 54 months to complete. The scope includes reconductoring of the Tesla –Newark #2 230 kV line - From 024/148 to Newark (approximately 4.28 miles), with minimum summer emergency rating of 3428 AMPS, matching other sections of the line or highest conductor feasible with existing structure. Will also include any other limiting element upgrades to achieve this line rating.

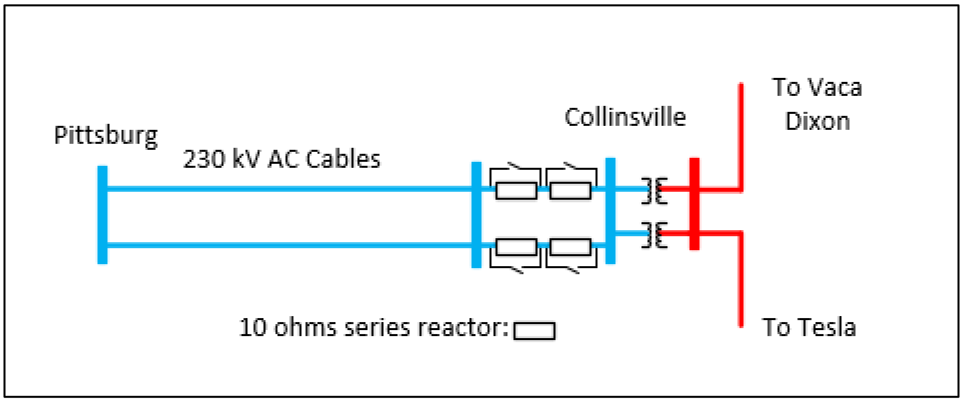
Figure 3.5-5: Recommended Tesla – Newark 230 kV line No 2 Reconductor



Collinsville 230 kV Reactor

To mitigate overloads identified as part of Interconnection Alternative E, the ISO is recommending approval of the Collinsville 230 kV reactors. The project will cost $39M- $58M. The project will go into service congruently with the Collinsville project. The scope includes adding 20 ohm reactors on the Collinsville – Pittsburg 230 kV lines.

Figure 3.5-6: Collinsville 230 kV Reactor



Off-Shore Wind Deliverability Sensitivity Assessment

The sensitivity portfolio includes 8,045 MW of offshore wind in the North Coast. The CPUC Modelling Assumptions for 2023-2024 TPP provided the following guidance:

“... the 13.4 GW of offshore wind have been mapped to one location on the Central Coast (Morro Bay) and three separate locations on the North Coast (Humboldt, Del Norte, and Cape Mendocino) to allow the ISO to identify transmission upgrades and cost information necessary to further advance offshore wind planning in line with the state’s offshore wind policy goals.”

Table 3.5-5: Off Shore Wind On-Peak Deliverability Constraints in Sensitivity Portfolio

Overloaded Facility	Contingency	Sensitivity Alternatives			
		Sen A1	Sen A2	Sen B	Sen C
Table Mountain – Vaca Dixon #1 500kV line	Base Case	<100%	<100%	<100%	134%
	TABLE MTN-TESLA 500KV	101%	101%	<100%	142%
Vaca Dixon – Telsa 500kV line	P1-2:A0:26:_COLLINSVILLE-TESLA 500KV [0]	104%	<100%	131%	139%
Table Mountain – Tesla 500 kV	Base Case	<100%	<100%	<100%	102%
	P1-2:A0:4:_TABLE MTN-VACA 500KV [6090]	<100%	<100%	<100%	116%
Table Mountain – Vaca Dixon #2 500kV line	Base Case	<100%	<100%	<100%	119%
Vaca Dixon – Collinsville #1 500kV line	Base Case	<100%	<100%	<100%	142%
	P7-2:A99:1:_HUMBOLDT OSW-Collinsville HVDC Line [0]	<100%	<100%	<100%	102%
Fern Road – Table Mountain #1 500 kV	Fern Road – Table Mountain #2 500 kV	<100%	<100%	<100%	164%
Fern Road – Table Mountain #2 500 kV	Fern Road – Table Mountain #1 500 kV	<100%	<100%	<100%	164%
Fern Road – Table Mountain #3 500 kV	Base Case	<100%	<100%	<100%	135%
Collinsville – Tesla 500kV line	Base Case	<100%	<100%	109%	<100%
	P1-2:A0:33:_HUMBOLDT OSW-FERN ROAD #1 500KV [6020]	<100%	<100%	139%	<100%
Collinsville 500/230 kV Transformer Bank #1	Collinsville 500/230 kV Transformer Bank #2	<100%	<100%	104%	<100%
Collinsville 500/230 kV Transformer Bank #2	Collinsville 500/230 kV Transformer Bank #1	<100%	<100%	104%	<100%
Collinsville – PittsburgF 230kV line	COLLINSVILLE-PITTSBURG-E #1 230KV	122%	142%	155%	120%
Eastshore 230/115kV Transformer #1	E. SHORE 230/115KV TB 2	111%	<100%	<100%	113%

Overloaded Facility	Contingency	Sensitivity Alternatives			
		Sen A1	Sen A2	Sen B	Sen C
Eastshore 230/115kV Transformer #2	E. SHORE 230/115KV TB 1	112%	<100%	<100%	112%
Martinez-Sobrante 115kV Line	OLEUM-MARTINEZ 115KV	<100%	<100%	101%	<100%
Pease - Marysville - Harter 60 kV Line	PALERMO-NICOLAUS 115KV	<100%	<100%	<100%	101%
Tesla - Newark 230 kV Line No. 2	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	<100%	107%	113%	<100%
Cayetano-Lone Tree (USWP-Cayetano) 230kV Line	CONTRA COSTA-LAS POSITAS 230KV	<100%	101%	111%	<100%
North Dublin -Vineyard 230 kV	CONTRA COSTA-LAS POSITAS 230KV	<100%	101%	113%	<100%
Fulton - Hopland 60 kV (Hopland Jct to Cloverdale Jct)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	103%	<100%	<100%	101%
Round MT- Cottonwood 230 kV line	CAPTJACK-OLINDA 500KV	<100%	<100%	<100%	115%

Off-Peak Deliverability Assessment

In the off-peak deliverability assessment of the North of Greater Bay interconnection, there were no constraints identified for the base portfolios.

3.5.2 PG&E Greater Bay Interconnection Area

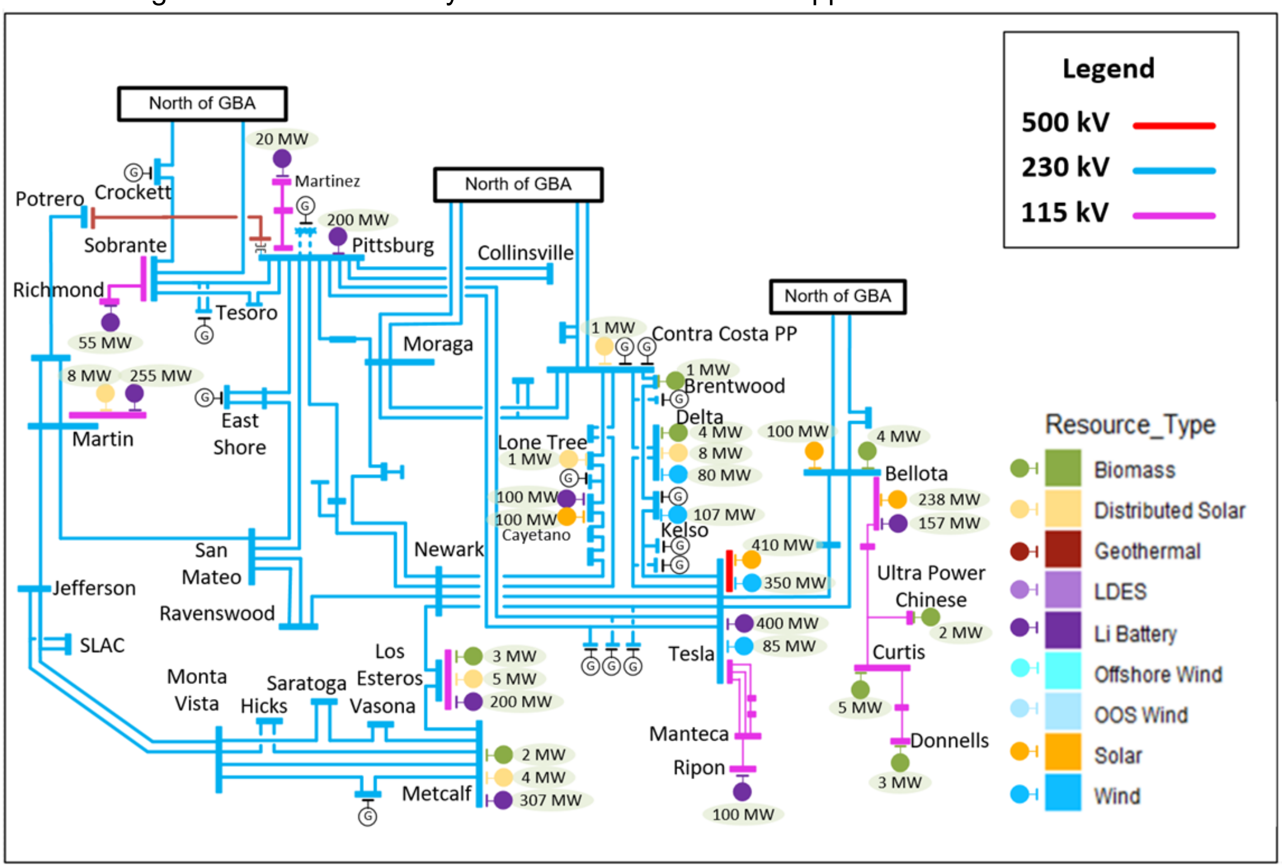
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Bay interconnection area are listed in Table 3.5-1. The portfolios in the interconnection area are comprised of solar, wind (in-state and offshore), battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-6: PG&E Greater Bay Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	500	348	848	-	338	338
Wind – In State	592	30	622	592	30	622
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	-	-	-	-	-	-
Li Battery	1,803	-	1,803	1,803	-	1,803
Geothermal	-	-	-	-	-	-
Long-duration Energy Storage (LDES)	-	-	-	-	-	-
Biomass/Biogas	24	-	24	24	-	24
Distributed Solar	27	-	27	27	-	27
Total	**2,945**	**378**	**3,324**	**2,445**	**368**	**2,814**

The resources as identified in the CPUC busbar mapping for the PG&E Greater Bay interconnection area are illustrated on the single-line diagram in Figure 3.5-7.

Figure 3.5-7: Greater Bay Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Greater Bay interconnection area along with the recommended mitigation plans are identified in Table 3.5-7.

Table 3.5-7 Greater Bay Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

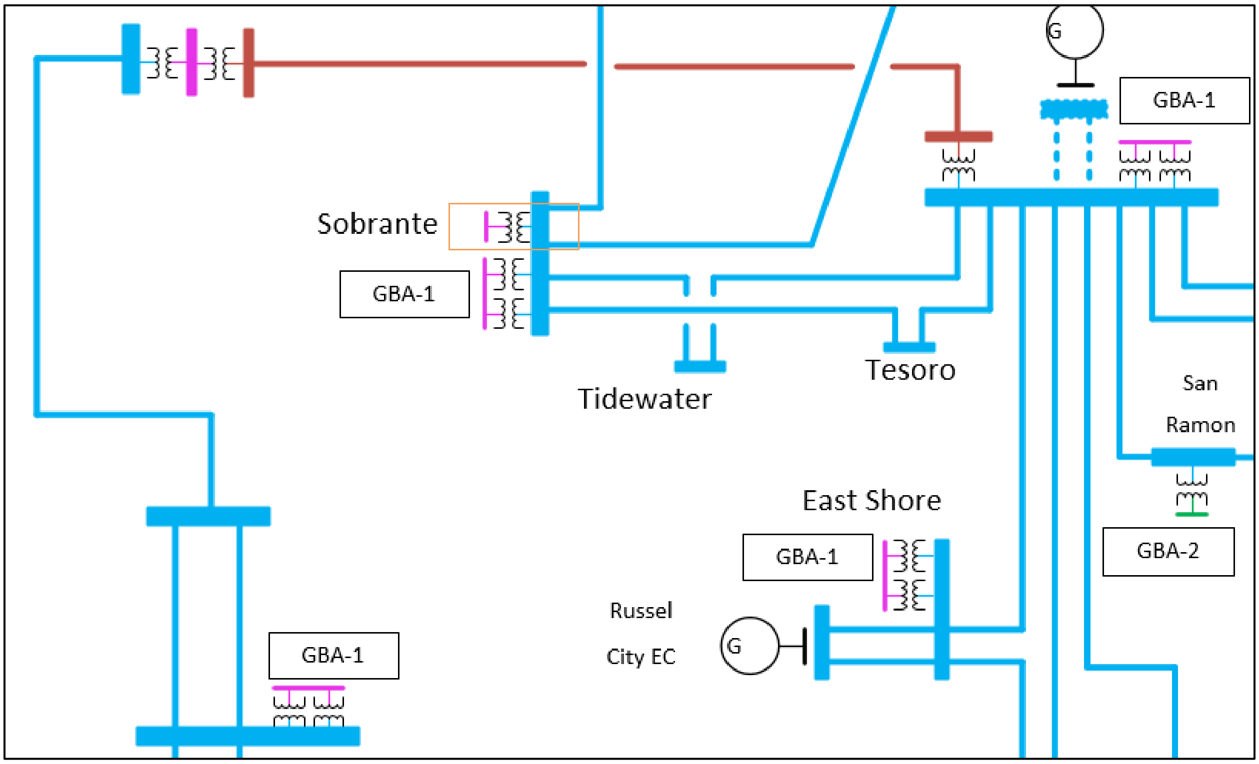
Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Spring Gap-MI-WUK 115 kV Line	Base	3	0	2	2	This constraint is a local constraint and therefore will be addressed in the GIP.
	Sensitivity	0	0	0	0	
Sobrante 230/115 kV Transformer Bank #1/ #2	Base	142	25	0	395	New 230/115 kV Bank ($20M-$40M)
	Sensitivity	98	25	0	655	

Based on the constraints identified in Table 3.5-7, there is one policy-driven upgrade identified in the Greater Bay interconnection planning area.

New Sobrante 230/115 kV Bank #3

To mitigate overloads identified in the on-peak baseline deliverability study, the ISO is recommending for approval the addition of a new 230/115 kV bank at Sobrante. The Project will cost $20M - $40M, with an estimated in-service year of 2034. The scope includes a new 230/115 kV Bank at Sobrante Substation with 420 MVA rating. It will also include any bus upgrades and limiting equipment upgrades to achieve this transformer rating.

Figure 3.5-8: New Sobrante 230/115 kV Bank #3



Off-Peak Deliverability Assessment

In the off-peak deliverability assessment of the Greater Bay interconnection area, there was one constraint identified for the base portfolios. The constraints that were observed in the baseline portfolio only are listed in Table 3.5-8. Potential mitigation has been identified for further assessment in the economic study

Table 3.5-8: Greater Bay Interconnection Area Off-Peak Deliverability Baseline Portfolio

Constraint	Portfolio	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
TESLA 500 kV - LOSBANOS 500 kV Line	Baseline	7443	3184	3767	Reconductor if economic

3.5.3 PG&E Greater Fresno Interconnection Area

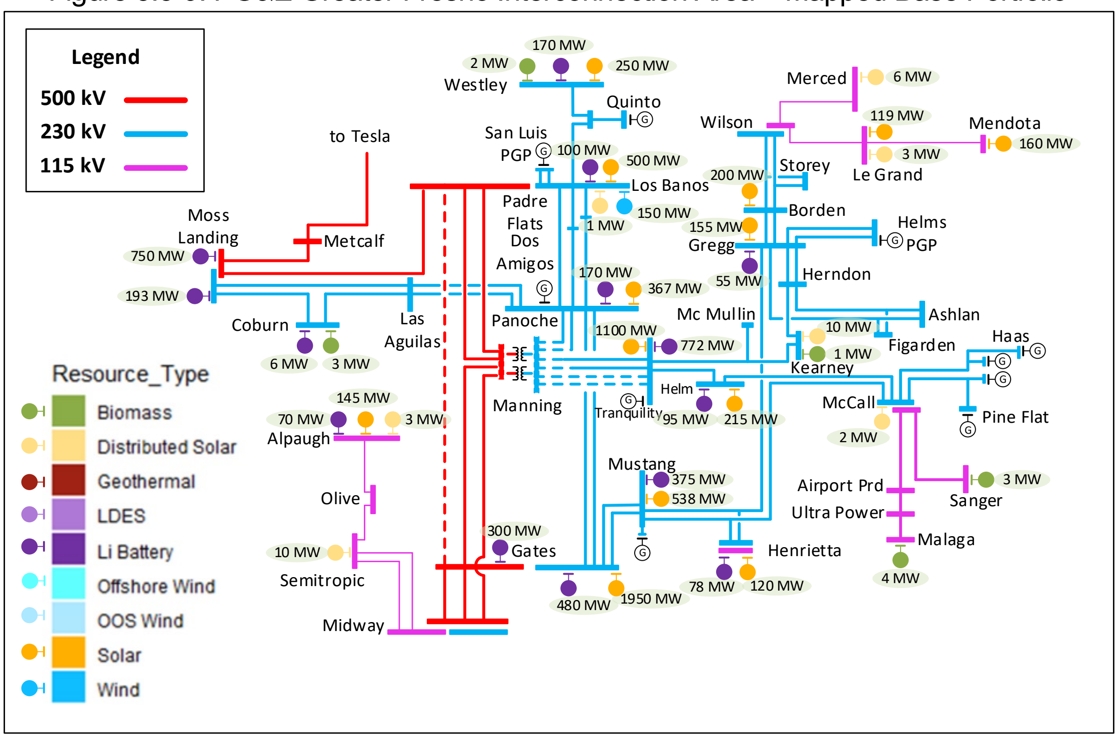
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Fresno interconnection area are listed in Table 3.5-9. The portfolios are comprised of solar, wind (in-state), battery storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-9: PG&E Greater Fresno Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	3,063	2,756	5,819	1,913	1,481	3,394
Wind – In State	150	0	150	150	0	150
Wind – Out-of-State (Existing TX)	0	0	0	0	0	0
Wind – Out-of-State (New TX)	0	0	0	0	0	0
Wind – Offshore	0	0	0	0	0	0
Li Battery	3,614	0	3,614	2,623	0	2,623
Geothermal	0	0	0	0	0	0
Long-duration Energy Storage (LDES)	0	0	0	0	0	0
Biomass/Biogas	12	0	12	12	0	12
Distributed Solar	35	0	35	35	0	35
Total	**6,873**	**2,756**	**9,629**	**4,732**	**1,481**	**6,213**

The resources as identified in the CPUC busbar mapping for the PG&E Greater Fresno interconnection area are illustrated on the single-line diagram in Figure 3.5-9.

Figure 3.5-9: PG&E Greater Fresno Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Greater Fresno interconnection area along with the recommended mitigation plans are identified in Table 3.5-10.

Table 3.5-10: PG&E Greater Fresno Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Mccall 230/115kV Bank 1/3	Baseline	7	95	0	149	This constraint is a local constraint and therefore will be addressed in the GIP.
McCall-Sanger #2 115 kV Line	Baseline	.2	0	0	292	This constraint is a local constraint and therefore will be addressed in the GIP.
McCall-Sanger #2 115 kV Line	Sensitivity	161	0	0	161	This constraint is a local constraint and therefore will be addressed in the GIP.
Herndon-Woodward 115 kV Line	Baseline	7	55	0	225	This constraint is a local constraint and therefore will be addressed in the GIP.

No policy-driven projects are recommended to mitigate the constraints in the Greater Fresno interconnection area.

<u>Off-Peak Deliverability Assessment</u>

The off-peak deliverability constraints identified in the base portfolio assessment of the Greater Fresno interconnection areas, along with the recommended mitigation plans, are identified in Table 3.5-11.

Table 3.5-11: PG&E Greater Fresno Interconnection Area Off-Peak Deliverability Constraints in Base Portfolio

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Huron-Calflax 70 kV line	GATES-PANOCHE #1 230KV & GATES-PANOCHE #2 230KV	101%	0	20	20	Portfolio energy storage in charging mode
Henrietta-Kingsburg 115 kV line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	191%	90	68	270	Reconductor if economic.
Kingsburg 115 kV bustie	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	143%	90	68	276	Reconductor if economic.
Sanger-McCall 115 kV line	MCCALL-SANGER #1 115KV & MCCALL-SANGER #2 115KV	173%	1.4	0	33	Reconductor if economic.
Sanger-Herndon 115 kV line	HENTAP1-MUSTANGSS #1 230KV & TRANQLTYSS-MCMULLN1 #1 230KV	166%	1.4	0	1.4	Reconductor if economic.
LeGrand-Wilson 115 kV line	WILSON-BORDEN 230KV #1 & #2	133%	96	0	96	Reconductor if economic.
Chowchilla-Kerckhoff 115 kV line	WILSON-BORDEN 230KV #1 & #2	118%	1.42	0	1.42	Reconductor if economic.
Gregg-Mustang 230 kV line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	123%	975	628	628	Portfolio energy storage in charging mode
Wilson-Melones 230 kV line	WARNERVILLE-WILSON 230KV	115%	381	75	377	Reconductor if economic.
Wilson-Storey 230 kV line	WILSON-BORDEN #2 230KV	126%	551	123	953	Reconductor if economic.
Las Aguilas-Panoche 230 kV line	LAS AGUILAS SW STA-PANOCHE #1 230KV	128%	290	170	344	Reconductor if economic.
Panoche-Gates 230 kV line	GATES-MANNING 500KV	NCONV	0	181	283	Reconductor if economic.
Los Banos-Panoche 230 kV line	LOS BANOS-PADRE FLAT SW STA 230KV	117%	290	170	623	Reconductor if economic.
Quinto-Los Banos 230 kV line	TESLA-LOS BANOS #1 500KV	NCONV	918	822	926	Reconductor if economic.
Quinto-Fink SS 230 kV line	TESLA-LOS BANOS #1 500KV	NCONV	918	822	926	Reconductor if economic.
Fink SS-Westley 230 kV line	TESLA-LOS BANOS #1 500KV	NCONV	968	1076	810	Reconductor if economic.
Moss Landing-Las Aguilas 230 kV line	Base Case	160	290	170	408	Reconductor if economic.
Warnerville-Wilson 230 kV line	COTTLE-MELONES 230KV	137%	381	75	377	Reconductor if economic.

