



# 2022-2023 TRANSMISSION PLAN



**REVISED DRAFT**  
May 10, 2023

## **Foreword to Revised Draft 2022-2023 Transmission Plan**

This revised draft transmission plan reflects a number of changes from the draft plan released on April 3, 2022. To assist our stakeholders following the transmission plan cycle, a few changes were made as summarized below:

- The recommendation for the Trout Canyon-Lugo 500 kV Line project, estimated at \$2 billion, has been held back pending additional analysis of stakeholder input and may be considered as an extension to this planning cycle or the next planning cycle,
  - With this, there are only three projects eligible for competitive solicitation at this time;
- Appendix I has been updated to include the descriptions and functional specifications for the transmission facilities that are eligible for competitive solicitation; and
- The High Voltage Transmission Access Charge model update has been added to Chapter 8.

A number of clarifications and edits have also been added throughout the plan.

## Table of Contents

<b>Executive Summary</b> .....	1
<b>Other Findings and Observations</b> .....	7
<b>Other Studies</b> .....	9
<b>Conclusions and Recommendations</b> .....	10
Chapter 1 .....	11
1    Overview of the Transmission Planning Process .....	11
1.1    Introduction .....	11
1.2    Key Inputs .....	14
1.2.1    Load Forecasting and Distributed Energy Resources Growth Scenarios .....	14
1.2.2    Resource Planning and Portfolio Development .....	16
1.3    The Transmission Planning Process .....	18
1.3.1    Structure of the Transmission Planning Process .....	21
1.3.2    Interregional Transmission Coordination per FERC Order No. 1000 ...	24
1.4    Other Influences.....	25
1.4.1    SB 887, the Accelerating Renewable Energy Delivery Act .....	25
1.4.2    Non-Transmission Alternatives and Storage.....	26
1.4.3    System Modeling, Performance, and Assessments .....	28
1.5    ISO Processes coordinated with the Transmission Plan.....	28
1.5.1    Distributed Generation (DG) Deliverability .....	28
1.5.2    Critical Energy Infrastructure Information (CEII) .....	30
1.5.3    Planning Coordinator Footprint.....	30
Chapter 2 .....	32
2    Reliability Assessment.....	33
2.1    Overview of the ISO Reliability Assessment.....	33
2.1.1    Backbone (500 kV and selected 230 kV) System Assessment.....	34
2.1.2    Regional Area Assessments.....	34
2.2    Reliability Standards Compliance Criteria.....	35
2.3    Study Assumptions .....	35
2.3.1    Load and Resource Assumptions .....	35
2.3.2    Study Horizon and Years.....	36
2.4    Reliability Studies.....	36
2.5    Reliability-Projects Needed .....	37
2.5.1    Management Approved Projects .....	37
2.5.2    Projects Recommended for Approval .....	41
2.5.3    Previously Approved Projects on Hold.....	53
2.5.4    Projects under Review for Potential Approval in 2022-2023 Transmission Planning Process.....	57
2.6    Conclusion .....	57
Chapter 3 .....	59
3    Policy-Driven Need Assessment.....	59
3.1    Background.....	59
3.2    Objectives of policy-driven assessment.....	60

3.3	Study methodology and components .....	61
3.4	Resource Portfolios .....	62
3.4.1	Mapping of portfolio resources to transmission substations .....	62
3.5	Transmission Interconnection Zone Assessments.....	63
3.5.1	PG&E Greater Bay and North of Greater Bay Interconnection Area .....	64
3.5.2	PG&E Greater Fresno Interconnection Area.....	68
3.5.3	PG&E East Kern Interconnection Area .....	74
3.5.4	East of Pisgah Interconnection Area.....	77
3.5.5	SCE Northern Interconnection Area .....	82
3.5.6	SCE North of Lugo Interconnection Area.....	84
3.5.7	SCE Metro Interconnection Area .....	88
3.5.8	SCE Eastern Interconnection Area .....	91
3.5.9	SDG&E Interconnection Area .....	95
3.6	Out-of-State Wind .....	102
3.7	Offshore Wind .....	102
3.8	CPUC Request to CAISO in Accordance with SB 887.....	103
3.9	Conclusion and Recommendations .....	105
Chapter 4	.....	107
4	Economic Planning Study.....	107
4.1	Introduction .....	107
4.2	Technical Study Approach and Process .....	109
4.3	Cost-Benefit Analysis .....	110
4.4	Study Steps of Production Cost Simulation in Economic Planning .....	111
4.5	Production cost simulation tools and database.....	111
4.6	Base Portfolio Production Cost Simulation Results .....	113
4.6.1	Summary of congestion results .....	113
4.6.2	Wind and solar curtailment results.....	114
4.7	Economic Planning Study Requests.....	116
4.7.1	Overview of economic planning study requests.....	116
4.7.2	Summary of economic planning study request evaluation .....	116
4.8	Detailed Investigation of Congestion and Economic Benefit Assessment.....	117
4.9	Summary and Recommendations .....	119
Chapter 5	.....	123
5	Interregional Transmission Coordination .....	123
5.1	Interregional Transmission Coordination per FERC Order No. 1000 .....	123
5.1.1	Procedure to Coordinate and Share ISO Planning Results with other WPRs.....	124
5.1.2	Submission of Interregional Transmission Projects to the ISO.....	125
5.1.3	Interregional Transmission Project Submittal Requirements.....	125
5.1.4	Evaluation of Interregional Transmission Projects by the ISO.....	126
5.2	2022-2023 Interregional Transmission Coordination ITP Submittals to the ISO.....	129
5.2.1	North Gila – Imperial Valley Transmission Project and Assessment Results .....	130
Chapter 6	.....	133
6	Other Studies and Results.....	133

6.1	Reliability Requirement for Resource Adequacy .....	133
6.1.1	Local Capacity Requirements.....	133
6.1.2	Resource adequacy import capability .....	137
6.2	Long-Term Congestion Revenue Rights Simultaneous Feasibility Test Studies .....	142
6.2.1	Objective .....	142
6.2.2	Data Preparation and Assumptions .....	142
6.2.3	Study Process, Data and Results Maintenance .....	143
6.2.4	Conclusions.....	143
6.3	Frequency Response Assessment and Data Requirements.....	144
6.3.1	Frequency Response Methodology & Metrics .....	144
6.3.2	FERC Order 842 .....	147
6.3.3	2021-2022 Transmission Plan Study .....	147
6.3.4	2022-2023 Transmission Plan Study .....	147
Chapter 7	.....	153
7	Special Reliability Studies and Results .....	153
7.1	Informational Only, Transmission Reliability Study of the LA Basin and San Diego-Imperial Valley Local Capacity Areas with Reduced Reliance on Aliso Canyon Gas Storage .....	153
7.1.1	Study Scope .....	154
7.1.2	Study Process .....	156
7.1.3	Study Results .....	157
7.1.4	Transmission Alternatives .....	157
7.2	Policy Driven Assessment of the High Electrification Sensitivity Scenario	160
Chapter 8	.....	161
8	Transmission Project List.....	161
8.1	Transmission Project Updates.....	161
8.2	Transmission Projects found to be needed in the 2022-2023 Planning Cycle .....	167
8.3	Reliance on Preferred Resources .....	170
8.4	Competitive Solicitation for New Transmission Elements .....	171
8.5	ISO Approved Transmission Projects Impacts on Transmission High-Voltage Access Charge .....	172

**Appendices**

Appendix A	System Data	A-1
Appendix B	Reliability Assessment	B-1
Appendix C	Reliability Assessment Study Results	C-1
Appendix D	2022 Request Window Submittals	D-1
Appendix E	Contingencies on the ISO System that may Impact Adjacent Systems	E-1
Appendix F	Policy Assessment	F-1
Appendix G	Economic Assessment	G-1
Appendix H	Project Need and Description	H-1
Appendix I	Description and Functional Specifications for Transmission Facilities Eligible for Competitive Solicitation	I-1
Appendix J	Long-term Local Capacity Technical Study	J-1
Appendix K	Informational Special Study of Reduced Reliance on Aliso Canyon Storage – Assumptions, Study Results and Alternative Analysis	K-1

## Executive Summary

The California Independent System Operator (ISO) has prepared this 2022-2023 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 2022-2023 Transmission Plan reflects a much more strategic and proactive approach to better synchronize power and transmission planning, interconnection queuing and resource procurement and 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)<sup>1</sup> signed by the three parties in December 2022. The MOU tightens the linkages between resource and transmission planning activities, interconnection processes and resource procurement so California is better equipped to meet its reliability needs and clean-energy policy objectives required by Senate Bill 100.<sup>2</sup>

As set out in the MOU, expectations are that the CPUC<sup>3</sup> 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 being 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.

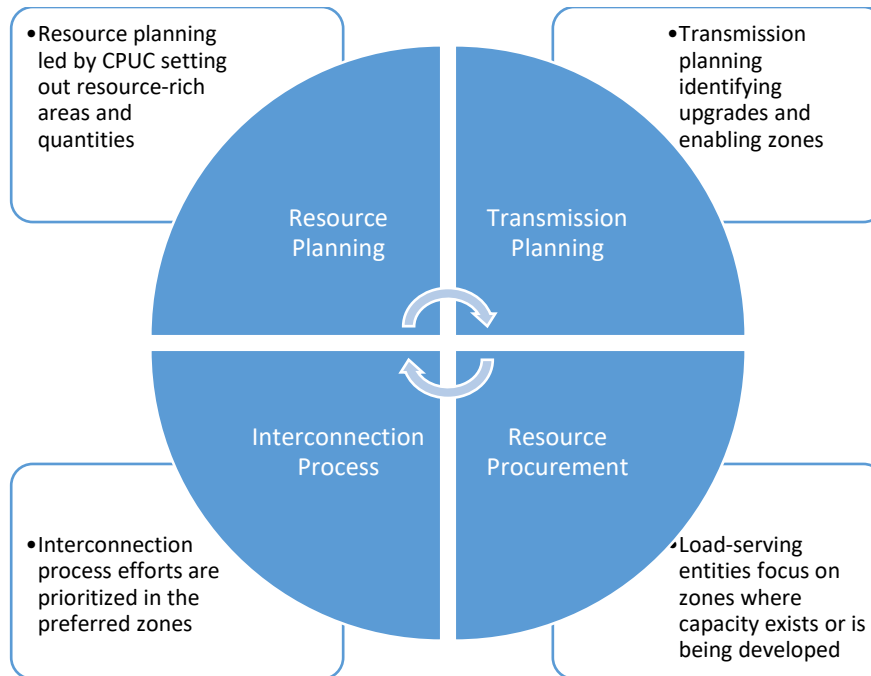
To bring this more coordinated approach full circle, the ISO will also give priority to interconnection requests located within those same zones in its generation interconnection process.

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

<sup>2</sup> 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.ca.gov/faces/billNavClient.xhtml?bill\\_id=201720180SB100](https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100)

<sup>3</sup> 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.



This year's transmission plan is based on state projections<sup>4</sup> provided to the ISO in 2022 that California needs to add more than 40 gigawatts (GW) of new resources over the next 10 years, and a sensitivity<sup>5</sup> study projection calling for 70 GW by 2032 reflecting the potential for increased electrification<sup>6</sup> occurring in other sectors of the economy, most notably in transportation and the building industry. The CPUC has recently established that next year's transmission plan is to be based on this projection of 70 GW by 2033.

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

<sup>4</sup> 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.

<sup>5</sup> Each year, the CPUC provides a base resource portfolio, that the ISO is expected to use in determining the need for new transmission projects. As well, the CPUC typically provides one or more sensitivity portfolios with higher or different levels of resource development that the ISO studies to develop transmission capacity and cost information that the CPUC uses in the next annual cycle of resource portfolio development. The sensitivity case, on its own, does not provide a basis for the ISO to approve a new transmission project. However, the ISO can consider the sensitivity case in selecting the preferred alternative to meet a need identified in the base studies.

<sup>6</sup> 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/2021-11>]. 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.aiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf>]



- Over 17 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 3.5 GW of in-state wind generation in existing wind development regions, including Tehachapi;
- Over 1 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 4.5 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
- Up to 3 GW of central coast offshore wind generation prior to the retirement of the Diablo Canyon Power Plant, and up to 5 GW after the retirement.

To achieve these outcomes, the ISO has found the need for a total of 45 transmission projects, the vast majority of which would be built in California. They range in projected costs from \$4 million to \$2.3 billion, for a total infrastructure investment of an estimated \$7.3 billion.<sup>7</sup> The comprehensive analysis included screening of hundreds of options and detailed assessments of over 60 alternatives in addition to the recommended projects. The alternative analysis considered transmission upgrades, preferred resources (such as storage) and remedial action schemes. The recommended projects include, most notably:

- A new 500 kV transmission line running west from the Arizona border into southern Imperial County, new 500 kV transmission lines angling up from southern Imperial County to northern San Diego and extending into the southern LA Basin, and upgrades to the existing 500 kV and 230 kV lines along the Interstate 10 (I-10) corridor. Together, these upgrades provide access to east Riverside County, Imperial County and Arizona solar generation, Imperial Valley geothermal, and New Mexico wind generation;
- Upgrades to the Lugo–Victor–Kramer 230 kV transmission system to access north of Lugo solar resources; and
- A host of smaller upgrades improving access to other smaller resource zones.

Figure ES-1 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 and, in Southern California, to also make most of the sensitivity<sup>8</sup> amounts

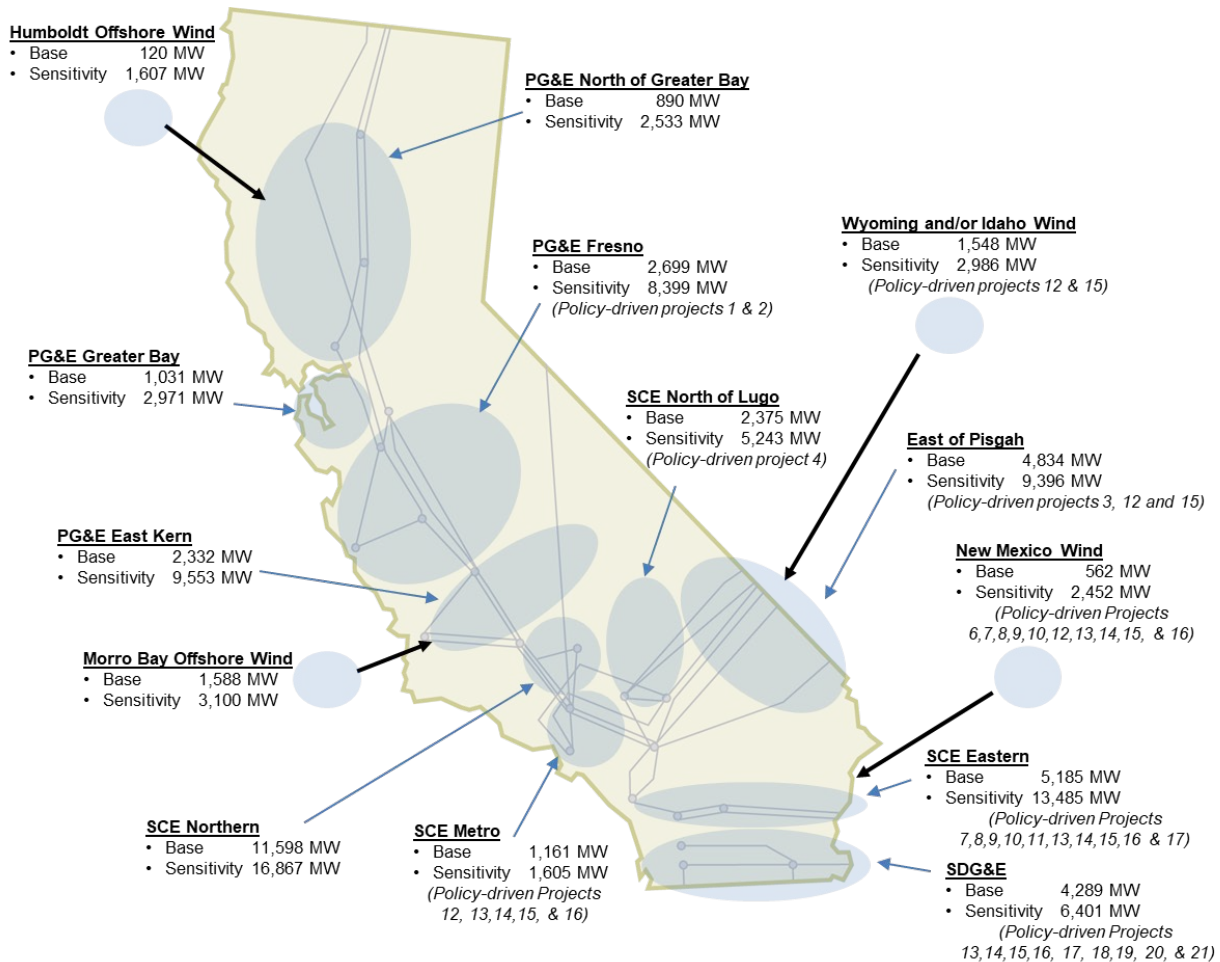
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<sup>7</sup> The recommendation in the draft plan for the Trout Canyon-Lugo 500 kV, estimated at \$2 billion, has been held back pending additional analysis of stakeholder input and a recommendation will be brought to the Board at a later date.

<sup>8</sup> The sensitivity portfolio was provided CPUC with higher levels of resource development than the ISO studied to develop transmission capacity and cost information that the CPUC uses in the next annual cycle of resource portfolio development. The ISO also considered the sensitivity case in selecting the preferred alternative to meet the needs identified in the base studies

available as well. As the CPUC has already determined that the sensitivity amounts in this year’s plan will be the base in next year’s transmission plan, the remaining network upgrades needed to achieve the sensitivity amounts will be approved next year.

Figure ES-1: Transmission Planning Zones and Capacity



The transmission projects 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 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 the most efficient and cost effective long term solutions are achieved. The infrastructure investments also have tremendous reliability and economic benefits for California and its robust economy. Significant

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

amounts of new diverse generating capacity and the transmission upgrades are required to cost-effectively bring reliable decarbonized power to California consumers and industry across all seasons of the year.

## Transmission Projects Recommended for Approval

The 46 reliability-driven and policy driven transmission projects that have been found to be needed 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 24 of the aforementioned projects, totaling \$1.76 billion. The projects are required to reliably supply the increase in forecasted load related to electrification and electric vehicle transportation loads. The 24 projects are set out in Table ES-1.

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

Project Name	PTO Area	Planning Area	Cost (\$M)
Banta ring bus <sup>9</sup>	PG&E	Central Valley	17.5
Metcalf 230/115 kV Transformers Circuit Breaker Addition <sup>9</sup>	PG&E	Greater Bay Area	15.0
South Bay Area Limiting Elements Upgrade <sup>9</sup>	PG&E	Greater Bay Area	11.0
Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation <sup>9</sup>	PG&E	Greater Fresno	1.6
Barre 230 kV Switchrack Conversion to Breaker-and-a-Half <sup>9</sup>	SCE	Main	45
Mira Loma 500 kV Circuit Breaker Upgrade <sup>9</sup>	SCE	Main	10
Garberville area reinforcement project	PG&E	Humboldt	204.0
Tulucay-Napa #2 60 kV line reconductoring project	PG&E	North Coast & North Bay	4.6
Santa Rosa 115 kV lines reconductoring project	PG&E	North Coast & North Bay	74.0
Tesla 115 kV Bus Reconfiguration Project	PG&E	Central Valley	55.0
Lone Tree – Cayetano – Newark Corridor Series Compensation	PG&E	Greater Bay Area	25.0
Los Banos 70 kV Area Reinforcement Project	PG&E	Fresno	60.0
Redwood City Area 115 kV System Reinforcement	PG&E	Greater Bay Area	110.8
Pittsburg 115 kV Bus Reactor project	PG&E	Greater Bay Area	26
Los Banos 230 kV Circuit Breaker Replacement	PG&E	Fresno	66
Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	Fresno	184
North East Kern 115 kV Line Reconductoring Project	PG&E	Kern	256.0
Mesa Spare Transformer Installation	PG&E	Central Coast & Los Padres	24
Coolwater 1A 230/115 kV Bank Project	SCE	North of Lugo	47
Control 115 kV Shunt Reactor	SCE	North of Lugo	4
Serrano 4AA 500/230 kV Transformer Bank Addition	SCE	Main	120
Sylmar Transformer Replacement	SCE	Main	23
Antelope-Whirlwind 500 kV Line Upgrade Project	SCE	Main	6
Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Projec	SDG&E	SDG&E	375
		<b>Total</b>	<b>1,764.5</b>

<sup>9</sup> 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.

- In reviewing previously approved projects in the PG&E service territory in Chapter 2 that have subsequently been put on hold and were identified in the last planning cycle as needing more review, one project will continue to be on hold, another is recommended to be canceled and one is recommended to proceed with a modification to its original scope.

**Policy-Driven Projects:** The ISO found the need for an additional 21 transmission projects that are policy driven. These total \$5.53 billion and are listed in Table ES-2. They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios.

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

No.	Project Name	PTO Area	Geographic Area	Cost (\$M)
1	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Fresno	50
2	Henrietta 230/115 kV Bank 3 Replacement	PG&E	Fresno	20
3	Beatty 230 kV	VEA/GLW	East of Pisgah	155
4	Lugo-Victor-Kramer 230 kV Upgrade	SCE	North of Lugo	482
5	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	SCE Eastern	50
6	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	SCE Eastern	140
7	Devers-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	40
8	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	60
9	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	65
10	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	SCE Eastern	18
11	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	13
12	Mira Loma-Mesa 500 kV Underground Third Cable	SCE	SCE Metro	35
13	Imperial Valley-North of SONGS 500 kV Line and Substation	SDG&E	SDG&E	2,288
14	North of SONGS-Serrano 500 kV line	SDG&E / SCE	SDG&E and SCE Metro	503
15	Serrano-Del Amo-Mesa 500 kV Transmission Reinforcement	SCE	SCE Metro	1,125
16	North Gila-Imperial Valley 500 kV line	SDG&E	SDG&E (Potential Joint Project with IID)	340
17	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	APS	27
18	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	SDG&E	21
19	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	SDG&E	28
20	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	SDG&E	8
21	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	SDG&E	60
			<b>Total</b>	<b>5,528</b>

- The ISO has determined and included in the above transmission projects its internal transmission system requirements necessary to get access to out-of-state wind resources. These out-of-state resources have been identified by the CPUC and considered in the planning analysis by expanding the maximum import capability of the

internal ISO paths to import out-of-state wind.<sup>10</sup> In addition to the study of the SWIP North project proposed by LS Power to access Idaho wind resources as a potential regional policy-driven transmission project discussed on the following page, the ISO has also been working with two subscription-based transmission developments seeking to bring wind resources in Wyoming (TransWest Express) and New Mexico (Sunzia) to the ISO boundary. Both transmission developments have sold transmission capacity on their planned facilities reaching to the ISO border to resource developers seeking to access California markets. That work is ongoing and the timing of those projects is driven by the developers and their subscribers.

- The ISO also continues working to refine its recommendation regarding the SWIP North project mentioned above taking into account participation interest of neighboring transmission service providers. This work will be conducted as an extension of the 2022-2023 Transmission Plan, with ISO Board of Governor approval anticipated to be sought in Q2 or Q3 of this year.
- **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 – all found in Table ES-2 above - are eligible for competitive solicitation, and the ISO will provide a schedule for those processes in May, 2023:
  - Imperial Valley–North of SONGS 500 kV Line and Substation;
  - North of SONGS–Serrano 500 kV line; and
  - North Gila–Imperial Valley 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 and also conducted a review of high-priority transmission projects as requested by the CPUC for this planning cycle. The request, as set out in SB 887, was to ask the ISO to explore and

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<sup>10</sup> The base portfolio for the 2022-2023 transmission planning cycle includes 1,500 MW of out-of-state wind resources (1,062 MW from Wyoming or Idaho and 438 MW from New Mexico) and the sensitivity portfolio includes 4,832 MW (1,500 MW from Wyoming, 1,000 MW from Idaho and 2,328 MW from New Mexico).

consider approving the highest priority transmission facilities that are needed to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources or zero-carbon resources that are expected to be developed by 2035. This review took into account:

- 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 needed 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 2022-2023 Plan and the gas-fired generation is being relied upon across the planning horizon for system capacity.
- The ISO has identified 12 reliability-driven and policy-driven projects recommended for approval in this transmission plan that also reduce gas-fired generation local capacity requirements, and that are listed in Table ES-1 or Table ES-2 above:
  - Metcalf 230/115 kV Transformers Circuit Breaker Addition project (reliability-driven) – Section 2. This project is recommended to address reliability needs in the Greater Bay Area. This project, along with the two HVDC projects in the San Jose area in the 2021-2022 Transmission Plan, will reduce the local capacity requirements within the San Jose LCR sub-area.
  - The seven recommended upgrades to four existing 500 kV lines and three 230 kV lines in the SCE Eastern area (Section 3.5.8) and the addition of the third cable addition to the Mesa-Mira Loma 500 kV underground section (Section 3.5.7) will increase the 500 kV and 230 kV supply to the LA Basin area.
  - The three southern area reinforcement projects (the Imperial Valley–North of SONGS 500 kV Line and Substation, North of SONGS–Serrano 500 kV Line, and Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement projects) will increase the transmission capacity in the LA Basin by establishing a 500 kV source at the existing Del Amo 230 kV substation, and in the San Diego and LA Basin local capacity areas by establishing a new 500 kV source north of San Diego.
- The ISO has also reviewed the Pacific Transmission Expansion Project - a multi-terminal HVDC project from Diablo Canyon 500 kV substation to multiple 230 kV substations in the LA Basin area - that was submitted into the Economic Request window in the 2022-2023 transmission planning process. The ISO has also been in discussion with the Los Angeles Department of Water and Power (LADWP) about its potential interest in the project and the possibilities of a joint project;

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, offload 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 collaboration opportunities after the Plan has been approved.

- **North Coast Offshore Wind:** Based on the sensitivity portfolio provided by the CPUC, the ISO studied the need for transmission capacity from the North Coast for offshore wind. As the study was only informational and set the stage for future planning, no projects were recommended for approval in this 2022-2023 Plan. Given the growing volumes already identified in the North Coast in the renewable generation portfolios provided for the 2023-2024 planning cycle, the ISO expects to make a decision on North Coast transmission in next year's transmission plan.
- **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 Northern Grid. Of the seven potential projects submitted into the ISO's 2023 interregional transmission project (ITP) submission window in the first quarter of 2022, only the North Gila – Imperial Valley No. 2 project met the requirements of an interregional transmission project in the submission validation process and received further detailed review by WestConnect and the ISO. Although WestConnect's subsequent review did not find a need for the project, it was determined to be necessary by the ISO and is recommended for approval as a regional ISO project as shown in Table ES-2.

## 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 additional local capacity technical study analyses, frequency response analysis, examination of viability of congestion revenue rights, and a preliminary assessment of the transmission impact of potential reduced reliance on Aliso Canyon. The latter informational study highlights the potential need for additional transmission in the LA Basin and San Diego local capacity areas if there is reduced reliance on the Aliso Canyon Natural Gas Storage Facility in the future and is being shared with the CPUC.

These studies are set out in Chapter 6 and Chapter 7.

## Conclusions and Recommendations

The 2022-2023 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 46 transmission projects, estimated to cost a total of \$9.3 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 46<sup>11</sup> identified transmission solutions through ISO transmission rates, subject to regulatory approval; and
- Initiate the ISO's competitive solicitation process for the four eligible projects identified above.

As well, the ISO will conduct additional stakeholder and market outreach regarding the SWIP North project, as a continuation of the 2022-2023 transmission planning cycle and will conclude that effort in Q3, 2023. The ISO will also continue to explore gas-fired generation retirement plans with the CPUC and work with LADWP on potential collaboration opportunities regarding the Pacific Transmission Expansion Project both leading up to presenting this Plan to the ISO Board of Governors for approval, and after the Plan has been approved.