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Gates-Midway 500 kV line	MIDWAY-MANNING 500KV	NCONV	933	1233	2592	Reconductor if economic.
Gates Bank	MUSTANGSS-GATES #1 230KV & MUSTANGSS-GATES #2 230KV	113%	2246	1407	5428	Reconductor if economic.
Manning-Midway 500 kV line	GATES-MANNING 500KV	NCONV	4294	1283	6636	Reconductor if economic.
Manning-Gates 500 kV line	MIDWAY-MANNING 500KV	NCONV	5109	2337	8977	Reconductor if economic.
Los Banos-Manning 500 kV line	LOSBANOS-MANNING 500KV	206%	5867	3014	11128	Reconductor if economic.
Metcalf-Moss Landing 500 kV line	TESLA-LOS BANOS #1 500KV	NCONV	1565	296	1861	Reconductor if economic.
Tesla-Los Banos 500 kV line	Base Case	180%	5856	1484	9459	Reconductor if economic.
Tracy-Los Banos 500 kV line	Base Case	153%	5109	1295	9032	Reconductor if economic.

3.5.4 PG&E Kern Interconnection Area

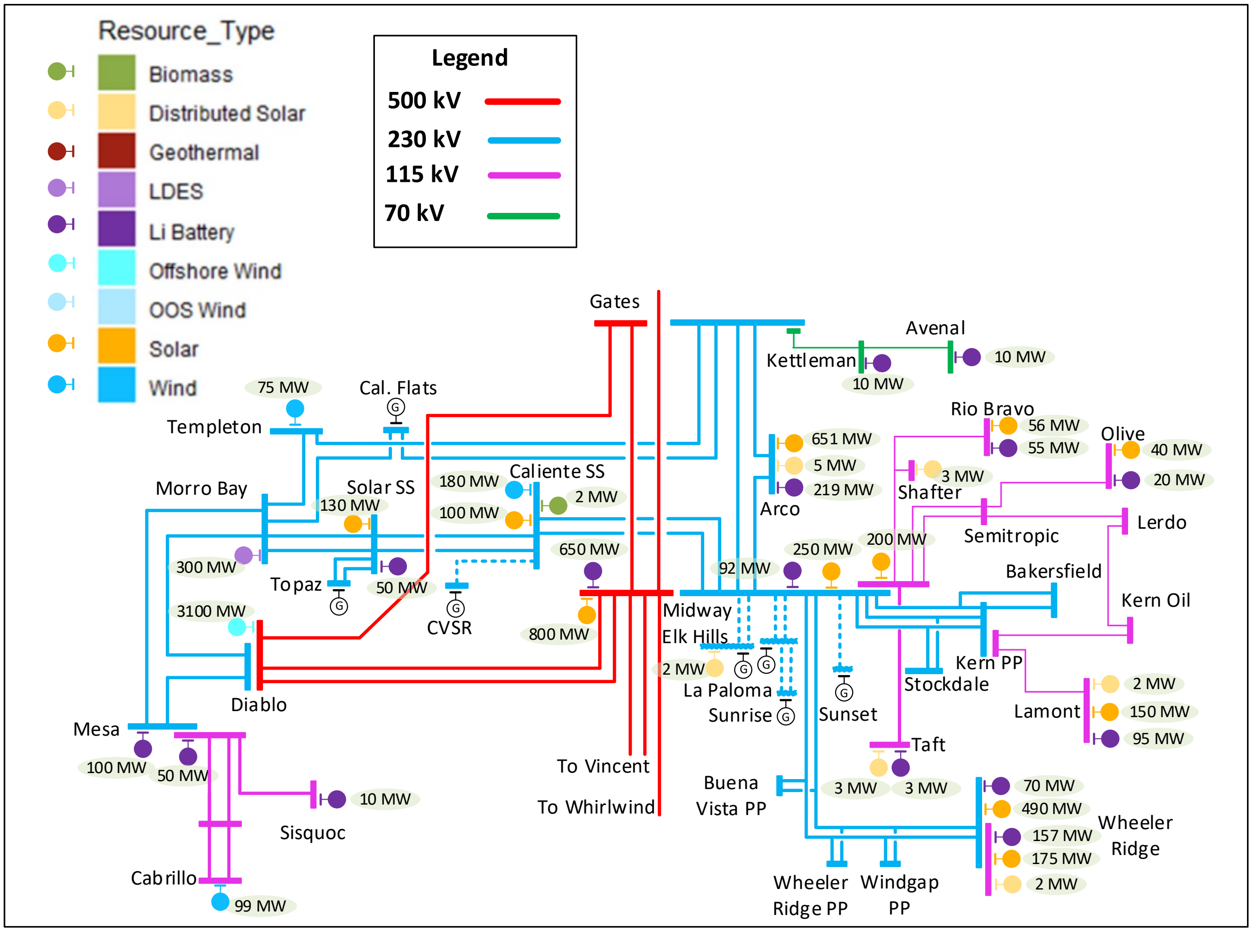
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Kern interconnection area are listed in Table 3.5-12. The portfolios in the interconnect area are comprised of solar, wind (in-state and offshore), battery storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-12: PG&E Kern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	1,060	1,982	3,042	780	556	1,336
Wind – In State	354	-	354	354	-	354
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	3,100	-	3,100	5,355	-	5,355
Li Battery	1,590	-	1,590	578	-	578
Geothermal	-	-	-	-	-	-
Long-duration Energy Storage (LDES)	300	-	300	-	-	-
Biomass/Biogas	2	-	2	2	-	2
Distributed Solar	18	-	18	18	-	18
Total	**6,424**	**1,982**	**8,406**	**7,087**	**556**	**7,643**

The resources as identified in the CPUC busbar mapping for the PG&E Kern interconnection area are illustrated on the single-line diagram in Figure 3.5-10.

Figure 3.5-10: PG&E Kern Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Kern interconnection area along with the recommended mitigation plans are identified in Table 3.5-13.

Table 3.5-13: PG&E Kern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Wheeler 115/70 kV Bank 2	Base	0.2	87	53	34	Relocate policy generation

Based on the constraints identified in Table 3.5-13, there are no policy-driven upgrades identified in the Kern interconnection planning areas

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base portfolio assessment of the Kern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-14.

Table 3.5-14: PG&E Kern Interconnection Area Off-Peak Deliverability Constraints in Base Portfolio

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
San Miguel-Union 70 kV line	TEMPLETON-GATES 230KV & GATES-CALFLATSSS #1 230KV	116%	77	161	161	Portfolio energy storage in charging mode
Casa Loma-Arvin J2 115 kV line	CASALOMA-LAMONT 115KV	135%	111	95	95	Portfolio energy storage in charging mode
Casa Loma-Lamont 115 kV line	CASALOMA-LAMONT 115KV (2)	135%	111	95	95	Portfolio energy storage in charging mode
Smyrna-Olive 115 kV line	Base Case	149%	147	90	90	Portfolio energy storage in charging mode
Smyrna-Ganso 115 kV line	Base Case	141%	147	90	90	Portfolio energy storage in charging mode
Arco-Midway 230 kV Line	GATES-ARCO & GATES-MIDWAY 230 KV LINES	162%	516	205	312	Reconductor if economic
Gates-Arco 230 kV line	ARCO-MIDWAY 230KV	160%	516	205	935	Reconductor if economic

3.5.5 East of Pisgah Interconnection Area

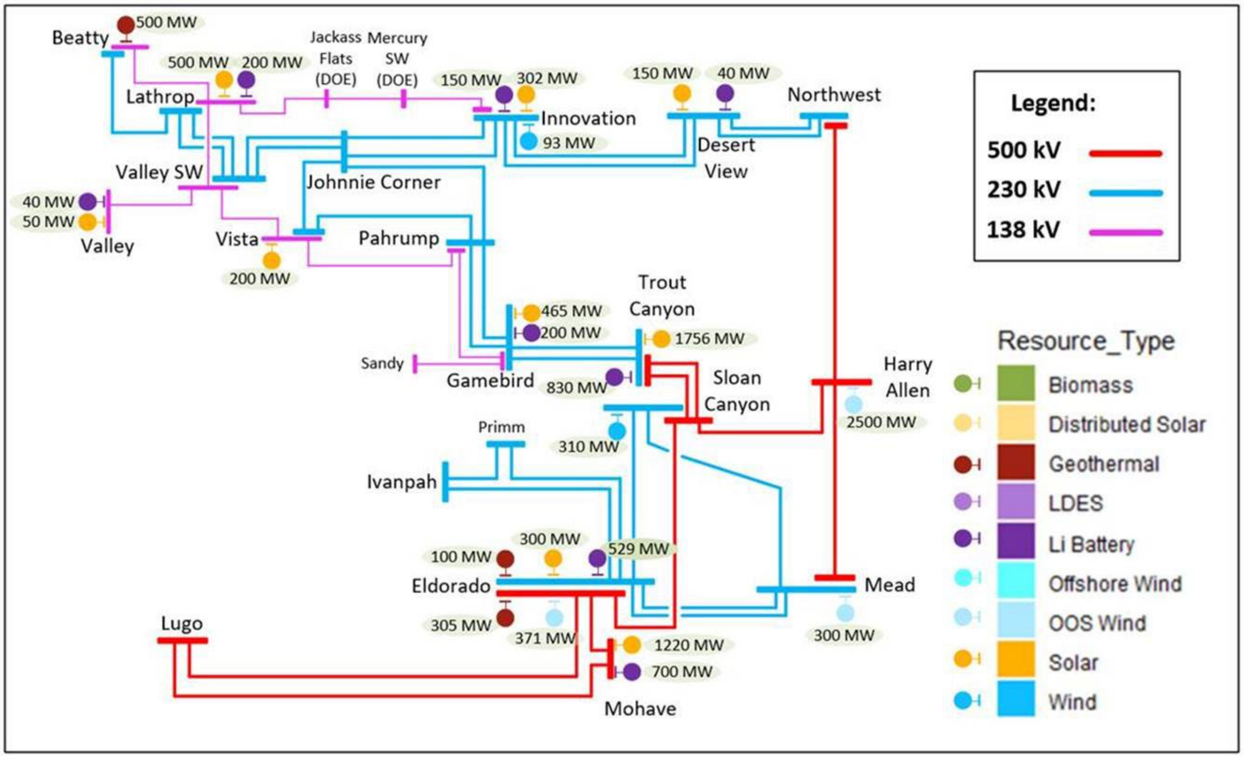
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the East of Pisgah interconnection area are listed in Table 3.5-15. The portfolios in the interconnection area are comprised of solar, wind (in-state and out-of-state), battery storage and geothermal resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-15: East of Pisgah Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	2,157	2,786	**4,943**	Not applicable for EOP area		
Wind – In State	403	-	**403**			
Wind – Out-of-State (Existing TX)	571	100	**671**			
Wind – Out-of-State (New TX)	2,500	-	**2,500**			
Wind – Offshore	-	-	**-**			
Li Battery	2,689	-	**2,689**			
Geothermal	905	-	**905**			
Long-duration Energy Storage (LDES)	-	-	**-**			
Biomass/Biogas	-	-	**-**			
Distributed Solar	-	-	**-**			
Total	**9,225**	**2,886**	**12,111**			

The resources as identified in the CPUC busbar mapping for the East of Pisgah interconnection area are illustrated on the single-line diagram in Figure 3.5-11.

Figure 3.5-11: East of Pisgah Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the East of Pisgah interconnection areas along with the recommended mitigation plans are identified in Table 3.5-16.

Table 3.5-16: East of Pisgah Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Sloan Canyon – Eldorado 500 kV Line	Base	7,509	2,186	7,509	0	Curtail MIC expansion request
	Sensitivity	N/A				
VEA-GLW Constraint	Base	3,412	1,417	3,115	297	New Trout Canyon RAS
	Sensitivity	N/A				
Lugo – Victorville 500 kV Line	Base	9,074	3,131	7,978	1,096	Expand the Lugo – Victorville RAS Potential Eldorado 500 kV SCD mitigation
	Sensitivity	N/A				

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the East of Pisgah interconnection area along with the recommended mitigation plans are identified in Table 3.5-17.

Table 3.5-17: East of Pisgah Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
VEA-GLW Constraint	Base	3,506	1,466	1,240	New Trout Canyon RAS Charge portfolio energy storage
	Sensitivity	N/A			
Eldorado – McCullough 500 kV Line	Base	8,175	2,695	500	Charge portfolio energy storage Potential Eldorado 500 kV SCD mitigation
	Sensitivity	N/A			

3.5.6 SCE Northern Interconnection Area

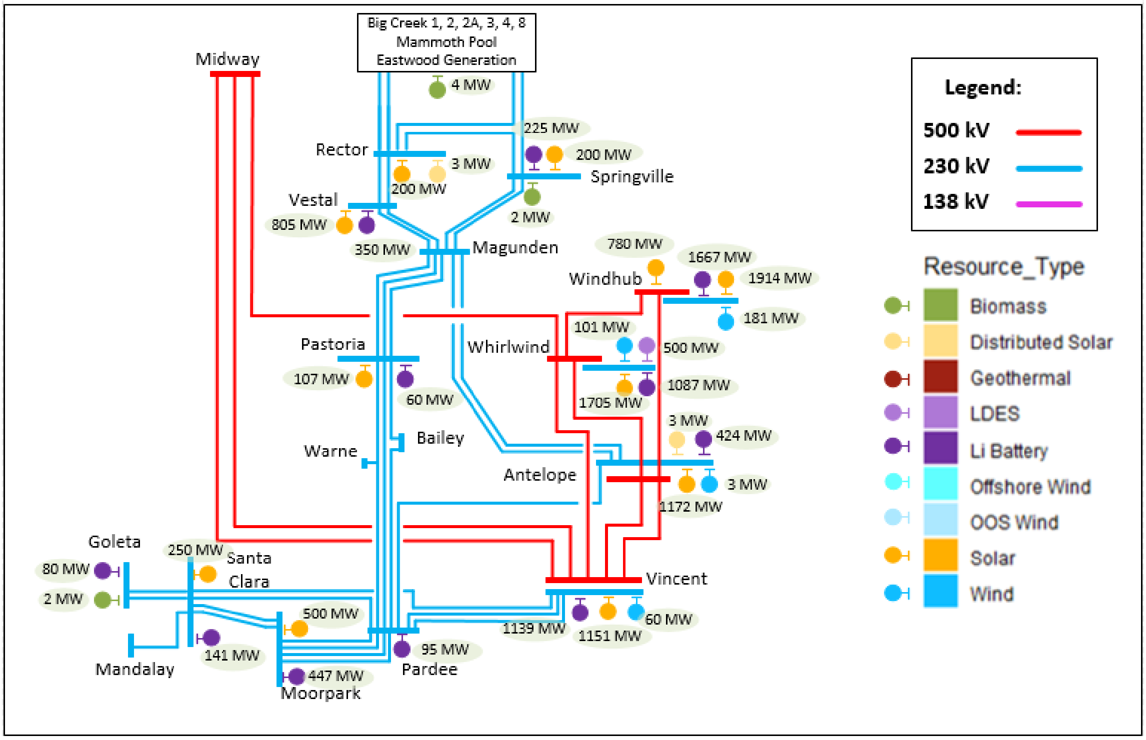
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Northern interconnection area are listed in Table 3.5-18. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, long-duration energy storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-18: SCE Northern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	3,763	5,022	8,784	Not applicable for the Northern area		
Wind – In State	345	-	345			
Wind – Out-of-State (Existing TX)	-	-	-			
Wind – Out-of-State (New TX)	-	-	-			
Wind – Offshore	-	-	-			
Li Battery	5,714	-	5,714			
Geothermal	-	-	-			
Long-duration Energy Storage (LDES)	500	-	500			
Biomass/Biogas	8	-	8			
Distributed Solar	6	-	6			
Total	**10,336**	**5,022**	**15,358**			

The resources identified in the CPUC busbar mapping for the SCE Northern interconnection area are illustrated on the single-line diagram in Figure 3.5-12.

Figure 3.5-12: SCE Northern Interconnection Area – Mapped[49] Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE Northern interconnection area along with the recommended mitigation plans are identified in Table 3.5-19.

Table 3.5-19: SCE Northern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Windhub #1 and #2 500/230 kV transformer	Base	1163	1033	530	633	Planned Windhub CRAS
	Sensitivity	N/A	N/A	N/A	N/A	N/A
Windhub #3 and #4 500/230 kV transformer	Base	1603	761	1395	208	Planned Windhub CRAS
	Sensitivity	N/A	N/A	N/A	N/A	N/A
Windhub Area Export	Base	3546	1795	2483	1063	See conclusion and recommendation section and Appendix F for additional detail
	Sensitivity	N/A	N/A	N/A	N/A	N/A

[49] Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Northern Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

Off-Peak Deliverability Assessment

The Off-peak deliverability constraints identified in the base portfolio assessment of the SCE Northern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-20.

Table 3.5-20: SCE Northern Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio solar and wind MW behind the constraint	Energy storage portfolio MW behind the constraint	Renewable curtailment without mitigation (MW)	Mitigation
Windhub #1 and #2 500/230 kV transformer	Base	1216	1033	371	Planned Windhub CRAS
	Sensitivity	N/A	N/A	N/A	N/A
Whirlwind #1 and #3 500/230 kV transformer	Base	1579	1635	103	Planned Whirlwind CRAS
	Sensitivity	N/A	N/A	N/A	N/A
Midway–Whirlwind 500 kV line	Base	27047	22582	1042	Reduce thermal generation and dispatch baseline storage in charging mode
	Sensitivity	N/A	N/A	N/A	N/A

Conclusion and recommendation

The SCE Northern area base portfolio deliverability assessment identified on-peak and off-peak deliverability constraints. All but one of the constraints can be addressed by using RAS or reducing thermal generation and dispatching energy storage in charging mode, as applicable.

For the Windhub Area Export Constraint, there was an inaccuracy in the transmission capability estimate provided to the CPUC during the development of the resource portfolio, thus, it was not anticipated that a transmission upgrade would be triggered. In addition, with the updated estimate, the 2024-2025 TPP portfolio is not expected to require a transmission upgrade for this constraint.

As a result, transmission upgrades were not found to be needed in the area in the current planning cycle.

3.5.7 SCE North of Lugo Interconnection Area

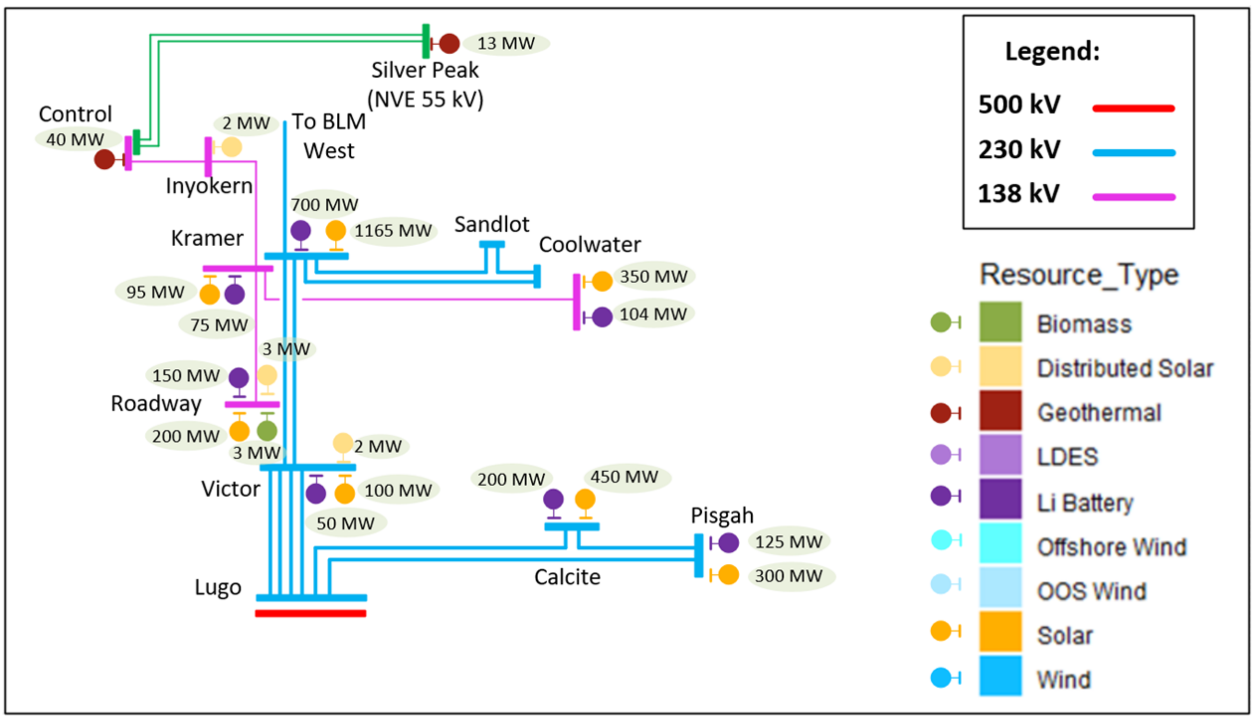
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE North of Lugo interconnection area are listed in Table 3.5-21. The portfolios in the interconnection area are comprised of solar, battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-21: SCE North of Lugo Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	1,310	1,350	2,660			
Wind – In State	0	0	0			
Wind – Out-of-State (Existing TX)	0	0	0			
Wind – Out-of-State (New TX)	0	0	0			
Wind – Offshore	0	0	0			
Li Battery	1,404	0	1,404	**Not applicable for the NOL area**		
Geothermal	53	0	53			
Long-duration Energy Storage (LDES)	0	0	0			
Biomass/Biogas	3	0	3			
Distributed Solar	7	0	7			
Total	**2,777**	**1,350**	**4,127**			

Base portfolio resources as identified in the CPUC busbar mapping for the SCE North of Lugo interconnection area are illustrated on the single-line diagram in Figure 3.5-11.

Figure 3.5-13: SCE North of Lugo Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE North of Lugo interconnection area along with the recommended mitigation plans are identified in Table 3.5-22.

Table 3.5-22: SCE North of Lugo Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Coolwater–Kramer 230/115 kV Corridor	Base	1,186	376	747	439	Expanded Mohave Desert RAS
	Sensitivity	N/A				
Control–Inyokern/Haiwee Tap 115 kV	Base	54	0	54	26	Existing Bishop RAS
	Sensitivity	N/A				
Control–Silver Peak 55kV Corridor	Base	13	0	13	35	Reduce requested MIC expansion to 4 MW
	Sensitivity	N/A				
Calcite–Lugo 230 kV	Base	625	325	522	103	Planned Calcite RAS
	Sensitivity	N/A				

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE North of Lugo interconnection areas along with the recommended mitigation plans are identified in Table 3.5-23.

Table 3.5-23: SCE North of Lugo Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Coolwater–Kramer 230/115 kV Corridor	Base	987	617	456	Expanded Mojave Desert RAS
	Sensitivity	N/A			
Victor–Kramer 230 kV Constraint	Base	1,792	1,242	377	Expanded Mojave desert RAS
	Sensitivity	N/A			
Lugo–Calcite–Pisgah 230 kV Corridor	Base	750	325	200	Dispatch portfolio battery storage in charging mode
	Sensitivity	N/A			

Conclusion and recommendation

The following conclusions can be made based on the North of Lugo (NOL) Area deliverability assessment that is performed with the transmission upgrades approved for the NOL Area in the 2022-2023 Transmission Plan modeled:

- All portfolio resources in the NOL area are deliverable with existing or expanded Remedial Action Schemes (RAS). Off-peak deliverability constraints in the area can be addressed using RAS or portfolio battery storage;
- Out of the 39 MW of California Community Power's SILVERPK_BG MIC expansion request, only about 4 MW is deliverable.

3.5.8 SCE Metro Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Metro interconnection area, are listed in

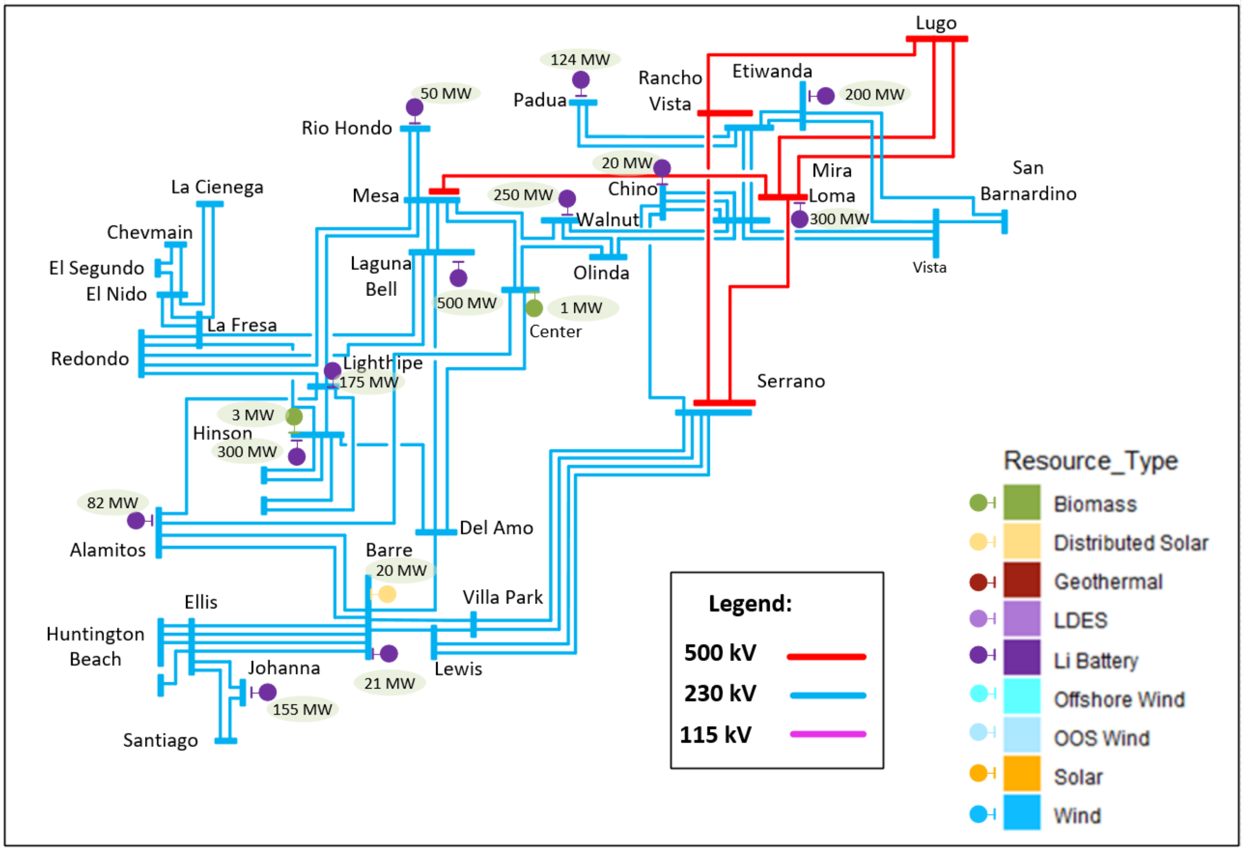
Table 3.5-24. The portfolios in the interconnection area are comprised of battery storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-24: SCE Metro Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	-	-	-	Not applicable for the Metro Area		
Wind – In State	-	-	-			
Wind – Out-of-State (Existing TX)	-	-	-			
Wind – Out-of-State (New TX)	-	-	-			
Wind – Offshore	-	-	-			
Li Battery	2,177	-	2,177			
Geothermal	-	-	-			
Long-duration Energy Storage (LDES)	-	-	-			
Biomass/Biogas	4	-	4			
Distributed Solar	20	-	20			
Total	**2,201**	**-**	**2,201**			

The resources as identified in the CPUC busbar mapping for the SCE Metro interconnection area are illustrated on the single-line diagram in Figure 3.5-14.

Figure 3.5-14: SCE Metro Interconnection Area – Mapped[50] Base Portfolio



On-Peak Deliverability

The on-peak deliverability did not identify any constraints in the base portfolio assessment of the SCE Metro interconnection area.

Off-Peak Deliverability

The off-peak deliverability did not identify any constraints in the base portfolio assessment of the SCE Metro interconnection area.

50 Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Metro Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

3.5.9 SCE Eastern Interconnection Area

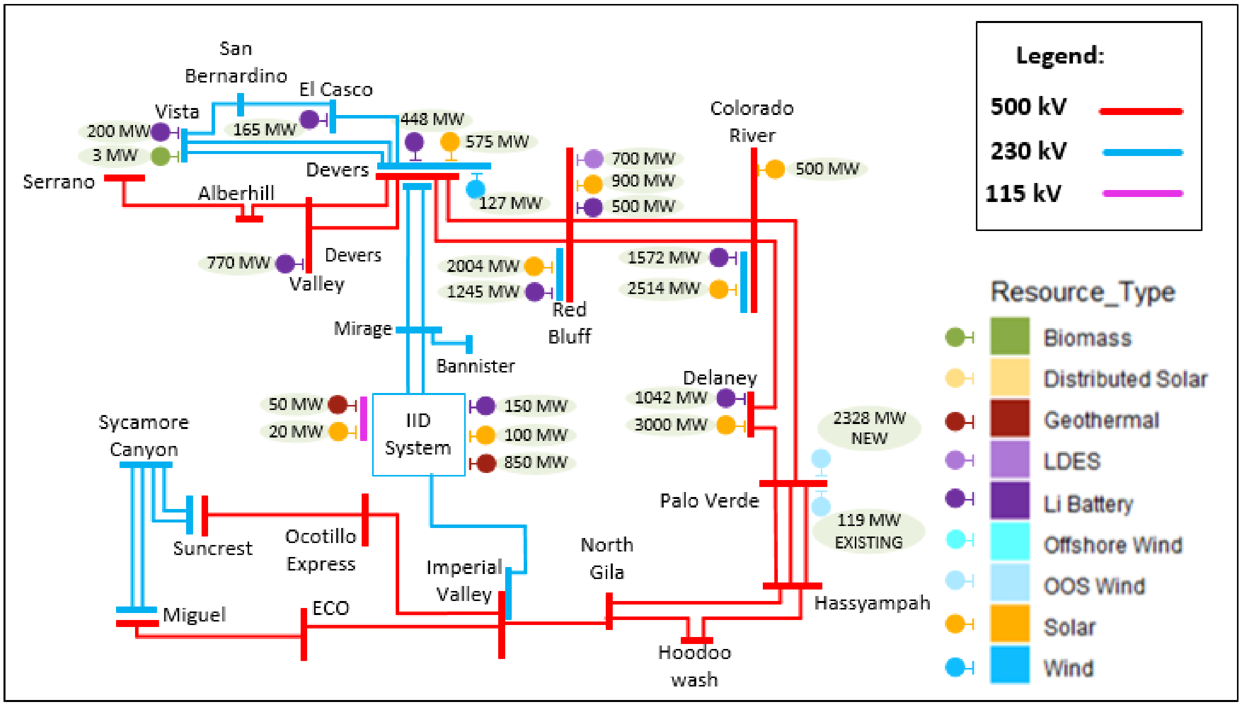
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Eastern interconnection area are listed in Table 3.5-25. The portfolios are comprised of solar, wind (in-state and out-of-state), battery storage and biomass/biogas resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-25: SCE Eastern Interconnection Area – Base Portfolio by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	2,949	6,664	9,613	Not applicable for the Eastern Area		
Wind – In State	107	20	127			
Wind – Out-of-State (Existing TX)	119	-	119			
Wind – Out-of-State (New TX)	2,328	-	2,328			
Wind – Offshore	-	-	-			
Li Battery	6,092	-	6,092			
Geothermal	900	-	900			
Long-duration Energy Storage (LDES)	700	-	700			
Biomass/Biogas	3	-	3			
Distributed Solar	-	-	-			
Total	**13,198**	**6,684**	**19,881**			

The resources as identified in the CPUC busbar mapping for the SCE Eastern interconnection area are illustrated on the single-line diagram in Figure 3.5-15.

Figure 3.5-15: SCE Eastern Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE Eastern interconnection area along with the recommended mitigation plans are identified in Table 3.5-26.

Table 3.5-26: SCE Eastern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Colorado River 500/230 kV	Base	2530	1499	2052	478	West of Colorado River CRAS
	Sensitivity	N/A	N/A	N/A	N/A	

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE Eastern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-27.

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Table 3.5-27: SCE Eastern Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio solar and wind MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Colorado River 500/230 kV Transformers	Base	2262	1563	1501	West of Colorado River CRAS and/or batteries in charging mode
	Sensitivity	N/A	N/A	N/A	
Red Bluff 500/230 kV Transformers	Base	2168	1280	906	West of Colorado River CRAS and/or batteries in charging mode
	Sensitivity	N/A	N/A	N/A	

3.5.10 SDG&E Interconnection Area

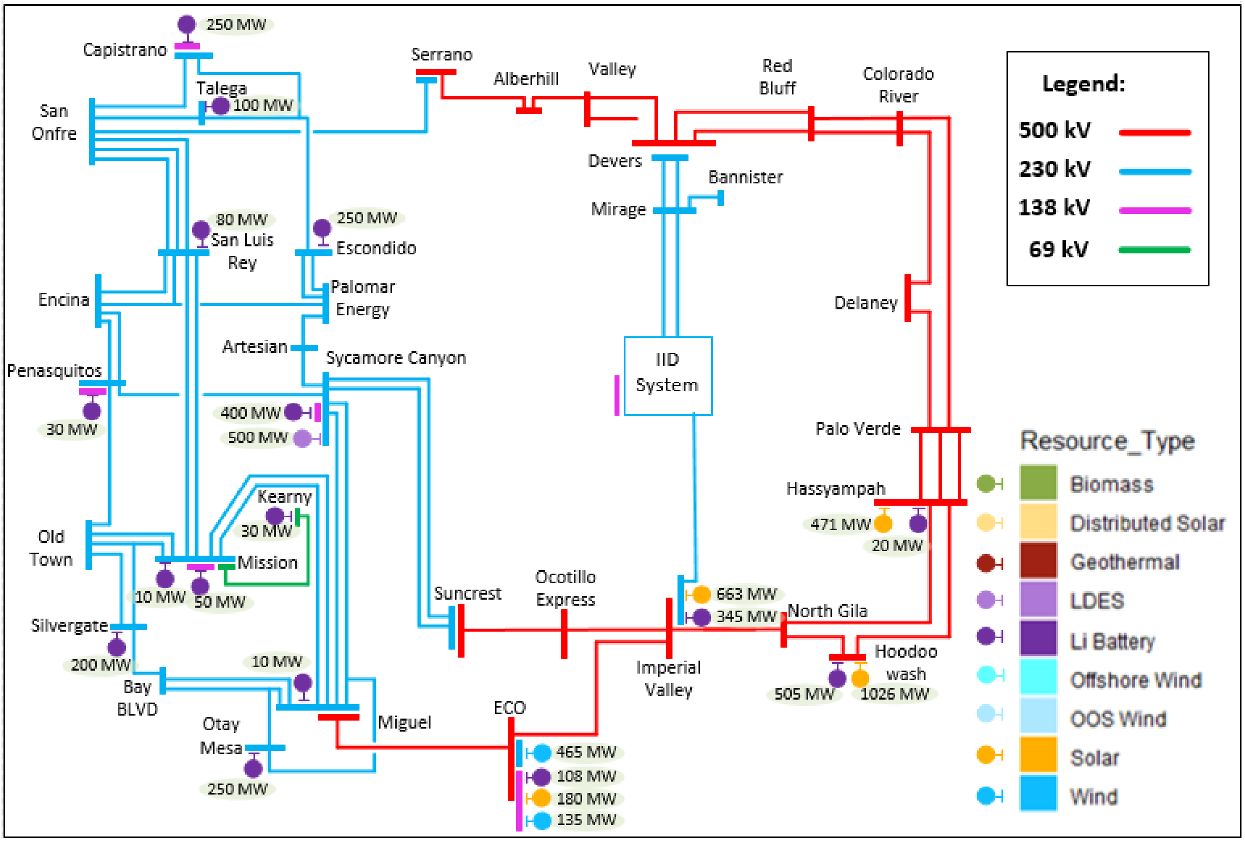
Table 3.5-28 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SDG&E interconnection area. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, geothermal, and long-duration energy storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-28: SDG&E Interconnection Area – Base Portfolio by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	650	1,690	**2,340**	**Not applicable for the SDG&E Area**		
Wind – In State	240	360	**600**			
Wind – Out-of-State (Existing TX)	-	-	**-**			
Wind – Out-of-State (New TX)	-	-	**-**			
Wind – Offshore	-	-	**-**			
Li Battery	2,617	-	**2,617**			
Geothermal	-	-	**-**			
Long-duration Energy Storage (LDES)	500	-	**500**			
Biomass/Biogas	-	-	**-**			
Distributed Solar	-	-	**-**			
Total	**4,007**	**2,050**	**6,057**			

The resources as identified in the CPUC busbar mapping for the SDG&E interconnection area are illustrated on the single-line diagram in Figure 3.5-16.

Figure 3.5-16: SDG&E Interconnection Area – Mapped Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SDG&E interconnection area along with the recommended mitigation plans are identified in Table 3.5-29.

Table 3.5-29: SDG&E Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Bay Boulevard-Silvergate	Base	2,133	695	863	1,270	2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line
	Sensitivity	N/A	N/A	N/A	N/A	
Silvergate-Old Town	Base	1,017	417	586	431	30 minute emergency ratings on Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines
	Sensitivity	N/A	N/A	N/A	N/A	

The overloads identified in the on-peak deliverability assessment in the SDG&E area can be mitigated by using 2-hour and 30-minute emergency ratings for the overloaded lines.

Off-Peak Deliverability Assessment

The off-peak deliverability assessment did not identify any constraints in the SDG&E area.

3.6 Out-of-State Wind

The base portfolio includes 4,828 MW of out-of-state wind resources (1,500 MW from Wyoming, 1,000 MW from Idaho, and 2,328 MW from New Mexico). These resources have been identified by the CPUC as requiring new transmission. They were studied in detail under the 2022-2023 TPP in policy analysis and alternative analysis related to expanding the maximum import capability of the paths to determine the ISO internal transmission needs required to accommodate the identified out-of-state wind.. Policy driven transmission projects recommended and approved by the ISO under the 2022-2023 TPP will support the integration of out-of-state wind resources identified in the base portfolio of the 2023-2024 TPP.

Two out-of-state subscriber transmission developments to accommodate the wind resources in Wyoming (TransWest Express) and New Mexico (Sunzia) are currently underway. The ISO filed the Subscriber PTO tariff for TransWest Express with FERC on September 22, 2023 under Docket No. ER23-2917-001, and it was approved by FERC on March 12, 2024. The TransWest SPTO application had been approved by the ISO Board of Governors on July 20, 2023. On January 24, 2024, the ISO received a PTO application from Sunzia to include its HVDC transmission facilities in New Mexico and certain transmission rights in Arizona under the ISO operational control as a Subscriber PTO.[51]

The ISO has been and continues to engage with Idaho Power on SWIP North as a regional policy-driven transmission project to take advantage of cost-sharing benefits. The ISO Board of Governors conditionally approved the SWIP North transmission project on December 14, 2023 as an extension of the 2022-2023 TPP to be consistent with Idaho Power's timelines. [52] The conditionally approved transmission project calls for the ISO's assumption of Great Basin Transmission's entitlements of 1,117.5 MW in the North to South direction and 572.5 MW in the South to North direction, with the remaining 500 MW in the South to North direction held by Idaho Power. SWIP North will facilitate the integration of Idaho wind resources consistent with the 2023-2024 TPP base portfolio and the CPUC approved decision regarding the 2024-2025 TPP base portfolio on February 15, 2024. SWIP North is the sole known transmission project that would serve California Load-Serving Entities (LSEs) in accessing wind resources in Idaho by 2027. The ISO's economic studies also demonstrate other economic benefits contributing to the overall value provided by the project, as set out in the 2021-2022 TPP and the 2022-2023 TPP. Concurrently, Idaho Power studied the value proposition that SWIP North delivers to Idaho to access power markets in the Desert Southwest and add resource diversity to its portfolio. Idaho Power has indicated the need for 500 MW in the South to North direction in its 2023 integrated resource plan which was submitted to public utility commissions in Idaho and Oregon

[51] SunZia Transmission, LLC Submits New Participating Transmission Owner application to California ISO (caiso.com)

[52] California ISO - Documents By Group (caiso.com)

on September 29, 2023.[53] The ISO expects Idaho Power to file a SWIP-related case with the Idaho Public Utilities Commission by end of March this year. The ISO also expects to conduct additional stakeholder sessions in 2024 on SWIP North as the project progresses in addressing conditions set by the ISO Board.

Both the SWIP North project and the TransWest Express project would deliver significant quantities of out-of-state wind into the Harry Allen-Eldorado area, and the combined impact on existing WECC Paths in the area will need to be studied.

3.7 Conclusion and Recommendations

The policy assessment has identified 7 new policy-driven projects recommended for approval in this transmission planning cycle for a total estimated cost of $4.59 billion as listed in Table 3.8-1.

Table 3.7-1: Recommended Policy-Driven Transmission Projects for Approval

Project Name	PTO	Planning Area	Cost($M)	
Sobrante 230/115 kV Transformer Bank Addition	PG&E	GBA	20	40
New Humboldt 500 kV Substation with 500 kV line to Collinsville [HVDC operated as AC]	PG&E	NGBA	1913	2740
New Humboldt to Fern Road 500 kV Line	PG&E	NGBA	980	1,400
New Humboldt 115/115 kV Phase Shifter with 115 kV line to Humboldt 115kV Substation	PG&E	NGBA	40	57
North Dublin -Vineyard 230 kV Reconductoring	PG&E	NGBA	116.3	232.6
Tesla - Newark 230 kV Line No. 2 Reconductoring	PG&E	NGBA	29	58
Collinsville 230 kV Reactor	PG&E	NGBA	39	58
		Total	**3,137**	**4,586**

[53] 2023 Integrated Resource Plan (idahopower.com)

Chapter 4

4 Economic Planning Study

4.1 Introduction

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.

The studies used a production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and to assess benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all hours for each study year.