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<sup>11</sup> As noted earlier, 6 reliability projects have already been approved by Management pursuant to the ISO tariff, and do not require additional approval by the Board of Governors.



## Chapter 1

# 1 Overview of the Transmission Planning Process

## 1.1 Introduction

The 2022-2023 Transmission Plan reflects two significant course changes from previous years' plans, and these changes are present throughout the document. First, the ISO has reshaped the Plan to provide the proactive zonal transmission planning foundation for transformational changes the ISO is pursuing in close coordination with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to tighten linkages between resource and transmission planning activities, interconnection processes and resource procurement. Second, the Plan acts on and 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 climbing in next year's plan 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 being able to achieve its reliability and decarbonization goals in a timely and cost-effective manner, the ISO is adopting a much more proactive approach to transmission planning. This new, more 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 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 more than 4000 MW per year and the portfolios for next year’s plan identify resource requirements of approximately 7000 MW per year.<sup>12</sup> The continuing growth in these numbers will by next year represent a sevenfold increase in annual requirements from the 2020-2021 Transmission Plan approved in March, 2021. The 2022-2023 transmission plan is a transitional step, recognizing the ISO and industry at-large are not yet positioned within this single planning cycle to address the full impact of the pivot to these new challenges. In addition to considering significantly larger resource portfolios, the ISO is also considering in this planning cycle more extensive system upgrades in several areas that are supported by relevant considerations and information beyond the resource portfolios provided by the CPUC. This approach recognizes that the requirements expected in next year’s transmission planning process will call for an even faster pace of resource development. It also allows several low-risk projects to proceed now, providing for a more balanced development workload given that additional projects will also be initiated next year. The increased capacity provided by those upgrades, on top of what is called for in the current year’s portfolios, will create 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.

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<sup>12</sup> Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, <http://www.caiso.com/InitiativeDocuments/Day2Presentation-2022-2023TransmissionPlanningProcessSep27-28-2021.pdf>

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 a 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.<sup>13</sup>

Reacting to previously approved authorizations and numerous signals about the accelerated pace of adding resources, the resource development industry responded with a record-setting number of new interconnections requests in April, 2021. The ISO received 373 new interconnection requests in its Cluster 14 open window, layered on top of an already heavily populated interconnection queue.<sup>14</sup> The ISO assumed that the unprecedented number of projects studied in Phase I would, for a number of reasons, result in a large percentage of projects withdrawing, making for a much more reasonable number of projects needing to be studied in Cluster 14 Phase II. But that high withdrawal rate did not materialize, as 205 projects are proceeding into Phase II studies, a higher than normal percentage of advancing projects.

#### *Resource Interconnections:*

In parallel with the transmission planning changes being made and reflected in the Plan, the ISO is moving forward with corresponding changes in the generation interconnection process. It released an issues paper<sup>15</sup> 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.

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<sup>13</sup> In ordering an additional 4000 MW of additional capacity (2000 MW each in 2026 and 2027, (D.) 23-02-040 allowed the 2000 MW of long lead-time resources ordered in the earlier D.21-06-035 to shift from June 2026 to June 2028 recognizing the challenges of bringing those long-lead time resources online by 2026

<sup>14</sup> ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, <http://www.caiso.com/Documents/Briefing-Renewables-GeneratorInterconnection-Queue-Memo-July-2021.p>

<sup>15</sup> <http://www.caiso.com/InitiativeDocuments/Issue=Paper-and-Straw-Proposal-Interconnecton-Process-Enhancements-2023-Mar132023.pdf>

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 reach its renewable energy objectives reliably.

## **1.2 Key Inputs**

This Section 1.2 provides background and detail on key load and resource forecast inputs into the 2022-2023 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 is particularly important, and has driven the need for far more attention not only on peak loads and total energy consumption but

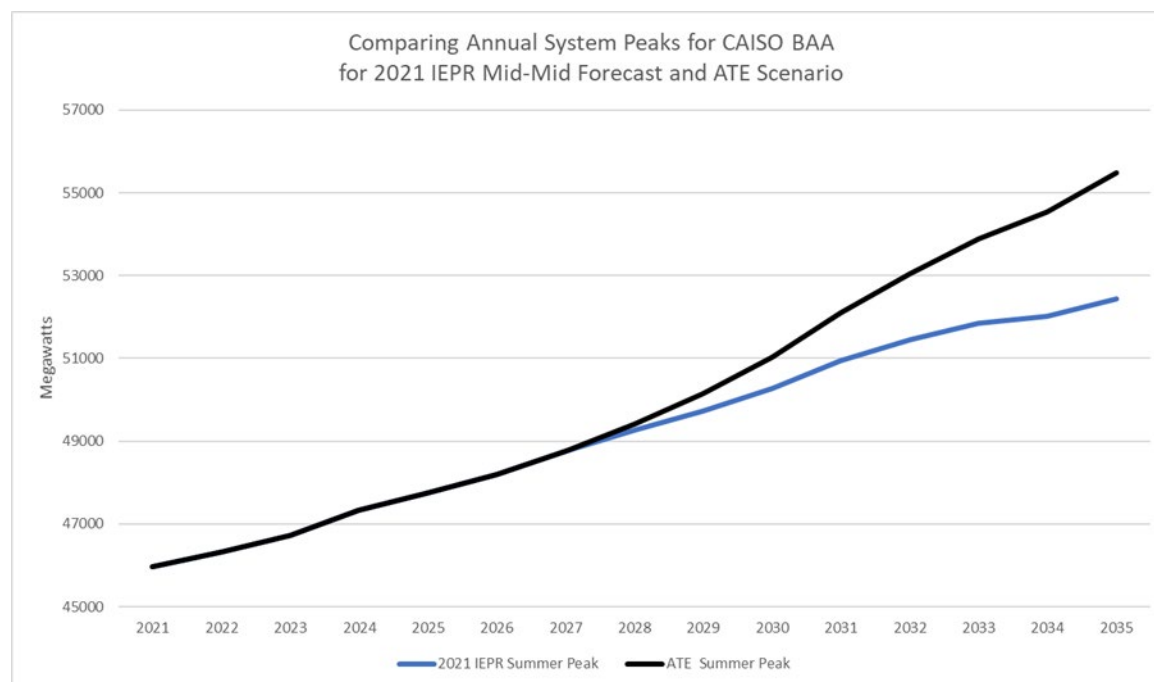
also on the shape of the aggregate customer load shape on an hourly, daily, and seasonal basis.

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

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.

The CEC adopted the 2021 IEPR Energy Demand Forecast, 2021-2035 on January 26, 2022.<sup>16</sup> On July 1, 2022, the CEC and the CPUC submitted a letter to the ISO requesting it use in this year’s Transmission Plan the 2021 IEPR Additional Transportation Electrification scenario developed by the CEC, which has higher loads than the 2021 IEPR forecast the ISO had originally planned to use.<sup>17</sup> The ISO has acceded to this request and Figure 1.2-1 provides a comparison for the summer peak of the CEC’s adopted 2021 IEPR Energy Demand Forecast to the 2021 IEPR Additional Transportation Electrification Scenario.

Figure 1.2-1 Comparison of CEC’s adopted 2021 IEPR Energy Demand Forecast to the 2021 IEPR Additional Transportation Electrification Scenario



<sup>16</sup> <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1>

<sup>17</sup> <http://www.caiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf>

## 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 that 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.<sup>18</sup> These targets also meet or exceed the current 2030 renewables portfolio standard requirement established by Senate Bill 100.<sup>19</sup> 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 provided to the ISO via Decision (D) 22-03-004<sup>20</sup> issued on February 15, 2022, a base case and sensitivity portfolio for use in this planning cycle. The base case, provided for reliability and policy-driven study, meets the 46 million metric ton (MMT) greenhouse gas (GHG) emissions target by 2032.

In transferring the sensitivity portfolio, the CPUC called on the ISO:

1. To study the 30 million metric ton (MMT) High Electrification policy-driven sensitivity portfolio transmitted herein as in the 2022-23 TPP High Electrification Sensitivity Scenario; and
2. To continue studying the deliverability needs and corresponding transmission needs related to out-of-ISO long-lead time resources, such as out-of-state wind and geothermal resources beyond the CAISO's balancing area authority.

These portfolios also took into account the announced retirements of approximately 3700 MW of gas-fired generation to comply with state requirements for thermal generation relying on coastal

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<sup>18</sup> 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.

<sup>19</sup> SB 100, the 100% Clean Energy Act of 2018, also authored by Senator Kevin De León, was signed into law by Governor Jerry Brown on September 10, 2018. Among other provisions, SB 100 built on existing legislation including SB 350 and revised the previously established goals to achieve the 50% renewable resources target by December 31, 2026, and to achieve a 60% target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. [https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill\\_id=201720180SB100](https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100)

<sup>20</sup> Decision 22-02-004 released on February 10, 2022 for the Decision Adopting 2021 Preferred System Plan, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF>

water for once-through cooling,<sup>21</sup> and the announced retirement of the Diablo Canyon Power Plant.<sup>22</sup>

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

In developing the base portfolio for the 2022-2023 transmission planning cycle, the CPUC's modeling showed that while no new natural gas-fired power plants are identified in the 2031 new resource mix, existing gas-fired plants – other than those relying on once-through-cooling and scheduled for retirement - are needed in 2032 as operable and operating resources, providing a renewable integration service. Accordingly, to align with the CPUC's assumptions, the ISO has not presumed retirement regardless of age.

The ISO notes that existing legislation<sup>23</sup> 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. These projections are not yet reflected in the portfolios provided by the CPUC for the 2022-2023 Plan.

### 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 northern coast areas.

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 northern 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 1,588 MW of offshore wind in the base portfolio in the Morro Bay call area and increasing to 3,100 MW in in the central

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<sup>21</sup> The Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) has recommended the State Water Resources Control Board (SWRCB) extend the compliance date from December 31, 2023 to December 31, 2026 for some once-through cooling (OTC) gas-fired generation in the ISO footprint to achieve compliance with state policies on the use of coastal and estuarine waters for power plant cooling. The recommendation to extend the OTC policy compliance dates for Alamitos Units 3, 4, and 5, Huntington Beach Unit 2, and Ormond Beach Units 1 and 2 beyond current December 31, 2023 retirement dates is contingent on these resources participating in the Electricity Supply Strategic Reliability Reserve Program (Strategic Reserve) established through Assembly Bill 205 (AB 205), which was signed by Governor Newsom on June 30, 2022. Pursuant to AB 205, Strategic Reserve resources are to be accessed to maintain reliability during extreme events beyond traditional resource planning requirements or other emergency conditions..

<sup>22</sup> Senate Bill 846 (SB 846), authored by Senator Bill Dodd, was signed by Governor Newsom on September 2, 2022. Among other provisions, SB 846 established that the CPUC shall not include the energy, capacity, or any attribute from Diablo Canyon Unit 1 beyond November 1, 2024, or Unit 2 beyond August 26, 2025, in the adopted integrated resource plan portfolios, resource stacks, or preferred system plans.

<sup>23</sup> SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

coast area and 1,500 MW in the Humboldt call area in the sensitivity portfolio. The ISO has continued to assess transmission alternatives, particularly in the north coast area in this planning cycle and will continue to do so in next year's planning cycle, where the Humboldt call area offshore wind resources are in 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 2022-2023 planning cycle, ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable NERC reliability standards.<sup>24</sup> The ISO performed this analysis across a 10-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions. The ISO assessed the transmission facilities under ISO operational control, which range in voltage from 60 kV to 500 kV. The ISO also identified plans to mitigate observed concerns considering upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and examining the potential for conventional and non-conventional resources (preferred resources including storage) to meet these needs. Although the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades and work with the relevant parties and agencies to seek their implementation.

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<sup>24</sup> This document provides detail of all study results related to transmission planning activities. However, consistent with the changes made in the 2012-2013 transmission plan and subsequent transmission plans, the CAISO has not included in this year's plan the additional documentation necessary to demonstrate compliance with NERC and WECC standards but not affecting the transmission plan itself. The CAISO has compiled this information in a separate document for future NERC/FERC audit purposes. In addition, detailed discussion of material that may constitute Critical Energy Infrastructure Information (CEII) is restricted to appendices that the CAISO provides only consistent with CEII requirements. The publicly available portion of the transmission plan provides a high level, but meaningful, overview of the comprehensive transmission system needs without compromising CEII requirements.



*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<sup>25</sup> 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<sup>26</sup> 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 three planning cycles, the ISO has programmatically studied the economic benefits of transmission and combinations of transmission upgrades and storage to reduce reliance on gas-fired generation in local capacity areas. In this 2022-2023 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 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

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<sup>25</sup> 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.ca.gov/faces/billNavClient.xhtml?bill\\_id=201720180SB100](https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100)

<sup>26</sup> 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.

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 if that planning cycle is the first or second year of the biennial coordination process. The 2022-2023 transmission planning cycle is the first 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. Local Capacity Requirement Studies: Near and mid-term local capacity technical studies were prepared for 2023 and 2027, respectively, as part of the annual study process supporting the state's resource adequacy program for the 2023 resource adequacy compliance year. These studies also provide the basis for determining the need for any ISO "backstop" capacity procurement that may be necessary once the load-serving entity procurement is submitted and evaluated. Consistent with past practices, each of these studies identified the extent to which storage could meet the needs in local capacity areas in lieu of gas-fired generation. The ISO also conducts a long-term local capacity requirements study every second year to further support state resource planning efforts. The long-term local capacity requirements study is conducted every second planning cycle and has been performed in the 2022-2023 planning cycle.
2. The 2022-2023 Transmission Plan also continued migrating certain special studies (e.g., frequency response studies) into a more permanent category of "other studies" within the transmission plan itself, now that the ISO has identified a need to perform this analysis on an annual basis.

### 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 2022-2023 planning cycle began in January 2021 and concluded in March 2022.

#### 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 modify the list of high-priority studies later based on new information

such as revised generation development assumptions and preliminary production cost simulation results.

### 1.3.1.2 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 12 months and ends with Board approval of the transmission plan. Thus, Phases 1 and 2 take 15 months to complete. Identifying non-transmission alternatives that the ISO is relying upon in lieu of transmission solutions also takes place at this time. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

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,<sup>27</sup> which are intended to

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<sup>27</sup> 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 CAISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key

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.<sup>28</sup> 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.

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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.

<sup>28</sup> 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<sup>29</sup> 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 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 2022-2023 transmission planning cycle was the first 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

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<sup>29</sup> 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.<sup>30</sup> 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 2022-2023 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. The ISO has also addressed the specific request made by the CPUC to the ISO applicable to this 2022-2023 Plan as set out below.

#### 1.4.1.1 CPUC Request to CAISO in Accordance with SB 887

The CPUC submitted a letter<sup>31</sup> to the ISO on January 13, 2023 in accordance with SB 887 indicating the following:

*“Pursuant to Senate Bill 887 (Becker, 2022), this letter requests the California Independent System Operator to (1) identify, based as much as possible on studies and projections completed before January 1, 2023, by the CAISO, the CPUC and the California Energy Commission, the highest priority transmission facilities that are needed*

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<sup>30</sup> Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website at <http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx>

<sup>31</sup> <http://www.caiso.com/InitiativeDocuments/Letter-2022-2023-Transmission-Planning-Process-Jan%2013,%202023.pdf>

*to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources or zero-carbon resources that are expected to be developed by 2035, and (2) consider whether to approve such transmission projects as part of the CAISO's 2022–23 transmission planning process.”*

The ISO has accordingly considered its past planning efforts, the 2022-2023 planning study results, and the policy direction applicable to this year's planning cycle. The results of this exercise are set out in Chapter 3, as the primary focus is associated with accessing renewable energy resources.

## 1.4.2 Non-Transmission Alternatives and Storage

Since implementing the current comprehensive transmission planning process in 2010, the ISO has considered and placed a great deal of emphasis on assessing non-transmission alternatives, including conventional generation, preferred resources (e.g., energy efficiency, demand response, renewable generating resources), and market-based energy storage solutions as a means to meet local transmission system needs. As stated earlier, the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan but can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades and work with the relevant parties and agencies to seek their implementation. As the volumes of renewable generation and storage required to meet system needs have escalated rapidly in recent years, the challenge has shifted from seeking to support resources that may not otherwise develop, to testing the effectiveness 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,<sup>32</sup> as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources<sup>33</sup> — 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.<sup>34</sup> Storage also played a major role in the consideration of preferred resource alternatives in LA Basin studies as well as the Oakland Clean Energy Initiative approved in the 2017-2018 Transmission Plan and modified in the 2018-2019 Plan. These efforts help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs.

In addition to providing opportunities for preferred resources including storage to be proposed in meeting needs that are being addressed within the year's transmission plan, each year's

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<sup>32</sup> “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>

<sup>33</sup> 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.

<sup>34</sup> 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](http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf).



transmission plan also identifies areas where future reinforcement may be necessary but immediate action is not required. The ISO has also expanded the scope of the biennial 10-year local capacity technical requirements study to provide additional information on the characteristics defining the 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 preferred 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 the 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. The ISO notes that in Decision (D.) 22-02-004, the CPUC directed one utility, in its role of Central Procurement Entity, to conduct a competitive solicitation process for a specific resource; the ISO sees this as a positive outcome in setting the direction for other needs in the future. Further, the CPEs can now contract with resources for 5 years or less that shall be deemed reasonable and preapproved if the 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.<sup>35</sup> This work was founded on the analysis of the necessary characteristics for “slow response” demand response programs that was undertaken initially through special study work in the 2016-2017 Transmission Plan, which continued into 2017 through a joint stakeholder process with the CPUC.<sup>36</sup>

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.

### **1.4.3 System Modeling, Performance, and Assessments**

The grid is being called upon to meet broader ranges of generating conditions and more frequent changes from one operating condition to another, as resources are committed and dispatched on a more frequent basis and with higher ramping rates and boundaries than in the past. This necessitates managing thermal, stability, and voltage limits constantly and across a broader range of operating conditions.

This has led to the need for greater accuracy in planning studies 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 the 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

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<sup>35</sup> 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>

<sup>36</sup> 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](http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf)

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

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

In the first step, during the transmission planning process the ISO performs a DG deliverability study to identify available transmission capacity at specific grid nodes to support deliverability status for distributed generation resources. This is done without requiring any additional delivery network upgrades to the ISO-controlled grid and without adversely affecting the deliverability status of existing generation resources or proposed generation in the interconnection queue. In constructing the network model for use in the DG deliverability study, the ISO models the existing transmission system, including new additions and upgrades approved in prior transmission planning process cycles, plus existing generation and certain new generation in the interconnection queue and associated upgrades. The DG deliverability study uses the nodal DG quantities specified in the base case resource portfolio that was adopted in the latest transmission planning process cycle to identify public policy-driven transmission needs. This is done both as a minimal target level for assessing DG deliverability at each network node and as a maximum amount that distribution utilities can use to assign deliverability status to generators in the current cycle. This ensures that the DG deliverability assessment aligns with the public policy objectives addressed in the current transmission planning process cycle. It also precludes the possibility of apportioning more DG deliverability in each cycle than was assumed in the base case resource portfolio used in the transmission planning process. As the amounts of distributed generation forecast in the recent renewable generation portfolios have declined from previous years, this creates less opportunity for this process to identify and allocate deliverability status to new resources. (Please refer to Chapter 3.)

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

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

### 1.5.2 Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.<sup>37</sup> 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, partly in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities, and documented its interpretation in a technical bulletin.<sup>38</sup>

Beginning in 2015, the ISO then reached out to several "adjacent systems" that are inside the ISO's balancing authority area and were confirmed transmission owners, but which did not appear to be registered as a planning coordinator. The ISO did this to determine whether these adjacent systems needed to have a planning coordinator and, if they did not have one, to offer to provide planning coordinator services to them through a fee-based planning coordinator services agreement. Unlike the requirements for the ISO's participating transmission owners who have placed their facilities under the ISO's operational control, the ISO is not responsible for planning and approving mitigations to identified reliability issues under the planning coordinator services agreement – but only for verifying that mitigations have been identified and that they address the identified reliability concerns. In essence, these services are provided to address mandatory standards via the planning coordinator services agreement, separate from and not part of the ISO's FERC-approved tariff governing transmission planning activities for facilities placed under ISO operational control. As such, the results are documented separately, and do not form part of this transmission plan.

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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<sup>37</sup> 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.

<sup>38</sup> 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 as defined by NERC.

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

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## Chapter 2

### 2 Reliability Assessment

#### 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 2022-2023 planning cycle, the ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable reliability standards. The ISO performed this analysis across a 10-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions.

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

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

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

The 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 identify and address proactively potential fault level issues affecting future resource additions.

### 2.1.1 Backbone (500 kV and selected 230 kV) System Assessment

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

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

### 2.1.2 Regional Area Assessments

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

- PG&E Local Areas 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 2022-2023 transmission plan spans a 10-year planning horizon 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 2022-2031 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 2022-2023 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<sup>39</sup> for this planning cycle. The study assumptions and methodologies are included in Section B2.3 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 the California Energy Commission's (CEC) energy demand forecast and the California Public Utilities Commission's (CPUC) base portfolio developed through its integrated resource plan. As described in Section 1.2, the reliability analysis is based on the CEC's 2021 IEPR Additional Transportation Electrification Scenario<sup>40</sup> and the base portfolio provided to the ISO via Decision (D) 22-03-004<sup>41</sup> issued on February 15, 2022.

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.

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<sup>39</sup> <http://www.aiso.com/InitiativeDocuments/FinalStudyPlan-2022-2023TransmissionPlanningProcess.pdf>

<sup>40</sup> 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.aiso.com/InitiativeDocuments/2022-2023TransmissionPlanningProcess-PortfolioTransmittalLetter.pdf>]

<sup>41</sup> Decision 22-02-004 released on February 10, 2022 for the Decision Adopting 2021 Preferred System Plan, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF>

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

PTO	Planning Area	2024	2027	2032	2035 (Sensitivity Study)
PG&E	Humboldt	122	127	161	181
	North Coast & North Bay	1481	1511	1817	2005
	North Valley	880	905	984	1027
	Central Valley	3855	3979	4554	4888
	Greater Bay Area	9028	9259	10754	11801
	Greater Fresno	3468	3566	3869	3942
	Kern	2106	2152	2252	2339
	Central Coast & Los Padres	1095	1412	1640	1782
SCE	Tehachapi and Big Creek Corridor	2274	2102	1913	2044
	North of Lugo area	981	981	1024	1059
	Eastern	5095	5127	5465	5642
	Main	24436	24797	25685	26218
SDG&E		4821	4985	5459	6340
VEA	VEA	167	174	188	

### 2.3.2 Study Horizon and Years

The studies that comply with TPL-001-5 were conducted for both the near-term<sup>42</sup> (2024-2027) and longer-term<sup>43</sup> (2028-2032) per the requirements of the reliability standards.

Within the identified near and longer term study horizons the ISO conducted detailed analysis on years 2024, 2027 and 2032. 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 are 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 by stakeholders, to select the most effective and

<sup>42</sup> 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.

<sup>43</sup> System peak load conditions for one of the years and the rationale for why that year was selected.

efficient 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 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 24 new reliability-driven projects required in this transmission planning cycle for a total estimated cost of \$1.76 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 17, 2022 stakeholder meeting. Based on comments received and no objection raised at the following ISO Board of Governors meeting on December 15, 2022, ISO Management approved the transmission projects and informed the respective participating transmission owners of those approvals.

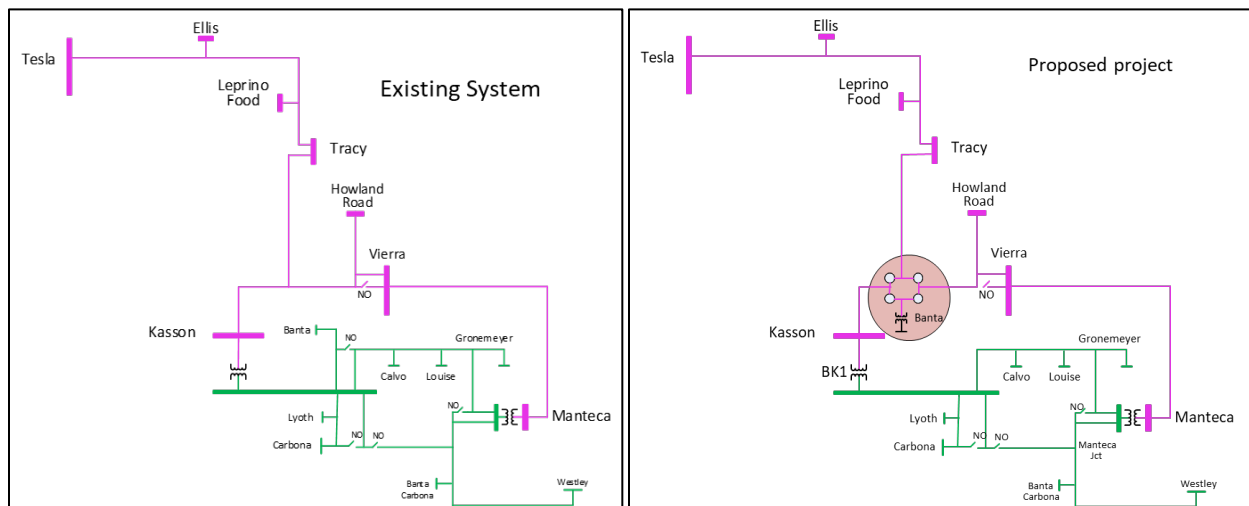
#### Banta Ring Bus Project

The reliability assessment of the PG&E Central Valley planning area in Section B3.3 of Appendix B identified contingencies (P1, P2 and P3) which resulted in overloads on the Vierra-Tracy-Kasson 115 kV line. The scope of the project to mitigate the identified constraints consists of the following:

- Convert existing Banta substation from 60 kV to 115 kV;
- Establish a 115 kV ring bus configuration to terminate the 115 kV lines from Kasson, Tracy and Vierra at the Banta 115 kV substation;
- Install a 115/12 kV 60 MVA transformer; and
- Re-terminate the 12 kV distribution feeders to the 12 kV bus at the new Banta 115 kV substation.

The estimated cost of the transmission component of this project is \$9M to \$17.5M and the expected in-service date is 2024. In the interim, the area will rely on operating action plans.

Figure 2.5-1: Banta Ring Bus Project



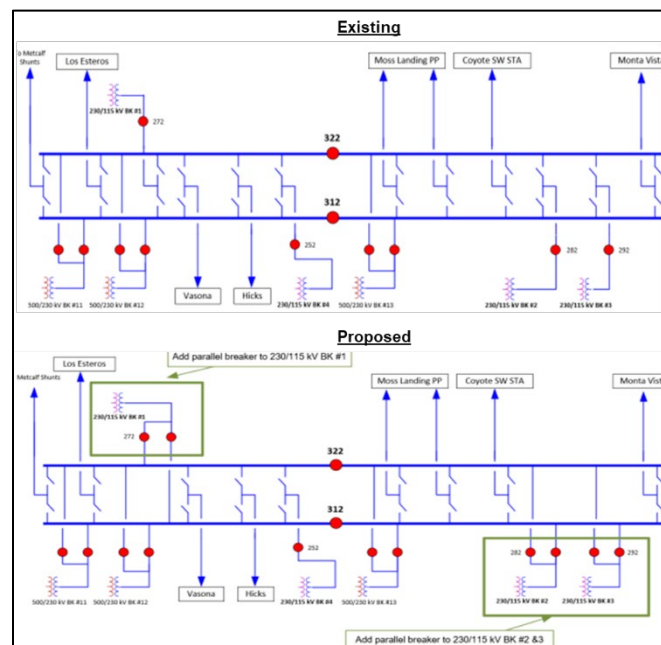
**Metcalf 230/115 kV Transformers Circuit Breaker Addition**

The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P2 and P6) which resulted in overloads of the Metcalf 230/115 kV banks in both the near-term and long-term planning horizons of the assessment. The scope of the project to mitigate the identified constraints consists of the following:

- Adding parallel breakers to each of the 230/115 kV banks Nos. 1, 2, and 3 at Metcalf 230 kV Substation.