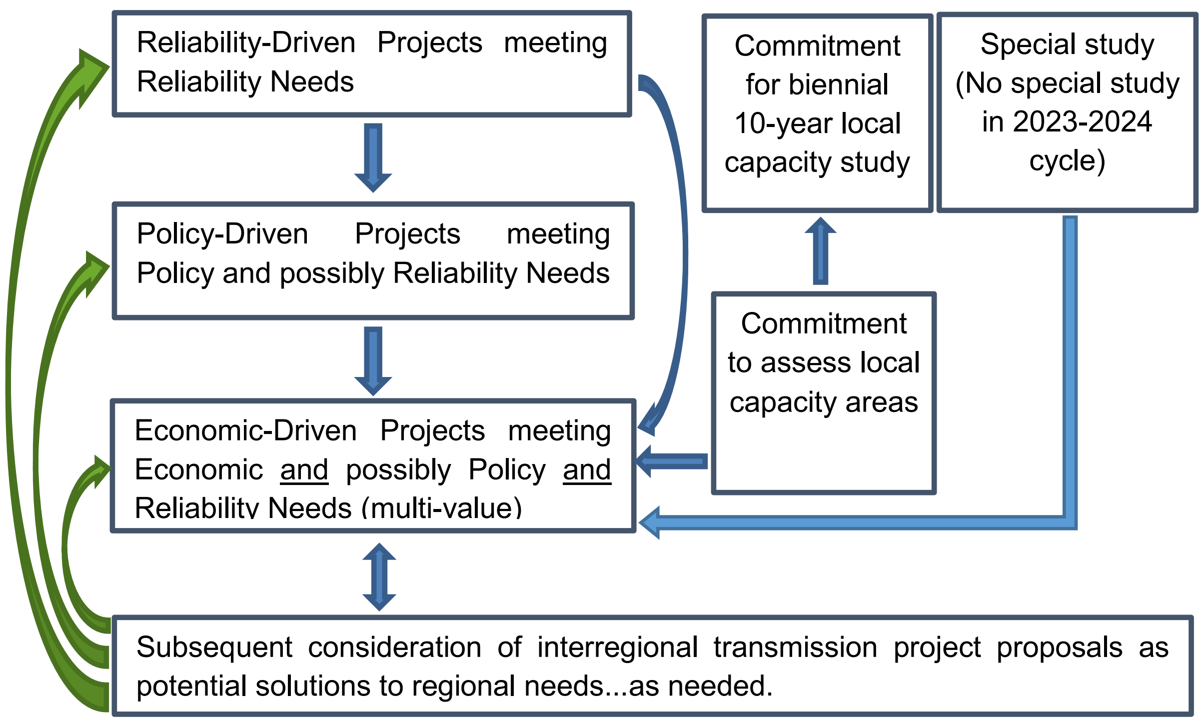
Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling;
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analyses or to meet local capacity deficiencies;
- An economic-driven transmission solution may be upsizing a previously identified reliability solution, or replacing that solution with a different project;
- Opportunities to reduce the cost of local capacity requirements (LCR),considering capacity costs in particular; and
- Considering interregional transmission projects as potential alternatives to regional solutions to regional needs.

All transmission solutions identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation database. The ISO then performed the economic planning study to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the ISO. These more comprehensive 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).[54]

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 4.1-1.

Figure 4.1-1: Interrelationship of Transmission Planning Studies



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.

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

4.2 Technical Study Approach and Process

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

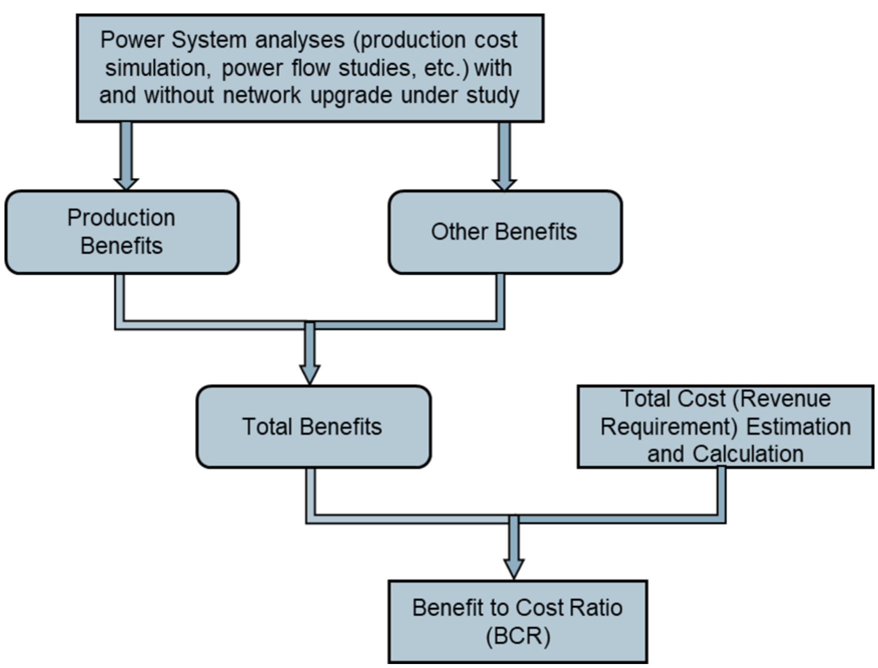
First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the “pre-project” and “post-project” study results, production benefits can be calculated from savings of production costs or ratepayer payments. These include: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues.

Additionally, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings, 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 4.2-1.

Figure 4.2-1: Technical approach of economic planning study



4.3 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 2022 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.

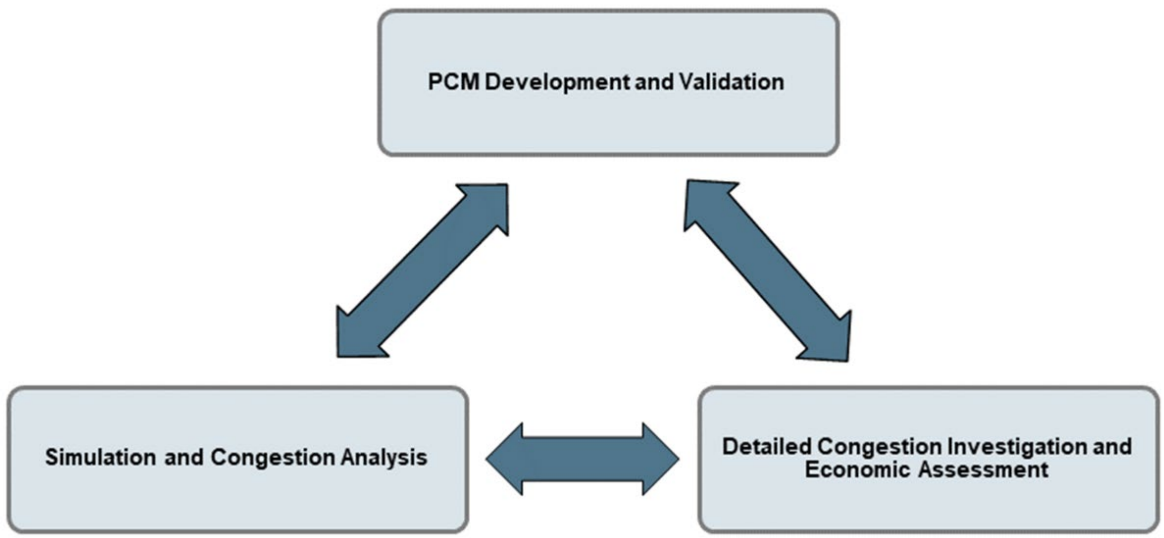
As the "capital cost to revenue requirement" multiplier was developed on the basis of the long lives associated with transmission lines, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and can then be compared to the annual benefits identified for those projects.

In considering how to assess the value to ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas, the ISO recognizes that additional coordination on the long-term need for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. If there are sufficient gas-fired generation resources to meet local capacity needs over the planning horizon, there are no needs for reliability-driven reinforcement; rather, the question shifts to the economic value provided by the reduction in local capacity requirement for the gas-fired generation. However, the gas-fired generation may still be required for system or flexible capacity reasons.

4.4 Study Steps of Production Cost Simulation in Economic Planning

As discussed earlier, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost-model development needs to be coordinate with the entire WECC and the management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database development and validation, simulation and congestion analysis, and production benefit assessments of congestion mitigation. Each of these steps is described in more detail in Appendix G. Because of the complexity of the models and analysis, there is often iteration between the three steps as a careful review of results lead to revisiting model aspects. Figure 4.4-1 shows these components and their interaction.

Figure 4.4-1: Steps of Production Cost Simulation in Economic Planning



The final product of this analysis is an assessment of the volume and cost impact of congestion on the transmission system, as well as of the effectiveness of different mitigations across all hours of the study year. These results must then be combined with other economic benefits derived through power flow analysis.

4.5 Production cost simulation tools and database

The ISO primarily used the Hitachi GridView™ software version 10.3.72 for this economic planning study.

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO may also develop an optional 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five-year period of benefits before the 10-year case becomes relevant.

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

The 2023-2024 transmission planning process PCM development started from the ISO 2022-2023 transmission planning PCM cases. The ISO then modified the network model for the ISO system to exactly match the 2023-2024 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. Appendix G also highlights the major ISO enhancements and modifications to the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) database that were incorporated into the ISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized 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.

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. Different from the 2022-2023 planning cycle, both the base portfolio PCM and the sensitivity portfolio PCM used the CEC California Energy Demand Updated Forecast for 2035 with high electrification load, consistent with the demand forecast in the reliability assessment as described in Chapter 2. Generator locations and installed capacities in the PCM are consistent with the policy assessment power flow case for 2035, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

The CPUC IRP base and sensitivity portfolios included out-of-state wind resources in different areas. Some of the out-of-state wind resources in the CPUC IRP portfolios expected to require new transmission, while some rely on existing transmission, to deliver their wind energy to the ISO load. For the out-of-state wind resources that require new transmission, the CPUC IRP portfolio provided specified injection points to the ISO system, but did not specify particular out-of-state transmission projects to deliver the resources to the ISO boundary.

In the planning PCM in this planning cycle, New Mexico wind generation that requires new transmission was modeled at the Pinal Central 500 kV bus in Arizona, which is consistent with the last planning cycle. This is equivalent to assuming that a new transmission line would be built to deliver New Mexico wind generation to the Pinal Central 500 kV bus.

The CPUC IRP base portfolio included out-of-state wind with 1500 MW of capacity identified in Wyoming areas, and 1000 MW of capacity identified in Idaho areas, which are expected to require new transmission. In the planning PCM in this planning cycle, Wyoming wind was modeled associated with the TransWest Express project. The Idaho wind was modeled associated with the SWIP North project as baseline assumption in the base portfolio PCM.

The CPUC IRP base and sensitivity portfolios also included offshore wind resources in different areas. In the base portfolio PCM, the energy only portion of Humboldt Bay offshore wind (161 MW) was modeled at Humboldt 115 kV, the incremental Humboldt Bay offshore wind (1446 MW) was modeled at Fern Road 500 kV bus. Morro Bay offshore wind (3100 MW) were modeled at the Diablo Canyon 500 kV bus. In the sensitivity portfolio PCM, the 161 MW of energy only Humboldt Bay offshore wind was still modeled at Humboldt 115 kV, and the total 5355 MW of Morro Bay offshore wind was still modeled at the Diablo Canyon 500 kV bus. However, the 7884 MW of the incremental Humboldt Bay offshore wind was modeled at a new 500 kV bus at Humboldt area with the following transmission upgrades:

- Humboldt - Fern Road 500 kV AC line
    - Also includes Fern Road – Vaca Dixon – Tesla 500 kV AC line
- Humboldt – Collinsvile HVDC
- Humboldt – Bayhub HVDC with Bayhub local 230 kV upgrades

The 2023-2024 planning PCM continued to use the multi-block renewable generator model that was first developed and used in the 2019~2020 planning cycle PCM. This model was applied to all ISO wind and solar generators. Each generator was modeled as five equal and separate generators (blocks) with identical hourly profiles, and each block's Pmax was 20% of the Pmax of the actual generator. Each block had a different curtailment price around $-25/MWh

The ISO continued its modeling of battery storage, refined through the course of the 2019-2020 planning cycle, to reflect limitations associated with the depth of discharge of battery usage cycles (DoD or cycle depth) and replacement costs associated with the cycle life (i.e. the number of cycles) and depth of discharge the battery is subjected to. In this refined battery model, the battery's operation cost was modeled as a flat average cost.

4.6 Base Portfolio Production Cost Simulation Results

This section shows the summary of base portfolio production cost simulation results. The detailed results are included in Appendix G.

4.6.1 Summary of congestion results

High-level assessments were conducted in this section on the constraints that may have a large impact on the bulk system or the heavily congested areas, or showed recurring congestion. The assessment results are shown in Table 4.6-1.

Table 4.6-1: Summary of high-level investigation on major transmission congestions

Constrained area or branch group	Cost (M$)	Duration (Hours)	Overview of investigation
COI Corridor	159.61	1903	COI corridor congestion increased compared with the results in the previous planning cycle. Humboldt Bay offshore wind connected to the Fern Road 500 kV bus caused congestion increased on the 500 kV lines south of Round Mountain.
Path 26 Corridor	61.06	3220	Path 26 corridor congestion was mostly attributed to the Path 26 path rating binding and the Whirlwind- Midway 500 kV line normal rating binding. The congestion was mostly observed when the Path 26 flow was from south to north. The main driver of the Path 26 corridor congestion is the large amount of renewable generation and battery in Southern CA identified in the CPUC portfolio
Path 61 (Victorville-Lugo)	54.64	1247	Congestion in the Path 61 corridor was observed mainly on the Victorville-Lugo 500 kV line under N-1 contingency of the Eldorado-Lugo 500 kV line. Path 61 path rating was also observed binding at different time of the year. Renewable generation in the CPUC portfolio delivered to the Eldorado buses, including the renewable generation in the Eldorado/Mohave area and the GLW/VEA area, and the out-of-state wind in Wyoming and/or Idaho, contributed to this congestion
PG&E Moss Landing-Las Aguilas 230 kV	27.00	1115	Congestion on the Moss Landing - Las Aguilas 230 kV line under the N-1 contingency of the Moss Landing - Los Banos 500 kV line occurred when the flow was from Las Aguilas to Moss Landing. The congestion was observed in daytime. The congestion is attributed to both the PG&E's Fresno area solar generation and the PG&E's Greater Bay Area load. The congestion was aggravated as solar generation in the PG&E Fresno area increased in this cycle's base portfolio.

Constrained area or branch group	Cost (M$)	Duration (Hours)	Overview of investigation
SDG&E/CFE	23.95	1218	Congestion between the SDGE and CFE systems was observed mainly on Path 45 path rating binding. In spring, congestion on this corridor mainly occurred when there was solar surplus in the ISO system and the Path 45 flow was from SDGE to CFE. In other times of the year, congestion can be observed when the flow was from CFE to SDGE, which is mainly due to the natural gas price difference across the border. This congestion is impacted by the CFE's generation and load modeling assumption. Further clarity of such factors will be required before detailed investigations need to be conducted.
PG&E Collinsville corridor	22.97	1075	Collinsville-Pittsburg 230 kV line congestion was correlated with COI congestion, and was also impacted by future offshore wind development.
Path 15 Corridor	21.77	1140	Path 15 corridor congestion was attributed to both Path 15 path rating binding and binding of the 500 kV or 230 kV lines of the path when the flow is from south to north. The Path 15 corridor congestion was highly correlated with the Path 26 congestion, which was also observed when the flow is from south to north. Renewable generators in the PG&E Fresno/Kern area and offshore wind modeled at Diablo Canyon also contributed to the Path 15 corridor congestion.
SCE North of Lugo	18.29	3613	Congestion in the SCE North of Lugo area in this planning cycle was observed mainly on the Calsite-Lugo 230 KV line. Renewable resources in the Calsite area, identified in the CPUC base portfolio, are the driver of the congestion.
Path 46 WOR	17.26	19	Congestion on Path 46 (WOR) was observed in 19 hours over the year as the flow was in the direction from east to west and there was scheduled maintenance
PG&E Panoche/Oro Loma area	9.53	1973	Congestions on the 115 kV lines in the PG&E's Panoche/Oro Loma area were observed under both normal and contingency conditions. Local solar generations and loop flow between the 230 kV system and 115 system contributed most to the congestion in this area. The most severe congestion in this area is the congestion on the Oro Loma - El Nido 115 kV line under normal condition.
PG&E Kern 230kV	9.21	1381	Congestion on the Arco-Midway and Arco-Gates 230 kV lines was observed in the PG&E Kern area, attributed to renewable generators in the PG&E Kern area.
PG&E Sierra	8.29	1686	Congestion in the PG&E Sierra area was observed mainly on Path 24 when flow was from Nevada to California.
SDG&E 230 kV	6.19	1080	SDG&E 230 kV system congestion was observed mainly on the Silvergate - Bay Boulevard 230 kV lines, and was also observed on the Silvergate - Old Town 230 kV lines, and on the San Luis Rey - S. Onofre 230 kV lines.
GridLiance/VEA	4.61	1076	In the GridLiance West/VEA area, congestion significantly reduced with the transmission upgrades approved in the last planning cycle modeled. The remaining congestion was mainly observed on the Sloan Canyon - Mead S 230 kV line and on the Gamebird 230/138 kV transformer.

4.6.2 Wind and solar curtailment results

Table 4.6-2 shows wind and solar generation curtailment in the ISO system in the base portfolio PCM. In this table, the renewable resources were aggregated by zone based on the transmission constraints to which the resources in the same zone normally contributed in the same direction, or based on geographic locations if there were no obvious transmission constraints nearby.

Table 4.6-2: Wind and solar curtailment summary in the base portfolio PCM

Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	42,241	2,560	44,800	5.71%
SCE Eastern	23,642	1,344	24,987	5.38%
PG&E Fresno	18,385	4,267	22,651	18.84%
NM	14,694	1,239	15,933	7.78%
SDG&E Bulk	11,693	0	11,693	0.00%
GLW/VEA	8,811	2,622	11,433	22.93%
AZ-PV	9,884	1,355	11,239	12.05%
PG&E OSW-Diablo	9,886	604	10,490	5.76%
SCE NOL	8,803	1,449	10,252	14.14%
PG&E Kern	8,357	756	9,113	8.30%
PG&E GBA	8,492	271	8,762	3.09%
SCE East of Pisgah	6,386	645	7,032	9.18%
PG&E OSW-Humboldt	6,204	71	6,276	1.14%
WY	4,921	781	5,702	13.70%
PG&E Central Coast	3,425	205	3,630	5.64%
PG&E North Valley	2,635	115	2,749	4.17%
ID	2,605	136	2,741	4.97%
NW	1,636	423	2,059	20.55%
AZ-Mead	924	51	975	5.19%
PG&E Sacramento	854	51	905	5.62%
IID	781	19	801	2.41%
SCE Metro	419	7	426	1.71%
SDG&E Eastern	156	0	156	0.00%
SDG&E Northeast	106	0	106	0.07%
PG&E Humboldt	4	1	5	10.77%
Total	**195,942**	**18,972**	**214,915**	**8.83%**

Compared with the last planning cycle's Sensitivity portfolio, which had the similar renewable resource capacity as in this cycle's Base portfolio, the curtailment in the SCE, SDG&E, and Gridliance West/VEA areas reduced. This is mainly attributed to the transmission upgrades approved in the last planning cycle. Curtailment was still observed, however, due to transmission constraints that are worth further assessment in this and future planning cycles. Detailed analyses were discussed in Appendix G.

4.7 Economic Planning Study Requests

4.7.1 Overview of economic planning study requests

As part of the economic planning study process, economic planning study requests are accepted by the ISO to be considered in addition to the congestion areas identified by the ISO. These study requests are individually considered for designation as a High Priority Economic Planning Study for consideration in the development of the transmission plan. These economic study requests are distinct from the interregional transmission projects discussed in Chapter 5, but the interregional transmission projects discussed in Chapter 5 may be considered as options to meeting the needs identified though the economic planning studies.

Other economic study needs driven by stakeholder input have also been identified through other aspects of the planning process. Those are also set out here, with the rationale for proceeding to detailed analysis where warranted.

The ISO's tariff and Business Practice Manual allows the ISO to select from economic study requests and other sources the high priority areas that will receive detailed study while developing the Study Plan, based on the previous year's congestion analysis. Recognizing that changing circumstances may lead to more favorable results in the current year's study cycle, the ISO has over the past number of planning cycles carried all study requests forward as potential high-priority study requests, until the current year's congestion analysis is also available for consideration in finalizing the high-priority areas that will receive detailed study. This additional review gives more opportunity for the study requests to be considered that can take into account on a case-by-case basis the latest and most relevant information available.

Accordingly, the ISO reviewed each regional study or project being considered for detailed analysis. The basis for carrying the project forward for detailed analysis as high-priority economic planning studies – or not – is set out in this section. The section also describes how the study requests or projects selected for detailed analysis were studied, e.g. on a stand-alone basis or as one of several options of a broader area study.

4.7.2 Summary of economic planning study request evaluation

The received study requests and the evaluation results for the requests are summarized in Table 4.7-1. Detailed evaluations for the study requests for purposes of selecting the final list of high-priority economic planning studies are included in Appendix G.

Table 4.7-1: Economic study requests

No.	Study Request	Submitted By	Location	Evaluation Results
1	SWIP North Project	LS Power	ID/NV	The SWIP North project was conditionally approved by the ISO in December 2023. This project was modeled in the 2023-2024 planning cycle's PCM cases
2	Valley Power Connect Project (NGIV2)	IID/Citizen Energy/Valley Power Connect LLC	AZ/CA	The N.Gila – Imperial Valley 500 kV #2 line was approved by the ISO in the 2022-2023 planning cycle, and was modeled in the 2023-2024 planning cycle's PCM cases. The need to connect the ISO's N.Gila-Imperial Valley 500 kV lines and the IID system was not identified in reliability and policy assessments in the 2023-2024 planning cycle. There was no congestion observed in this area in this planning cycle either. Therefore, no further economic assessment was conducted for this study request.
4	Moss Landing – Las Aguilas 230 kV line reconductoring	Vistra	Northern CA	The interim solution of adding 10 ohm series reactor on the Moss Landing – Las Aguilas 230 kV line that was approved in the 2021-2022 TPP cycle can effectively reduce flow on the line. However, congestion on this line under the Moss Landing-Los Banos 500 kV line N-1 contingency was still observed in the Base Portfolio PCM study because the PG&E Fresno area solar generation increases and the Great Bay Area load increased, compared with the last planning cycle. This congestion was assessed in detail in this planning cycle.
5	Path 15 conversion to HVDC	Center for Energy Efficiency and Renewable Technology	Northern CA	Path 15 corridor congestion was observed in this planning cycle, and was assessed in detail in this planning cycle. The proposed HVDC conversion was not assessed though due to lack of clarity of the detailed scope. Converting existing 500 kV lines of Path 15 to HVDC will significantly change transmission topology in this area, and potentially impact the Fresno/Kern area solar generators to connect to the system. The study request submitter is recommended to provide detailed scope of the upgrade to the ISO in future planning cycle for further evaluation. Still, Path 15 corridor congestion was selected to receive detailed economic assessment in this planning cycles, with considering different AC alternatives of Path 15 corridor congestion mitigation.
3	PTE Project	California Western Grid Development	Northern/Southern CA	The PTE project was assessed in previous planning cycles, and did not show sufficient benefit to the ISO's ratepayers. The previous studies also demonstrated that the PTE project was not effective to mitigate Path 26 corridor congestion. However, the PTE project was still selected to receive detailed study in this planning cycle because of the significant changes in northern California offshore wind and the Fresno/Kern area solar assumptions.
6	Beatty – Esmeralda Project	GridLiance West	Southern NV	Congestions in the Gridliance West/VEA area in this planning cycle was mainly observed on the Mead S – Sloan Canyon 230 kV line. The Beatty – Esmeralda project was not identified effective to mitigate any reliability, policy, or congestion issues in this area based on the resource assumption in the CPUC renewable portfolio. Alternatives that can directly reinforce the congested components were assessed in this planning cycle.