The estimated cost of this project is \$7.5M to \$15M and the in-service date is 2026. In the interim, the area will rely on operating action plans.

Figure 2.5-2: Metcalf 230/115 kV Transformers Circuit Breaker Addition Project



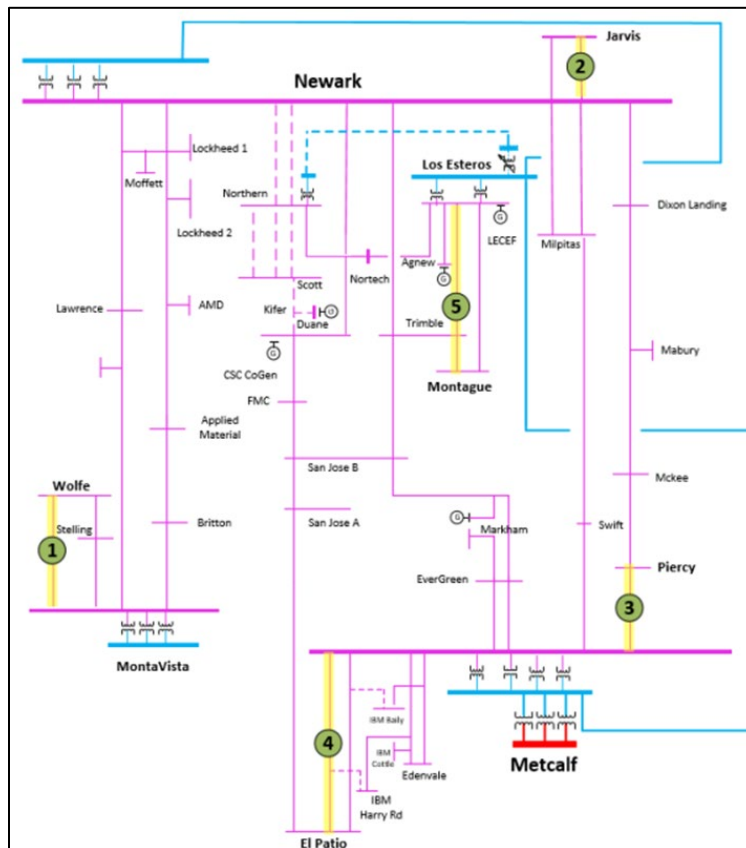
South Bay Area Limiting Elements Upgrade Project

The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P1, P6 and P7) which resulted in overloads on 115 kV lines in South Bay Area due to limiting elements on the existing 115 kV lines in the area in both the near-term and longer-term planning horizons. The scope of the project to mitigate the identified constraints consists of the following:

- Monta Vista –Wolfe 115 kV Line (limiting element – terminal conductor);
- Newark –Jarvis #1 115 kV Line (limiting element – line switch);
- Metcalf-Piercy 115 kV Line (limiting element – terminal conductor);
- Metcalf-El Patio#1 115 kV Line (limiting element – terminal conductor); and
- Los Esteros-Montague 115 kV Line (limiting element – CB 132 & associated switches).

The estimated cost of this project is \$5.5M to \$11M and the in-service date is 2027. In the interim, the area will rely on operating action plans.

Figure 2.5-3: South Bay Area Limiting Elements Upgrade project one-line diagram



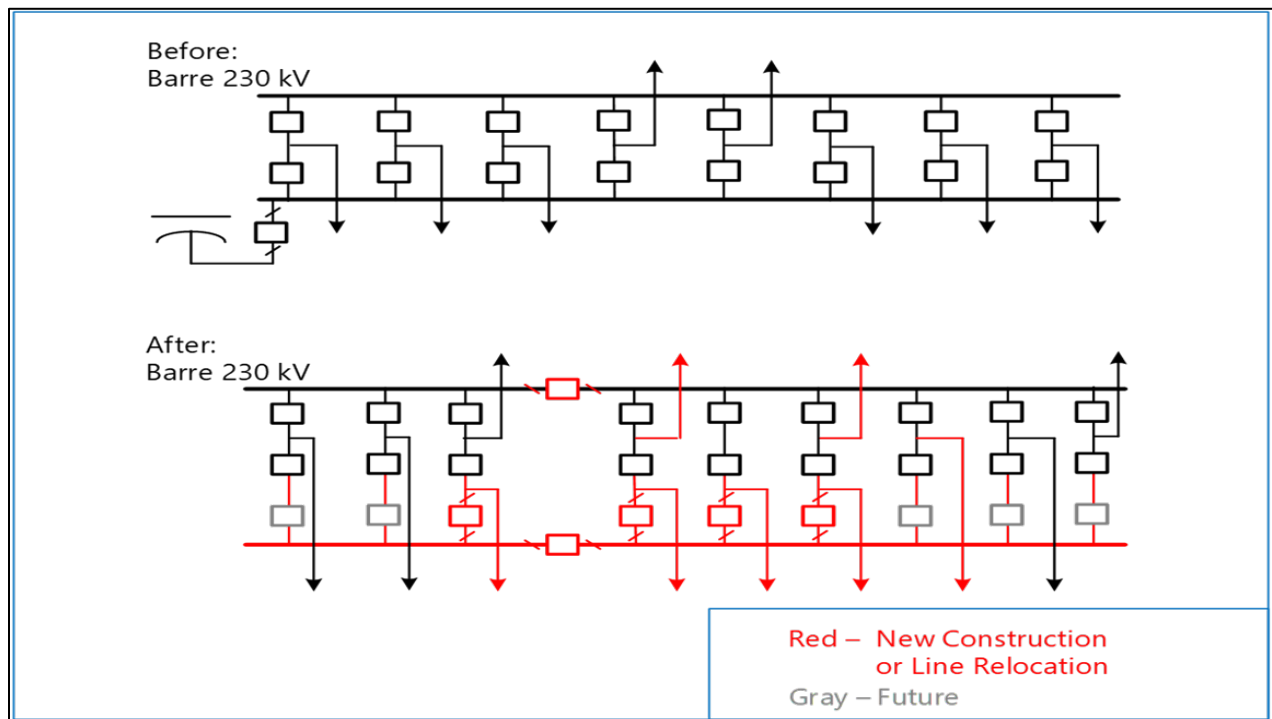
Barre 230 kV Switchrack Conversion to Breaker-and-a-Half Project

The project was submitted by SCE in the Request Window, as indicated in the SCE Main planning area in Section B5.4 of Appendix B, to mitigate short circuit duty issues driven by the extension of once-through-cooling units in the LA basin. The project converts Barre 230 kV switchrack to breaker-and-a-half configuration and split Barre 230 kV by adding bus sectionalizing circuit breakers. The project reduces the short circuit duty at Barre 230 kV well below the 63 kA existing capability to accommodate new generation and maintain safety. The scope of the project to mitigate the identified constraints consists of the following:

- Convert Barre 230 kV switchrack to breaker-and-a-half configuration by relocating the south bus and adding a third circuit breaker to four bay positions;
- Add sectionalizing circuit breakers and split the Barre 230 kV bus; and
- Relocate 230 kV lines, towers, and other facilities within substation.

The estimated cost of this project is \$45 million with a targeted in-service date of 6/30/2026. The project scope includes the following:

Figure 2.5-4: Barre 230 kV Switchrack Conversion to Breaker-and-a-Half Project



### Mira Loma 500 kV Circuit Breaker Upgrade Project

The project was submitted by SCE in the Request Window, as indicated in the SCE Main planning area in Section B5.4 of Appendix B, to address the short circuit duty concerns on four (4) 500 kV circuit breakers at Mira Loma 500/230 kV substation that are loaded to greater than 95% and 100% of the rated 50 KA short circuit duty capability in the near-term and the longer-term planning horizon. The scope of the project to mitigate the identified constraints consists of the following:

- Replace four 50 kA 500 kV circuit breakers at Mira Loma with new 63 kA rated circuit breakers.

The estimated cost of this project is \$10 million with a targeted in-service date of 12/31/2026.

## **2.5.2 Projects Recommended for Approval**

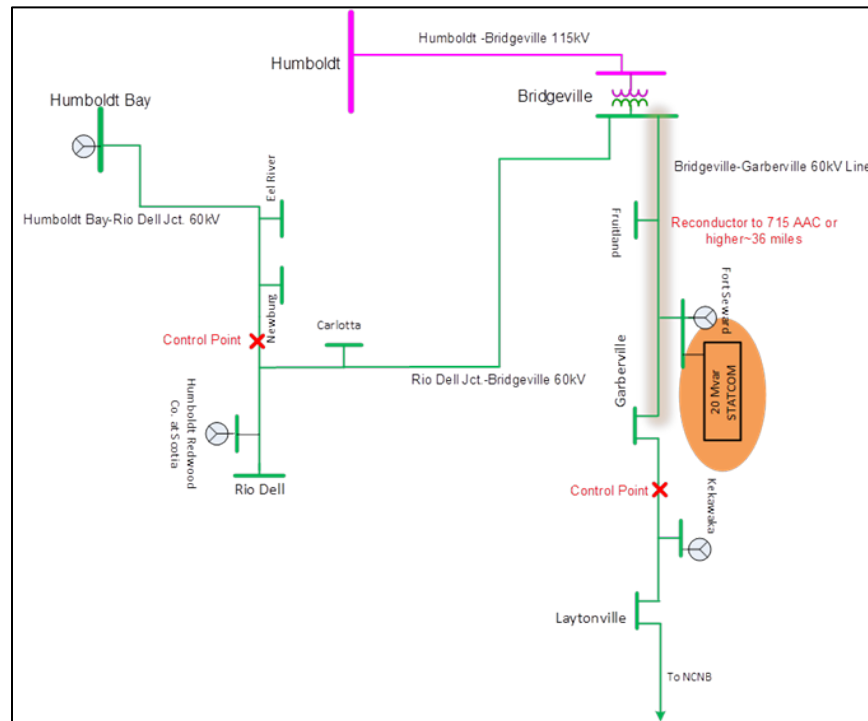
### Garberville Area Reinforcement Project

The ISO is recommending approval of the Garberville Area Reinforcement Project. The reliability assessment of the PG&E Humboldt planning area in Section B3.1 of Appendix B identified contingencies (P1, P2, P3 and P6) in the near-term and long-term planning assessments that resulted in overloads and low voltages on the Humboldt 60 kV system. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductoring of the entire Bridgeville-Garberville 60 kV line to achieve at least 631 Amps of summer normal rating (715 AAC conductor) which is about 36 circuit miles in length;
- Replacement of wood poles with LDSP will be required;
- Installation of a 20 MVAR STATCOM at Fort Seward 60 kV Substation;
- Establishing an operational control point to be able to open the line section from Garberville to Kekawaka 60 kV line; and
- Establishing an operational control point to be able to open the line section from Newburg to Rio Dell Jct. 60 kV line.

The estimated cost of this project is \$102M to \$204M and the expected in-service date is 2032. In the interim, the area will rely on operating action plans.

Figure 2.5-5: Garberville Area Reinforcement Project one-line diagram.



### Expanded Scope of Tulucay-Napa #2 Line Capacity Increase Project

The ISO is recommending approval of expanding the scope of the previously approved Tulucay - Napa #2 60 kV Line Capacity Increase project in the ISO's 2019-2020 Transmission Plan. The reliability assessment of the PG&E North Coast and North Bay area in Section 3.2 of Appendix B identified contingencies (Categories P1 and P3) which resulted in overloads on the Tulucay - Napa #2 60 kV line starting in 2024. The previously approved Tulucay - Napa #2 60 kV Line Capacity Increase project that is expected to be in-service by the fourth quarter of 2025 will mitigate the overloads identified in 2027; however is not adequate to mitigate the overload observed by 2032. The original scope of the Tulucay - Napa #2 60 kV Line Capacity Increase project was as follows:

- Replace limiting switches and jumpers at Basalt and Tulucay 60 kV substations.

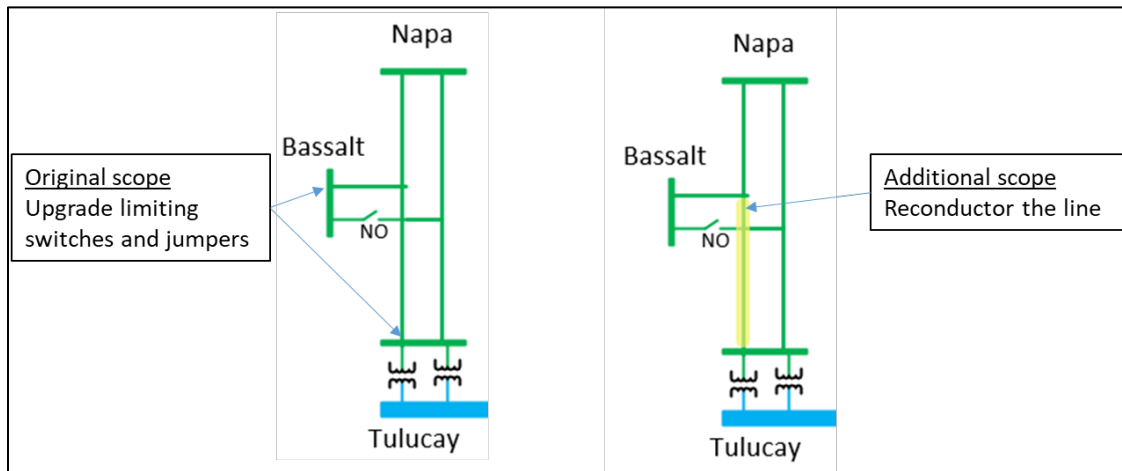
To mitigate the incremental constraints identified by the year 2032, the ISO is recommending to re-scope the previously approved project to include the following in the scope of the project:

- Reconductor the Tulucay-Napa #2 60 kV line from Tulucay to Basalt.

The estimated total cost of the original scope to replace limiting switches and jumpers at Basalt and Tulucay 60 kV substations and the expansion of the project to reconductor the Tulucay-Napa #2 60 kV line from Tulucay to Basalt was \$5 to \$10 million. The expected cost of the expansion of the project is \$2.3 to 4.6 million, with a new total estimated cost of \$7.3 to 14.6 million and the expected in-service date is 2028.



Figure 2.5-6: Reconductoring the Tulucay - Napa #2 60 kV (Tulucay 60 kV to Basalt 60 kV) line



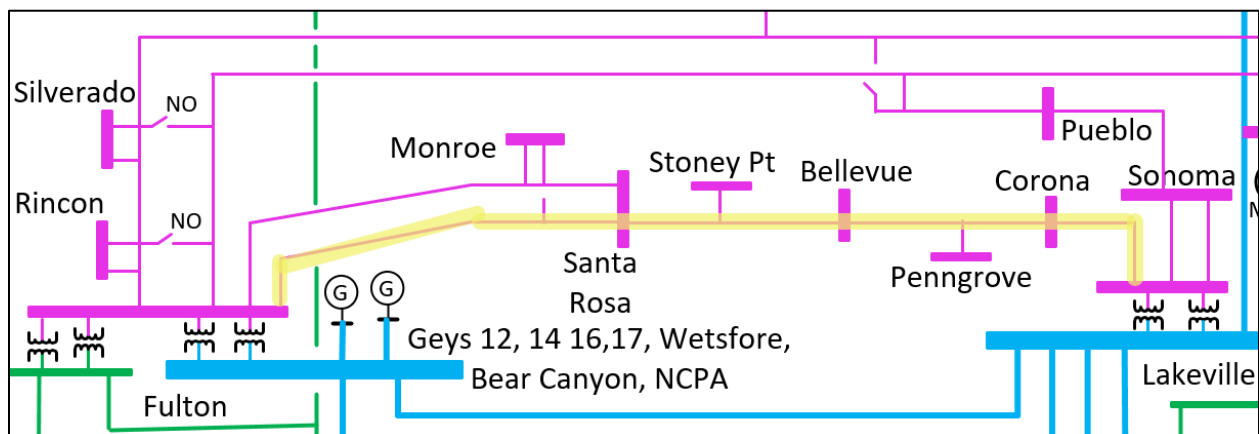
Reconductoring Santa Rosa Area 115 kV Lines Project

The ISO is recommending approval of the Reconductoring Santa Rosa Area 115 kV Lines project. The reliability assessment of the PG&E North Coast and North Bay area in Section B3.2 of Appendix B identified contingencies, Categories P2-4, P6 and P7, which resulted in overloads on the Corona-Lakeville 115 kV line, Santa Rosa-Corona 115 kV and Fulton-Santa Rosa No.1&2 115 kV lines starting in 2024. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductoring the Fulton-Santa Rosa #1 and #2 115 kV lines;
- Reconductoring the Santa Rosa-Corona 115 kV line; and
- Reconductoring the Corona-Lakeville 115 kV lines.

The estimated cost of this project is \$37M to \$74M and the expected in-service date is 2028. In the interim, the area will rely on operating action plans.

Figure 2.5-7: Reconductoring Santa Rosa Area 115 kV Lines Project



The ISO also considered RAS, which turned out not feasible as the number of required elements (both contingency and overloaded facilities) to be monitored will exceed the maximum per the ISO Planning Standard.

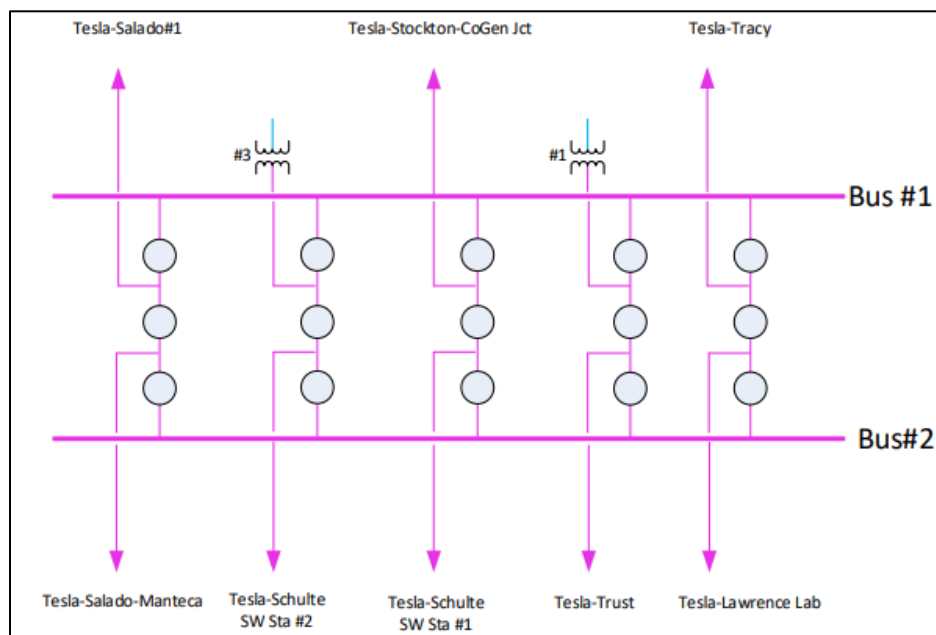
### Tesla 115 kV Bus

The ISO is recommending approval of the Tesla 115 kV Bus Reconfiguration project. The reliability assessment of the PG&E Central Valley planning area in Section B3.3 of Appendix B identified contingencies, P2-4, at Tesla 115 kV substation resulting in overloads and voltage issues in the underlying 115 kV network in the area starting in the near-term. The scope of the project to mitigate the identified constraints consists of the following:

- Converting the current Tesla 115 kV substation from the current double bus single breaker configuration to a breaker-and-a-half configuration with folded bus design.

The estimated cost of this project is \$27.5M to \$55M and the expected in-service date is 2030. In the interim, the area will rely on operating action plans.

Figure 2.5-8 Recommended Breaker-and-a-Half Bus Configuration at Tesla 115 kV Substation



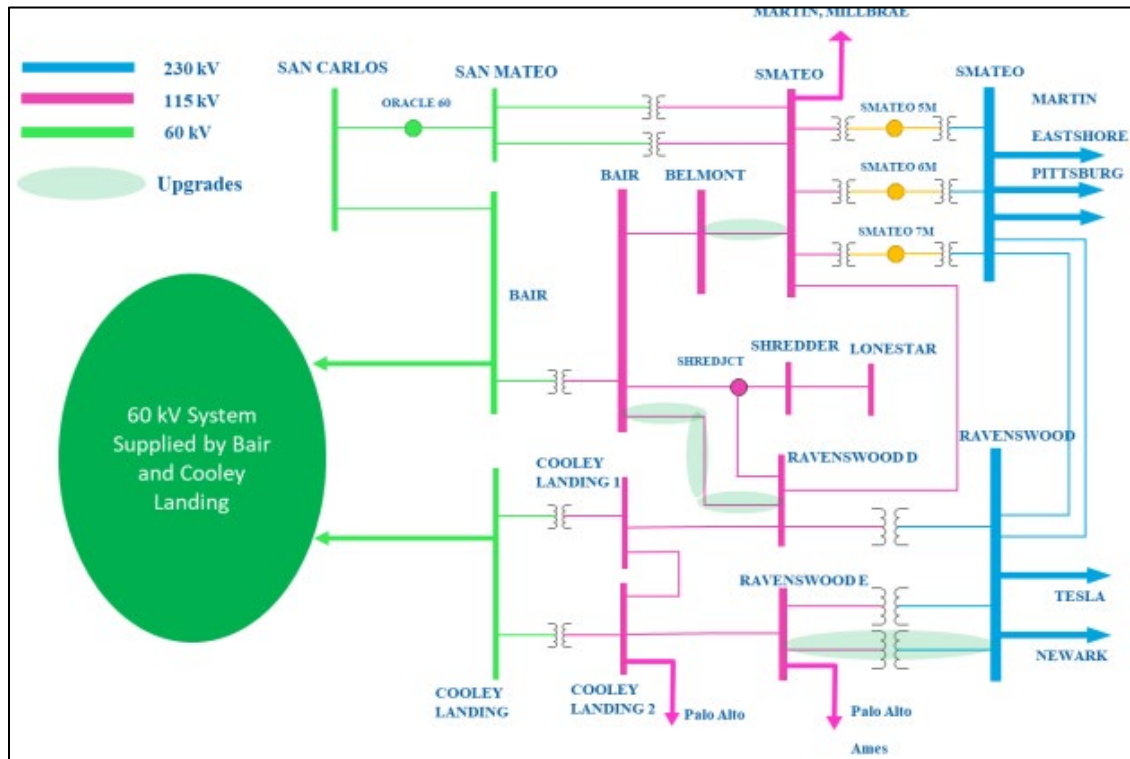
### Redwood City Area 115 kV System Reinforcement Project

The ISO is recommending approval of the Redwood City Area 115 kV System Reinforcement project. The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P6 and P7) which resulted in overloads on multiple 115 kV and 60 kV lines in Peninsula area in both the near-term and longer-term planning horizon. In addition, in the longer-term planning horizon only there were contingencies (P1, P3 and P6) which resulted in overloads on the Ravenswood 230/115 kV banks. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductoring the San Mateo-Belmont and Ravenswood-Bair 115 kV lines; and
- Adding a new 230/115 kV transformer at the Ravenswood substation.

The estimated cost of this project is \$55.4M to \$110.8M and the in-service date is 2030. In the interim, the area will rely on operating action plans.

Figure 2.5-9: Figure – Redwood City Area 115 kV System Reinforcement project one-line diagram.



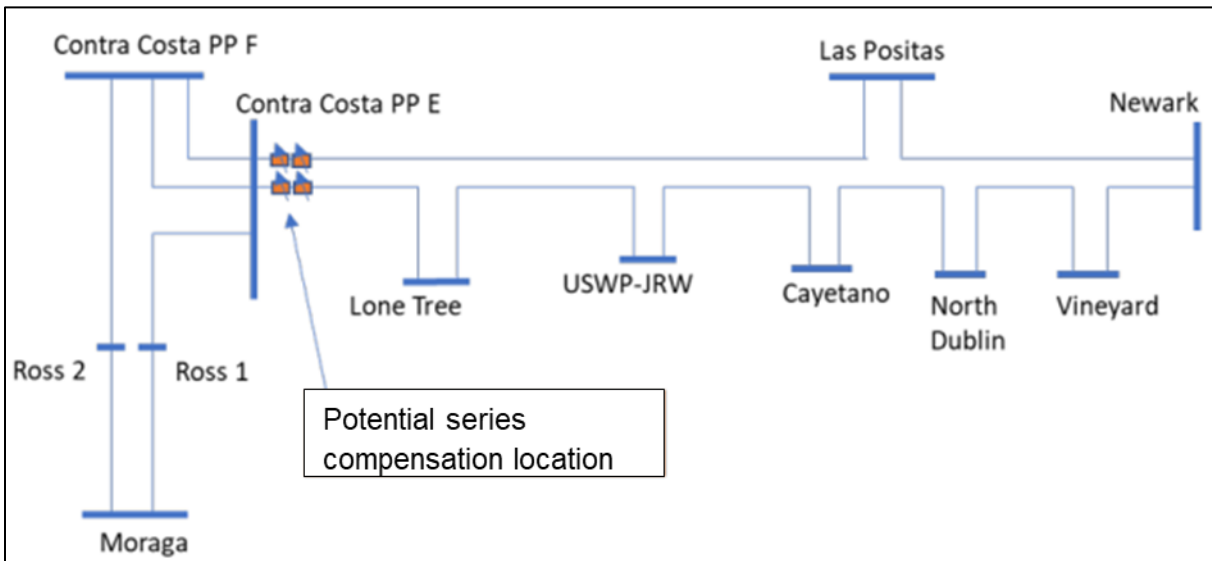
Lone Tree – Cayetano – Newark Corridor Series Compensation

The ISO is recommending approval of the “Lone Tree – Cayetano – Newark Corridor Series Compensation” project. The reliability assessment of the PG&E Greater Bay planning area in Section B3.5 of Appendix B identified contingencies (P2, P3, P6 and P7) which resulted in overloads were on the Contra Costa-Newark corridor 230 kV lines in both the near-term and longer-term planning horizons. The scope of the project to mitigate the identified constraints consists of the following:

- Installing 6 to 8 ohm series compensation (reactance) devices on the Cayetano-Lone Tree and Las Positas-Newark 230 kV lines. The series compensation would only require to be switched in under system conditions that could potentially overload the Cayetano-Lone Tree and Las Positas-Newark 230 kV lines.

The estimated cost of this project is \$15M to \$25M and the in-service date is 2027. In the interim, the area will rely on operating action plans.

Figure 2.5-10: Lone Tree – Cayetano – Newark Corridor Series Compensation Project



### Los Banos 70 kV related issues

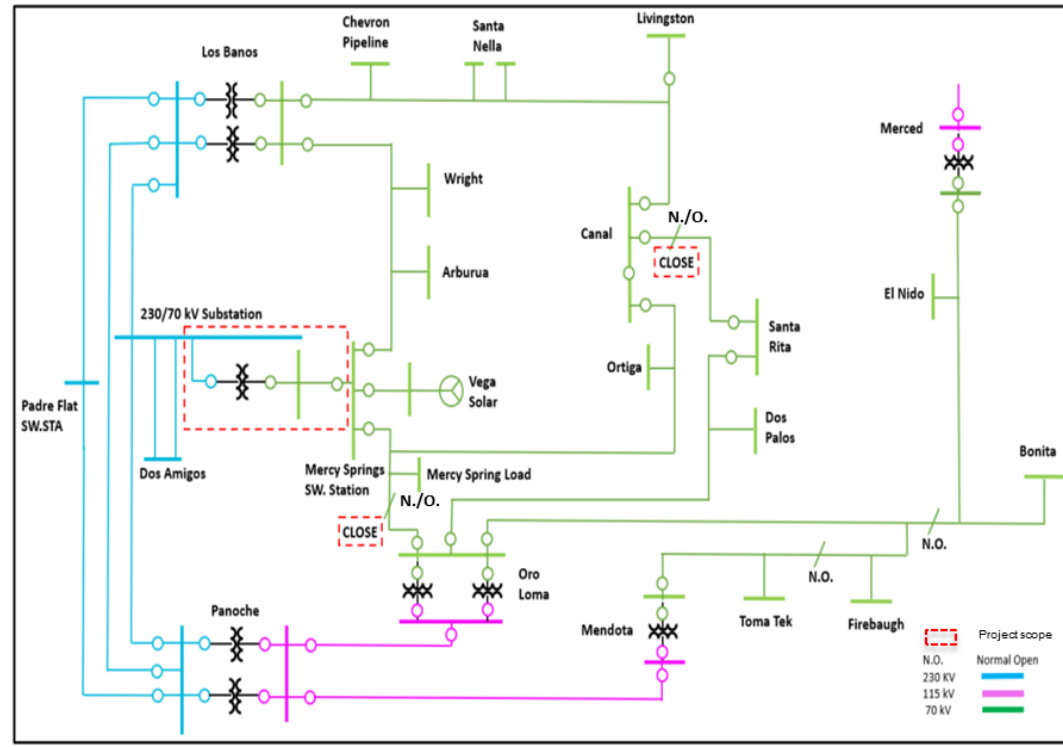
The ISO is recommending approval of the Los Banos 70 kV Area Reinforcement project. The existing Los Banos 70 kV area is served by two 230/70 kV transformers and a 115/70 kV transformer at Mendota. The reliability assessment of the PG&E Greater Fresno planning area in Section B3.6 of Appendix B identified contingencies (P1) which resulted in overloads on the underlying 70 kV lines and transformer, which includes the Los Banos 230/70 kV Transformer #3 and Los Banos-Canal-Oro Loma, Los Banos-Livingston Jct-Canal, Mercy Springs-Canal #1, Mercy Springs Sw Station-Oro Loma and Oro Loma-Mendota 70 kV lines. In addition, the overloads are increasing due to additional new distribution customer driven load increases at the Canal, Ortiga, Santa Nella and Wright 70 kV substations starting 2024 further requiring system upgrades to enhance reliability. The scope of the project to mitigate the identified constraints consists of the following:

- Install 230 kV partial bay at the new generation driven 230 kV switching station adjacent to Dos Amigos PP 230 kV Substation;<sup>44</sup>
- Add a new 70 kV Bus in the new generation driven 230 kV switching station, then it will be converted to a new 230/70 kV substation;
- Install one 230/70 kV transformer at the new 230/70 kV substation;
- Install a new 70 kV transmission line from new 70 kV Bus to Mercy Springs 70 kV Bus, and the new line is about one mile; and
- Install one breaker at Mercy Springs 70 kV Switching Station.

<sup>44</sup> Network upgrade in PG&E area, ID 22rsmt-4 New 230 kV switching station to loop Dos Amigos – Panoche # 3 230 kV, with in-service date of Q4-2028 from ISO January 25 quarterly Transmission Development forum.  
<http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=2CC974D9-6145-438D-9EB5-B9A784549FA9>

The total estimated cost of this project is \$30M to \$60M. The expected in-service date of this project is May 2029. In the interim, the area will rely on operating action plans.

Figure 2.5-11: Los Banos 70 kV Area Reinforcement Project



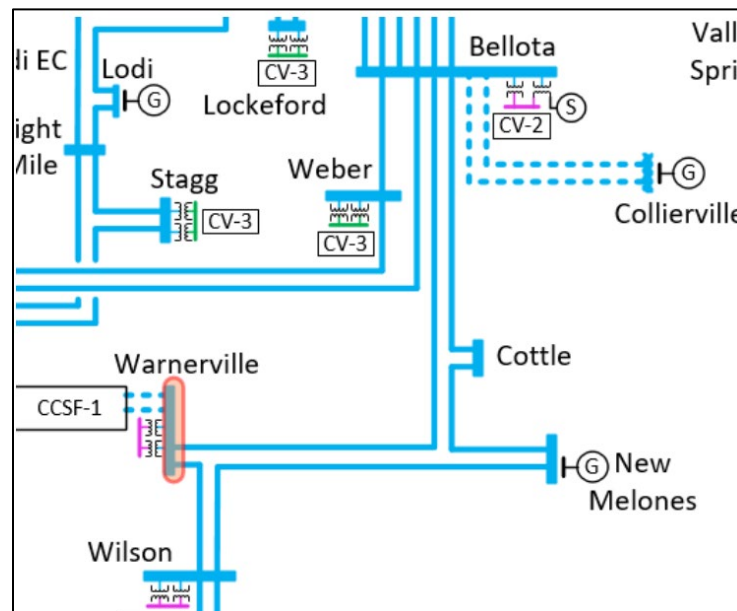
Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation as part of the previously approved Bellota-Warnerville 230 kV line reconductoring project

The Bellota-Warnerville 230 kV line reconductoring project was previously approved in the 2012-2013 transmission planning process. In the 2021-2022 transmission planning process, updated information was shared with the ISO that neighboring system equipment upgrades at Warnerville 230 kV substation, which is owned and operated by City and County of San Francisco (CCSF), are triggered by this previously approved project and that the rating of the Bellota-Warnerville 230 kV line following reconductoring will be limited by equipment at the Warnerville end. The ISO has voluntarily agreed, as set out in Section 24.10 of the ISO tariff, to the cost of the upgrades to limiting equipment. The incremental project scope that is being recommended for approval in this cycle includes the following:

- Upgrade limiting equipment at Warnerville 230 kV, which includes installing new jumpers, switches and new relays.

The total estimated cost of this incremental scope is \$1.6M. The expected in-service date of this project is 2024.

Figure 2.5-12: Bellota-Warnerville 230 kV line reconductoring



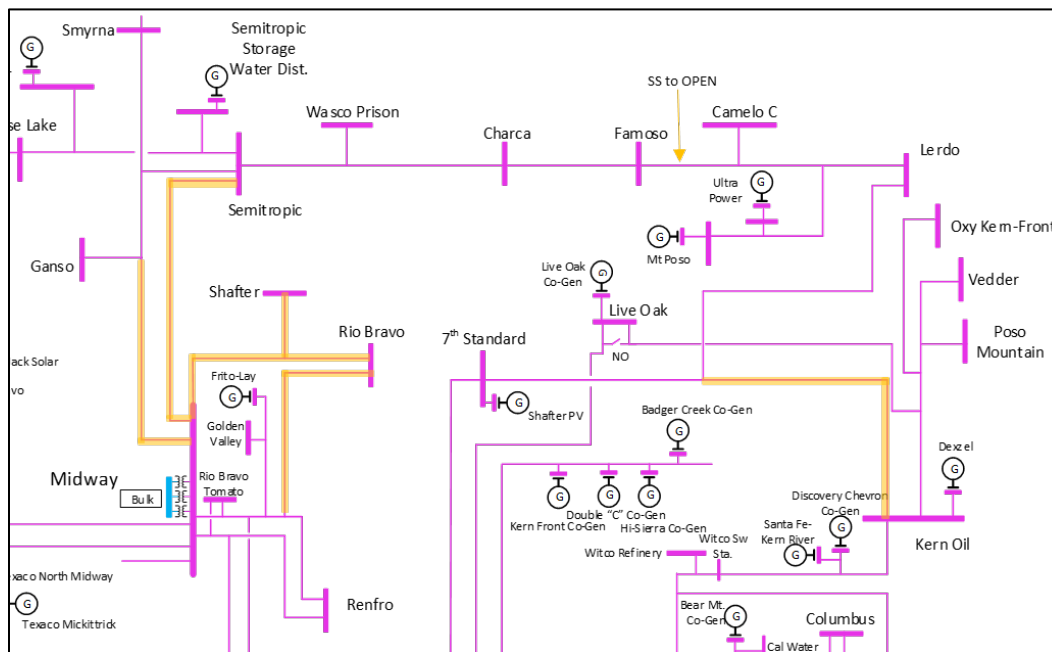
### North East Kern 115 kV Line Reconductoring Project

The ISO is recommending approval of the North East Kern 115 kV Line Reconductoring project. The reliability assessment of the PG&E Kern planning area in Section 3.7 of Appendix B identified contingencies (P1 and P7) which resulted in multiple overloads in the 115 kV area around the Midway substation in both the near-term and longer-term planning horizon. The scope of the project to mitigate the identified constraints consists of the following:

- Reconductor ~13.6 circuit miles of Midway – Shafter 115 kV Line with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~8.3 circuit miles on the Shafter-Rio Bravo 115 kV with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~3.9 circuit miles on the Midway-Tupman-Rio Bravo-Renfro 115 kV (between Rio Bravo and Renfro Junction From 11/62 To Rio Bravo Sub) with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~3.5 circuit miles on the Lerdo-Kern Oil-7th Standard 115 kV Line (between Lerdo J and Kern Oil, from 023/005 To Kern Oil Sub) with a larger conductor to achieve at least 975 amps under summer emergency conditions;
- Reconductor ~6.8 circuit miles on the Smyrna-Semitropic-Midway 115 kV Line (between Midway and Ganso from Midway to 081/634 and from 081/634 to Ganso) with a larger conductor to achieve 1517 at least amps under summer emergency conditions;
- Reconductor ~14.1 circuit miles on the Semitropic-Midway #1 115 kV Line (between Midway and Semitropic\_E) with a larger conductor to achieve at least 1517 amps under summer emergency conditions;

- Remove any limiting components as necessary to achieve full conductor capacity;
- Convert the existing control point to a summer setup to open line section from Wasco to McFarland 70 kV line; and
- Convert the existing control point to a summer setup to open line section from Famoso to Cawelo C 115 kV line.

Figure 2.5-13: Figure - North East Kern 115 kV Line Reconductoring Project



The estimated cost of this project is \$128M to \$256M and the in-service date is 2032. In the interim, the area will rely on operating action plans.

Several alternatives were assessed that included:

- Connecting Rio Bravo 115 kV to 7TH Standard 115 kV substation by using a portion of an idle line (Rio Bravo to Kern Oil 115 kV) and any necessary substation upgrades required in Rio Bravo and 7TH Standard 115 kV substations as well as building a new switching station at Shafter 115 kV junction.
  - This alternative was estimated at a similar cost \$130M - \$260M; however, it was not selected as it does not fully address all the constraints identified in planning assessment.
- Adding battery storage in the Shafter 115 kV area:
  - This alternative was not selected as it would also not address all the constraints identified in the planning assessment and there would be significant additional costs required to upgrade stations in the area for the interconnection of the battery storage, as well as concerns with deliverability of the battery within the area.

Coolwater 1A 230/115 kV Bank Project

The ISO is recommending approval of the Coolwater 1A 230/115 kV Bank Project project. The reliability assessment of the SCE North of Lugo planning area in Section 5.2 of Appendix B identified contingencies (P5 and P6) that resulted in low voltage and potential voltage collapse low voltages and potential voltage collapse at Coolwater, Dunn Siding, Baker, Tortilla and Tiefert 115 kV buses as well as high voltage at the locations under specific conditions in the near-term and longer-term planning horizons. The project will also provide operational flexibility, enhance reliability and retire the existing operating procedure which would radialize the system for a forced and scheduled outage in advance of the Category P6 contingencies. The Coolwater 1A 230/115 kV Bank Project will also allow a high speed rail project to energize with minimal delays as the bank is also needed for the retail load interconnection. The scope of the project to mitigate the identified constraints consists of the following:

- Adding a new 230/115 kV transformer bank at Coolwater.

The estimated cost for this project is \$47 million. The proposed in-service date of the project is 12/31/2026. The ISO has identified the proposed reliability project as needed.

Control 115 kV Shunt Reactor Project

The ISO is recommending approval of the proposed Control 115 kV Shunt Reactor Project. The reliability assessment of the SCE North of Lugo planning area in Section 5.2 of Appendix B identified high voltage issues following P6 contingencies at Control and Inyo 115 kV buses. Based on the historical Inyo 230 kV bus voltage data, the Inyo and Control area has been experiencing normal high voltage issues in real time operation. The scope of the project to mitigate the identified constraints consists of the following:

- The project scope includes installing a 45 MVAR 115 kV shunt reactor at Control Substation.

The estimate cost of the project is \$4 million. The proposed in-service date of the project is 12/31/2026.

Serrano 4AA 500/230 kV Transformer Bank Addition Project

The ISO is recommending approval of the Serrano 4AA 500/230 kV Transformer Bank Addition project. The reliability assessment of the SCE Main planning area in Section B5.4 of Appendix B identified contingencies (P6) which resulted in overloads of the remaining 500/230 kV transformer bank at Serrano substation in both the near-term and longer-term planning horizon. The scope of the project to mitigate the identified constraints consists of the following:

- Install a 4th 500/230 kV 1120/1344 MVA transformer bank at Serrano Substation;  
and
- Rebuild the 230 kV switching facility to 80 kA.

The estimated cost for this project is \$120 million with a targeted in-service date of Q4 2027.



### Sylmar Transformer Replacement Project

The ISO is recommending approval of the Sylmar Transformer Replacement project. The reliability assessment of the SCE Main planning area in Section B5.4 of Appendix B identified contingencies (P2, P4 and P6) which resulted in overloads on the SCE and LADWP joint-owned Sylmar 230/220 kV transformer banks E and F in the near-term and longer-term planning horizon. In addition, on November 26th, 2022, the LADWP-owned 230/220 kV Transformer Bank E at Sylmar substation suffered a failure. LADWP notified SCE that Bank E could not be repaired and would remain permanently inoperable. LADWP will replace the bank with increased capacity. SCE has also requested approval to replace (with increased capacity) the SCE-owned Bank F. The scope of the SCE project to mitigate the identified constraints consists of the following:

- Replace 230/220 kV transformer bank E at Sylmar substation with 1,290 MVA transformer.

The SCE estimated cost of the Bank F replacement is \$23M.

### Antelope-Whirlwind 500 kV Line Upgrade Project

The ISO is recommending approval of the Antelope-Whirlwind 500 kV Line Upgrade project. The reliability assessment of the SCE Main planning area in Section B5.7 of Appendix B identified contingencies (P2, P4, P5, and P6) which resulted in overloads of the Antelope-Whirlwind 500 kV line. The scope of the project is to mitigate the identified constraints consists of upgrading the Antelope – Whirlwind 500 kV line by increasing the ground clearance for nine (9) towers, which increases the normal and emergency line ratings by 32% and 27%. The estimated cost for this project is \$4 to 6 million with an estimated in-service date of 2025.

### Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Project

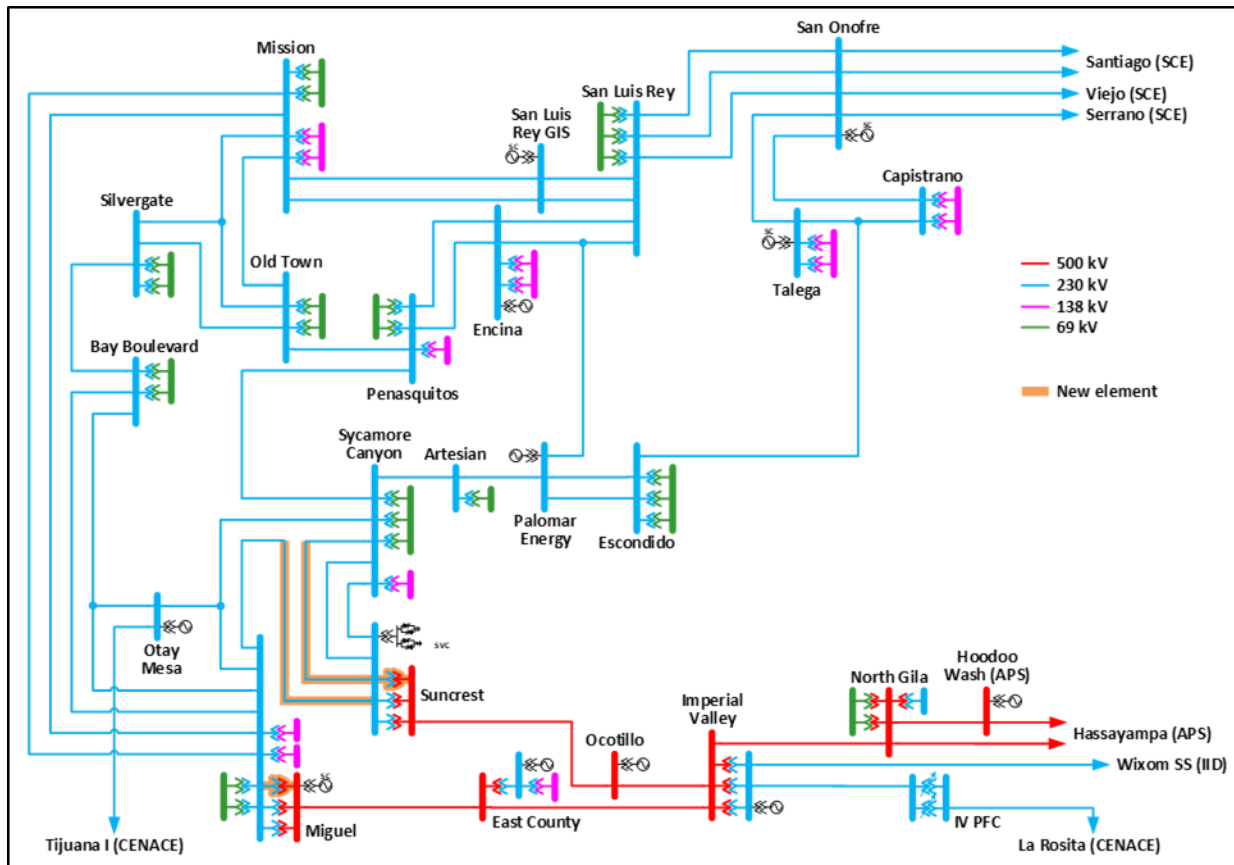
The ISO is recommending approval of the following project. The reliability assessment of the SDG&E planning area in Section B.6 of Appendix B identified contingencies (P3 and P6) in the near-term and long-term planning assessments that resulted in thermal overloads on the Suncrest – Sycamore Canyon 230 kV transmission lines and Suncrest and Miguel 500/230 kV banks. The scope of the project to mitigate the identified constraints consists of the following:

- A 16-mile double circuit 230 kV transmission line that will loop-in the existing TL23021 Miguel – Sycamore Canyon into Suncrest substation; and
- Install two new 500/230 kV banks at Suncrest and Miguel substations (one at each substation).

The estimated cost of this project is \$275M to \$375M and the expected in-service date is 2032.

In the interim, the area will continue relying on the existing RAS, 30-minute short-term emergency ratings and operational actions to mitigate the identified thermal overloads.

Figure 2.5-14: Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Project



**PG&E Area Short Circuit Upgrade Projects**

The following short-circuit upgrade projects were identified in PG&E’s short circuit analysis as a part of this year’s planning cycle including previously approved projects (i.e. Manning and Collinsville Substation project’s) and the resources in the CPUC base portfolio.

**Pittsburg 115 kV Bus Reactor**

The analysis identified thirteen 230 kV circuit breakers at Pittsburg substation to be overstressed. The overstress is caused by the addition of the new Collinsville substation and contributions by the portfolio resources. The scope of the Pittsburg 115 kV Bus Reactor project is as follows:

- Six 18-ohm 3,000 Amp reactors;
- One spare reactor unit; and
- Associated switches and bus work.

The ISO is recommending approval of the Pittsburg 115 kV Bus Reactor project as an addition to the previously approved Collinsville 500/230 kV substation policy project. The estimated cost

of this project is \$13 million to \$26 million. This additional scope is to be completed concurrently with the implementation of the new Collinsville substation.

#### Los Banos 230 kV Circuit Breaker Replacement

The analysis identified four 230 kV circuit breakers at Los Banos substation to be overstressed in the 2032 scenario. The overstress is caused by the portfolio resources. The scope of the Los Banos 230 kV Circuit Breaker Overstress project is as follows:

- Breaker 212, 222: Replace in place with new SMP Relays. May replace foundations/structures as needed; and
- Breaker 252, 262: Replace with two (2) new breaker-and-a-half bays in the new breaker-and-a-half bus section to meet the ultimate plan. T-Line relocations into new breaker-and-a-half positions.

The estimated cost of this project is \$33 million to \$66 million and the in-service date is 2032.

#### Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade

The analysis identified four 115 kV circuit breakers and thirteen 230 kV circuit breakers at Panoche substation to be overstressed. The overstress is caused by addition of the new Manning substation and contributions by the portfolio resources. The scope of the Panoche 115 kV and 230 kV Circuit Breaker Overstress project is as follows:

- Replace the 115 kV circuit breakers 132, 152, 102 and 162;
- Install a new MPAC building for the 115 kV bus section; and
- Convert 230 kV Bus Section D to breaker-and-a-half and replace overstressed breakers in Bus E to 63 kA at Panoche substation.

The ISO is recommending approval of the Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project as an addition to the previously approved Manning 500/230 kV substation policy project. The estimated cost of four 115 kV circuit breakers replacement is \$22 million to \$44 million and the cost for the 230 kV bus upgrade is \$70 million to \$140 million. The total estimated cost of the Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project is \$92 to 184 million. This additional scope is to be completed concurrently with the implementation of the new Manning substation.

### **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 and a contingency (P6) which resulted in an overload only in the 2035 ATE sensitivity scenario. The ISO will continue to assess the need in future planning cycles.

### North of Mesa Upgrades

The North of Mesa project was originally approved as the Midway-Andrew 230 kV project in the 2012-2013 Transmission Plan. The Midway-Andrew 230 kV project was split into two separate projects in the 2018-2019 Transmission Plan, with the South of Mesa Upgrades approved to proceed while the North of Mesa was placed on hold for further assessments in future planning cycles. In the 2020-2021 Transmission Plan, the ISO recommended as a mitigation procuring a 50 MW 4 hour battery storage at the Mesa 115 kV substation to address ISO Planning Standard maintenance requirements and utilizing existing Mesa, Divide and Santa Maria UVLS for peak load conditions, instead of proceeding with the North of Mesa upgrade. The ISO also recommended the North of Mesa upgrade project remain on hold pending procurement of the battery storage. Regarding battery storage procurement at Mesa 115 kV, on December 29, 2022, PG&E reported its progress on energy storage procurement at the Mesa 115 kV substation in compliance with Decision 22-02-004<sup>45</sup> to the CPUC, stating that no storage project has been procured by PG&E as part of its procurement requirements adopted in D.21- 06-035 that meets the operational requirements identified in the 2020-2021 TPP at the 115 kV bus of the Mesa substation.

In this cycle PG&E has proposed to change the Point of Interconnection (POI) of the battery storage from the 115 kV to the 230 kV at the Mesa substation due to the complications associated with the 115 kV interconnection. As part of this change in the POI, PG&E proposed to address the maintenance issue related to the Mesa 230/115 kV transformers by installing a system spare transformer. The estimated cost to install the system spare transformer is \$12 million to \$24 million. The new spare 230/115 kV transformer at the Mesa substation in combination with the battery storage at the Mesa 230 kV bus is the most cost effective solution for the identified maintenance issue in the Mesa area. As such, the ISO concurs with PG&E proposed change of battery storage POI to the Mesa 230 kV bus and recommends approval for installation of the system spare transformer.

The ISO recommends canceling the North of Mesa project. As a portion of the mitigation plan to address maintenance planning requirements, the ISO recommends changing the interconnection location of the 50 MW procured storage solution from the 115 kV bus to the 230 kV at the Mesa substation. The ISO also recommends approval of the Mesa Spare Transformer Installation project with an estimated cost of \$12 million to \$24 million.

### Wheeler Ridge Junction Project

The ISO is recommending that the previously approved Wheeler Ridge Junction project be taken off hold and proceed with a scope modification described below. The reliability assessment of the PG&E Kern planning area in Section 3.7 of Appendix B identified contingencies (P1, P2, and P6) resulted in overloads on the Midway-Wheeler Ridge #1 and #2 230 kV lines. In addition to increasing load and commercial interest in this area for new generation, the Wheeler Ridge junction project with a revised scope is being recommended to

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<sup>45</sup> [ELEC. 6804-E.pdf \(pge.com\)](#)

be reinstated. This project will also address the issues identified in the Lamont 115 kV pocket. In the 2020-2021 transmission planning process, the ISO recommended procurement of a 95 MW 4-hour energy storage option to mitigate the 115 kV issues on the Kern-Lamont 115 kV system. In regards to the battery storage procurement at Lamont 115 kV, on December 28, 2022, PG&E submitted progress on energy storage procurement on the Kern-Lamont 115 kV system in compliance with Decision 22-02-004<sup>46</sup> to the CPUC, stating that no viable offers remain and that the PG&E CPE closed the Kern-Lamont RFO. With the Wheeler Ridge Junction project reinstated, the previously recommended procurement of a 95 MW 4-hour energy storage is no longer required for mitigation of reliability issues identified in the Kern-Lamont 115 kV system.

The scope of the Wheeler Ridge Junction project remains consistent with what was originally proposed with the exception of removing the following:

- Reconductor and upgrade 6 miles of the idle line from Wheeler Ridge Junction towards Magunden substation. Upgrade for 115 kV operation, and terminate at Magunden and WRJ stations.

Therefore the updated scope of the project is as follows:

- Build new 230/115 kV transmission substation at Wheeler Ridge Junction (WRJ) with:
  - 2.5 – 230 kV Breaker-and-a Half (ultimate 7),
  - 2.5 – 115 kV Breaker-and-a Half (ultimate 7), and
  - 2 – 230/115 kV 420 MVA transformers;
- Convert 14.5 miles of the Adobe Switching Station #1 Tap 115 kV line from Adobe Switching Station to tower 011/065 to 230 kV operation:
- Extend the newly converted 230 kV line the remaining 1.25 miles to Wheeler Ridge substation;
- Terminate the newly converted 230 kV circuit at Wheeler Ridge;
- Open end Kern-Tevis-Stockdale-Lamont 115 kV line at tower 005/035 and loop Stockdale 115 kV substation;
- Convert/Re-conductor 5 miles of the Kern-Tevis-Stockdale-Lamont 115 kV lines section from Towers 005/035 to 011/065 to 230 kV operation on both sides of double circuit tower line;
- Terminate both circuits at the WRJ station. Terminate both remaining 115 kV lines to Lamont at WRJ station;
- Remove Kern PP-Stockdale #2 230 kV line from Stockdale substation, and terminate the first newly converted 230 kV circuit. Bypassing Stockdale substation, creating the Kern-WRJ 230 kV Line;

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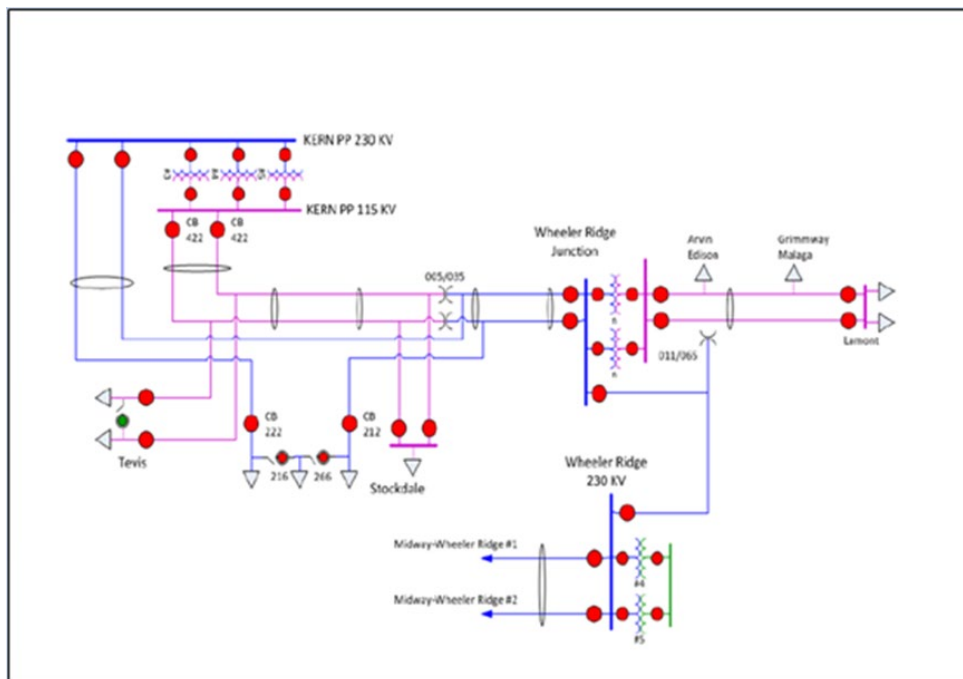
<sup>46</sup> [ELEC. 6801-E.pdf \(pge.com\)](#)

- Terminate second newly converted 230 kV circuit at Stockdale substation, for a loop arrangement;
- Reconductor 6 miles of the Kern PP-Stockdale #1 and #2 230 kV lines; and
- Upgrade Stockdale 230 kV bus equipment as necessary to allow loop operation.