4.8 Detailed Investigation of Congestion and Economic Benefit Assessment

The ISO selected the high priority study areas listed in Table 4.8-1 for further detailed assessment. This was done after evaluating identified congestion, considering potential local capacity reduction opportunities and stakeholder-proposed reliability projects citing material economic benefits, and reviewing stakeholders' study requests, consistent with tariff Section 24.3.4.2. The ISO then conducts its technical and economic evaluations to select the most effective and efficient recommendation. Details of the economic and technical comparisons of alternatives are provided in Appendix G.

High-priority areas were selected not solely based on congestion costs or duration, but by taking other considerations into account. Facilities identified as potential mitigations in those study areas include stakeholder proposals from a number of sources: request window submissions that cite economic benefits, economic study requests and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements.

Congestion on radial transmission lines or some local areas may not be selected as a high-priority study even though the congestion cost or duration are relatively large and if the congestion was only driven by local renewable generators identified in the CPUC default renewable portfolio. Congestion in these areas is subject to change with further clarity of the interconnection plans or busbar mapping of future resources.

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.8-1 for ease of tracking where and how these stakeholder proposals were addressed.

The detailed analysis also considers other ISO-identified potential mitigations which have been listed in Table 4.8-1 as well. The detailed study results can be found in Appendix G.

Table 4.8-1: Areas receiving detailed economic benefit investigation

Detailed investigation	Alternative	Proposed by	Reason
GLW/VEA Mead S – Sloan Canyon 230 kV line congestion	Add the second Mead S – Sloan Canyon 230 kV line	ISO	Mead S – Sloan Canyon 230 kV line remained a bottleneck for local renewable resources to connect to the system. The mitigation alternatives are expected to help to mitigate the congestion and reduce renewable curtailment in the GridLiance West/VEA area.
SCE East of Pisgah and Path 61 corridor congestion	Add the Trout Canyon – Lugo 500 kV line with 70% compensation	ISO	Significant congestion on the Path 61 corridor under both contingency and normal condition when the flow was from Victorville to Lugo was observed. The congestion in this area is mainly attributed to renewable generation in the SCE's East of Pisgah area, GridLiance West/VEA area, and the out of state wind generation delivered to the Harry Allen and Eldorado area.
	Marketplace to Adelanto project with converting the Marketplace-Adelanto 500 kV line to HVDC, and adding a 500 kV line from Adelanto to Lugo and a 500 kV line from Marketplace to Eldorado		
Path 26 corridor congestion	PTE project	California Western Grid Development	Path 26 congestion is a recurring congestion with large congestion cost. The mitigation alternatives are expected to help to mitigate the congestion, and to reduce local capacity requirements.

Detailed investigation	Alternative	Proposed by	Reason
Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion	Alternative 1: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring, removing the existing Moss Landing – Las Aguilas 230 kV line	ISO	Path 15 corridor congestion and Moss Landing – Las Aguilas 230 kV 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. These two corridors were selected to be assessed together in this planning cycle because the power flows of these two corridors impact each other, hence the individual mitigations for one corridor may also impact the other corridor. Comprehensive mitigations may be needed. Note: Alternative 1 assumed that the new Manning – Moss Landing 500 kV line will use the right of way of the existing Moss Landing – Las Aguilas 230 kV line.
	Alternative 2: Moss Landing – Las Aguilas 230 kV reconductoring, keep the series reactor approved in the 2021-2022 planning cycle		
	Alternative 3: Moss Landing – Las Aguilas 230 kV reconductoring, not keep the series reactor		
	Alternative 4: Midway – Gates – Manning new 500 kV line		
	Alternative 5: Manning-Los Banos-Tracy new 500 kV line		
	Alternative 6: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring plus Midway – Gates – Manning new 500 kV line (alt 1 plus alt 4)		
	Alternative 7: Moss Landing – Las Aguilas 230 kV reconductoring plus Midway – Gates – Manning new 500 kV line (alt3 plus alt 4)		
	Alternative 8: Manning-Los Banos-Tracy new 500 kV line, plus Midway-Gates-Manning new 500 kV line (alt 4 plus alt 5)		

This study step consists of conducting detailed investigations and modeling enhancements as needed. To the extent that economic assessments for potential transmission solutions are necessary, the production benefits and other benefits of potential transmission solutions are based on the ISO's Transmission Economic Analysis Methodology (TEAM),[55] and potential economic benefits are quantified as reductions of ratepayer costs.

In addition to the production benefit, other benefits were also evaluated as needed. As discussed in Section 4.2, other benefits are also taken into account on a case-by-case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven.

All costs and payments provided in this section are in 2022 real dollars.

Finally, it is important to reiterate that all regional transmission solutions – other than modifications to existing facilities -- are subject to the ISO's competitive solicitation process as

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

set out in the ISO's tariff. While many projects have been submitted with narrowly defined project scopes, the ISO is not constrained to only study those scopes without modification, or to study the projects exclusively on the basis under which the proponent suggested.

4.9 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 continue analysis from previous years' studies, also guided the selection of study areas.

The ISO then conducted extensive assessments of potential economic transmission solutions. These potential transmission solutions included stakeholder proposals received from a number of sources, including: request window submissions that cited economic benefits, economic study requests, and comments in various stakeholder sessions. Alternatives also included interregional transmission projects as set out in Chapter 5 of the 2023-2024 Transmission Plan.

The study results in this planning cycle were heavily influenced by certain ISO planning assumptions driven by overall industry conditions. In particular, the longer-term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined, in the CPUC's integrated resource planning process, but actionable direction regarding the need for these resources for those purposes is not yet available. As noted earlier, existing legislation[56] calls for the CPUC to provide to the ISO by March 31, 2024 resource projections that are expected to reduce by 2035 the need to rely on non-preferred resources in local capacity areas. However, these projections are not yet reflected in the portfolios provided by the CPUC for the 2023-2024 Plan. As there were no material changes in the assumption regarding the value of reducing capacity requirements in this planning cycle, the ISO did not update the results of the local capacity reduction assessment; rather, the capacity value results of previous planning cycles were used in the economic assessment for the transmission projects that potentially had the benefit of reducing local capacity. The ISO recognizes that the capacity value of many of these projects will need to be revised when actionable direction on the need for gas-fired generation for system and flexible needs is available.

The overall economic planning study results in the 2023-2024 planning cycle are summarized in Table 4.9-1, including the Base portfolio out-of-state wind study results.

[56] SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

Table 4.9-1: Summary of economic assessment in the 2023-2024 planning cycle

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
GLW/VEA Mead S – Sloan Canyon 230 kV line congestion	Add the second Mead S – Sloan Canyon 230 kV line	Mead S – Sloan Canyon 230 kV line congestion was mitigated. However, further clarity is needed regarding the feasibility and availability of adding another line position within the Mead substation.	Appears to be economically justified, pending further assessment for the feasibility of expanding Mead substation	No
SCE East of Pisgah and Path 61 corridor congestion	Add the Trout Canyon – Lugo 500 kV line	Victorville – Lugo 500 kV line congestion under the Eldorado – Lugo 500 kV line N-1 contingency was mitigated, but Path 61 path rating was still binding in about 2000 hours through the year. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Marketplace to Adelanto HVDC conversion project	Path 61 congestion and the congestion on the Lugo – Victorville 500 kV line under the Eldorado – Lugo 500 kV line N-1 contingency was mitigated. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
Path 26 corridor congestion	PTE project	Path 26 corridor congestion was partially mitigated; Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion	Alternative 1: Manning – Moss Landing 500 kV line and reconductoring the Moss Landing – Metcalf 500 kV line, removing the existing Moss Landing – Las Aguilas 230 kV line	Moss Landing – Las Aguilas 230 kV congestion was mitigated, but Path 15 congestion was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project. LCR reduction benefits were not assessed, as further clarity of gas-fired generator retirement assumption in the CPUC IRP is needed.	Further assessment of LCR reduction benefit is needed to complete the economic assessment	No
	Alternative 2: Moss Landing – Las Aguilas 230 kV reconductoring, keep the series reactor approved in the 2021-2022 planning cycle	Moss Landing – Las Aguilas 230 kV congestion was mitigated, but Path 15 congestion was aggravated. Ratepayer benefit is sufficient to cover the total cost of the project, however, the ISO deferred recommendation for approval in this planning cycle in order to have opportunity to assess least-regret long term solution with consideration of resource assumption change beyond the 10-years horizon	Yes, but recommendation for approval was deferred	No
	Alternative 3: Moss Landing – Las Aguilas 230 kV reconductoring, not keep the series reactor	Moss Landing – Las Aguilas 230 kV congestion was mitigated, but Path 15 congestion was aggravated. Ratepayer benefit is sufficient to cover the total cost of the project, however, the ISO deferred recommendation for approval in this planning cycle in order to have opportunity to assess longer term	Yes, but recommendation for approval was deferred	No

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
		solution with consideration of resource assumption change beyond the 10-years horizon.		
	Alternative 4: Midway – Gates – Manning new 500 kV line	Los Banos – Manning congestion was aggravated, although congestions on other components of Path 15 corridor were mitigated or partially mitigated. Path 26 congestion was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 5: Manning-Los Banos-Tracy new 500 kV line	Gates - Manning congestion was aggravated. Moss Landing – Las Aguilas congestion was partially mitigated. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 6: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring plus Midway – Gates – Manning new 500 kV line (alt 1 plus alt 4)	Path 15 corridor and Moss Landing – Las Aguilas 230 kV congestions were mitigated. Path 26 congestion was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 7: Moss Landing – Las Aguilas 230 kV reconductoring plus Midway – Gates – Manning new 500 kV line (alt3 plus alt 4)	Moss Landing – Las Augilas 230 kV congestion was mitigated, but Los Banos – Manning congestion and Path 26 congestion was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project	No	No
	Alternative 8: Manning-Los Banos-Tracy new 500 kV line, plus Midway-Gates-Manning new 500 kV line (alt 4 plus alt 5)	Path 15 corridor congestion was mitigated, and Moss Landing – Las Aguilas congestion was partially mitigated. Path 26 congestion was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No

In summary, several transmission solutions were found to have sufficient economic benefits based on the available cost estimate, however, the ISO decided to not recommend these transmission upgrades for approval as economic-driven projects in this planning cycle for the reasons explained below:

- Adding the second Mead S – Sloan Canyon 230 kV line in the GridLiance West/VEA area showed potential economic benefit to ISO's ratepayers. However, due to the limitation within the Mead Substation for adding another line position, further assessment for the feasibility and cost of adding the second Mead S – Sloan Canyon 230 kV line will be conducted in coordination with GridLiance West and the facility owners of Mead substation.
- Moss Landing – Las Aguilas 230 kV line reconductoring showed benefit to cost ratio greater than 1.0. Some of the 500 kV alternatives assessed in this planning cycle also showed meaningful production cost saving. Considering the potential changes in resource assumption in future CPUC integrated resource planning for PG&E areas,

including assumptions for the Fresno/Kern area solar, Greater Bay area gas-fired generator retirement, and offshore wind, it is expected that the flow and congestion pattern on Path 15 corridor and the Moss Landing – Las Aguilas 230 kV line will have large variation from this planning cycle's results. Production cost saving of these transmission alternatives will be impacted as well. Also, the potential LCR reduction benefit was not considered in this planning cycle, which requires further clarity of gas-fired generator retirement assumption in the CPUC's IRP. Therefore, the ISO recommended to not approve any of these transmission alternatives for Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion mitigation in this planning cycle. Instead, the ISO will continue to investigate different transmission alternatives and their combinations for Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion mitigation in the next planning cycles based on the new CPUC IRP resource assumption.

Other transmission alternatives assessed in this chapter can help to address transmission congestion or renewable curtailment issues in respective study areas. Some alternatives showed positive benefits to ISO's ratepayers, but none of them showed sufficient economic justification in this planning cycle's economic assessments. Some alternatives showed effectiveness to mitigate or partially mitigate congestion on some corridors, but may aggravate congestion in other parts of the system. Comprehensive mitigation plans will be evaluated for these transmission constraints in future transmission planning cycles.

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Chapter 5

5 Interregional Transmission Coordination

The ISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with FERC Order No. 1000. The ISO's 2023-2024 transmission planning cycle was completed during the even-year portion of the 2022-2023 interregional transmission coordination cycle.

The ISO started its 2022-2023 ITP cycle in the first quarter of 2022 in which proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2022-2023 transmission planning process. During the submission period, seven projects were submitted by their project sponsors for consideration by the ISO. However, based on the assessments documented in the 2022-2023 transmission plan, no interregional project moved into year two and therefore, no further consideration of the submitted ITPs was required in this 2023-2024 transmission planning process.

5.1 Background on the Order No. 1000 Common Interregional Tariff

FERC Order No. 1000 broadly reformed the regional and interregional planning processes of public utility transmission providers. While instituting certain requirements to clearly establish regional transmission planning processes, Order No. 1000 also required improved coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. Since the final rule was issued, the ISO has continued to collaborate with neighboring transmission utility providers and Western Planning Regions (WPRs) across the Western Interconnection through a coordinated process for considering interregional projects.

Early on in the interregional transmission coordination process, the WPRs developed certain business practices for the specific purpose of providing stakeholders visibility and clarity on how the WPRs would engage in interregional coordination activities among their respective regional planning processes. Commensurate with each WPR's regional arrangement with its members, these business practices were incorporated into the WPR regional processes to be followed within the development of regional plans. For the ISO, these business practices have been incorporated into the ISO's Business Practice Manual (BPM) for the Transmission Planning Process.

Commensurate with past interregional transmission coordination cycles, the ISO continued to play a leadership role in Order No. 1000 processes within the ISO's planning region, through direct coordination with the other WPRs and representing and supporting interregional coordination concepts and processes in public forums such as WECC. The WPRs have actively engaged to resolve conflicts and challenges that have arisen since the first coordination cycle was initiated in 2016. The ISO and other WPRs have continued to consider and forge new opportunities to facilitate coordination among its stakeholders and neighboring planning regions for the benefit of interregional coordination.

5.2 Interregional Transmission Project Submittal Requirements

As described in the ISO's BPM for the Transmission Planning Process, ITPs may be submitted into the ISO's transmission planning process on January 1 through March 31 of every even year of the interregional transmission coordination process. The ITPs must be properly submitted and in doing so must meet the following requirements:

- The ITP must electrically interconnect at least two Order 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.

All WPRs are consistent in how they consider interregional transmission projects within their Order No. 1000 regional planning processes.

5.3 Interregional Transmission Coordination per Order No. 1000

Overall, the interregional coordination requirements established by Order No. 1000 are reasonably straight-forward. In general, the interregional coordination order requires that each WPR: (1) commit to developing a procedure to coordinate and share the results of its planning region's regional transmission plans to provide greater opportunities for the WPRs to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost-effectively than separate regional transmission facilities; (2) develop a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions; (3) establish a formal agreement to exchange among the WPRs, at least annually, their planning data and information; and finally (4) develop and maintain a website or e-mail list for the communication of information related to the interregional transmission coordination process.

On balance, the ISO fulfills these requirements by following the processes and guidelines documented in the BPM for the Transmission Planning Process and through its development and implementation of the transmission planning process.

5.3.1 Procedure to Coordinate and Share ISO Planning Results with other WPRs

During each planning cycle the ISO predominately exchanges its interregional information with the other WPRs in two ways: (1) an annual coordination meeting hosted by the WPRs; and (2) a process by which ITPs can be submitted to the ISO for consideration in its transmission planning process. While the annual coordination meetings are organized by the WPRs, one WPR is designated as the host for a particular meeting and in turn, is responsible for facilitating the meeting. The annual coordination meetings are generally held in February/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. WestConnect hosted the 2023 meeting and NorthernGrid is hosting the 2024 meeting.

In general, the purpose of the coordination meeting is to provide a forum for stakeholders to discuss planning activities in the West, including a review of each region's planning process, its needs and potential interregional solutions, update on ITP evaluation activities, and other related issues. It is important to note that the ISO's planning processes is annual while the planning processes of NorthernGrid and WestConnect are biennial. To address this difference in planning cycles, the WPRs have agreed to annually share the planning data and information that is available at the time the annual interregional coordination meeting is held; divided into an "even" and "odd"-year framework.

5.3.2 Submission of Interregional Transmission Projects to the ISO

As part of its transmission planning process, the ISO provides a submission window during which proponents may submit their ITPs into the ISO's annual planning process within the current interregional coordination cycle. The submission window is open from January 1st through March 31st of every even-numbered year. Interregional Transmission Projects will be considered by the WPRs on the basis that:

- The ITP must electrically interconnect at least two Order 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 process. For the ISO, validated ITPs will be included in the ISO's Transmission Planning Process Unified Planning Assumptions and Study Plan for the current planning cycle and evaluated in that year's transmission planning process.

All WPRs are consistent in how they consider interregional transmission projects within their Order No. 1000 regional planning processes.

5.3.3 Evaluation of Interregional Transmission Projects by the ISO

Once the submittal and validation process has been completed, the ISO shares its planning data and information with the other Relevant Planning Regions and develops a coordinated evaluation plan for each ITP to be considered in its regional planning process. The process to evaluate an ITP can take up to two years where an “initial” assessment is completed in the first or even year and, if appropriate, a final assessment is completed in the second or odd year. The assessment of an ITP in a WPR’s regional process continues until a determination is made on whether the ITP will or will not meet a regional need within that Relevant Planning Region. If a WPR determines that an ITP will not meet a regional need within its planning region, no further assessment of the ITP by that WPR is required. Throughout this process, as long as an ITP is being considered by at least two Relevant Planning Regions, it will continue to be assessed as an ITP for cost allocation purposes; otherwise, the ITP will no longer be considered within the context of Order No. 1000 interregional cost allocation. However, if one or more planning regions remain interested in considering the ITP within its regional process even though it is not on the path of cost allocation, it may do so with the expectation that the planning region(s) will continue some level of continued cooperation with other planning regions and with WECC and other WECC processes to ensure all regional impacts are considered.

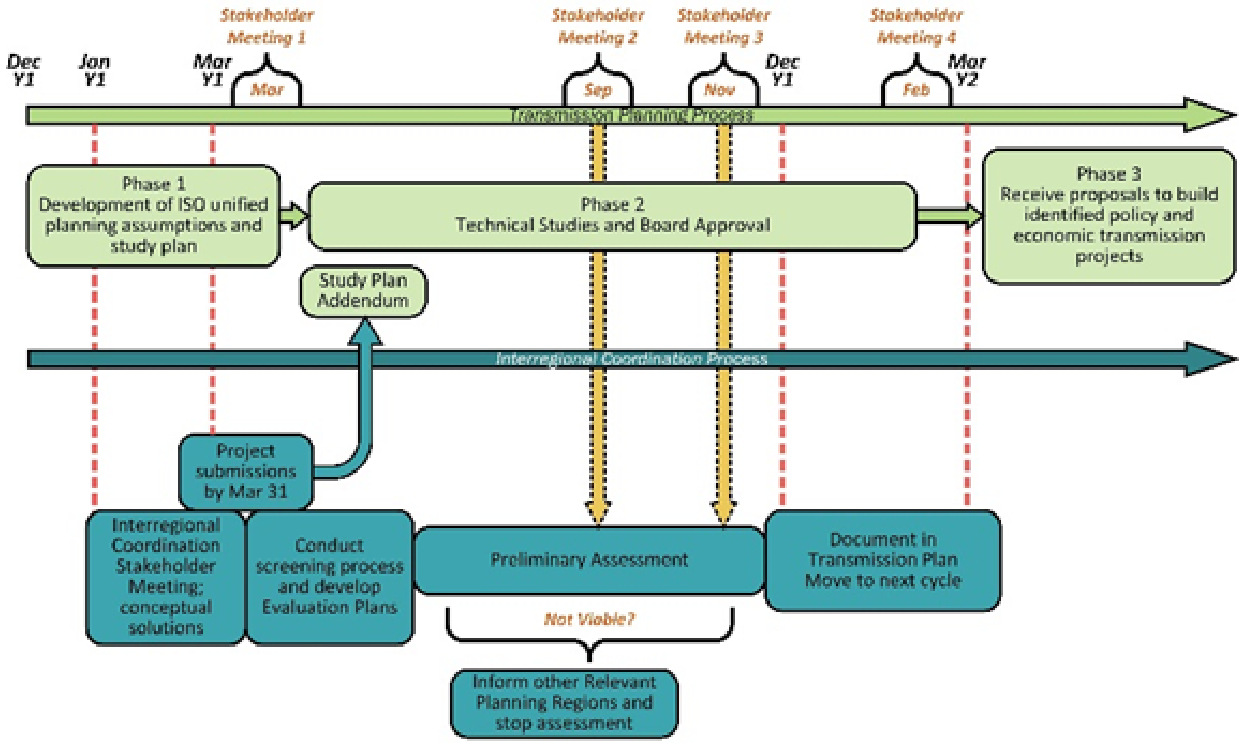
5.3.3.1 Even Year ITP Assessment

The even-year ITP assessment begins when the relevant planning regions initiate the coordinated ITP evaluation process. This evaluation process constitutes the relevant planning regions’ formal process to identify and jointly evaluate transmission facilities that are proposed to be located in planning regions in which the ITP was submitted. The goal of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP that will be used by all relevant planning regions in their individual evaluations of the ITPs. The relevant planning regions are required to complete the ITP evaluation process within 75 days after the ITP submittal deadline of March 31, during which a lead planning region is selected for each ITP proposal to develop and post for ISO stakeholder review a coordinated ITP evaluation process plan for each ITP. Once the ITP evaluation plans are final, each relevant planning region independently considers the ITPs that have been submitted into its regional planning process.