The previously approved project with the scope change is estimated to cost \$259-517M and estimated to take 8-10 years to complete. After completion of the project the P1 RAS at Bitterwater 230 kV will be converted to a P6/P7 RAS and continue to be utilized as mitigation for P6 and P7 overloads that could still occur.

Several Alternatives were considered including three additional 230 kV options and three 500 kV options. These options were not recommended due to feasibility concerns, cost, or concerns with both feasibility and cost.

Figure 2.5-15: Wheeler Ridge Junction Project



## 2.5.4 Projects under Review for Potential Approval in 2022-2023 Transmission Planning Process

### Eldorado Short Circuit Duty Project

The ISO has identified a need for the Eldorado Short Circuit Duty project in the reliability assessment of the SCE Bulk System planning area in Section B5 of Appendix B. The short circuit studies conducted by SCE identified overstressed 230 kV and 500 kV breakers at Eldorado Substation. The existing Eldorado 230 kV and 500 kV breakers have a short circuit duty rating of 63kA. The short circuit duty assessment identified that with all active queued projects (generation and transmission) from SCE, NV Energy and LADWP modeled, including the approved GLW Upgrade project, the Eldorado jointly owned 230 kV bus SCD could reach 74.2 kA and the Eldorado 500 kV bus SCD could reach 68.9 kA. To address this identified issue the ISO has requested a mitigation plan from SCE. However, SCE's analysis is still ongoing. The ISO expects that the mitigation plan, in coordination with SCE, will be completed in the May 2023 time frame and will be evaluated for approval as a part of this planning cycle at a later date.

## 2.6 Conclusion

The 24 new reliability-driven projects are required in this transmission planning cycle for a total estimated cost of \$1.76 billion are listed below. Table 3.0-1 includes the six projects that were approved by ISO management in this planning cycle for an estimated total cost of \$100.1 million. Table 3.0-2 lists the 18 projects recommended for approval in this planning cycle for an estimated total cost of \$1.66 billion.

Table 2.6-1: Management Approved Transmission Projects

Project Name	PTO Area	Planning Area	Cost (\$M)	
			Low (\$M)	High (\$M)
Banta ring bus	PG&E	Central Valley	9.0	17.5
Metcalf 230/115 kV Transformers Circuit Breaker Addition	PG&E	Greater Bay Area	7.5	15.0
South Bay Area Limiting Elements Upgrade	PG&E	Greater Bay Area	5.5	11.0
Equipment Upgrade at CCSF Owned Wamerville 230 kV Substation	PG&E	Greater Fresno	1.6	1.6
Barre 230 kV Switchrack Conversion to Breaker-and-a-Half	SCE	Main	45	45
Mira Loma 500 kV Circuit Breaker Upgrade	SCE	Main	10	10
		<b>Total</b>	<b>78.6</b>	<b>100.1</b>

Table 2.6-2 Recommended Transmission Projects for Approval

Project Name	PTO Area	Planning Area	Cost (\$M)	
Garberville area reinforcement project	PG&E	Humboldt	102.0	204.0
Tulucay-Napa #2 60 kV line reconductoring project	PG&E	North Coast & North Bay	2.3	4.6
Santa Rosa 115 kV lines reconductoring project	PG&E	North Coast & North Bay	37.0	74.0
Tesla 115 kV Bus Reconfiguration Project	PG&E	Central Valley	27.5	55.0
Lone Tree – Cayetano – Newark Corridor Series Compensation	PG&E	Greater Bay Area	15.0	25.0
Los Banos 70 kV Area Reinforcement Project	PG&E	Fresno	30.0	60.0
Redwood City Area 115 kV System Reinforcement	PG&E	Greater Bay Area	55.4	110.8
Pittsburg 115 kV Bus Reactor project	PG&E	Greater Bay Area	13	26
Los Banos 230 kV Circuit Breaker Replacement	PG&E	Fresno	33	66
Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	Fresno	92	184
North East Kern 115 kV Line Reconductoring Project	PG&E	Kern	128.0	256.0
Mesa Spare Transformer Installation	PG&E	Central Coast & Los Padres	12	24
Coolwater 1A 230/115 kV Bank Project	SCE	North of Lugo	47	47
Control 115 kV Shunt Reactor	SCE	North of Lugo	4	4
Serrano 4AA 500/230 kV Transformer Bank Addition	SCE	Main	120	120
Sylmar Transformer Replacement	SCE	Main	23	23
Antelope-Whirlwind 500 kV Line Upgrade Project	SCE	Main	4	6
Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Projec	SDG&E	SDG&E	275	375
		<b>Total</b>	1,020.2	1,664.4

Three previously approved transmission projects were on hold pending further assessment. Based on this reliability assessment, the ISO recommends the following:

- Keep the Moraga- Sobrante 115 kV Line Reconductor project on hold;
- Cancel the North of Mesa project. Relocate the previously recommended procured storage at Mesa substation from the 115 kV bus to the 230 kV bus, and approve the Mesa Spare Transformer project; and
- Remove from being on hold and proceed with the Wheeler Ridge Junction project with a minor scope modification.

The ISO has identified the need for the Eldorado Short Circuit Duty project; however, this requires further assessment and coordination with SCE before the project can be recommended for approval. The ISO expects that the mitigation plan, in coordination with SCE, will be completed in the May 2023 timeframe and will be evaluated for approval at a later date.



## Chapter 3

### 3 Policy-Driven Need Assessment

#### 3.1 Background

The overarching public policy objective for the California ISO's Policy-Driven Need Assessment is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets 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 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 ISO, for example, 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 and the MOU signed by the three parties in December 2022 reaffirms our respective roles and commitment 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.

The CPUC issued Decision 22-02-004<sup>47</sup> on February 15, 2022 to transmit a portfolio based on the 38-million metric ton (MMT) greenhouse gas (GHG) target by 2030 and the 2020 Integrated Energy Policy Report demand forecast utilizing the high electric vehicle assumptions as the reliability and policy-driven base portfolio in the ISO 2022-2023 Transmission Planning Process (TPP). The portfolio includes a 2032 GHG target of 35 MMT, consistent with the 10-year timeline of the portfolio. The Decision is accompanied by Attachment A,<sup>48</sup> which provides the methodology and results of the resources-to-busbar mapping<sup>49</sup> 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, and the use of that zonal approach to shape and guide interconnection and resource procurement processes.

Decision 22-02-004 also delegated to the CPUC's Energy Division staff the development of a policy-driven sensitivity portfolio and associated busbar mapping based on a 30-million metric ton greenhouse gas target in consultation with staff of the California Energy Commission (CEC)

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<sup>47</sup> <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF>

<sup>48</sup> <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF>

<sup>49</sup> The busbar is the electrical connection within the ISO planning models where the generator is connected to the electrical system.

and ISO. Accordingly, the 2022-23 TPP High Electrification Sensitivity Portfolio was developed and transmitted to the ISO on July 1, 2022. In the transmittal letter,<sup>50</sup> the CPUC and CEC requested the ISO to:

- Use the 2021 Integrated Energy Policy Report (IEPR) Additional Transportation Electrification scenario as its load assumptions for 2022-2023 Transmission Planning Process (TPP) base and sensitivity case studies;
- Study the 30-million metric ton (MMT) High Electrification policy-driven sensitivity portfolio transmitted as the 2022-23 TPP High Electrification Sensitivity Scenario; and
- Continue studying the deliverability needs and corresponding transmission needs related to out-of-CAISO long-lead time resources, such as out-of-state wind and geothermal resources beyond the CAISO's balancing authority area. The letter further requested the ISO to assess the deliverability needs of these long lead-time resources while preserving the existing transmission capacity that has been allocated to other projects earlier in the queue.

### 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.

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<sup>50</sup> <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/tpp-portfolio-transmittal-letter.pdf>

### 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 of the constraints on renewable curtailment 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.<sup>51</sup>

#### 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.<sup>52</sup>

#### 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 in only the policy-driven assessment. Details of PCM modeling assumptions and approaches are provided in Chapter 4 and Appendix G.

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<sup>51</sup> <http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf>

<sup>52</sup> <http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf>

### 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 2022-2023 transmission planning process. The detailed portfolios are available at the CPUC website.<sup>53</sup>

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 Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	5,490	11,889	17,379	12,068	28,686	40,754
Wind – In State	2,533	499	3,032	2,697	546	3,244
Wind – Out-of-State (Existing TX)	610	-	610	610	-	610
Wind – Out-of-State (New TX)	1,500	-	1,500	4,828	-	4,828
Wind - Offshore	1,588	120	1,708	4,587	120	4,707
Li Battery	13,564	-	13,564	28,402	-	28,402
Geothermal	1,159	-	1,159	1,794	-	1,794
Long Duration Energy Storage (LDES)	1,000	-	1,000	2,000	-	2,000
Biomass/Biogass	134	-	134	134	-	134
Distributed Solar	125	-	125	125	-	125
<b>Total</b>	<b>27,703</b>	<b>12,508</b>	<b>40,211</b>	<b>57,246</b>	<b>29,352</b>	<b>86,598</b>

#### 3.4.1 Mapping of portfolio resources to transmission substations

The portfolios that RESOLVE<sup>54</sup> 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*<sup>55</sup> with further refinements as described in the CPUC staff report entitled *Modeling Assumptions for the 2022-2023 Transmission Planning Process*.<sup>56</sup> The detailed documentation of the busbar mapping inputs is discussed in Appendix F. Figure 3.4-1 illustrates the interconnection planning areas that the resources have been mapped to, based upon the CPUC busbar mapping workbooks below, with the total resources in both the base and sensitivity portfolios.

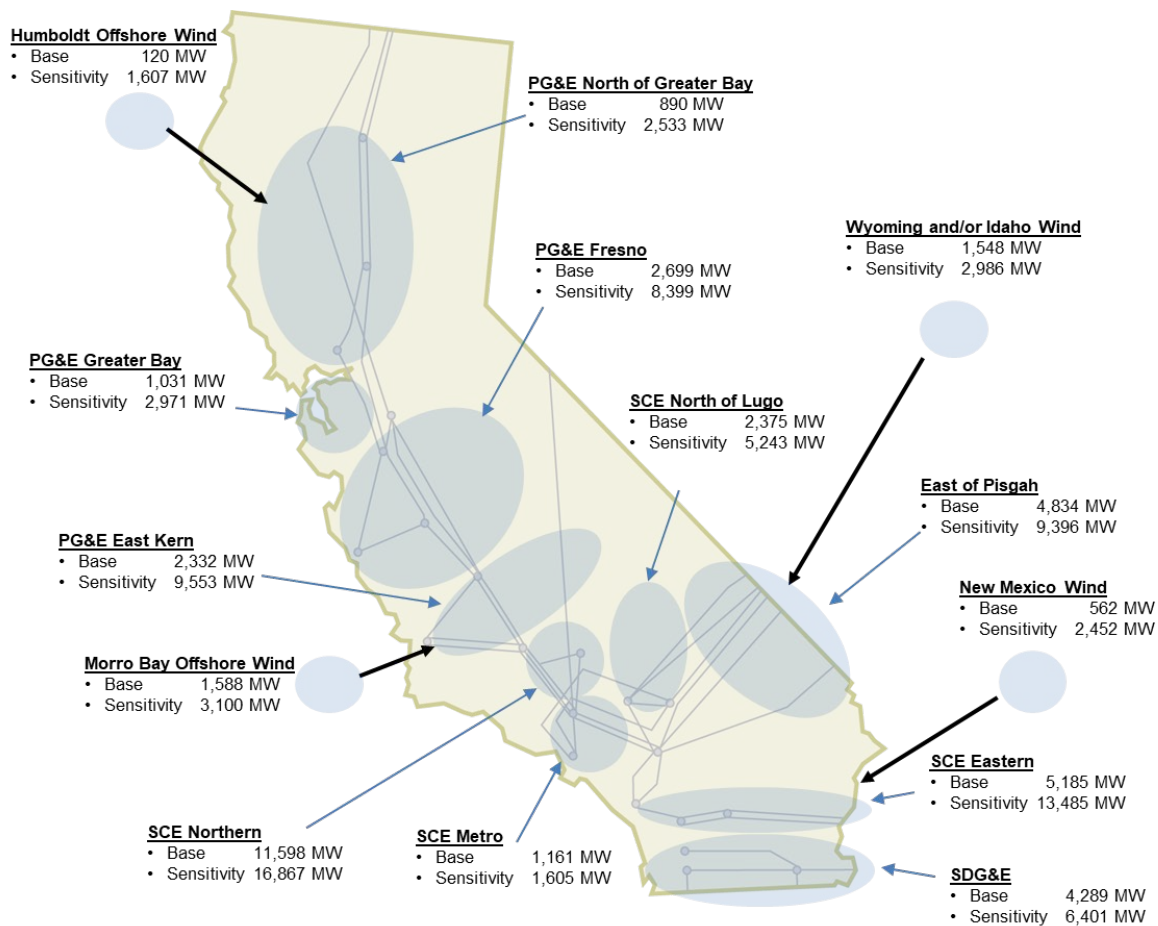
<sup>53</sup> <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials>

<sup>54</sup> Is the resource optimization model that the CPUC uses to develop resource portfolios.

<sup>55</sup> [https://files.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%20the%20TPP\\_V2021\\_12\\_21.pdf](https://files.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%20the%20TPP_V2021_12_21.pdf)

<sup>56</sup> <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF>

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



### 3.5 Transmission Interconnection Zone Assessments

The on-peak and off-peak deliverability assessments have been conducted for each of the transmission interconnection zones to determine where constraints are on the transmission system limiting deliverability of the portfolio base and sensitivity resource. The detailed analysis of the policy assessment is included in Appendix F. Transmission mitigation has been recommended to address the constraints so resources in the portfolio can be deliverable.

The ISO then conducts its technical and economic evaluations of the alternatives identified by the ISO or by stakeholders, to select the most effective and efficient recommendation. Details of the technical assessments and comparisons of alternatives are provided in Appendix F.

The following section identifies the recommended policy-driven projects that are recommended for approval. In total, the policy assessment has identified 21 new policy-driven projects required in this transmission planning cycle for a total estimated cost of \$5.53 billion.

### 3.5.1 PG&E Greater Bay and North of Greater Bay Interconnection Area

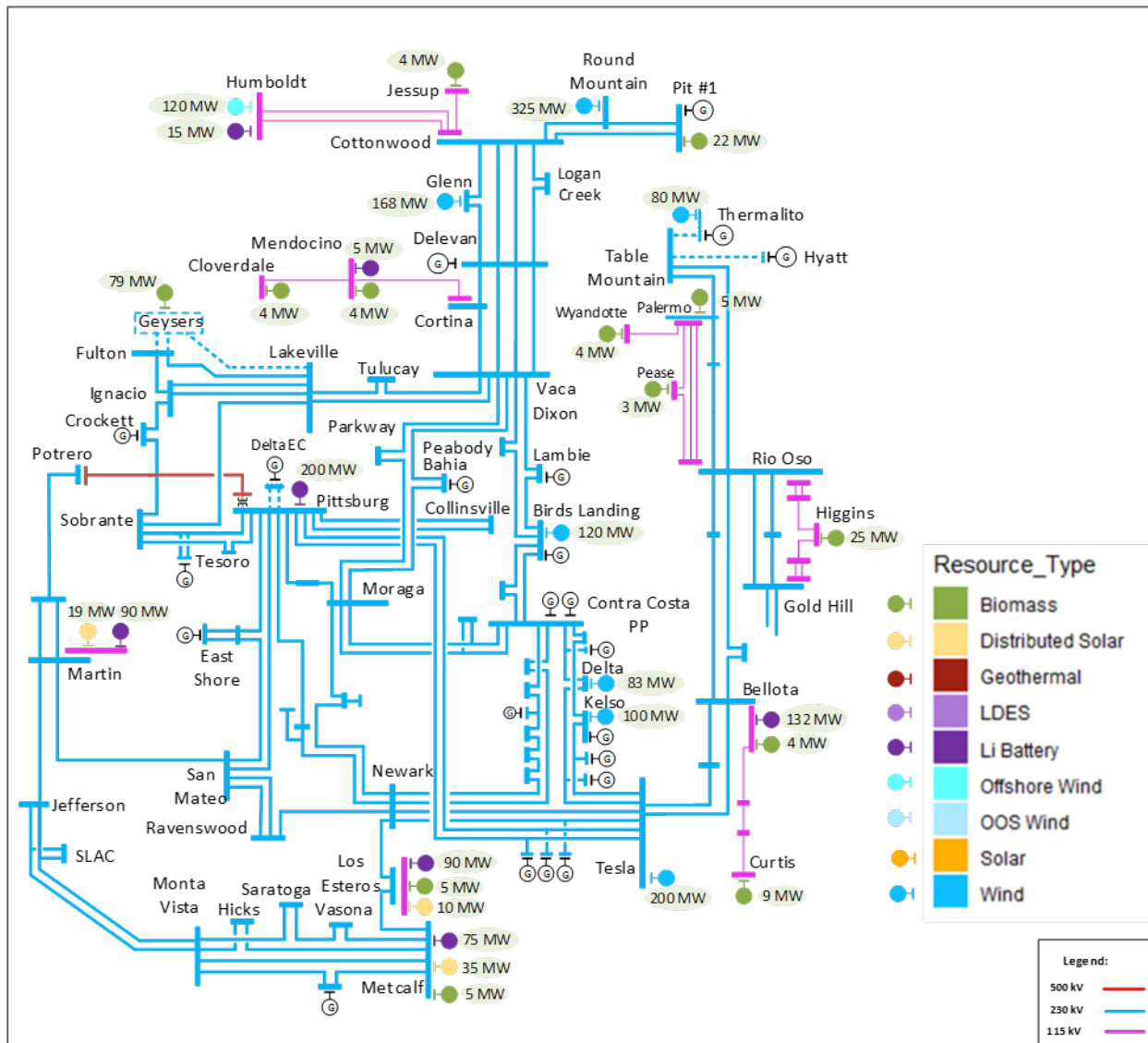
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Bay and North of Greater Bay interconnection area are listed in Table 3.5-1. The portfolios in the interconnection area are comprised 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 Greater Bay and 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	-	-	-	344	1,512	1,856
Wind – In State	577	499	1,076	626	546	1,172
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	-	120	120	1,487	120	1,607
Li Battery	607	-	607	2,198	-	2,198
Geothermal	79	-	79	119	-	119
Long Duration Energy Storage (LDES)	-	-	-	-	-	-
Biomass/Biogas	95	-	95	95	-	95
Distributed Solar	64	-	64	64	-	64
<b>Total</b>	<b>1,422</b>	<b>619</b>	<b>2,041</b>	<b>4,933</b>	<b>2,178</b>	<b>7,111</b>

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

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



**On-Peak Deliverability Assessment**

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

Table 3.5-2: Greater Bay and 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
Collinsville – Pittsburg E 230 kV Lines	Base	40	0	0	1,342	Reduce the overall series compensation on the Table Mountain-Vaca-Collinsville-Tesla 500 kV path.
	Sensitivity	1,527	0	0	2,629	
Cloverdale – Eagle Rock 115 kV Line	Base	79	0	41	38	Portfolio resource to be moved to higher kV level
	Sensitivity	0	0	0	264	
Eagle Rock- Fulton-Silverado 115 kV Line	Base	133	5	114	24	Continue to monitor
	Sensitivity	-	-	-	-	None required
Humboldt Bay Area 60 kV	Base	0	15	0	71	Garberville Area Reinforcement reliability project recommended for approval in this cycle
	Sensitivity	0	15	0	240	
Cortina No. 4 60 kV Line	Base	50	0	42	8	Portfolio resource to be moved to higher kV level
	Sensitivity	-	-	-	-	None required

Based on the constraints identified in Table 3.5-2, there are no policy-driven upgrades identified in the Greater Bay and the North of Greater Bay interconnection planning areas. To mitigate the Collinsville-Pittsburg constraint, it is recommended to reduce the overall series compensation on the Table Mountain-Vaca-Collinsville-Tesla 500 kV path. The ISO continue to will work with PG&E for feasibility and determination of the most effective series cap arrangement for the 500 kV path. For the Humboldt Bay Area 60 kV constraint, the reliability-driven project identified in Chapter 2 as the Garberville Area Reinforcement project will mitigate the identified constraint.

The constraints identified in Table 3.5-3 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle. For the North Dublin-Vinyard 230 kV constraint, the reliability-driven project identified in Chapter 2 as the Lone Tree – Cayetano – Newark Corridor Series Compensation project will mitigate the identified constraint.



Table 3.5-3: Greater Bay and North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
East Shore – San Mateo 230 kV line	Sensitivity	828	400	781	446	Reduce the overall series compensation on the Table Mountain-Vaca-Collinsville-Tesla 500 kV.
North Dublin – Vineyard 230 kV line	Sensitivity	0	150	121	28	Contra Costa - Lone Tree Series compensation TPP project
Lincoln - Pleasant Grove 115 kV Line	Sensitivity	0	127	5	122	Possible RAS or Reconductor
Stanislaus-Melones-Manteca 115 kV Line No.1	Sensitivity	0	287	201	86	Reconductor
Drum – Higgins 115 kV	Sensitivity	0	0	0	34	Reconductor

**Off-Peak Deliverability Assessment**

In the off-peak deliverability assessment of the Greater Bay and North of Greater Bay interconnection there were no constraints identified for the base portfolios. The constraints that were observed in the sensitivity portfolio only are listed in Table 3.5-4. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-4: Greater Bay and North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Midway-Gates 500 kV line	Sensitivity	6,964	2,279	1,748	Portfolio energy storage in charging mode
Moss Landing-Los Banos 500 kV line	Sensitivity	13,284	5,466	4,729	Portfolio energy storage in charging mode
Belridge J-Pumpjack Tp	Sensitivity	55	55	26	Portfolio energy storage in charging mode
Borden-Storey #1/#2 230 kV	Sensitivity	4,264	2,168	2,683	Portfolio energy storage in charging mode
Quinto-Los Banos 230 kV line	Sensitivity	13,394	5,462	4,082	Portfolio energy storage in charging mode.
Gates-Arco 230 kV line	Sensitivity	2,751	1,674	272	Portfolio energy storage in charging mode
Los Banos-Panoche #2 230 kV	Sensitivity	1,569	880	1,040	Portfolio energy storage in charging mode

Constraint	Portfolio	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Schindler-Coalinga #2 70 kV Line (Schindler-Paige Section)	Sensitivity	150	75	93	Portfolio energy storage in charging mode
Tesla-Westley 230 kV line	Sensitivity	5,631	2,839	1,503	Portfolio energy storage in charging mode
Westley-Q1244 SS 230 kV line	Sensitivity	13,394	5,462	3,714	Portfolio energy storage in charging mode
Wilson-Dairyland 115 kV Line	Sensitivity	100	75	62	Portfolio energy storage in charging mode
Arco-Midway 230 kV line	Sensitivity	586	318	181	Portfolio energy storage in charging mode
Gregg - Mustang 230 kV line	Sensitivity	8,891	3,099	1,485	Reconductor if economic
Gates - Manning 500 kV line	Sensitivity	9,604	3,588	4,888	Reconductor or new line if economic.
Panoche 115 kV Area	Sensitivity	150	85	104	Reconductor or new line if economic.
Panoche 230 kV Area	Sensitivity	3,100	1,352	2,361	Reconductor or new line if economic.
Panoche 70 kV Area	Sensitivity	150	75	104	Reconductor or new line if economic.

### 3.5.2 PG&E Greater Fresno Interconnection Area

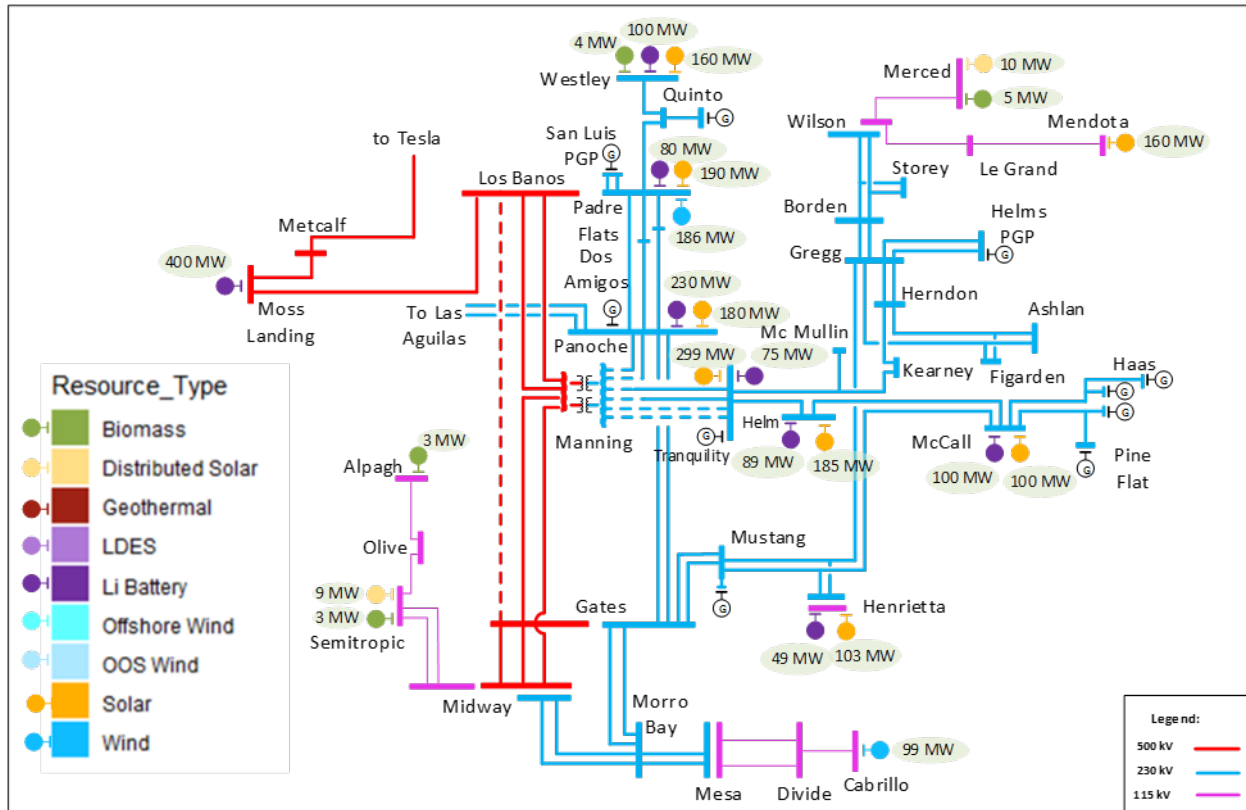
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Fresno interconnection area are listed in Table 3.5-5. The portfolios are comprised of solar, wind (in-state), battery storage, biomass/biogass 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 3.5-5: 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	447	930	1,377	1,527	3,530	5,057
Wind – In State	285	-	285	285	-	285
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Li Battery	1,003	-	1,003	3,023	-	3,023
Geothermal	-	-	-	-	-	-
Long Duration Energy Storage (LDES)	-	-	-	-	-	-
Biomass/Biogass	15	-	15	15	-	15
Distributed Solar	19	-	19	19	-	19
<b>Total</b>	<b>1,769</b>	<b>930</b>	<b>2,699</b>	<b>4,869</b>	<b>3,530</b>	<b>8,399</b>

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 3.5-2.