As with the other relevant planning regions, the ISO assesses the ITP proposals under the ISO tariff. As illustrated in the ISO shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the ISO manages its assessment of an ITP proposal across the two-year interregional coordination cycle in two steps. During the even year, the ISO makes a preliminary assessment of the ITP and once it completes that task, the ISO must consider whether consideration of the ITP should continue into the next ISO planning cycle (odd-year interregional coordination process). That determination can be made based on a number of factors including economic, reliability, and public policy considerations.

Figure 5.3-1: Even Year Interregional Coordination Process

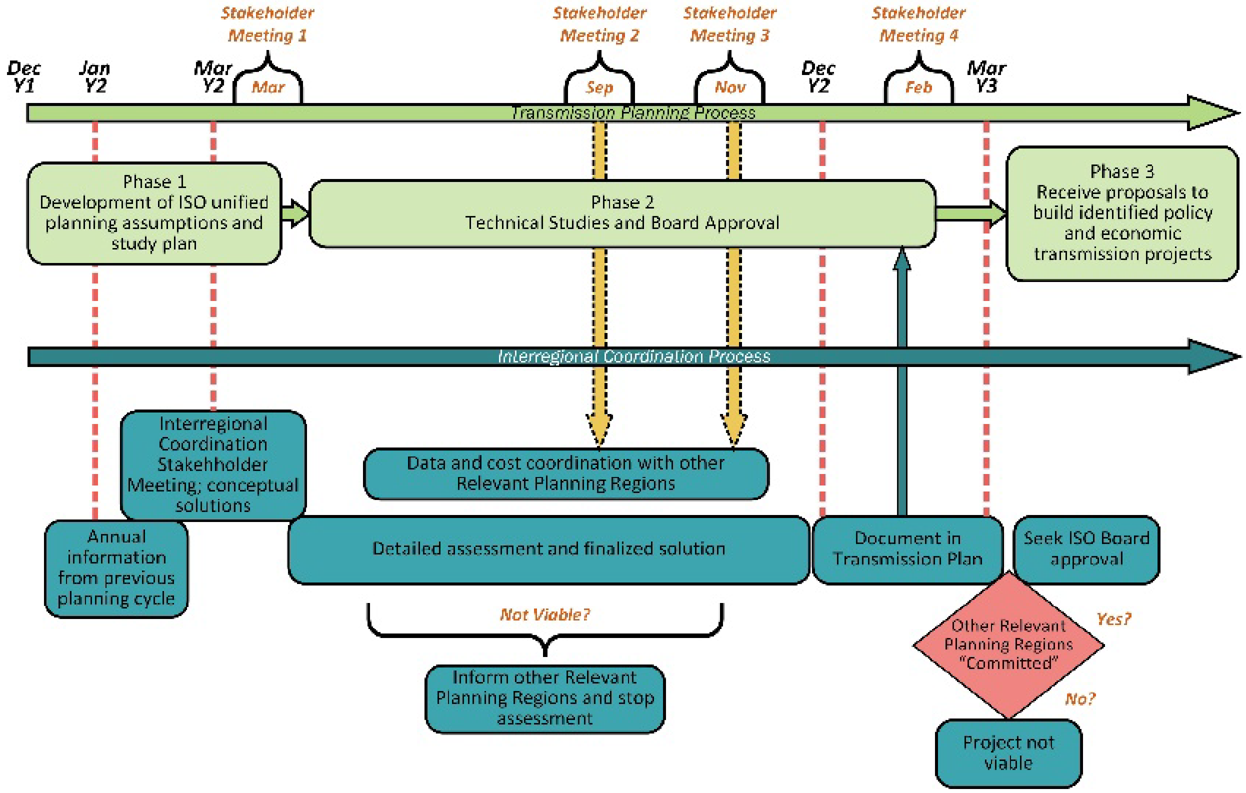


The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation on whether to continue assessment of the ITP in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission plan.

5.3.3.2 Odd-Year ITP Assessment

A recommendation in the even-year transmission plan to continue assessing an ITP will initiate consideration of the ITP in the following, or odd-year transmission planning cycle and, as such, will be documented in the odd-year transmission planning process, unified planning assumptions, and study plan. Similar to the even-year coordination process shown in Figure 5.3-1, the ISO will follow the odd-year interregional coordination process shown in Figure 5.3-2.

Figure 5.3-2: Odd Year Interregional Coordination Process



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

5.4 Development of the Anchor Data Set (ADS)

The ISO continues to support WECC's ADS activities and remains engaged in the ADS development process through standing WECC subcommittees and workgroups. The ADS remains the best representative approach for addressing existing and ongoing data inconsistencies and applications, while facilitating a common dataset that accurately represents the regional plans of the WPRs. Each year the ISO builds over 100 power-flow cases to perform its reliability assessment of the ISO-controlled grid as well as a detailed production cost model dataset from which it performs economic, policy, and other studies. Clearly, significant ISO resources are committed to developing these study models during each planning cycle and, as such, their accuracy is of paramount importance to that process. The ISO believes that the successful development and implementation of the ADS will yield, through a consistent and repeatable process, better coordinated and more accurate datasets that will maximize their use and minimize errors in WPR regional and WECC assessments

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Chapter 6

6 Other Studies and Results

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan. 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 and 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 2024. 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 2023. A short-term analysis was conducted for the 2024 system configuration to determine the minimum local capacity requirements for the 2024 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 28, 2023. For detailed information on the 2024 LCT Study Report please visit:

http://www.caiso.com/InitiativeDocuments/Final-2024-Local-Capacity-Technical-Report.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2028 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years. The 2028 LCT Study Report was published on April 28, 2023. For detailed information please visit:

http://www.caiso.com/InitiativeDocuments/Final-2028-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 2022-2023 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 2032 long-term LCT study results, please refer to the stand-alone report in Appendix J of the 2022-2023 transmission planning process.

As shown in the LCT study reports and indicated in the LCT study manual that the ISO prepares each year setting out how that year's LCT studies will be performed, 12 load pockets are located throughout the ISO-controlled grid as shown in Table 6.1-1; however only 10 of them have local capacity area requirements as illustrated in Figure 6.1-1.

Table 6.1-1: List of Local Capacity Areas and the corresponding service territories within the ISO Balancing Authority Area

No	LCR Area	Service Territory
1	Humboldt	PG&E
2	North Coast/North Bay	
3	Sierra	
4	Stockton	
5	Greater Bay Area	
6	Greater Fresno	
7	Kern	
8	Los Angeles Basin	SCE
9	Big Creek/Ventura	
10	Greater San Diego/Imperial Valley	SDG&E
11	Valley Electric	VEA
12	Metropolitan Water District	MWD

Figure 6.1-1: Approximate geographical locations of LCR areas

Each load pocket is unique and varies in its capacity requirements because of different system configurations. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 140 MW. In contrast, the requirements of the Bay Area are approximately 7,300 MW. The short-term and long-term LCR needs from this year's studies are shown in Table 6.1-2.

Table 6.1-2: Local capacity areas and requirements for 2024, 2028 and 2032

LCR Area	LCR Capacity Need (MW)		
	2024	2028	2032
Humboldt	133	148	154
North Coast/North Bay	983	891	911
Sierra	1,212	1,415	1,450
Stockton	750	772	755
Bay Area	7,329	6,261	7,936
Fresno	2,028	2,728	2,750
Kern	427	427	424
Big Creek/Ventura	1,971	1,216	1,366
Los Angeles Basin	4,413	5,940	7,388
San Diego/Imperial Valley	2,834	3,575	4,849
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	22,080	23,373	27,983

Notes:
For more information about the LCR criteria, methodology and assumptions, please refer to the ISO LCR manual.[57]
For more information about the 2024 LCT study results, please refer to the report posted on the ISO website.
For more information about the 2028 LCT study results, please refer to the report posted on the ISO website.

[57] "Final Manual 2024 Local Capacity Area Technical Study," January 12, 2023, http://www.caiso.com/InitiativeDocuments/FinalStudyManual-2024LocalCapacityRequirements.pdf.

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 2024 in accordance with the ISO tariff Section 40.4.6.2.1. This data can be found on the ISO website.[58] The entire import allocation process[59] is posted on the ISO website.

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

http://www.caiso.com/Documents/AdvisoryEstimatesofFutureResourceAdequacyImportCapabilityforYears2024-2033.pdf

The maximum import capability (MIC) from the Imperial Irrigation District (IID) was increased to 702 MW starting in year 2024 to accommodate renewable resources development in this area that ISO has established in accordance with Reliability Requirements BPM Section 5.1.3.5. The import capability from IID to the ISO is the combined amount from the IID-SCE_ITC and the IID-SDGE_ITC intertie.

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

Table 6.1-3: Maximum Import Capability fully approved increases

Orig. Year	Driver	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	2023 NQC 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)

Yearly NQC deliverability study:

Only 5 scheduling points had a MIC expansion requests that triggered an increase applicable to the 2024 RA year.

Table 6.1-4: 2024 NQC deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	GONDIPPDC_ITC (GONIPP)	Failed	CPUC portfolio – includes MIC expansion requests.
2	BLYTHE_ITC (BLYTHE161)	Failed	MIC expansion request only.
3	ELDORADO_ITC (WILLOWBEACH)	Failed	Includes both the CPUC portfolio and additional MIC expansion requests.
4	MEAD_ITC (MEAD 230)	Failed	Includes both the CPUC portfolio and additional MIC expansion requests.
5	SILVERPK_ITC (SILVERPEAK55)	Pass	CPUC portfolio – includes MIC expansion requests. Temporary expansion included in 2024 MIC.

[58] "California ISO Maximum RA Import Capability for year 2024," available on the ISO's website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2024.pdf .

[59] See general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

The appropriate amount of MWs to the scheduling points that passed the test of the 2024 NQC deliverability study were given to the LSEs as a temporary MIC increase for RA year 2024.

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

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 assure all import resources are deliverable to the aggregate of load.

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

Table 6.1-5: Base portfolio driven MIC increase (per TPP) that awaits GIP deliverability studies

Orig. Year	Status	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	2023 NQC MWs	Waiting for:	First RA year[60]
2022	Active	IID-SDGE_ITC (IVLY2) & IID-SCE_ITC (DEVERS230 & MIR2)	600	Geothermal	600	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2022	Active	ELDORADO_ITC (WILLOWBEACH)	19.35	Wind	6.47	Lugo-Victorville line upgrade.	2030
2022	Active	MEAD_ITC (MEAD 230)	300	Wind	118.95	Lugo-Victorville line upgrade.	2030
2022	Active	PALOVRDE_ITC (PVWEST)	438	Wind	145	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2023	Active	IID-SCE_ITC (DEVERS230 & MIR2)	224	Geothermal	224	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2023	Active	ELDORADO_ITC (WILLOWBEACH)	164.7	Wind	53.68	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	HA500_ISL (HA500)	2500	Wind	1095.94	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	HA500_ISL (HA500)	225	Geothermal	225	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	MEAD_ITC (MEAD230)	100	Geothermal	100	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	GONDIPPDC_ITC (GONIPP)	80	Geothermal	80	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	SILVERPK_ITC (SILVERPEAK55)	13	Geothermal	13	Lugo-Victorville line upgrade, the Bishop RAS and expansion of the Lugo-Victorville RAS.	2030
2023	Active	PALOVRDE_ITC (PVWEST)	1890	Wind	778	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036

[60] 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 2023 submitted base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2033.

Based on the TPP deliverability studies (and most likely 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 6.1-6: Base portfolio MIC increases awaiting new TPP upgrades and GIP deliverability studies

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	SUMMIT_ITC (SUMMIT120)	Failed	For potential increase see mitigation for PG&E 500 kV constraint.

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.

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 2 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 6.1-7: Valid 2023 Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource Type
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	23	Hydro
3	Marin Clean Energy	GONDIPPDC_ITC (GONIPP)	20	Geothermal
		MONAIPPDC_ITC (MWDP)		
4-6	California Community Power	GONDIPPDC_ITC (GONIPP)	38.5	Geothermal
		SILVERPK_ITC (SILVERPEAK55)		
		SUMMIT_ITC (SUMMIT120)		
		IID-SDGE_ITC (IVLY2)	40	
		GONDIPPDC_ITC (GONIPP)	13	
		SILVERPK_ITC (SILVERPEAK55)		
7	Fervo Energy Cal Choice Energy Authority Clean Energy Alliance Desert Energy Community	IPPDCADLN_ITC (IPP & IPPUTAH)	20	Geothermal
8	Fervo Energy Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	Geothermal
9	Clean Power Alliance	MEAD_ITC (MEAD 230)	119	Wind

The ISO has received 5 submissions with requests for MIC expansion. They contained 9 distinct requests.

Based on the ISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) requirements, all 9 distinct requests qualify as valid requests based on the following factors:

- LSEs with valid RA contracts not already accounted for as Pre-RA Import Commitments 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 6.1-8: Assessment of valid 2023 Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Triggers Expansion	Comments
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	23	Yes	Partial
3	Marin Clean Energy	GONDIPPDC_ITC (GONIPP)	20	In CPUC Portfolio	CPUC Portfolio triggers MIC expansion.
		MONAIPPDC_ITC (MWDP)			
4-6	California Community Power	GONDIPPDC_ITC (GONIPP)	38.5	In CPUC Portfolio	CPUC Portfolio triggers MIC expansion.
		SILVERPK_ITC (SILVERPEAK55)			Active as back-up location only.
		SUMMIT_ITC (SUMMIT120)			
		IID-SDGE_ITC (IVLY2)	40		No expansion need.
		GONDIPPDC_ITC (GONIPP)	13		CPUC Portfolio triggers MIC expansion.
		SILVERPK_ITC (SILVERPEAK55)			
7	Fervo Energy Cal Choice Energy Authority Clean Energy Alliance Desert Energy Community	IPPDCADLN_ITC (IPP & IPPUTAH)	20	Yes	Full
8	Fervo Energy Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	Yes	Full
9	Clean Power Alliance	MEAD_ITC (MEAD 230)	119	In CPUC Portfolio	CPUC Portfolio triggers MIC expansion.

After the elimination of: duplicate entries (vis-à-vis the 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 6.1-9: Maximum Import Capability expansion requests currently being assessed

No.	Year	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource Type
1-2	2022	San Diego Community Power	ELDORADO_ITC (WILLOWBEACH)	90	Wind
3-5		Valley Electric Association	MEAD_ITC (MEAD 230)	33	Hydro
6				90	Hybrid (Solar/Battery)
7-8	2023	Southern California Edison	BLYTHE_ITC (BLYTHE161)	23	Hydro
9		California Community Power	SILVERPK_ITC (SILVERPEAK55)[61]	38.5	Geothermal
			SUMMIT_ITC (SUMMIT120)[56]		
10		Fervo Energy Cal Choice Energy Authority Clean Energy Alliance Desert Energy Community	IPPDCADLN_ITC (IPP & IPPUTAH)	20	Geothermal
11		Fervo Energy Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	Geothermal

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

[61] As back-up locations only – main delivery point included as GONDIPPDC_ITC (GONIPP) and part of the CPUC portfolio.

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.

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 6.1-10: TPP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed/ Denied	Part not in the CPUC portfolio. Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
2	MEAD_ITC (MEAD 230)	Failed/ Denied	Part not in the CPUC portfolio. Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
3	IPPDCADLN_ITC (IPP & IPPUTAH)	Failed/ Denied	Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests.
4	BLYTHE_ITC (BLYTHE161)	Failed/ Denied	Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests.
5	SILVERPK_ITC (SILVERPEAK55)	Failed/ Denied	Used as back-up only – main in the CPUC portfolio. The Control-Silver Peak 55 kV constraint allows for 4 MWs of deliverability however the mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
6	SUMMIT_ITC (SUMMIT120)	Failed/ Denied	Used as back-up only – main in the CPUC portfolio. The Drum-Higgins 115 kV constraint has no mitigation required for reliability, economic or policy needs.

All MIC expansion requests have failed the TPP deliverability test and therefore 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 (none at this time). 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.

GIP deliverability study:

The GIP deliverability study includes all resources with deliverability included in the TPP deliverability study, (including MIC expansion 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 new cycle of GIP deliverability studies, however, since the GIP deliverability study includes additional new resources with prior TPD and DGD allocation beyond those modeled in the TPP deliverability study, it is reasonably assumed that they would fail the GIP deliverability studies.

Table 6.1-11: GIP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed*/ Denied	Part not in the CPUC portfolio. Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
2	MEAD_ITC (MEAD 230)	Failed*/ Denied	Part not in the CPUC portfolio. Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
3	IPPDCADLN_ITC (IPP & IPPUTAH)	Failed*/ Denied	Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests.
4	BLYTHE_ITC (BLYTHE161)	Failed*/ Denied	Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests.
5	SILVERPK_ITC (SILVERPEAK55)	Failed*/ Denied	Used as back-up only – main in the CPUC portfolio. The Control-Silver Peak 55 kV constraint allows for 4 MWs of deliverability however the mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
6	SUMMIT_ITC (SUMMIT120)	Failed*/ Denied	Used as back-up only – main in the CPUC portfolio. The Drum-Higgins 115 kV constraint has no mitigation required for reliability, economic or policy needs.

* All MIC expansion requests will likely fail the GIP deliverability test and therefore 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 (none at this time). 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.

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 2023 LT CRR study leveraged the base case network topology used for the annual 2024 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 2023-2024 Transmission Plan. In the SFT-based market run, all CRR sources and sinks from the released CRR nominations were applied to the full network model (FNM). All applicable constraints that were applied during the running of the original LT CRR market were considered to determine flows as well as to identify the existence of any constraint violations. In the long-term CRR market run setup, the network was limited to 60% of available transmission capacity. The fixed CRR representing the transmission ownership rights and merchant transmission were also set to 60%. All earlier LT CRR market awards were set to 100%, since they were awarded with the system capacity already reduced to 60%. For the study year, the market run was set up for two seasons (with season one being January through March and season three July through September) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as 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 sed to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs SFT is completed successfully:

- The worst-case base loading in each market run does not exceed 60% of enforced branch rating; and
- There are overall improvements on the flow of the monitored transmission elements.

6.2.3 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

- The base case network model data for long-term grid planning is prepared by the regional transmission engineering (RTE) group. The data preparation may involve using one or more of these applications: PTI PSS/E, GE PSLF and MS Excel;
- RTE models new and approved projects and perform the AC power flow analysis to ensure power flow convergence;
- RTE reviews all new and approved projects for the transmission planning cycle;
- Applicable projects are modeled into the base case network model for the CRR allocation and auction in collaboration with the CRR team, consistent with the BPM for Transmission Planning Process Section 4.2.2;
- CRR team sets up and performs market runs in the CRR study system environment in consultation with the RTE group;
- CRR team reviews the results using user interfaces and displays, in close collaboration with the RTE group; and
- The input data and results are archived to a secured location as saved cases.

6.2.4 Conclusions

The SFT studies involved four market runs that reflected two three-month seasonal periods (January through March, and July through September) and two time-of-use (on-peak and off-peak) conditions.

The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as planned. In compliance with Section 24.4.6.4 of the ISO tariff, the ISO followed the LTCRR SFT study steps outlined in Section 4.2.2 of the BPM for the Transmission Planning Process to determine whether there are any existing released LT CRRs that could be at risk and for which mitigation measures should be developed. Based on the results of this analysis, the ISO determined in December of 2023 that there are no existing released LT CRRs “at-risk” that require further analysis. Thus, the transmission projects and elements approved in the 2023-2024 Transmission Plan did not adversely impact feasibility of the existing released LT CRRs. Hence, the ISO did not evaluate the need for additional mitigation solutions.

6.3 Frequency Response Assessment and Data Requirements

As penetration of renewable resources increases, conventional synchronous generators are being displaced with renewable resources using converter-based technologies. Given the materially different operating characteristics of renewable generation, this necessitates broader consideration of a range of issues in managing system dispatch and maintaining reliable service across the range of operating conditions. One of the primary concerns is that there be adequate frequency response from inverter-based resources (IBR) when unplanned system outages and events occur.

Over past planning cycles, the ISO conducted a number of studies to assess the adequacy of forecast frequency response capabilities, and those studies also raised broader concerns with the accuracy of the generation models used in the analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

In the subsections below, the progress achieved and issues to be considered going forward 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

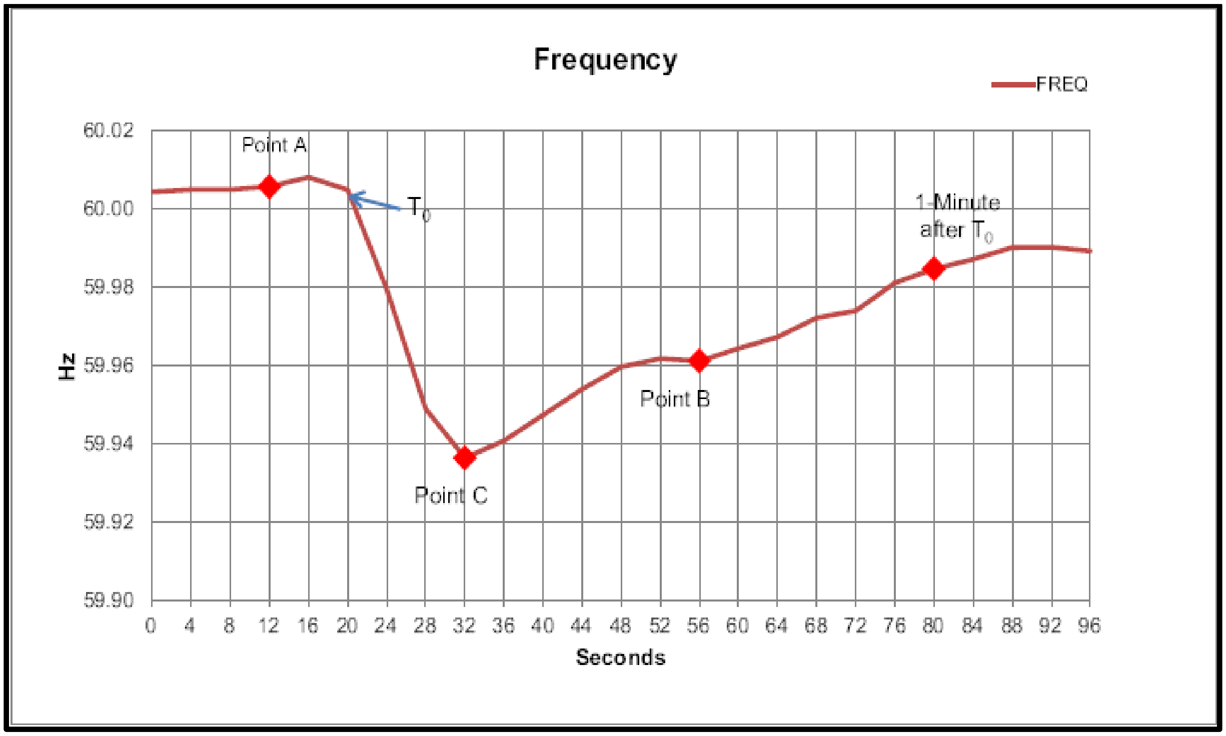
The ISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in subsequent years, using the latest dynamic stability models. In this planning cycle, the potential impact of inverter-based resources (IBR), particularly battery energy storage systems (BESS) as a means of aiding frequency response, was investigated.

Background on Frequency Response and Frequency Bias Setting Methodology

NERC has established the methodology for calculating frequency response obligations (FRO) outlined in Reliability Standard BAL-003-2 (Frequency Response and Frequency Bias Setting). A balancing authority's FRO is determined by first defining the FRO of the interconnection as a whole, which is referred to as the interconnection frequency response obligation (IFRO). The methodology then assigns a share of the total IFRO to each balancing authority based on its share of the total generation and load of the interconnection. The IFRO of the WECC Interconnection is determined annually based on the largest potential generation loss, which is the loss of two units of the Palo Verde nuclear generation station (2,740 MW). This is a credible outage that results in the most severe frequency excursion post-contingency.

A generic system disturbance that results in frequency decline, such as the loss of a large generating facility, is illustrated in Figure 6.3-1. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 6.3-1: Illustration of Primary Frequency Response



The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

The Interconnection Frequency Response Obligation changes from year to year primarily as the result of the changes in the statistical frequency variability during actual disturbances, and statistical values of the frequency nadir and settling frequency observed in the actual system events. Allocation of the Interconnection FRO to each balancing authority also changes from year to year depending on the balancing authority's portion of the interconnection's annual generation and load. This year, NERC has maintained the 2016 IFRO value of 858 MW/0.1 Hz be retained for the present operating year. The ISO's share of this obligation remains at 257.4 MW/0.1 Hz.

More conventional 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 generation, inverter-based renewable resources must specifically have a dedicated control mechanism to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their MW output. When a frequency response characteristic is incorporated into IBR control parameters, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has headroom remaining. As more wind and solar resources displace conventional synchronous generation, the mix of the remaining synchronous generators may not be able to adequately meet the ISO's FRO under BAL-003-2 for all operating conditions.

The most critical condition when frequency response may not be sufficient is when 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[62]; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt has not been standardized.

For the ISO studies, the comparable metric is defined as the ratio of power generation capability of units with responsive governors to the MW capability of all generation units. For units that don't respond to frequency changes, power capability is defined as equal to the MW dispatch rather than the nameplate rating because these units will not contribute beyond their initial dispatch.

Rate of Change of Frequency (ROCOF)

- ROCOF is defined as the rate of change of frequency and is proportional to power imbalance during a system disturbance. The ROCOF value is most responsive immediately after a contingency and is increasingly being used by the industry to gauge the severity of the event and the ability of connected generators to respond in a timely manner to arrest excessive frequency excursions. ROCOF is particularly important as it anticipates the magnitude of frequency changes and in real time can be used to signal and react quickly to excessive frequency excursions.
- ROCOF is difficult to accurately measure post-contingency as the change in frequency is inherently noisy with multiple slope profiles potentially resulting in a wide margin of error. Despite this challenge, the ROCOF is a good predictor of system response to a bulk

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

system frequency event. When reliably measured, it also provides a good means of ranking contingencies in terms of severity.

6.3.2 FERC Order 842

On February 15, 2018, FERC issued Order 842 that requires newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. 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 2021-2022 Transmission Plan Study

In the 2021-2022 transmission planning cycle, the frequency response was assessed and it was determined that the Frequency Response Obligation (FRO) required from ISO was 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 2022-2023 Transmission Plan Study

As in the 2021-2022 transmission planning process, this study is to re-assess the frequency response of the ISO system to a dual Palo Verde unit outage. Once again an emphasis is 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. IBR plants are those with a ‘repc_a’ plant controller models. Turning off frequency control for these units consists of changing the up and down frequency gains to zero.

The study scenarios are summarized in Table 6.3-1. The study results for the baseline scenarios and the sensitivity study scenarios are illustrated in Figures 6.3-2 through 6.3-5.

Table 6.3-1: Study Scenarios for Frequency Response Study in the 2022-2023 TPP

	Study Scenarios				
	SC1	SC2	SC3	SC4	SC5
PFR enabled for existing IBRs?	No	Yes	Yes	Yes	Yes
Headroom	Existing	Existing	10% BESS units	Min CAISO spinning reserve	Min CAISO spinning reserve
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 existing IBR plants have frequency regulation shut off in the plant controller model.

Scenario 2 has all IBR plant frequency regulation turned on. This scenario is similar to that of the normal 2027 and 2032 base case and with unmodified dynamic models. Figure 6.3-3 shows the resultant 2027 and 2032 system frequency events with reference to Scenario 1. Both 2032 profiles show a marked improvement over that of 2027. The nadir is at 0.131 Hz and 0.153 Hz higher for Scenario 2 for 2027 and 2032 results. The better result in 2032 is explained by the fact that the Palo Verde units are lower proportion of the overall resource total in 2032 compared to 2027 and that there are a higher proportion of IBR plants with frequency control in 2032 than in 2027.

For scenario 3, all new BESS plants were adjusted to a headroom of 10%. In both original Spring Peak cases, the BESS units are in charging mode close to or at their minimum power limit which represents the IBR being in full charging mode. For this scenario all BESS units were re-dispatched using ISO generation to achieve 10% headroom. The net result is that there is a similar response profile for both scenarios 3 and scenario 1 (Figure 6.3-4). A 10% headroom does not inhibit the frequency response as shown in Figure 6.3-4. Both 2027 and 2032 responses with 10% headroom are virtually identical to the case in which all IBRs are all on (Scenario 2).

Scenario 4 is one where all the ISO generation has minimal headroom and is shown in Figure 6.3-5. The 2027 spring off-peak case with all IBR on is marked improved over the same case with ISO at minimum spinning reserve. The 2032 traces on the same plot show a much lesser gap between Scenarios 2 and 4.

Scenario 5 has the ISO BESS units at 10% headroom with the remainder of ISO at minimum spinning reserve. Figure 6.3-6 shows the comparative results of Categories 3 and 5 for both years surveyed. While a 10% BESS headroom scenario (Scenario 3) does not appreciably influence the frequency response (as per Figure 6.3-4), this restriction clearly shows a significant reduction in the overall frequency response for the Scenario 5.

These results indicate that by enabling the frequency response of the new IBR units coming online, particularly in 2032, the system recovers from frequency events faster and settles at higher frequencies. There is a higher proportion of IBR plants in 2032 which significantly aids the system frequency response when enabled. Also the Palo Verde outage drops a lesser proportion of the overall system generation in 2032 than it does in the 2027 base case.

Figure 6.3-2: 2027 & 2032 Scenarios 1 & 2: System Frequency Response for All IBR Frequency Control On and Off

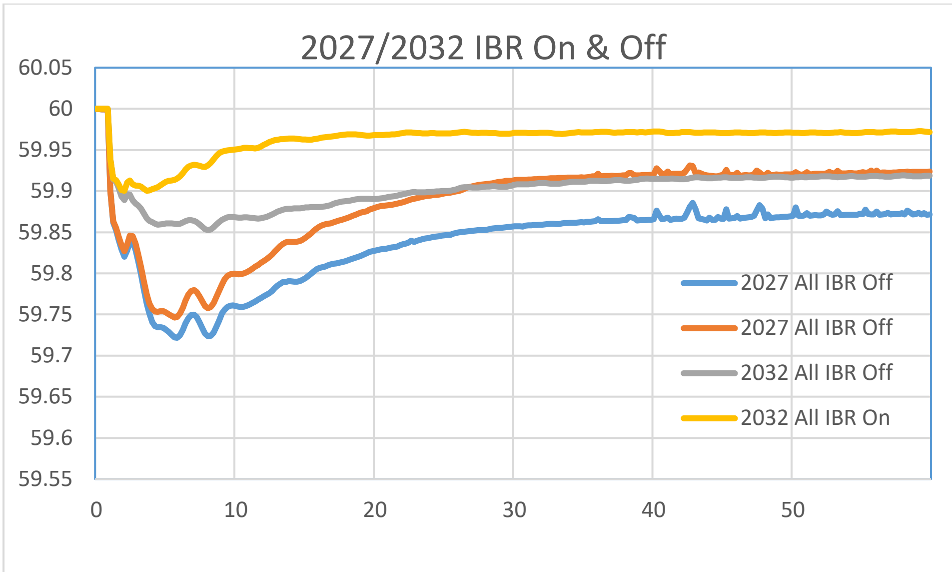


Figure 6.3-3: 2027 & 2032 Scenarios 2&3: System Frequency for all IBR Plants On and BESS Plants at 10% Headroom

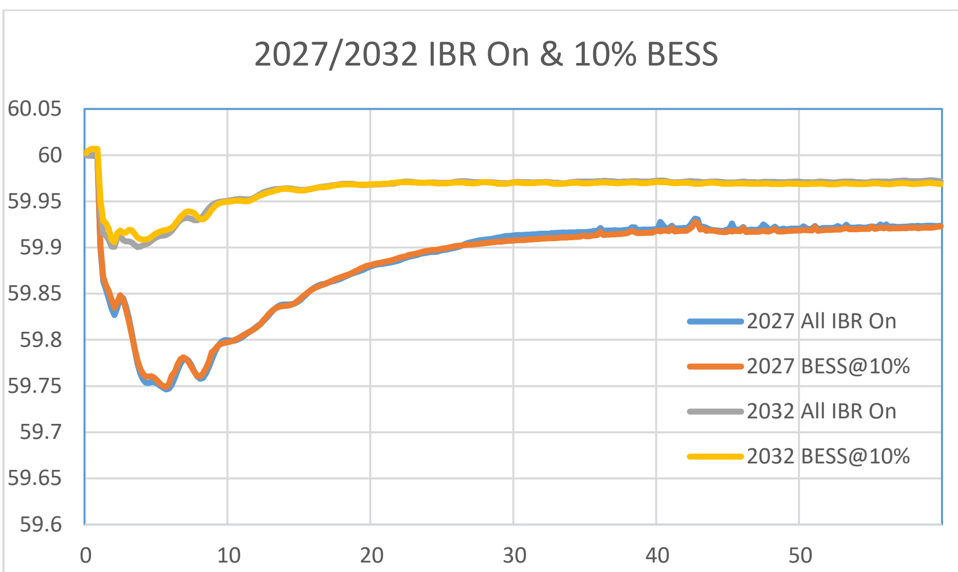


Figure 6.3-4: 2027 & 2023 Scenarios 2 &4: System Frequency for all IBR Plants On and the ISO at Minimum Spinning Reserve

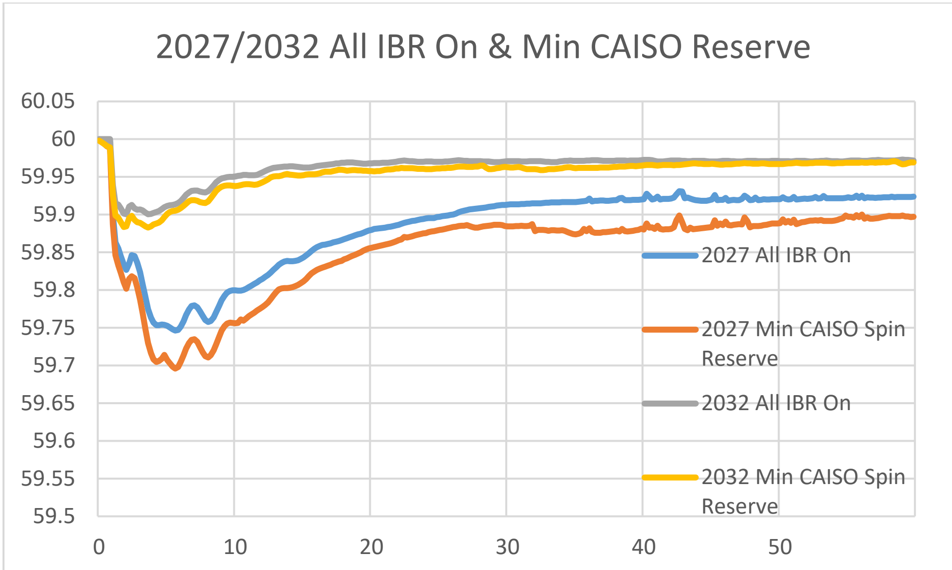
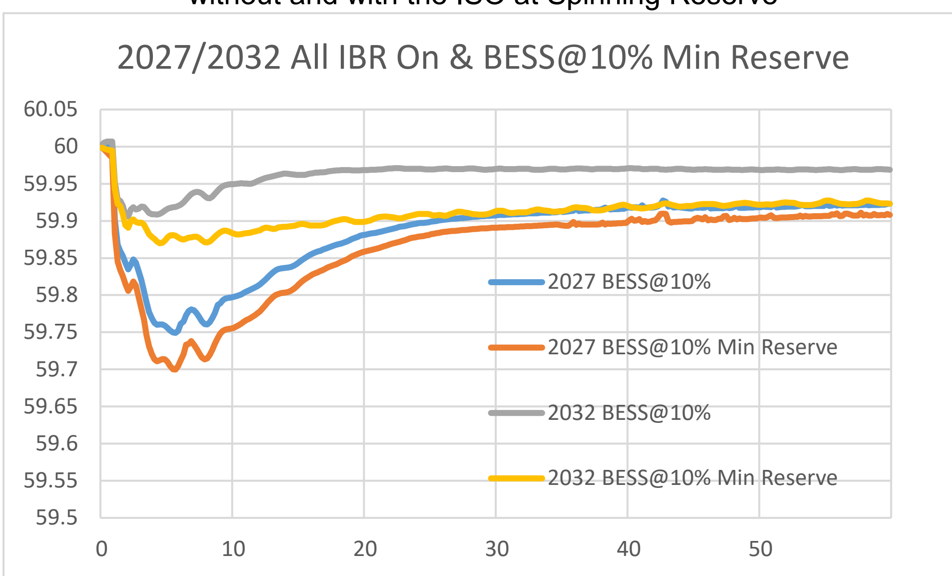


Figure 6.3-5: 2027 & 2023 Scenario 3 & 5: System Frequency Response with BESS@10% without and with the ISO at Spinning Reserve



Conclusions and recommendations from the 2022-2023 transmission planning process study

This study indicates that the ISO system response to major frequency events such as two Palo Verde units improves when IBRs have headroom, also when in charging mode (ample headroom), and have frequency response enabled.

The studies illustrated that the ISO is forecasted to meet its Frequency Response Obligation (FRO) with the frequency response of new IBRs enabled per FERC Order 842. It is sufficient to meet FRO just by enabling the PFR even with current values for droop and deadband.

A number of existing IBRs connected to the ISO footprint have primary frequency response (PFR) capability but there are still a significant number of units for which the PFR capabilities of the IBRs are not enabled. Considering the subset of existing IBRs that are BESS units with frequency response enabled and that all future IBR plants will have frequency response available and enabled, it is expected that the PFR capability of the IBRs would be beneficial to system recovery from frequency events and continue to meet the ISO Frequency Response Obligation (FRO).

6.3.4.1 Progress in Updating and Validating Models

There are various standards and procedures in place for the collection of modeling information from Transmission Owners, developers and their vendors. The ISO also continues to validate existing generator modes as set out in Section 10 of the ISO's Transmission Planning Process Business Practice Manual.[63] A whitepaper released in September 2021 entitled 'Dynamic Model Review Guideline for Inverter based Interconnection Requests'[64] outlines the selection of inverter parameters to ensure interconnection requirements. The later also ensures that frequency response from IBR resources, if enabled, will contribute to arresting abrupt frequency changes.

Validation of system models using simulations that emulate actual major frequency events is presently a process that may be more formally systematized during upcoming planning cycles. This will help ensure that primary frequency response from generators match the expected response and helps align operational results with planning studies. Also this provides an opportunity to determine that existing load models behave as realistically as possible.

63 https://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

64 http://www.caiso.com/Documents/InverterBasedInterconnectionRequestsIBRDynamicModelReviewGuideline.pdf

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Chapter 7

7 Special Reliability Studies and Results

In addition to the mandated analysis framework set out in the ISO's Tariff described above, the ISO has also pursued in past transmission planning cycles a number of additional "special studies" in parallel with the tariff-specified study processes. This is done to help prepare for future planning cycles that reach further into the issues emerging through the transformation of the California electricity grid. These studies are provided on an informational basis only and are not for identifying needs or mitigations for ISO Board of Governor approval. A number of those studies have now been incorporated into analysis in Chapter 3 exploring resource portfolio scenarios, or are now being conducted on an annual basis and are in Chapter 6.

The ISO has not performed any special reliability studies within the 2023-2024 Transmission Planning Process.

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Chapter 8

8 Transmission Project List

8.1 Transmission Project Updates

Table 8.1-1 and Table 8.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous transmission plans, the ISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location-constrained resource interconnection facility project or enhance economic efficiencies.

Table 8.1-1: Status of Previously Approved Projects Costing Less than $50 M

No	Project	PTO	Transmission Plan Approved [65]	Current Expected In-service date[66]
1	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	2008	Q4-2022
2	Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation	PG&E	2022-2023	Q3-2023
3	Giffen Line Reconductoring Project	PG&E	2018-2019	Q4-2023
4	Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Q3-2023
5	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Kern PP 230 kV Area Reinforcement Project)	PG&E	2010-2011	Q1-2021
6	Oakland Clean Energy Initiative (Oakland X 115kV Bus Upgrade)	PG&E	2017-2018	Q2-2022
7	Palermo – Wyandotte 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Q3-2021
8	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	2017-2018	Q4-2022
9	Tesla Substation 230 kV bus section D and circuit breakers 372, 382 and 842 overstress (reactors) TESLA: 230KV BUS REACTORS D - E	PG&E	2018-2019	Q2-2023
10	Tulucay-Napa #2 60 kV Line Capacity Increase	PG&E	2019-2020	Closeout
11	Vaca Dixon Area Reinforcement (Replace Bank 5)	PG&E	2017-2018	Q3-2022
12	Wilson-Le Grand 115 kV line reconductoring	PG&E	2012-2013	Q4-2023
13	Atlantic 230/60 kV transformer voltage regulator	PG&E	2021-2022	Dec-27
14	Banta 60 kV Bus Voltage Conversion	PG&E	2022-2023	Dec-27
15	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	2019-2020	Apr-26
16	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	2022-2023	May-29
17	Cascade 115/60 kV No.2 Transformer Project	PG&E	2010-2011	Jul-25

[65] Additional detail for the projects including cost information and scope can be found in the Transmission Plan in which they were approved. http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx

[66] Draft Transmission Plan in-service dates based on January 2024 Transmission Development Forum.