Figure 3.5-2: 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 3.5-6.

Table 3.5-6: 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
Borden - Storey #1 and #2 230 kV lines	Base	18	139	0	581	Borden-Storey 230 kV lines reconductoring project
	Sensitivity	79	2,168	0	2,689	
Henrietta 230/115 kV Bank 3	Base	0	0	0	191	Henrietta 230/115 kV Bank 3 replacement project
	Sensitivity	0	0	0	300	

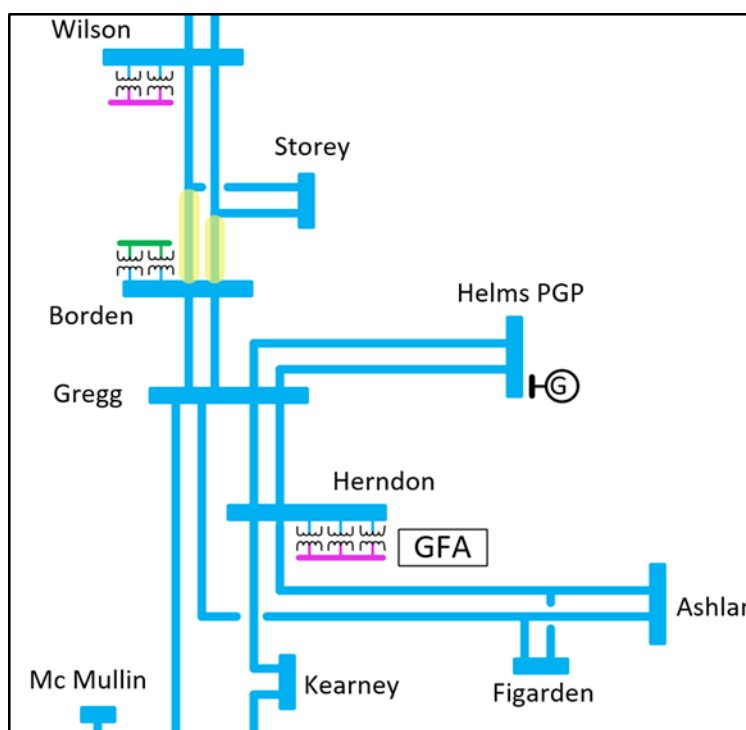
Two policy-driven projects are recommended to mitigate the constraints in the Greater Fresno interconnection area.

#### Borden-Storey 230 kV 1 and 2 Line Reconductoring

To address Borden-Storey 1 and 2 230 kV line constraint identified in the base and sensitivity portfolios the ISO recommends the approval of reconductoring the Borden – Storey 230 kV 1 and 2 Line Reconductoring project as illustrated in Figure 3.5-3. The estimated project cost is between \$25 million and \$50 million and is expected to be in-service before 2032.

RAS was considered as an alternative but was not selected as it does not meet the RAS standards and guidelines in ISO Planning Standards. Series compensation was also considered as an alternative but was not selected due to the size of compensation that would be required to mitigate the constraint.

Figure 3.5-3: Borden-Storey 230 kV 1 and 2 Lines Reconductoring Project

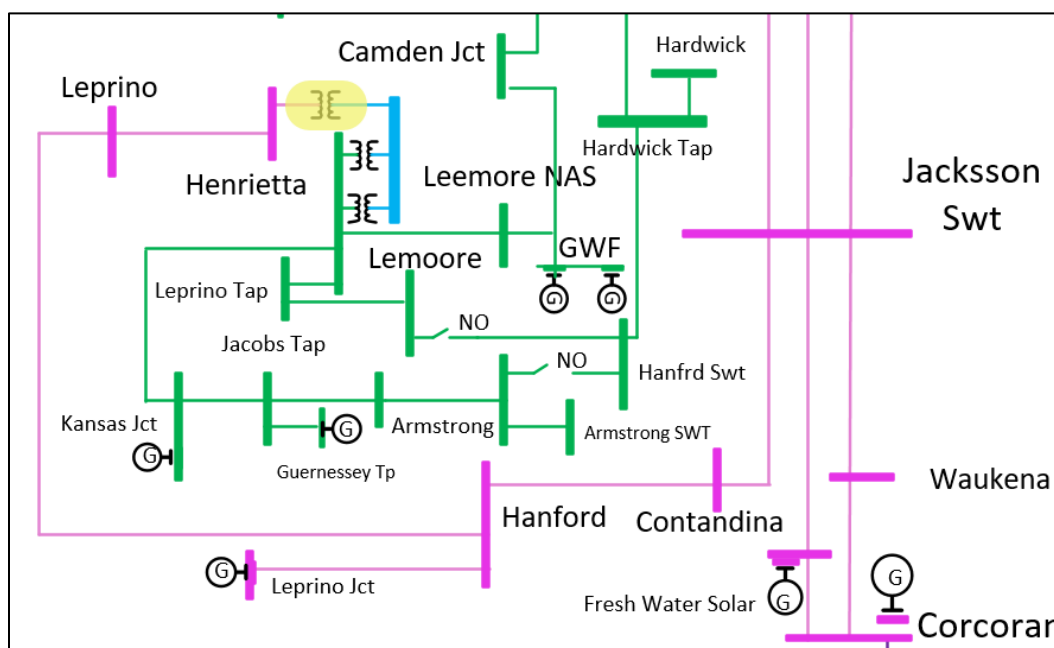


#### Henrietta 230/115 kV Bank 3 Replacement

To address Henrietta 230/115 kV Bank 3 constraint identified in the base and sensitivity portfolios the ISO recommends the approval of Henrietta 230/115 kV Bank 3 Replacement project as illustrated in Figure 3.5-4. The estimated project cost is between \$12 million and \$20 million and is expected to be in-service before 2032.

RAS was considered as an alternative but was not selected as it does not meet the RAS standards and guidelines in the ISO Planning Standards.

Figure 3.5-4: Henrietta 230/115 kV Bank 3 Replacement Project



The constraints identified in Table 3.5-7 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-7: PG&E Greater Fresno Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
Las Aguilas – Moss Landing 230 kV line	Sensitivity	3150	880	3155	875	Re-evaluate previously approved series reactor on the Moss Landing – Las Aguilas 230 kV line
McCall 115/230 kV Bank 1	Sensitivity	167	509	484	193	RAS or Bank replacement
Gates-Gregg 230 kV Line	Sensitivity	3948	810	3792	1774	Reconductor Line
Melones-Cottle 230 kV line	Sensitivity	18	335	263	90	Reconductor Line
Barton-Airways-Sanger 115 kV line	Sensitivity	0	509	0	940	Reconductor Line

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
Herndon – Woodward 115 kV line	Sensitivity	3	260	1	262	Reconductor Line
GWF-Kingsburg 115 kV Line	Sensitivity	25	54	0	626	Reconductor Line
Corcoran-Smyrna (Alpaugh-Smyrna) 115 kV line	Sensitivity	23	175	153	45	Reconductor Line

**Off-Peak Deliverability Assessment**

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the Greater Fresno interconnection areas along with the recommended mitigation plans are identified in Table 3.5-8.

Table 3.5-8: PG&E Greater Fresno 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	Curtailement MW w/o mitigation	Mitigation
Kettlemen – Gates 70 kV line	Base	-	10	1	None required
	Sensitivity	-	-	-	
Warnerville – Willison 230 kV Line	Base	398	228	1,420	
	Sensitivity	1,698	1,098	831	
Los Banos 500 kV	Base	3,404	932	2,786	
	Sensitivity	11,858	4,877	7,517	

The constraints identified in Table 3.5-9 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-9: PG&amp;E Greater Fresno Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Midway-Gates 500 kV line	Sensitivity	6,964	2,279	1,748	Portfolio energy storage in charging mode
Moss Landing-Los Banos 500 kV line	Sensitivity	13,284	5,466	4,729	Portfolio energy storage in charging mode
Belridge J-Pumpjack Tp	Sensitivity	55	55	26	Portfolio energy storage in charging mode
Borden-Storey #1/#2 230 kV	Sensitivity	4,264	2,168	2,683	Portfolio energy storage in charging mode
Quinto-Los Banos 230 kV line	Sensitivity	13,394	5,462	4,082	Portfolio energy storage in charging mode.
Gates-Arco 230 kV line	Sensitivity	2,751	1,674	272	Portfolio energy storage in charging mode
Los Banos-Panoche #2 230 kV	Sensitivity	1,569	880	1,040	Portfolio energy storage in charging mode
Schindler-Coalinga #2 70 kV Line (Schindler-Paige Section)	Sensitivity	150	75	93	Portfolio energy storage in charging mode
Tesla-Westley 230 kV line	Sensitivity	5,631	2,839	1,503	Portfolio energy storage in charging mode
Westley-Q1244 SS 230 kV line	Sensitivity	13,394	5,462	3,714	Portfolio energy storage in charging mode
Wilson-Dairyland 115 kV Line	Sensitivity	100	75	62	Portfolio energy storage in charging mode
Arco-Midway 230 kV line	Sensitivity	586	318	181	Portfolio energy storage in charging mode
Gregg - Mustang 230 kV line	Sensitivity	8,891	3,099	1,485	Reconductor if economic
Gates - Manning 500 kV line	Sensitivity	9,604	3,588	4,888	Reconductor or new line if economic.
Panoche 115 kV Area	Sensitivity	150	85	104	Reconductor or new line if economic.
Panoche 230 kV Area	Sensitivity	3,100	1,352	2,361	Reconductor or new line if economic.
Panoche 70 kV Area	Sensitivity	150	75	104	Reconductor or new line if economic.

### 3.5.3 PG&E East 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 East Kern interconnection area are listed in Table 3.5-10. The portfolios in the interconnect area are comprised of solar, wind (in-state and offshore), battery storage, biomass/biogass 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.

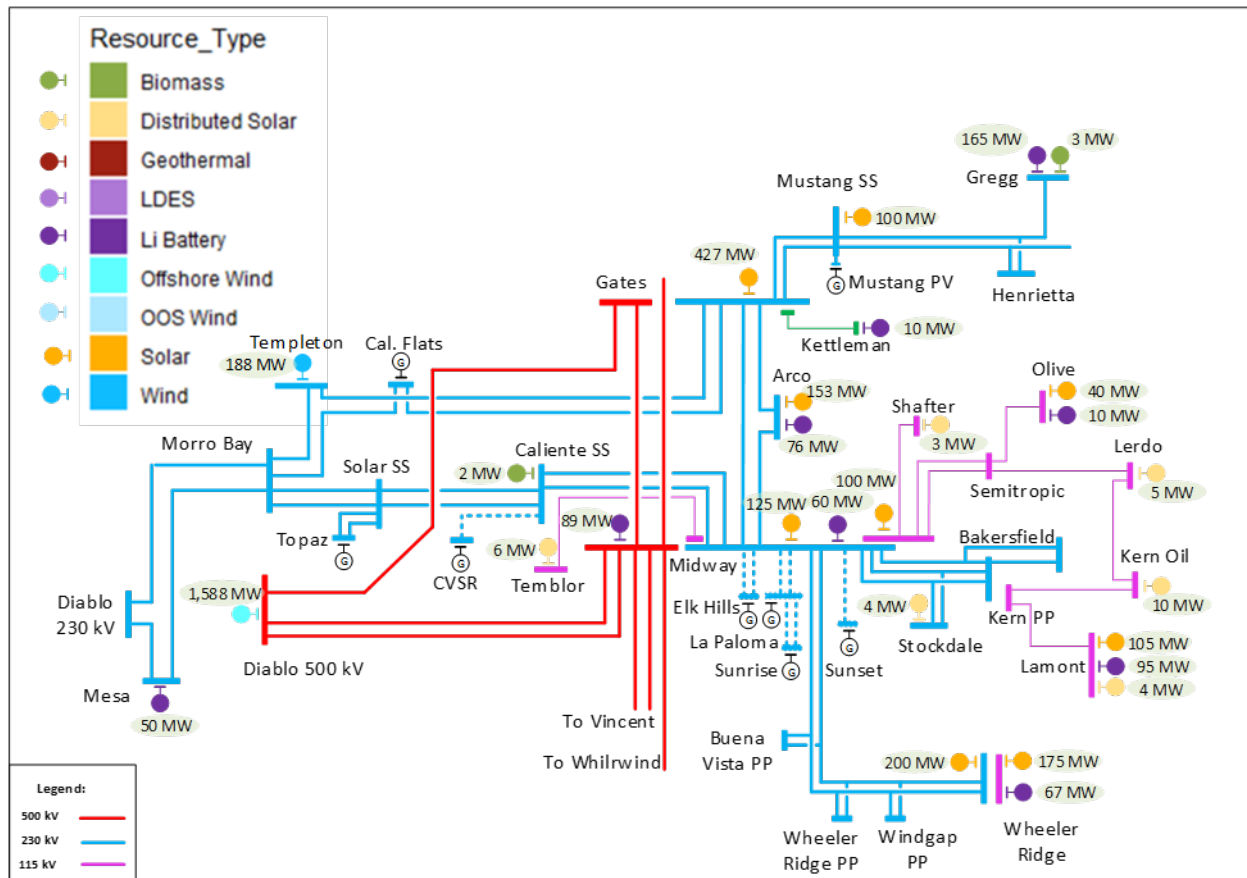
Table 3.5-10: PG&E East Kern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	575	850	1,425	2,008	3,909	5,917
Wind – In State	248	-	248	188	-	248
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	1,588	-	1,588	3,100	-	3,100
Li Battery	622	-	622	3,052	-	3,052
Geothermal	-	-	-	-	-	-
Long Duration Energy Storage (LDES)	-	-	-	300	-	300
Biomass/Biogass	5	-	5	5	-	5
Distributed Solar	32	-	32	32	-	32
<b>Total</b>	<b>3,070</b>	<b>850</b>	<b>3,920</b>	<b>8,685</b>	<b>3,909</b>	<b>12,653</b>

The resources as identified in the CPUC busbar mapping for the PG&E East Kern interconnection area are illustrated on the single-line diagram in Figure 3.5-5.



Figure 3.5-5: PG&E East Kern Interconnection Area – Mapped Base Portfolio



**On-Peak Deliverability Assessment**

The constraints identified in the on-peak deliverability assessment of the East Kern interconnection area along with the recommended mitigation plans are identified in Table 3.5-11.

Table 3.5-11: PG&E East Kern Interconnection Area On-Peak Deliverability Constraints in Base and Sensivity 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	67	53	14	Wheeler Ridge Junction previously approved reliability project currently on hold recommended to proceed in Chapter 2
	Sensitivity	70	117	103	84	
Arco-Cholame 70 kV Line	Base	60	0	31	14	Portfolio resource to be moved to higher kV level
	Sensitivity	-	-	-	-	

Based on the constraints identified in Table 3.5-11, there are no policy-driven upgrades identified in the East Kern interconnection planning areas. For the Wheeler 115/70 kV Bank 2 constraint, the previously approved reliability-driven project identified in Chapter 2 as the Wheeler Ridge Junction project that is currently on hold and recommended to proceed with a scope change will mitigate the identified constraint.

The constraints identified in Table 3.5-12 were only observed in the sensitivity portfolio and not in the base portfolio. Potential mitigation has been identified for further assessment in the 2023-2024 planning cycle.

Table 3.5-12: PG&E East Kern Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Portfolio	Generic Portfolio MW behind the constraint	Generic Battery storage portfolio MW behind the constraint	Deliverable Generic Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Potential Mitigation
Semitropic-Famoso 115 kV line	Sensitivity	35	250	81	204	Reconductor Line
Tembler-San Luis Obispo 115 kV line	Sensitivity	6	55	0	84	Reconductor Line
Semitropic-Wasco 70 kV line	Sensitivity	12	220	154	78	Reconductor Line
Tembler-PSE MCKJ 115 kV line	Sensitivity	106	55	33	22	Reconductor Line

### **Off-Peak Deliverability Assessment**

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the East Kern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-13.

Table 3.5-13: PG&E East Kern 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	Curtailed MW w/o mitigation	Mitigation
Kern-TEvis-Stockdale 1 and 2 115 kV	Base	109	95	57	Charging mode of Storage
	Sensitivity	304	135	179	Continue to assess in next planning cycle

### 3.5.4 East of Pisgah Interconnection Area

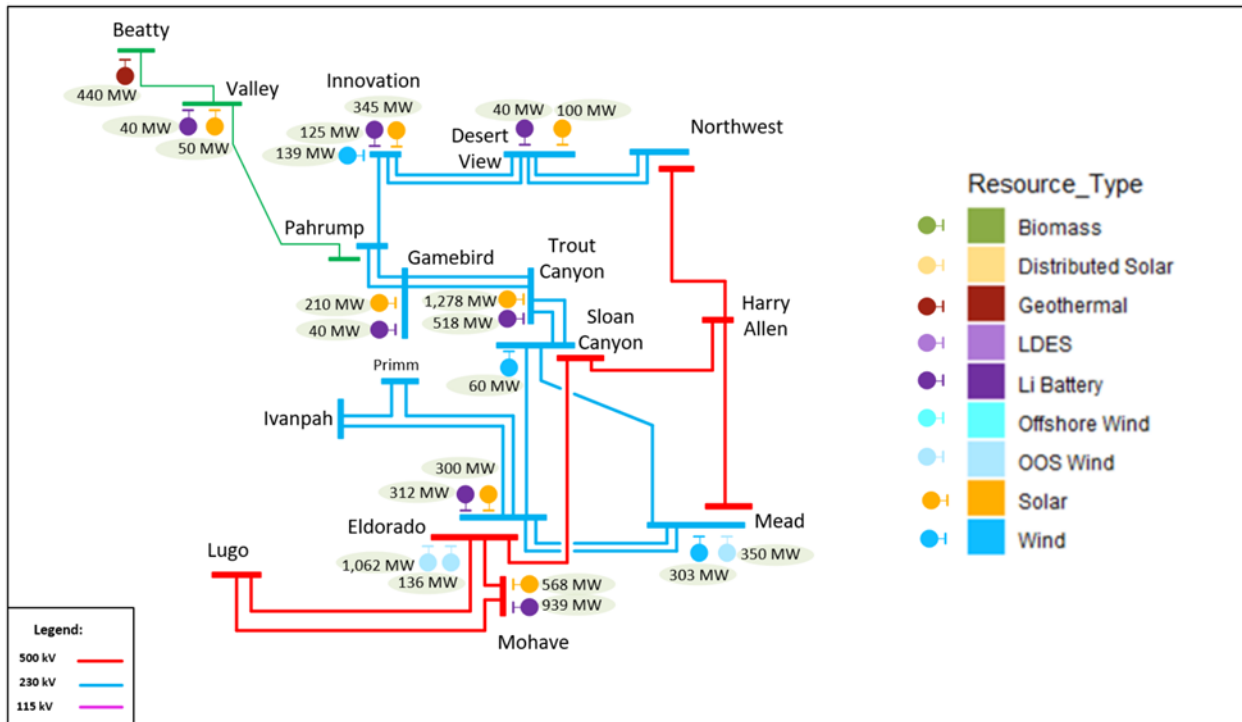
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the East of Pisgah interconnection area are listed in Table 3.5-14. The portfolios in the interconnection area are comprised of solar, wind (in-state 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 3.5-14: 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	770	1,946	<b>2,716</b>	1,320	4,196	<b>5,516</b>
Wind – In State	442	-	<b>442</b>	442	0	<b>442</b>
Wind – Out-of-State (Existing TX)	486	-	<b>486</b>	486	0	<b>486</b>
Wind – Out-of-State (New TX)	1,062	-	<b>1,062</b>	2,500	0	<b>2,500</b>
Wind – Offshore	-	-	<b>-</b>	0	0	<b>0</b>
Li Battery	1,236	-	<b>1,236</b>	2,711	0	<b>2,711</b>
Geothermal	440	-	<b>440</b>	727	0	<b>727</b>
Long Duration Energy Storage (LDES)	-	-	<b>-</b>	0	0	<b>0</b>
Biomass/Biogass	-	-	<b>-</b>	0	0	<b>0</b>
Distributed Solar	-	-	<b>-</b>	0	0	<b>0</b>
<b>Total</b>	<b>4,436</b>	<b>1,946</b>	<b>6,382</b>	<b>8,186</b>	<b>4,196</b>	<b>12,382</b>

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 3.5-6.

Figure 3.5-6: East of Pisgah Interconnection Area – Mapped<sup>57</sup> 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 3.5-15.

Table 3.5-15: 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
VEA 138 kV System	Base	480	40	120	360	Beatty 230 kV Project
	Sensitivity	1,330	590	430	900	
GLW 230 kV System	Base	2,253	635	2,034	219	Innovation RAS
	Sensitivity	4,102	2,022	2,456	1,646	Trout Canyon – Sloan Canyon 500 kV upgrade
Lugo-Victorville 500 kV	Base	6,895	2,246	6,500	395	Expand the Lugo – Victorville RAS
	Sensitivity	16,374	6,789	11,380	4,994	Trout Canyon – Lugo 500 kV line; or Eldorado – Lugo 500 kV 2 Line

<sup>57</sup> Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the East of Pisgah Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

To mitigate the VEA 138 kV and the GLW 230 kV, the ISO is recommending one new transmission project and to modify the scope of one previously approved project as follows.

#### GLW/VEA Area Upgrades – Revised Scope

To mitigate the GLW 230 kV System constraint, the ISO is recommending to re-scope the previously approved GLW/VEA Area Upgrades project that was approved in the 2021-2022 Transmission Plan. The scope of the previously approved project is as follows.

- Rebuild Northwest – Desert View, Pahrump – Gamebird, Gamebird – Trout Canyon and Trout Canyon – Sloan Canyon 230 kV to double circuit lines;
- Install a second Innovation – Desert View 230 kV line;
- Rebuild Innovation – Pahrump 230 kV line;
- Add a 500/230 kV transformer at Sloan Canyon and loop in the Harry Allen – Eldorado 500 kV line;
- Install a 138 kV phase shifter at Innovation on the planned tie-line to NVE; and
- Upgrade VEA’s 230/138 kV Amargosa transformer.

The recommended revised scope of the GLW/VEA Area Upgrades project scope is as follows:

- Install a new Trout Canyon 500 kV bus and three 500/230 kV transformers at Trout Canyon;
- Rebuild Trout Canyon – Sloan Canyon 230 kV DCTL lines to 500 kV DCTL lines;
- Rebuild Northwest – Desert View, Pahrump – Gamebird and Gamebird – Trout Canyon 230 kV to double circuit lines;
- Rebuild Innovation – Desert View 230 kV No.1 line with a normal rating of 1,154 MVA and an emergency rating of 1,578 MVA;
- Install a second Innovation – Desert View 230 kV line;
- Rebuild Innovation – Pahrump 230 kV line;
- Add a 500/230 kV transformer at Sloan Canyon and loop in the Harry Allen – Eldorado 500 kV line;
- Install a 138 kV phase shifter at Innovation on the planned tie-line to NVE; and
- Upgrade VEA’s 230/138 kV Amargosa transformer.

The estimated cost of the GLW/VEA Area Upgrades project as approved in the 2021-2022 Transmission Plan was \$278 million. The estimated cost of the increased scope is \$228 million for a total cost of the recommended re-scoped project of \$506 million. The in-service date for the re-scoped GLW/VEA Area Upgrades project is 2027.

Beatty 230 kV Project

To mitigate the VEA 138 kV constraint the ISO recommends approval of the Beatty 230 kV project. The recommended Beatty 230 kV Project scope includes:

- Build a new Johnnie Corner 230 kV station and loop into the Pahrump – Innovation 230 kV line;
- Expand existing Beatty, Lathrop, Valley Switch and Vista 138 kV substations to 230 kV substations;
- Build 32 miles Beatty – Lathrop 230 kV line next to the existing 138 kV line in an adjacent ROW;
- Build 30 miles Johnnie Corner – Valley Switch – Lathrop 230 kV DCTL lines next to the existing 138 kV line in an adjacent ROW; and
- Install a second Johnnie Corner – Innovation and Johnnie Corner – Vista – Pahrump 230 kV line on the Innovation – Pahrump double circuit tower approved in 2021/22 TPP.

The 230 kV line is to be routed parallel to the existing 138 kV lines from Pahrump to Beatty. The 138 kV system is considered to be aging infrastructure nearing the end of life. The 230 kV parallel to the 138 kV lines and stations will allow for when the 138 kV facilities reach the end of life so they can be retired and the load can be served from the parallel 230 kV system. This will defer the costs of converting the stations to 230 kV until they are required. The cost estimate of the Beatty 230 kV Project is \$155 million in 2022 dollars with an in-service date of 2027.