No	Project	PTO	Transmission Plan Approved [65]	Current Expected In-service date[66]
18	Christie-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	Feb-28
19	Clear Lake 60 kV System Reinforcement	PG&E	2009	Jul-29
20	Coburn-Oil Fields 60 kV system project	PG&E	2017-2018	Jun-29
21	Contra Costa PP 230 kV Line Terminals Reconfiguration Project	PG&E	2021-2022	May-25
22	Cooley Landing 60 kV Substation Circuit Breaker No #62 Upgrade	PG&E	2021-2022	Dec-26
23	Coppermine 70 kV Reinforcement Project	PG&E	2021-2022	May-27
24	Cortina 230/115/60 kV Transformer Bank No. 1 Replacement Project	PG&E	2021-2022	Jun-28
25	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	2018-2019	Jun-26
26	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	2017-2018	Oct-26
27	Dinuba Energy Storage (Rescoped from Reedley 70 kV Area Reinforcement Projects)	PG&E	2017-2018	Sep-26
28	East Marysville 115/60 kV Project	PG&E	2018-2019	Jan-28
29	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	2019-2020	Dec-25
30	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	2011-2012	Mar-24
31	Estrella Substation Project	PG&E	2013-2014	Jul-29
32	Garberville Area Reinforcement	PG&E	2022-2023	Dec-30
33	Gates 500 kV Dynamic Voltage Support	PG&E	2018-2019	Jan-25
34	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	2013-2014	May-24
35	Gold Hill 230/115 kV Transformer Addition Project	PG&E	2018-2019	Jun-28
36	Henrietta 230/115 kV Bank 3 Replacement	PG&E	2022-2023	Jun-27
37	Herndon-Bullard 115 kV Reconductoring Project	PG&E	2017-2018	Dec-26
38	Ignacio Area Upgrade	PG&E	2017-2018	Dec-28
39	Jefferson 230 kV Bus Upgrade	PG&E	2018-2019	Dec-26
40	Lakeville 60 kV Area Reinforcement	PG&E	2017-2018	Dec-28
41	Lone Tree–Cayetano–Newark Corridor Series Compensation	PG&E	2022-2023	Dec-27
42	Los Banos 230 kV Circuit Breakers Replacement	PG&E	2022-2023	Apr-28
43	Los Banos 70 kV Area Reinforcement	PG&E	2022-2023	Dec-28
44	Manteca #1 60 kV Line Section Reconductoring Project	PG&E	2020-2021	Jun-25
45	Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project	PG&E	2021-2022	Feb-29
46	Maple Creek Reactive Support	PG&E	2009	Oct-27
47	Mesa 230/115kV Spare Transformer	PG&E	2022-2023	Apr-28
48	Metcalf 230 / 115 kV Transformers Circuit Breaker Addition	PG&E	2022-2023	Jun-27

No	Project	PTO	Transmission Plan Approved [65]	Current Expected In-service date[66]
49	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	2003	Mar-27
50	Midway – Kern PP #2 230 kV Line	PG&E	2013-2014	Apr-27
51	Midway – Kern PP #2 230 kV Line (Bakersfield-Kern Reconductor)	PG&E	2013-2014	Jan-28
52	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Midway 230kV Bus Section D Upgrade Project)	PG&E	2010-2011	Oct-27
53	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	2012-2013	Oct-29
54	Monta Vista 230 kV Bus Upgrade	PG&E	2012-2013	Aug-25
55	Moraga 230 kV Bus Upgrade	PG&E	2019-2020	Dec-28
56	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	2010-2011	Mar-26
57	Moraga-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	TBD
58	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	2013-2014	Feb-29
59	Mosher Transmission Project	PG&E	2013-2014	Dec-27
60	Moss Landing – Las Aguilas 230 kV Series Reactor Project	PG&E	2021-2022	Apr-28
61	New Collinsville 500 kV substation	PG&E	2021-2022	Dec-27
62	New Manning 500 kV substation	PG&E	2021-2022	Dec-27
63	Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition	PG&E	2019-2020	Dec-26
64	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	2017-2018	Jun-25
65	North East Kern 115 kV Line Reconductoring	PG&E	2022-2023	Dec-33
66	North Tower 115 kV Looping Project	PG&E	2011-2012	Feb-28
67	Oakland Clean Energy Initiative (MORAGA 115KV BUS UPGRADE & BK 3 SW)	PG&E	2017-2018	Apr-25
68	Oro Loma 70 kV Area Reinforcement	PG&E	2010-2011	Jan-27
69	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	2015-2016	Apr-24
70	Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	2022-2023	Jun-28
71	Pittsburg 115 kV Bus Reactor project	PG&E	2022-2023	May-28
72	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	2007	Jun-26
73	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	2018-2019	Jun-25
74	Reconductor Delevan-Cortina 230kV line	PG&E	2021-2022	Feb-28
75	Reconductor Rio Oso–SPI Jct–Lincoln 115kV line	PG&E	2021-2022	Dec-28
76	Redwood City 115kV System Reinforcement	PG&E	2022-2023	Dec-29
77	Rio Oso 230/115 kV Transformer Upgrades	PG&E	2007	Apr-26
78	Rio Oso Area 230 kV Voltage Support	PG&E	2011-2012	Sep-25
79	Round Mountain 500 kV Dynamic Voltage Support	PG&E	2018-2019	Dec-24

No	Project	PTO	Transmission Plan Approved [65]	Current Expected In-service date[66]
80	Salinas-Firestone #1 and #2 60 kV Lines	PG&E	2019-2020	Dec-27
81	San Jose Area HVDC 230 kV Line (Newark - NRS)	PG&E	2021-2022	Apr-28
82	San Jose Area HVDC 500 kV Line (Metcalf – San Jose)	PG&E	2021-2022	May-28
83	Santa Rosa 115 kV lines Reconductoring project	PG&E	2022-2023	Dec-28
84	Series Compensation on Los Esteros-Nortech 115 kV Line	PG&E	2021-2022	Dec-25
85	South Bay Area Limiting Element Upgrade	PG&E	2022-2023	Mar-26
86	South of Mesa Upgrade	PG&E	2018-2019	Apr-27
87	South of San Mateo Capacity Increase	PG&E	2007	Dec-28
88	Table Mountain Second 500/230 kV Transformer	PG&E	2021-2022	Jun-28
89	Tesla 115 kV Bus Reconfiguration	PG&E	2022-2023	Jun-28
90	Tesla Substation 230 kV bus section D and circuit breakers 372, 382 and 842 overstress (reactors) TESLA: 230KV BUS REACTORS C - D	PG&E	2018-2019	Apr-24
91	Tie line Phasor Measurement Units	PG&E	2017-2018	Feb-28
92	Tulucay-Napa #2 60 kV line Reconductoring project	PG&E	2022-2023	Dec-26
93	Tyler 60 kV Shunt Capacitor	PG&E	2018-2019	Mar-27
94	Vaca Dixon Area Reinforcement (INSTALL (2) CAPACITOR BANKS)	PG&E	2017-2018	Apr-27
95	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	2017-2018	Jul-26
96	Vasona-Metcalf 230 kV Line Limiting Elements Removal Project	PG&E	2021-2022	Jun-25
97	Vierra 115 kV Looping Project	PG&E	2010-2011	May-27
98	Warnerville-Bellota 230 kV line reconductoring	PG&E	2012-2013	Apr-24
99	Weber-Mormon Jct 60 kV Line Section Reconductoring Project	PG&E	2021-2022	Feb-29
100	Wilson 115 kV Area Reinforcement	PG&E	2010-2011	Jan-28
101	Wilson-Oro Loma 115kV Line Reconductoring	PG&E	2019-2020	May-27
102	Antelope 66 kV Circuit Breaker Duty Mitigation Project	SCE	2021-2022	Dec-25
103	Antelope-Whirlwind Line Upgrade	SCE	2022-2023	Dec-25
104	Barre 230 kV Switchrack Conversion to BAAH Project	SCE	2022-2023	Jun-26
105	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	2022-2023	Dec-28
106	Devers 230 kV Reconfiguration Project	SCE	2021-2022	Jun-25
107	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	2022-2023	Dec-28
108	Devers-Valley 500 kV 1 Line Upgrade	SCE	2022-2023	Dec-28
109	Laguna Bell - Mesa No. 1 230 kV Line Rating Increase Project	SCE	2021-2022	Jun-24
110	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	2016-2017	Jan-27
111	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	2008	Dec-26

No	Project	PTO	Transmission Plan Approved [65]	Current Expected In-service date[66]
112	Lugo-Victor-Kramer Upgrade (1/3) Add 3rd Lugo 500/230 kV Transformer	SCE	2022-2023	Dec-28
113	Lugo-Victor-Kramer Upgrade (2/3) Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines using HTLS	SCE	2022-2023	Dec-28
114	Lugo-Victor-Kramer Upgrade (3/3) Rebuild/build Kramer–Victor 115 kV lines to 230 kV and Loop the old segment of Kramer–Victor 115 kV into Roadway	SCE	2022-2023	Jun-33
115	Method of Service for Wildlife 230/66 kV Substation	SCE	2007	TBD
116	Mira Loma 500 kV CB Upgrade Project	SCE	2022-2023	Aug-28
117	Mira Loma-Mesa Upgrade	SCE	2022-2023	Dec-26
118	New Control 115 kV Shunt Reactor	SCE	2022-2023	Pending
119	New CoolwaterA 115/230 kV Bank	SCE	2022-2023	Dec-27
120	New Serrano 4AA Bank & 230kV GIS Rebuild	SCE	2022-2023	Dec-27
121	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	2019-2020	Oct-27
122	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	2022-2023	Dec-31
123	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	2022-2023	Dec-28
124	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	2022-2023	Dec-28
125	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE	2022-2023	Dec-33
126	Sylmar Transformer Replacement	SCE	2022-2023	Dec-26
127	Tie line Phasor Measurement Units	SCE	2017-2018	Feb-24
128	Victor 230 kV Switchrack Reconfiguration	SCE	2021-2022	Apr-25
129	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	2022-2023	Dec-31
130	2nd Escondido-San Marcos 69 kV T/L	SDG&E	2013-2014	Closeout
131	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	2013-2014	Closeout
132	Rose Canyon-La Jolla 69 kV T/L	SDG&E	2013-2014	Closeout
133	TL644, South Bay-Sweetwater: Reconductor	SDG&E	2010-2011	Closeout
134	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	2012-2013	Closeout
135	3 Ohm Series Reactor on Sycamore-Penasquitos 230 kV line	SDG&E	2022-2023	2032
136	Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest	SDG&E	2022-2023	2032
137	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	2022-2023	2032
138	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	2022-2023	2032
139	Reconductor TL 605 Silvergate – Urban	SDG&E	2015-2016	Aug-24
140	Reconductor TL680C San Marcos -Melrose Tap	SDG&E	2022-2023	2032
141	SG and OT Redundant Bus Differential Relay	SDG&E	2022-2023	2024
142	Sweetwater Reliability Enhancement	SDG&E	2012-2013	Oct-27

No	Project	PTO	Transmission Plan Approved [65]	Current Expected In-service date[66]
143	TL623C Reconductor (San Ysidro - Otay Tap)	SDG&E	2017-2018	Feb-30
144	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	2013-2014	Dec-26
145	TL649D Reconductor (San Ysidro - Otay Lake Tap)	SDG&E	2017-2018	Aug-24
146	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	2013-2014	Jul-28
147	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	2011-2012	Dec-26
148	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	SDG&E	2022-2023	2032
149	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	2022-2023	2032
150	Gamebird 230/138 kV Transformer Upgrade	GLW	2019-2020	In Service
151	Tie line Phasor Measurement Units	VEA	2017-2018	Q1/Q2-2024
152	GLW/VEA area upgrades - revised scope	GLW	2022-2023	Dec-27
153	Beatty 230 kV Project	GLW	2022-2023	Dec-27
154	Collinsville 500/230 kV Substation Project	LSP	2021-2022	Dec-27
155	Manning 500/230 kV Substation Project	LSP	2021-2022	Dec-27
156	Metcalf - San José B HVDC Project	LSP	2021-2022	May-28
157	Newark - NRS HVDC Project	LSP	2021-2022	Apr-28
158	IID S-Line Upgrade	Citizens Energy	2017-2018	2023

Table 8.1-2: Status of Previously-Approved Projects Costing $50 M or More

No	Project	PTO	Transmission Plan Approved	Current Expected In-service date
1	South of Palermo 115 kV Reinforcement Project	PG&E	2010-2011	Complete Jan 2021
2	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)	PG&E	2012-2013	Cancelled
3	Vaca Dixon Area Reinforcement (Original project was the "Vaca – Davis Voltage Conversion Project" approved in 2010-2011 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan)	PG&E	2017-2018	Aug-22
4	Kern PP 115 kV Area Reinforcement	PG&E	2011-2012	Aug-29
5	Lockeford-Lodi Area 230 kV Development	PG&E	2012-2013	Dec-29
6	Martin 230 kV Bus Extension	PG&E	2014-2015	Oct-28
7	Midway – Kern PP #2 230 kV Line	PG&E	2013-2014	Apr-27
8	Red Bluff-Coleman 60 kV Reinforcement (Original project was the "Cottonwood-Red Bluff No2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project" approved in 2010-2011 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan.)	PG&E	2017-2018	Mar-29
9	Wheeler Ridge Junction Substation	PG&E	2013-2014	Dec-33
10	Mesa 500 kV Substation Loop-In	SCE	2013-2014	May-22
11	Alberhill 500 kV Method of Service	SCE	2009	Jun-29
12	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	2012-2013	Dec-24
13	Lugo-Mohave series capacitor upgrade	SCE	2012-2013	Dec-24
14	Artesian 230 kV Sub & loop-in TL23051	SDG&E	2013-2014	Jun-22
15	Southern Orange County Reliability Upgrade Project – Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	2010-2011	Dec-23
16	Delaney-Colorado River 500 kV line	DCR Transmission	2013-2014	May-24
17	Gates 500 kV Dynamic Voltage Support	LS Power	2018-2019	Jun-25
18	Round Mountain 500 kV Dynamic Voltage Support	LS Power	2018-2019	TBD

8.2 Transmission Projects found to be needed in the 2023-2024 Planning Cycle

In the 2023-2024 transmission planning process, the ISO determined that 19 transmission projects were needed to mitigate identified reliability concerns; 7 policy-driven projects were needed to meet the GHG reduction goals and no economic-driven projects were found to be needed. Summaries of the needed projects are in Table 8.2-1 and Table 8.2-2.

A list of projects that came through the 2023 Request Window can be found in Appendix E.

Additional details of projects can be found in Appendix H.

Table 8.2-1: New Reliability Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost (in millions of dollars)
1	Covelo 60 kV Voltage Support	PG&E	2030	11 - 22
2	Martin-Millbrae 60 kV Area Reinforcement	PG&E	2030	20 - 40
3	Atlantic High Voltage Mitigation	PG&E	Q2 2029	20 - 40
4	Mira Loma 500 kV Bus SCD Mitigation	SCE	Q2 2027	5
5	Inyo 230 kV Shunt Reactor	SCE	2027	20
6	Etiwanda 230 kV Bus SCD Mitigation	SCE	Q4 2027	15
7	Eldorado 230 kV Short Circuit Duty Mitigation	SCE	Q4 2029	48.8
8	Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring	PG&E	2030	54 - 108
9	Diablo Canyon Area 230 kV High Voltage Mitigation	PG&E	2027	35 - 70
10	Salinas Area Reinforcement	PG&E	TBD	226.1 – 452.3
11	Cortina #1 60 kV Line Reconductoring	PG&E	Q2 2028	47.1 – 94.3
12	French Camp Reinforcement	PG&E	Q2 2030	42.1 – 84.2
13	Rio Oso - W. Sacramento Reconductoring	PG&E	2030	48.7 - 97.4
14	Vaca-Plainfield 60 kV Line Reconductoring	PG&E	Q2 2030	34 – 68
15	Camden 70 kV Reinforcement	PG&E	2030	50 - 100
16	Gates 230/70 kV Transformer Addition	PG&E	2030	36 - 72
17	Reedley 70 kV Capacity Increase	PG&E	TBD	49 - 98
18	Tejon Area Reinforcement	PG&E	2029	28 - 56
19	Valley Center System Improvement	SDG&E	2028	51

Oakland Area Reinforcement Project: The assessment of alternatives to address escalating load forecasts in the Oakland area will be conducted as an extension of the 2023-2024 Transmission Plan, with ISO Board of Governor approval anticipated to be sought in Q2 or Q3 of this year.

Table 8.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost (in millions of dollars)
1	Sobrante 230/115 kV Transformer Bank Addition	PG&E	2034	20 - 40
2	New Humboldt 500 kV Substation with 500 kV line to Collinsville [HVDC operated as AC]	PG&E	2034	1,913 – 2,740
3	New Humboldt to Fern Road 500 kV Line	PG&E	2034	980 – 1,400
4	New Humboldt 115/115 kV Phase Shifter with 115 kV line to Humboldt 115kV Substation	PG&E	2034	40 - 57
5	North Dublin -Vineyard 230 kV Reconductoring	PG&E	2034	116 - 233
6	Tesla - Newark 230 kV Line No. 2 Reconductoring	PG&E	2034	29 - 58
7	Collinsville 230 kV Reactor	PG&E	2034	39 - 58

There are no new economic-driven transmission projects found to be needed in this planning cycle.

8.3 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
- Topology Optimizations

The California ISO (ISO) supports appropriate application and deployment of these technologies, and has considered them 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.

In the ISO's transmission planning processes, we have considered both advanced conductors and flow controllers in a number of applications. Flow controllers have to date been more successful. Table 8.3-1 lists GETS projects that have been approved in the transmission planning process. In this plan, a phase-shifting transformer that provides flow control is recommended for approval to increase the resiliency in the Humboldt area.

Table 8.3-1: Flow Control, Advanced Conductor and Dynamic Reactive Support Approved Projects

Projects	Transmission Plan approved	In service Date (planned or achieved)
Flow Control		
Imperial Valley phase shifters	2013-2014	2017
San Jose HVDC project - Newark-NRS	2021-2022	2028
San Jose HVDC project - Metcalf-San Jose B	2021-2022	2028
Series Reactor on Warnerville-Wilson 230 kV	2012-2013	2018
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
Lone Tree – Cayetano – Newark Corridor Series Compensation	2022-2023	2027
Series compensation on Eldorado-Lugo-Mohave	2012-2013	2024
Wilson 115 kV SVC/Statcom	2015-2016	2021

Projects	Transmission Plan approved	In service Date (planned or achieved)
Advanced Conductors		
Big Creek Rating Increase Project	2016-2017	2020
Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines;	2022-2023	2032
Moorpark-Pardee No. 4 230 kV Line[67]	2017-2018	2022
Laguna Bell – Mesa No. 1 Line Rating Increase Project[67]	2021-2022	2024
San Bernardino-Vista 230 kV 1 Line Upgrade[67]	2022-2023	2028
San Bernardino-Etiwanda 230 kV 1 Line Upgrade[67]	2022-2023	2031
Dynamic Voltage Control		
Round Mountain 500 kV Dynamic Voltage Support (Fern Road Substation)	2018-2019	2024
Round Mountain-Table Mountain statcom – re Diablo Canyon	2018-2019	2025
SVC at Suncrest	2013-2014	2017
Synchronous condensers in LA/San Diego area (loss of SONGS		
Rio Oso SVC	2011-2012	2025

8.4 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2023-2024 Transmission Plan. In some areas, such as the LA Basin, this reliance has been overt through the testing of various resource portfolios being considered for procurement, and in other areas through reliance on demand-side resources such as additional achievable energy efficiency and other existing or forecast preferred resources.

As set out in the 2023-2024 Transmission Planning Process Unified Planning Assumptions and Study Plan, the ISO assesses the potential for existing and planned demand-side resources to meet identified needs as a first step in considering mitigations to address reliability concerns.

The bulk of the ISO's additional and more focused efforts consisted of the development of local capacity requirement-need profiles for all areas and sub-areas, as part of the biennial 10-year local capacity technical study completed in this transmission planning cycle. This provides the necessary information to consider the potential to replace local capacity requirements for gas-fired generation, depending on the policy or long-term resource planning direction set by the CPUC's integrated resource planning process.

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

Additionally, the ISO considered numerous storage projects included in the base and sensitivity resource portfolios provided by the CPUC as mitigation for alleviating transmission constraints as set out in Chapters 2, 3, and 4 of this plan.

In addition to relying on the preferred resources incorporated into the managed forecasts prepared by the CEC, the ISO is also relying on preferred resources as part of integrated, multi-faceted solutions to address reliability needs in a number of study areas.

LA Basin-San Diego

Considerable amounts of grid-connected and behind-the-meter preferred resources in the LA Basin and San Diego local capacity area, as described in Appendix B, Sections B.5.4.8 and B.6.9, were relied upon to meet the reliability needs of this large metropolitan area. Various initiatives including the LTPP local capacity long-term procurement that was approved by the CPUC have contributed to the expected development of these resources. Existing demand response was also assumed to be available within the SCE and SDG&E areas with the necessary operational characteristics (i.e., 20-minute response) for use during overlapping contingency conditions.

Oakland Sub-area

The reliability planning for the Oakland 115 kV system anticipating the retirement of local generation is advancing mitigations that include in-station transmission upgrades, an in-front-of-the-meter energy storage project and load-modifying preferred resources. These resources are being pursued through the PG&E "Oakland Clean Energy Initiative" (OCEI) approved in the 2017-2018 Transmission Plan. Based on the development in the procurement activities, the location of the entire 36 MW and 173 MWh storage need has been moved to Oakland C substation in the 2021-2022 TPP. Based on this year's assessment, due to the significant increase in the load forecast for the area, it was determined that the OCEI project is not going to be sufficient to address all the local area needs in absence of the local thermal generation. As such, transmission alternatives are being evaluated for the area. Since the required transmission upgrade is likely going to have significant scope and very long implementation time, the OCEI project, as scoped, is recommended to continue to help reduce reliance on local thermal generation in the meantime.

Moorpark and Santa Clara Sub-areas

The ISO is supporting SCE's preferred resource procurement effort for the Santa Clara sub-area submitted to the CPUC Energy Division on December 21, 2017, by providing input into SCE's procurement activities and validating the effectiveness of potential portfolios identified by SCE. This procurement, together with the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double-circuit towers which was approved in the ISO's 2017-2018 Transmission Plan and went into service January 2022, will enable the retirement of the Mandalay Generating Station and the Ormond Beach Generating Station in compliance with state policy regarding the use of coastal and estuary water for once-through cooling. As set out in Appendix B Section B.5.4.8, there is 10,944 MW of energy storage in the 2032 base portfolio that was modeled in the SCE main system which includes the Moorpark and Santa Clara Sub-areas.

8.5 Competitive Solicitation for New Transmission Elements

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the ISO selects a regional transmission solution to meet an identified need in one of the three 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 solutions recommended for approval in this 2023-2024 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

- Humboldt off shore wind interconnection option E
    - 500 kV substation, with a 500/115 kV transformer; and HVDC line, initially operated as 500 kV AC line to interconnect Humboldt 500 kV to the Collinsville substation and,
    - 500 kV AC Line from new Humboldt 500 kV Substation to Fern Road and

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

8.6 Capital Program Impacts on Transmission High-Voltage Access Charge

8.6.1 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.

8.6.2 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 2024 model uses the average annual 1.27% energy growth rate based on the

CEC 2023 IEPR 2023-2040 California Energy Demand baseline forecast, which is also used in the 2023-2024 TPP.

To account for the impact of ISO-approved transmission capital projects, the tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

In reviewing the latest estimate, as illustrated in Figure 8.5 1, the trend of the 2024 TAC value for the 2024 projection is lower than the 2023 projection for all years. The projection also includes capital projects in this year's plan and all other transmission plan projects not already energized. The decrease of $3.58 from last year's projection for January 1, 2024 to this year's actuals reflects the decrease in TRR below the historical projections. Together with a higher Gross Load Growth Rate, the lower starting values in this year's model result in lower overall TAC Rates across all years. The higher Gross Load Growth rate also reduces the impact of the TAC Rates due to the recommended projects in this year's plan. However, the TAC rate sees a jump in projection from 2028 due to new projects approved in the 2023-2024 Transmission Planning Process (TPP), with the projected rate reaching $20.85 for 2035.

Figure 8.5-1 Forecast of ISO High Voltage Transmission Access Charge Trending from First Year of Transmission Plan