Figure 3.5-7: GLW/VEA Transmission System with 2021-2022 Transmission Plan Approved Project

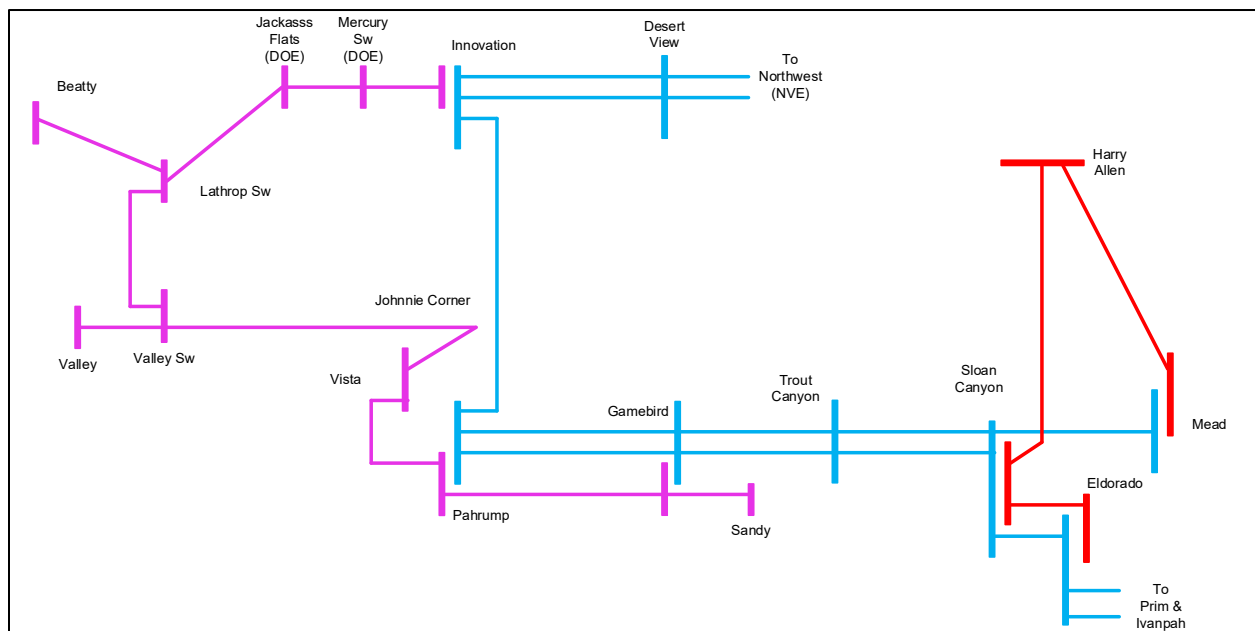
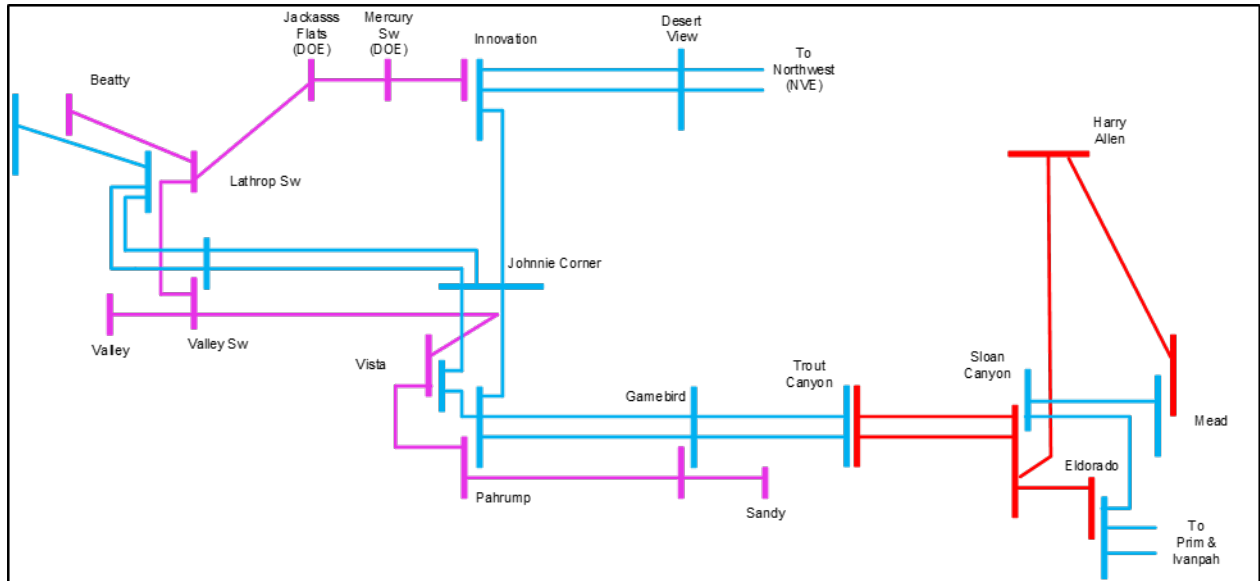
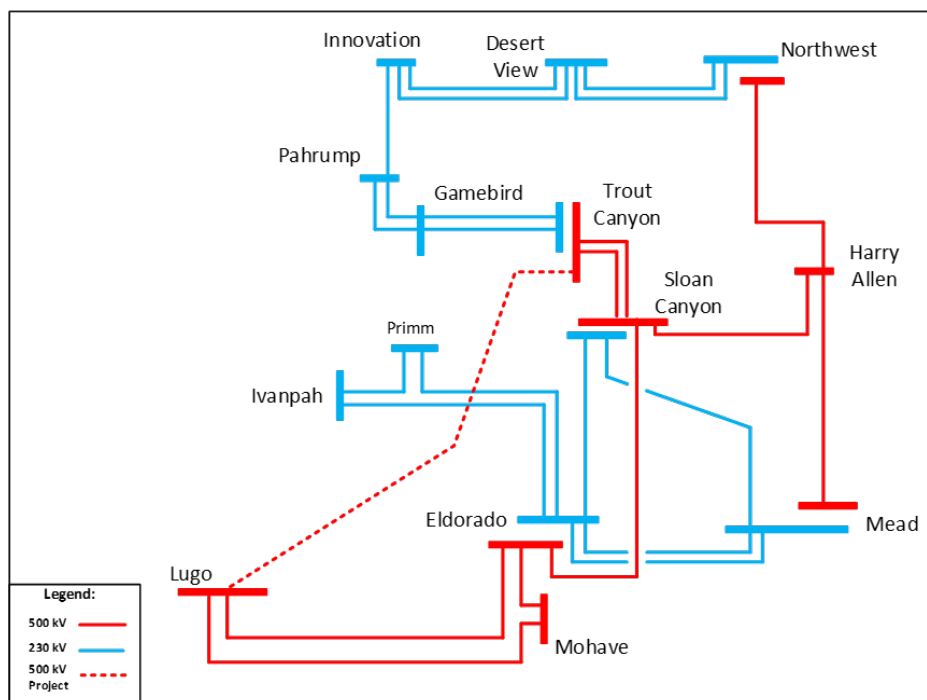


Figure 3.5-8: GLW/VEA Transmission System with Recommended Re-scoping of the GLW/VEA Area Upgrades Project and the Beatty 230 kV Projected



The Lugo – Victorville 500 kV area constraint was identified requiring mitigation in the base portfolio as well as in the sensitivity portfolio. The ISO was intending on recommending approval of the Trout Canyon – Lugo 500 kV Line based upon the alternative analysis to mitigate the constraint.

Figure F.3.5-9: Trout Canyon – Lugo 500 kV Line One-line Diagram



The ISO considered the alternatives of either a Trout Canyon – Lugo 500 kV line and Eldorado – Lugo 500 kV No. 2 line that would mitigate the identified Lugo – Victorville 500 kV area constraints in the sensitivity portfolio analysis. The cost estimate of the Trout Canyon – Lugo 500 kV line project is approximately \$1.5 to 2 billion while the cost estimate of the Eldorado – Lugo 500 kV No.2 line project is approximately \$2.1 billion. With Eldorado – Lugo 500 kV No. 2 line option, there is a need to build a second Sloan Canyon – Eldorado 500 kV line which has a cost estimate of \$14 million, and includes an increase in line crossings in a very congested area. Besides mitigating the Lugo – Victorville 500 kV area constraints, the Trout Canyon – Lugo 500 kV line would improve the deliverability of GLW and VEA area resources and mitigate GLW 230 kV area constraints as indicated in section F.10.2.1. It would also provide opportunity for future transmission expansion in the area and to build transmission access to the geothermal resources in Nevada.

The ISO received a letter from Lotus Infrastructure Partners on April 25, 2023<sup>58</sup> identifying an alternative that the ISO will need to take additional time to assess. The assessment will need to determine how much capacity of the estimated 2,200 MW capacity increase identified would be available to the CAISO and the technical performance of the alternative to meet the needs to address the identified constraint. The ISO will undertake the assessment and will bring forward a recommended mitigation plan for the Lugo – Victorville 500 kV area constraint as either an extension of the 2022-2023 transmission planning process or in the next planning cycle.

### **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 3.5-16.

Table 3.5-16: 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
Eldorado-McCullough 500 kV	Base	6,896	2,467	0	None required
	Sensitivity	8,757	2,605	1,807	Trout Canyon – Lugo 500 kV line; or Eldorado – Lugo 500 kV 2 Line

### **3.5.5 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 3.5-1. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, long duration energy storage,

<sup>58</sup> <http://www.caiso.com/InitiativeDocuments/Letter-Alternative-to-Trout-Canyon-Lugo-500-kV-line-Apr242023.pdf>



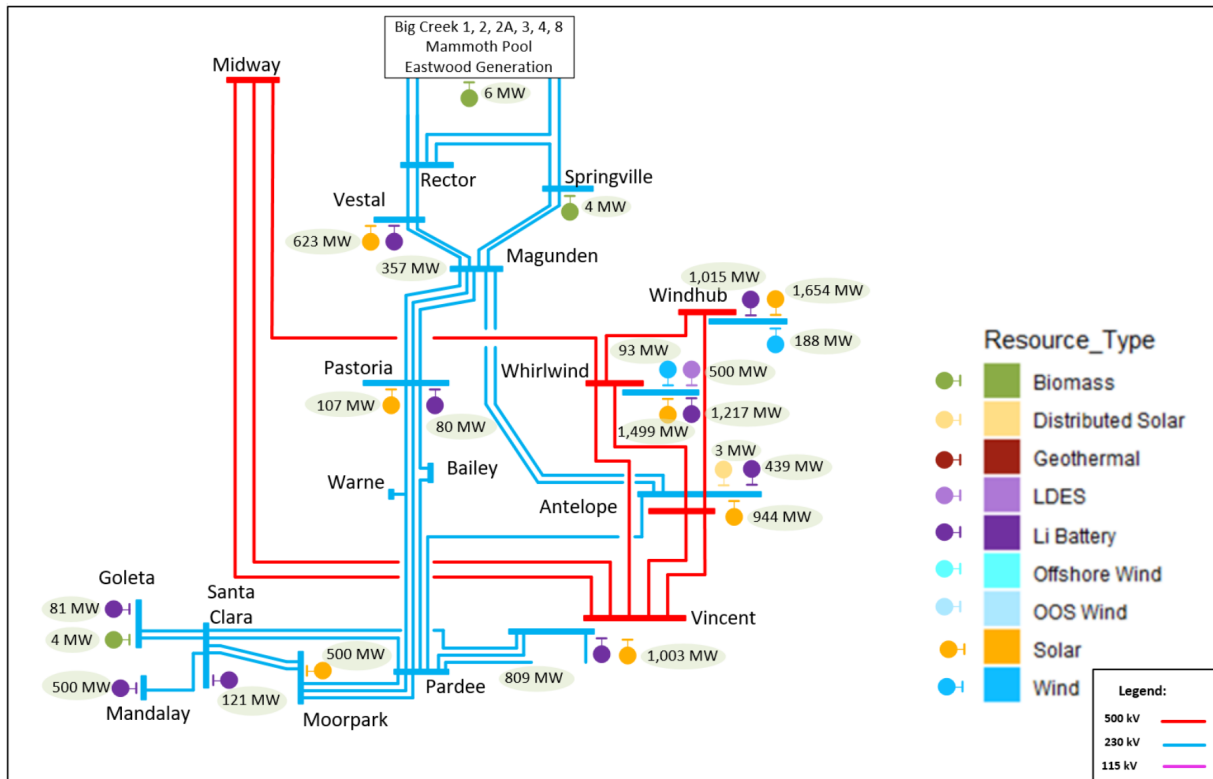
biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-17: 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	1,751	4,505	6,256	3,107	7,079	10,186
Wind – In State	275	-	275	281	-	281
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Li Battery	4,550	-	4,550	6,033	-	6,033
Geothermal	-	-	-	-	-	-
Long Duration Energy Storage (LDES)	500	-	500	500	-	500
Biomass/Biogass	14	-	14	14	-	14
Distributed Solar	3	-	3	3	-	3
<b>Total</b>	<b>7,093</b>	<b>4,505</b>	<b>11,598</b>	<b>9,987</b>	<b>7,079</b>	<b>16,867</b>

The resources as identified in the CPUC busbar mapping for the SCE Northern interconnection area are illustrated on the single-line diagram in Figure 3.5-10.

Figure 3.5-10: SCE Northern Interconnection Area – Mapped<sup>59</sup> Base Portfolio



<sup>59</sup> 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.

**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 3.5-18.

Table 3.5-18: 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 500/230 kV	Base	0	0	-	108	Planned Windhub CRAS
	Sensitivity	35	0	0	149	

**Off-Peak Deliverability Assessment**

The Off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE Northern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-19.

Table 3.5-19: SCE Northern 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	Deliverable Portfolio MW w/o mitigation	Mitigation
Windhub 500/230 kV	Base	361	361	306	Planned Windhub CRAS
	Sensitivity	1680	500	814	
Antelope-Vincent 500 kV Lines	Base	N/A	N/A	N/A	Not required
	Sensitivity	7,696	2,098	465	Charging mode of storage
Midway-Whirlwind 500 kV	Base	N/A	N/A	N/A	Not required
	Sensitivity	42,675	14,346	2,188	Charging mode of storage

**3.5.6 SCE North of Lugo Interconnection Area**

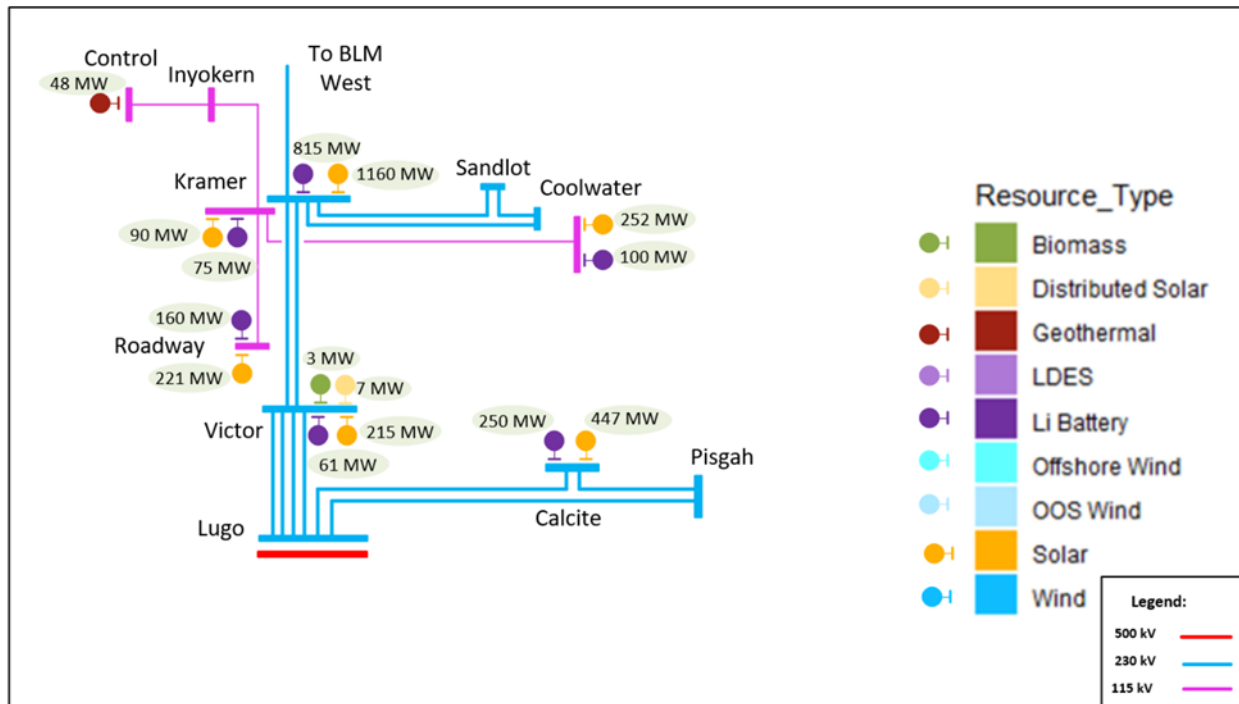
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE North of Lugo interconnection area are listed in Table 3.5-20. The portfolios in the interconnection area are comprised of solar, battery storage, geothermal, biomass/biogass 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 3.5-20: 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	385	1,071	1,456	770	2,411	3,181
Wind – In State	-	-	-	100	-	100
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	-	-	-	-	-	-
Li Battery	869	-	869	1,904	-	1,904
Geothermal	40	-	40	48	-	48
Long Duration Energy Storage (LDES)	-	-	-	-	-	-
Biomass/Biogass	3	-	3	3	-	3
Distributed Solar	7	-	7	7	-	7
<b>Total</b>	<b>1,304</b>	<b>1,071</b>	<b>2,375</b>	<b>2,962</b>	<b>2,411</b>	<b>5,243</b>

The 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 3.5-10.

Figure 3.5-11: SCE North of Lugo Interconnection Area – Mapped<sup>60</sup> Base Portfolio



<sup>60</sup> Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE North of Lugo Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

**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 3.5-21.

Table 3.5-21: 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
Lugo 500/230 kV Transformer	Base	466	400	0	944	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	1,860	1,132	821	1,092	
Lugo–Victor 230 kV 1, 2, 3 & 4	Base	164	150	0	354	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	1,191	692	843	401	
Kramer–Victor 1 & 2 – 230 kV (Voltage stability and overload)	Base	150	150	0	1,194	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	954	533	26	1,251	
Control–Silver Peak 55 kV	Base	0	0	-	38 <sup>61</sup>	Reduce MIC Expansion Request to 15 MW
	Sensitivity	0	0	-	38	
Lugo–Calcite–Pisgah 230 kV Corridor	Base	302	250	237	65	Planned Calcite area RAS
	Sensitivity	669	440	374	295	Further evaluation in 2023-2024 planning cycle

**Lugo–Victor–Kramer 230 kV Upgrade**

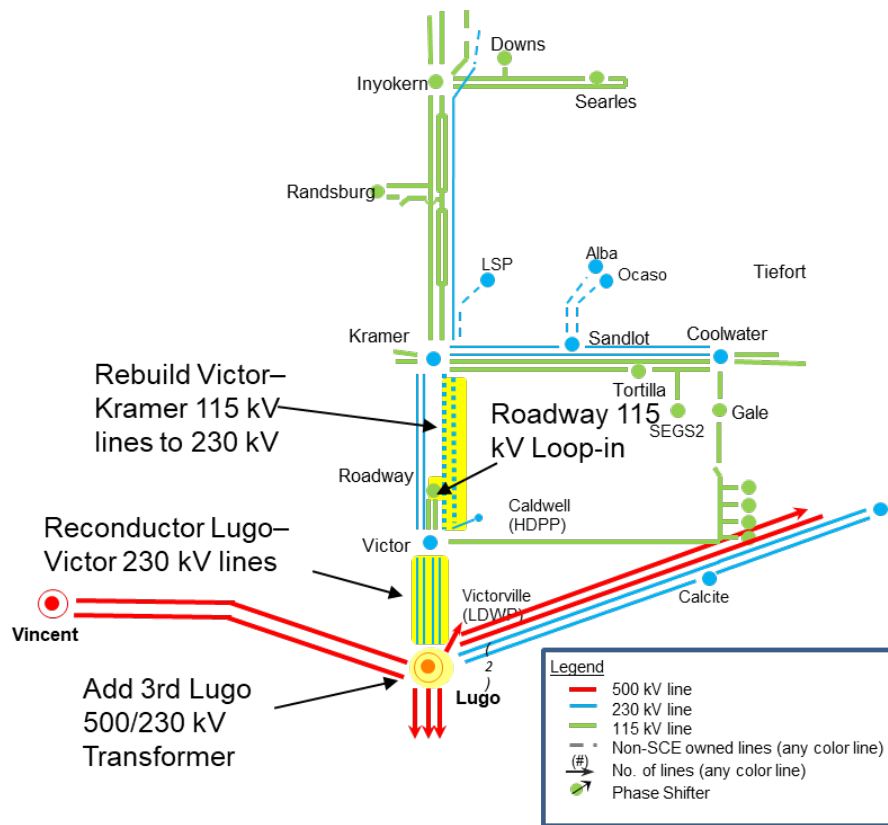
To address the Lugo 500/230 kV Transformer, Lugo–Victor 1, 2, 3 and 4 230 kV and Kramer–Victor 1 and 2 230 kV constraints and voltage instability identified in the base and sensitivity portfolios, the ISO recommends the approval of the Lugo–Victor–Kramer 230 kV Upgrade project as illustrated in Figure 3.5-12. The scope of the project is as follow:

- Add 3rd Lugo 500/230 kV Transformer;
- Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines;
- Rebuild/build Kramer–Victor 115 kV lines to 230 kV; and
- Loop the old segment of Kramer–Victor 115 kV into Roadway.

The estimated project cost is \$482 million and is expected to be in service in 2032.

<sup>61</sup> There were no resources in the portfolio behind this constraint. Per tariff Section 24.xx there was a 53 MW MIC expansion request on Silver Peak branch group.

Figure 3.5-12: Lugo–Victor–Kramer 230 kV Upgrade



The ISO had considered expanding the existing RAS in the area to mitigate the constraints, however it was determined that this was not a valid alternative per the following assessment.

- The area heavily relies on increasingly complex and overlapping RAS to ensure deliverability and reliability of in-development resources and to protect reliability of the system.
- A total of up to about 3,325 MW existing and planned resources will be connected to the NOL area RAS to mitigate deliverability and reliability constraints in the Lugo–Victor–Kramer corridor.
- The planned RAS has already gone beyond the ISO RAS guidelines ISO-G-RAS1 and ISO-G-RAS3 in the ISO Planning Standards, which state that a RAS should be designed for simple operation to trip a fixed set of generation under specific contingencies and the total net amount of generation tripped by a RAS should not exceed 1,150 MW or 1,400 MW depending on the type of contingency.
- The overlapping design of the area RAS is also inconsistent with ISO RAS guideline ISO-G-RAS2 in the ISO Planning Standard.
- Addition of portfolio resources without transmission upgrades is not a valid option and would cause long-term operational complexities and reliability impacts.

The ISO also considered establishing a 500 kV station at Kramer and a 500 kV line Lugo as an alternative to mitigate the constraints. The estimated cost of this alternative is \$700 million. While this alternative would provide a higher transfer capability out of the area, the Lugo–Victor–Kramer 230 kV Upgrade provides adequate capacity for the base and sensitivity portfolio as well as the portfolio identified in the ISO 20-Year Transmission Outlook for the area. In addition to the policy benefits which is the basis for recommending this project, the project also provides reliability benefits and production cost savings.

### **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 3.5-22.

Table 3.5-22: 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
Lugo 500/230 kV Transformers	Base	919	400	368	Transmission identified for on-peak deliverability
	Sensitivity	3,272	1,132	1,594	
Victor–Lugo 230 kV Lines	Base	-	-	0	Not required
	Sensitivity	2,052	692	994	Transmission identified for on-peak deliverability
Kramer–Victor 230 kV	Base	150	150	995	Transmission identified for on-peak deliverability
	Sensitivity	1,588	533	1,600	
Kramer–Sandlot–Coolwater 230 kV	Base	0	0	62	Planned NOL CRAS or energy storage charging
	Sensitivity	0	0	63	
Calcite–Pisgah–Lugo 230 kV corridor	Base	650	250	28	Energy storage charging
	Sensitivity	1,220	440	85	

### **3.5.7 SCE Metro Interconnection Area**

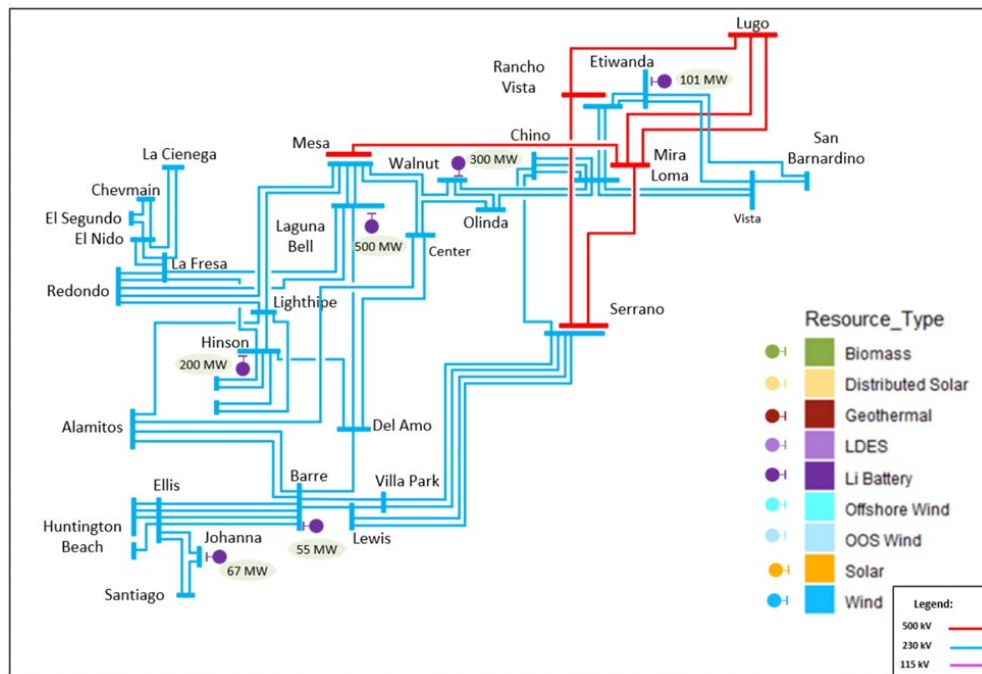
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Metro interconnection area, are listed in Table 3.5-23. The portfolios in the interconnection area are comprised of battery storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-23: 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	-	-	-	-	-	-
Wind – In State	-	-	-	-	-	-
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	-	-	-	-	-	-
Li Battery	1,161	-	1,161	1,605	-	1,605
Geothermal	-	-	-	-	-	-
Long Duration Energy Storage (LDES)	-	-	-	-	-	-
Biomass/Biogass	-	-	-	-	-	-
Distributed Solar	-	-	-	-	-	-
<b>Total</b>	<b>1,161</b>	<b>-</b>	<b>1,161</b>	<b>1,605</b>	<b>-</b>	<b>1,605</b>

The resources as identified in the CPUC busbar mapping for the SCE Metro interconnection area are illustrated on the single-line diagram in Figure 3.5-13.

Figure 3.5-13: SCE Metro Interconnection Area – Mapped<sup>62</sup> Base Portfolio



**On-Peak Deliverability**

The constraints identified in the on-peak deliverability assessment of the SCE Metro interconnection area along with the recommended mitigation plans are identified in Table 3.5-24.

<sup>62</sup> 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.

Table 3.5-24: SCE Metro 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
South of Mesa Constraint	Base	-	-	-	0	Not required
	Sensitivity	1,934	1,807	0	2,991	South Area Reinforcement
Serrano-Barre Corridor	Base	-	-	-	0	Not required
	Sensitivity	6,350	3,109	4,712	1,638	South Area Reinforcement
Mesa-Mira Loma 500 kV Line UG Segment	Base	8,917	3,932	8,851	388	Mesa-Mira Loma Underground Third Cable included in the South Area Reinforcement
	Sensitivity	21,160	9,192	18,031	3,451	

### Mira Loma-Mesa 500 kV Underground Third Cable

To mitigate the Mesa-Mira Loma 500 kV Line UG Segment constraint, the ISO is recommending the Mira Loma 500 kV Underground Third Cable project. In addition to mitigating the Mesa-Mira Loma 500 kV line UG segment, the project also provides mitigation to the Serrano-Alberhill-Valley 500 kV constraint in the SCE Eastern interconnection area identified in Section 3.5.8.

The scope of the project is as follows:

- Add a third underground cable on the underground section of the existing Mira Loma-Mesa 500 kV circuit, increasing the rating of the section from 1992 / 3204 MVA (normal/emergency) to 3421 / 4616 MVA (normal/emergency).

The estimated cost for upgrading the Mira Loma-Mesa 500 kV Underground Third Cable is \$35 million with an estimated in-service date of 2026.

To mitigate for the constraints in the sensitivity portfolio, in addition to the upgrades identified above, further southern area reinforcements are required. The resources in the portfolio within the SCE Metro, SCE Eastern and SDG&E interconnection area have been assessed together in considering alternatives that mitigate the constraints in the base and sensitivity portfolios for all areas. The recommended alternative of the southern interconnection area is included in San Diego interconnection area assessment in Section 3.5.9.



**Off-Peak Deliverability**

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE Metro interconnection areas along with the recommended mitigation plans are identified in Table 3.5-25.

Table 3.5-25: SCE Metro 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
South of Mesa Corridor	Base	-	-	0	Not required
	Sensitivity	2,782	1,227	334	Energy storage charging

**3.5.8 SCE Eastern Interconnection Area**

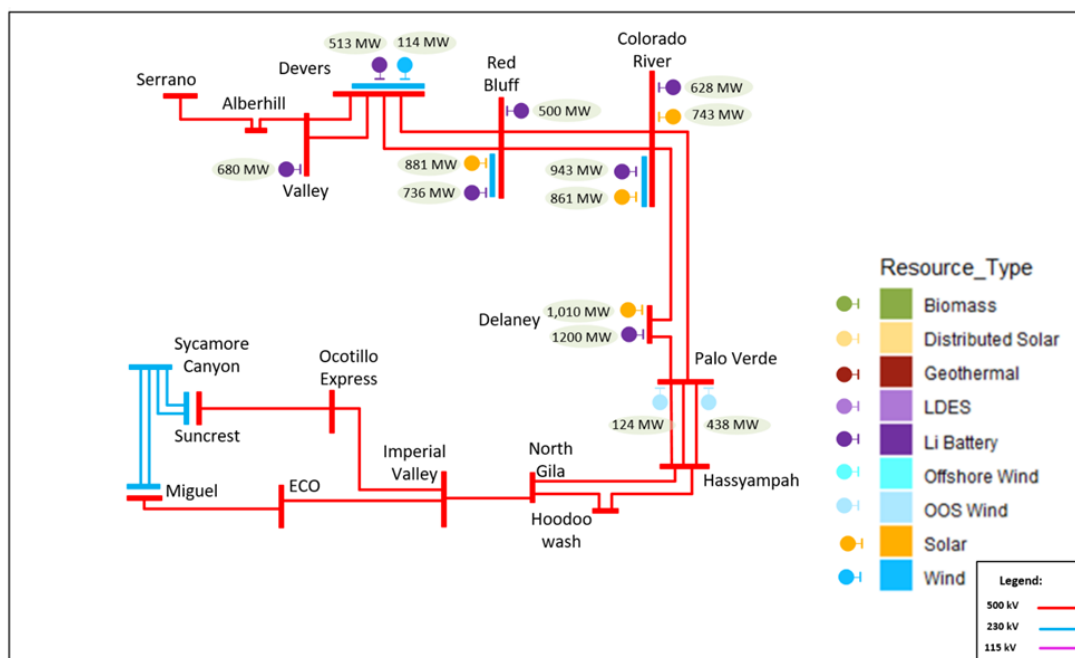
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Eastern interconnection area are listed in Table 3.5-26. The portfolios are comprised of solar, wind (in-state and out-of-state), battery storage and biomass/biogass 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 3.5-26: SCE Eastern 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	1,262	1,716	2,978	2,067	5,250	7,517
Wind – In State	106	-	106	116	-	116
Wind – Out-of-State (Existing TX)	124	-	124	124	-	124
Wind – Out-of-State (New TX)	438	-	438	2,328	-	2,328
Wind – Offshore	-	-	-	-	-	-
Li Battery	2,098	-	2,098	5,350	-	5,350
Geothermal	-	-	-	-	-	-
Long Duration Energy Storage (LDES)	-	-	-	700	-	700
Biomass/Biogass	3	-	3	3	-	3
Distributed Solar	-	-	-	-	-	-
<b>Total</b>	<b>4,031</b>	<b>1,716</b>	<b>5,747</b>	<b>10,687</b>	<b>5,250</b>	<b>15,937</b>

The resources as identified in the CPUC busbar mapping for the SCE Eastern interconnection area are illustrated on the single-line diagram in Figure 3.5-13.

Figure 3.5-14: SCE Eastern Interconnection Area – Mapped<sup>63</sup> 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 3.5-27.

Table 3.5-27: 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
Devers-Red Bluff 500 kV	Base	5,821	1,404	0	7,956	Devers-Red Bluff 1 and 2 Upgrade
	Sensitivity	14,739	5002	0	15,033	Base upgrade plus South Area Reinforcement
Serano-Alberhill-Valley 500 kV	Base	2,514	769	0	2,732	Upgrade of 2 – 500 kV lines, 3 – 230 kV lines and adding third underground cable to the existing Mira Loma 500 kV circuit.
	Sensitivity	8,233	2,961	2,952	5,281	
Colorado River-Red Bluff 500 kV	Base	5,821	1,404	4,847	1,150	Colorado River-Red Bluff 1 Upgrade
	Sensitivity	13,221	4,523	11,450	1,972	Devers-Red Bluff 1 and 2 Upgrade
Colorado River 500/230 kV	Base	0	0	-	323	West of Colorado River CRAS
	Sensitivity	371	207	0	465	

<sup>63</sup> Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Eastern Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

Devers-Red Bluff 500 kV 1 and 2 Line Upgrade

To mitigate the Devers-Red Bluff 500 kV constraint in the base portfolio, the ISO is recommending the Devers-Red Bluff 1 and 2 Upgrade project. Increasing the rating of the Devers-Red Bluff No.1 and Devers-Red Bluff No.2 500 kV lines is the first step of transmission upgrades considered to address this constraint. This would maximize the use of existing transmission infrastructure as much as possible. The scope of the project is as follows:

- Increase the rating of the Devers-Red Bluff 500 kV 1 Line from 2598 / 2858 MVA (normal/emergency) to 3291 / 3880 MVA (normal/emergency); and
- Increase the rating of the Devers-Red Bluff 500 kV 2 Line from 2598 / 2910 MVA (normal/emergency) to 3291 / 3880 MVA (normal/emergency).

The estimated cost for upgrading the Devers-Red Bluff 500 kV 1 and 2 Line is \$140 million with an expected in-service date of 2028.

Colorado River-Red Bluff 500 kV 1 Line Upgrade

To mitigate the Colorado River-Red Bluff 500 kV constraint, the ISO recommends approval of the following project. The scope of the Colorado River-Red Bluff 500 kV 1 Line Upgrade project is as follows:

- Increase the line rating from 2338 / 2858 MVA (normal/emergency) to 3421 / 3880 MVA (normal/emergency).

The estimated cost for upgrading the Colorado River-Red Bluff 500 kV 1 Line Upgrade is \$50 million with an estimated in-service date of 2028.

To mitigate the Serrano-Alberhill-Valley 500 kV constraint the ISO recommends approval of the following 6 upgrade projects.

Devers-Valley 500 kV 1 Line Upgrade

The scope of the Devers-Valley 500 kV 1 Line Upgrade project is as follows:

- Increase the line rating from 2598 / 2858 MVA (normal/emergency) to 3421 / 3880 MVA (normal/emergency).

The estimated cost for upgrading the Devers-Valley 500 kV 1 Line Upgrade is \$45 million with an estimated in-service date of 2028.

Serrano-Alberhill-Valley 500 kV 1 Line Upgrade

The scope of the Serrano-Alberhill-Valley 500 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the Serrano-Alberhill 500 kV 1 Line from 2598 / 4157 MVA (normal/emergency) to 3421 / 4157 MVA (normal/emergency); and
- Increase the line rating of the Alberhill-Valley 500 kV 1 Line from 2598 / 4157 MVA (normal/emergency) to 3421 / 4416 MVA (normal/emergency).

The estimated cost for upgrading the Serrano-Alberhill-Valley 500 kV 1 Line Upgrade is \$60 million with an estimated in-service date of 2028.

#### San Bernardino-Etiwanda 230 kV 1 Line Upgrade

The scope of the San Bernardino-Etiwanda 230 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the San Bernardino-Etiwanda 230 kV 1 Line from 988 / 1040 MVA (normal/emergency) to 1287 / 1737 MVA (normal/emergency).

The estimated cost for upgrading the San Bernardino-Etiwanda 230 kV 1 Line Upgrade project is \$65 million with an estimated in-service date of 2031.

#### San Bernardino-Vista 230 kV 1 Line Upgrade

The scope of the San Bernardino-Vista 230 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the San Bernardino-Vista 230 kV 1 line from 988 / 1331 MVA (normal/emergency) to 1287 / 1737 MVA (normal/emergency).

The estimated cost for upgrading the San Bernardino-Vista No.1 230 kV line Upgrade is \$18 million with an estimated in-service date of 2026.

#### Vista-Etiwanda 230 kV 1 Line Upgrade

The scope of the Vista-Etiwanda 230 kV 1 Line Upgrade project is as follows:

- Increase the line rating of the Vista-Etiwanda 230 kV 1 Line from 797 / 876 MVA (normal/emergency) to 988 / 1331 MVA (normal/emergency).

The estimated cost for upgrading the Vista-Etiwanda No.1 230 kV line Upgrade is \$13 million with an estimated in-service date off 2031.

#### Mira Loma-Mesa 500 kV Underground Third Cable

The Mira Loma-Mesa 500 kV Underground Third Cable project recommended for approval in the Metro interconnection area On-peak deliverability assessment in Section 3.5.7 is also required to mitigate the Serano-Alberhill-Valley 500 kV constraint.

To mitigate for the constraint in the sensitivity portfolio, in addition to the upgrades identified above, further southern area reinforcements are required. The resources in the portfolio within the SCE Metro, SCE Eastern and SDG&E interconnection area have been assessed together in considering alternatives that mitigate the constraints in the base and sensitivity portfolios for all areas. The recommended alternative of the southern interconnection area is included in San Diego interconnection area assessment in Section 3.5.9.

#### 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 3.5-28.

Table 3.5-28: SCE Eastern 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
Devers-Red Bluff 500 kV	Base	8,290	1,404	1,187	See SCE Eastern area On-Peak mitigation
	Sensitivity	23,391	5,702	6,137	
Serano-Alberhill-Valley 500 kV	Base	-	-	-	None required
	Sensitivity	13,686	3,661	1,541	See SCE Eastern area On-Peak mitigation
Colorado River 500/230 kV Transformers	Base	0	0	254	West of Colorado River CRAS and/or batteries in charging mode
	Sensitivity	986	207	1,038	
Red Bluff 500/230 kV Transformers	Base	0	0	140	West of Colorado River CRAS
	Sensitivity	894	78	940	

### 3.5.9 SDG&E Interconnection Area

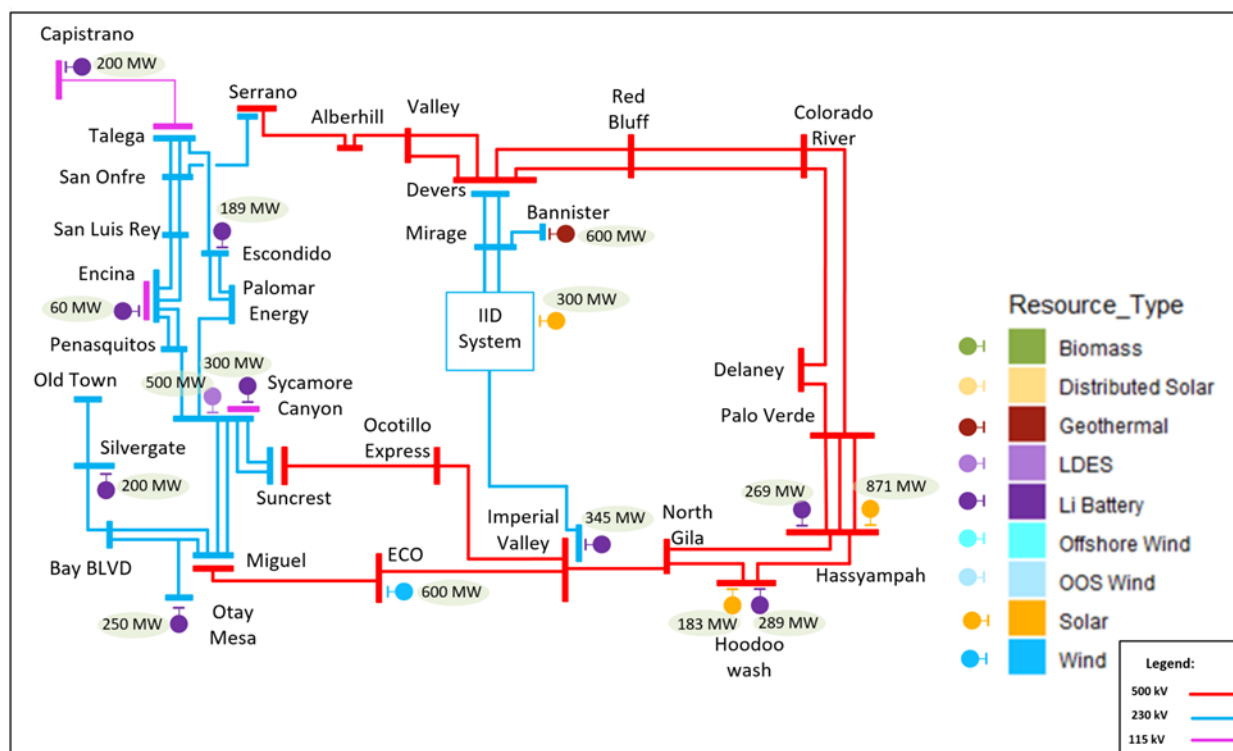
Table 3.5-29 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SDG&E interconnection area. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery 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 3.5-29: SDG&E 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	300	871	1,171	484	1,390	1,874
Wind – In State	600	-	600	600	-	600
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	-	-	-	-	-	-
Li Battery	1,418	-	1,418	2,527	-	2,527
Geothermal	600	-	600	900	-	900
Long Duration Energy Storage (LDES)	500	-	500	500	-	500
Biomass/Biogass	-	-	-	-	-	-
Distributed Solar	-	-	-	-	-	-
<b>Total</b>	<b>3,418</b>	<b>871</b>	<b>4,289</b>	<b>5,011</b>	<b>1,390</b>	<b>6,401</b>

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

Figure 3.5-15: SDG&E Interconnection Area – Mapped<sup>64</sup> 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 3.5-30.

Table 3.5-30: 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
East of Miguel	Base	1,178	279	0	3,080	Southern area reinforcement
	Sensitivity	5,834	2,173	0	10,398	
Bay Boulevard-Silvergate	Base	1,209	10	0	2,373	2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line and south area reinforcement
	Sensitivity	1,676	475	0	3,408	
Encina-San Luis Rey	Base	1,958	510	0	2,776	30 minute emergency rating on Encina Tap-San Luis
	Sensitivity	3,260	1,808	2,765	1,422	

<sup>64</sup> Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SDG&E Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

						Rey 230 kV Line and south area reinforcement
Sycamore Area	Base	1,509	310	1,030	680	30 min emergency rating for Sycamore-Scripps 69 kV line upgrade Sycamore-Chicarita 138 kV, new 3 ohm reactor on Sycamore-Penasquitos 230 kV and South area reinforcement
	Sensitivity	2,716	1,264	1,314	2,329	
San Luis Rey-San Onofre	Base	2,427	1,028	0	3,454	South area reinforcement
	Sensitivity	3,625	2,037	3,801	1,120	
Silvergate-Old Town	Base	909	210	0	1,944	Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines and South area reinforcement
	Sensitivity	1,376	675	0	2,466	
Friars-Doublet Tap	Base	500	500	0	1,339	SDGE Project Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento
	Sensitivity	2,155	1,055	0	2,604	
San Marcos-Melrose Tap	Base	1,189	689	0	1,784	Reconductor TLC680C San Marcos-Melrose Tap
	Sensitivity	2,279	1,179	797	1,482	

The following projects have been identified as required to address the local SDG&E constraints from the On-peak delivability assessment.

#### Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento

To address the Friars-Doublet Tap constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento project Figure 3.5-12. The scope of the project is as follow:

- Swap TL23013 Penasquitos-Old Town with TL6959 Penasquitos-Mira Sorrento so that TL23013 & TL23071 will not share same Structures (TL23071 sharing structures with TL6959 and TL23013 sharing structures with TL13810). This proposal will require to upgrade 2 miles of 138 kV structures for 230 kV operation.

The estimated project cost is between \$19 to \$21 million and is expected to be in-service in 2032.

#### Reconductor TL680C San Marcos-Melrose Tap

To address the San Marcos-Melrose Tap constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the Reconductor TL680C San Marcos-Melrose Tap project. The scope of the project is as follow.

- Reconductor San Marcos-Melrose Tap 69 kV line to 250 MVA.

The estimated project cost is \$28 million and is expected to be in service in 2032.

3 ohm series reactor on Sycamore-Penasquitos 230 kV Line

To address the Sycamore Area constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the 3 ohm series reactor on Sycamore-Penasquitos 230 kV Line project. The scope of the project is as follow.

- • Install 3 ohm series reactor on Sycamore-Penasquitos 230 kV Line

The estimated project cost is \$8 million and is expected to be in service in 2032.

Upgrade TL13820 Sycamore-Chicarita 138 kV

To address the Sycamore Area constraint identified in the base and sensitivity portfolios, the ISO recommends the approval of the Upgrade TL13820 Sycamore-Chicarita 138 kV project. The scope of the project is as follow:

- Reconductor Sycamore-Chicarita 138 kV line to 250 MVA

The estimated project cost is \$60 million and is expected to be in service in 2032.

In addition to the above projects recommended for approval, the following would be required as a part of the mitigation plan:

- Existing Miguel banks RAS;
- CEC RAS, under construction. Trip gen at Encina for P1 outages of Encina-San Luis Rey 230 kV or Encina-San Luis Rey-Palomar 230 kV;
- Use 2 hour emergency rating for Silvergate-Bay Boulevard 230 kV line;
- Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines;
- Use 30 min emergency rating for Encina Tap-San Luis Rey 230 kV line;
- Use 30 min emergency rating for San Luis Rey-San Onofre 230 kV #1 line; and
- Use 30 min emergency rating for Sycamore-Scripps 69 kV line

In addition to the upgrades identified in the SCE Mesa (Section 3.5.7) and the SCE Eastern (Section 3.5.8) interconnection area On-peak deliverability assessment, further southern area reinforcements are required. The resources in the portfolio within the SCE Metro, SCE Eastern and SDG&E interconnection area have been assessed together in considering alternatives that mitigate the constraints in the base and sensitivity portfolios for all areas. To address the East of Miguel, Bay Boulevard-Silvergate, Encina-San Luis Rey, Sycamore area, San Luis Rey-San Onofre, and Silvergate-Old Town constraints identified in the base and sensitivity portfolios, the ISO is recommending the following projects identified in the southern area reinforcement as follows.



### **Southern Area Reinforcement**

#### **Imperial Valley–North of SONGS 500 kV Line and Substation**

The ISO is recommending the Imperial Valley–North of SONGS 500 kV Line and Substation project as a part of the south area reinforcement. The scope of the project is as follows:

- New Imperial Valley–N.SONGS 500 kV line, estimated at 145 miles, with 50% series compensation;
- New 500/230 kV Substation north of SONGS complete with three (3) 500/230 kV transformers; and
- Loop the San Onofre–Santiago 230 kV 1 and 2 lines and the San Onofre–Viejo 230 kV line into the new substation.

The estimated project cost is \$2,288 million and is expected to be in service by 2034.

#### **North of SONGS–Serrano 500 kV Line**

The ISO is recommending the North of SONGS–Serrano 500 kV AC Line project as a part of the south area reinforcement. The scope of the project is as follows:

- North of SONGS–Serrano 500 kV AC line, estimated at 30 miles.

The estimated project cost is between \$503 million and is expected to be in-service by 2034.

#### **Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement**

The ISO is recommending the Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement project as a part of the south area reinforcement. The scope of the project is as follows:

- New 500 kV switchyard at Del Amo complete with three (3) 500/230 kV transformers;
- Utilize the existing conductor on Mesa-Mira Loma 500 kV line and build approximately a 2-mile new section into Mesa and an approximately 13-mile new 500 kV line to Serrano;
- Interconnect the new Mesa-Serrano 500 kV line with 2 new 500 kV lines from Del Amo (approximately 13 miles) to form the Del Amo-Mesa and Del Amo-Serrano 500 kV lines; and
- Loop Alamitos–Barre No. 1 and No. 2 230 kV lines into Del Amo Substation.

The estimated project cost is between \$1,125 million and is expected to be in-service by 2033.

#### **North Gila-Imperial Valley 500 kV Transmission Line**

The ISO is recommending the North Gila-Imperial Valley 500 kV Transmission Line project as a part of the south area reinforcement. The scope of the project is as follows:

- A new North Gila–Imperial Valley 500 kV line,<sup>65</sup> estimated at approximately 97 miles.

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<sup>65</sup> An economic study request was submitted for a joint project with IID to for a 500 kV line from North Gila-Imperial Valley with a new 500 kV switchyard at IID Highline Substation and one (1) 500/230 kV transformer. The ISO is continuing to explore a potential joint project with IID.

The estimated project cost is \$340 million and is expected to be in service in 2032.

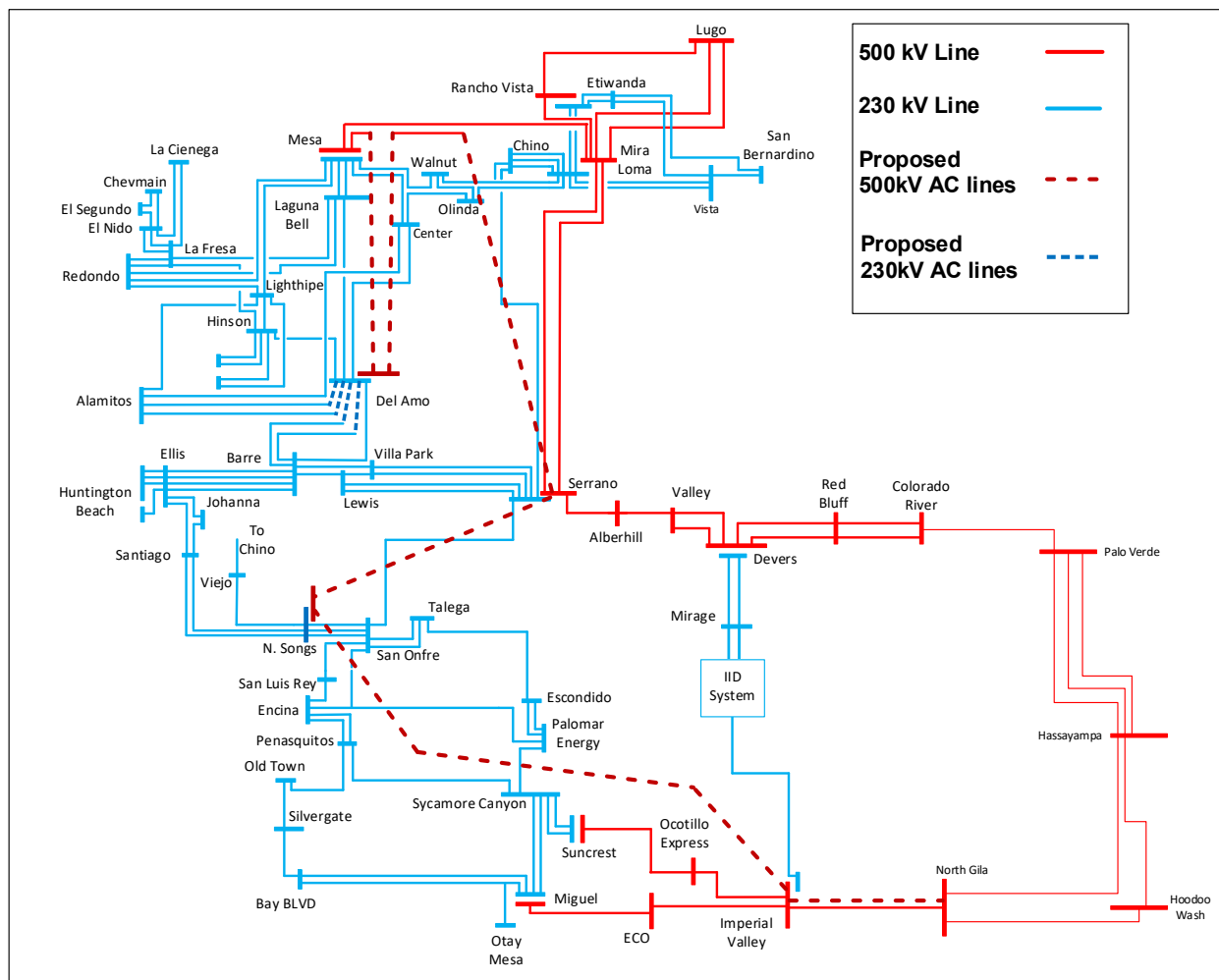
Upgrade on Hoodoo Wash-North Gila and Hassayampa-North Gila Transmission Lines

The ISO is recommending to upgrade the Hoodoo Wash-North Gila and Hassayampa-North Gila transmission lines and their series compensation as a part of the south area reinforcement. These upgrades are to the Arizona Public Service (APS) neighboring system equipment upgrades as an affected system, and to the SDG&E system.<sup>66</sup> For the APS portions, the ISO has voluntarily agreed, as set out in Section 24.10 of the ISO tariff, to the cost of the upgrades to limiting equipment. The scope of the project is as follows:

- Upgrade the Hoodoo Wash-North Gila and Hassayampa-North Gila 500 kV lines and series capacitors to 3250 Amps emergency rating.

The estimated project cost is \$27 million and is expected to be in service in 2032.

Figure 3.5-16: South Area Reinforcement Projects



<sup>66</sup> The Hoodoo Wash-North Gila Line is owned by SDG&E, APS, and IID. The Hassayampa-North Gila line is owned by APS and IID. APS is the planning, design, construction and maintenance company for the Hoodoo Wash-North Gila line. APS has all the responsibilities for the Hassayampa-North Gila line.

The ISO considered a number of transmission development alternatives for the south area reinforcements in Appendix F. The following are the alternative developments.

- North Gila–Imperial Valley–Inland–Serrano–Del Amo–Mesa 500 kV AC Development.
  - Creating the 230 kV North of SONGS provides better technical performance and avoids having to rebuild the 230 kV lines between Talega and Escondido.
- North Gila–Imperial Valley AC & Imperial Valley–Inland–Del Amo 500 kV HVDC Development.
  - HVDC projects provide opportunity if undergrounding of sections is required and additional flow control on path; however cost is approximately \$2,000 million more.
- North Gila–Imperial Valley–North of SONGS AC and North of SONGS–Del Amo HVDC 500 kV Development.
  - HVDC projects provide opportunity if undergrounding of sections is required and additional flow control on path; however cost is approximately \$2,000 million more.
  - Limited land available, other within existing SCE land, at Del Amo for an HVDC converter station.
- North Gila–Imperial Valley–Inland AC and Inland–Del Amo HVDC 500 kV Development.
  - HVDC projects provide opportunity if undergrounding of sections is required and additional flow control on path; however cost is approximately \$2,000 million more.
- North Gila–Imperial Valley–Suncrest and Red Bluff–Devers–Mira Loma 500 kV Development.
  - Alternative is approximately \$2,000 million more.

**Off-Peak Deliverability Assessment**

The Off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SDG&E interconnection areas along with the recommended mitigation plans are identified in Table 3.5-31.

Table 3.5-31: SDG&E 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
East of Miguel	Base	2,781	769	1,956	On-peak mitigation
	Sensitivity	4,479	2,173	3,833	

### 3.6 Out-of-State Wind

The base portfolio includes 1,500 MW of out-of-state wind resources (1,062 MW from Wyoming or Idaho and 438 MW from New Mexico) and the sensitivity portfolio includes 4,832 MW (1,500 MW from Wyoming, 1,000 MW from Idaho and 2,328 MW from New Mexico). These resources have been identified by CPUC as requiring new transmission and have been included in the policy analysis and alternative analysis as expanding the maximum import capability of the paths to import the out-of-state wind to determine the CAISO internal transmission needs required to accommodate the out-of-state wind identified. Further, the ISO also notes that the base portfolio for the 2023-2024 transmission plan reflects the same volumes and sources of out-of-state wind as this year's sensitivity.<sup>67</sup>

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 is continuing to assess the SWIP North project proposed by LS Power for accessing wind resources in Idaho given the resource portfolios being studied in this year's planning analysis and the base portfolio for the 2023-2024 Transmission Plan. The ISO's economic studies also demonstrate other economic benefits contributing to the overall value provided by the project, as set out in Chapter 4. Idaho Power has expressed interest in the SWIP North project and the ISO has initiated discussions with Idaho Power about joint participation. Idaho Power has expressed an interest in South to North capacity, though potentially not for the full 1,000 MW of capability. The ISO notes there may be opportunities for DOE funding for unutilized capacity that the ISO is currently exploring. Idaho Power is currently performing a detailed analysis of the SWIP North project in its 2023 IRP which will be filed with its Public Utilities Commission by September 30th. The filing, originally planned for June, had to be extended due to the nature of analysis being performed.

The SWIP North project does not meet the criteria defining interregional transmission projects, as set out in the ISO's tariff. Accordingly, the ISO intends to work with Idaho Power and other potential interested transmission service providers and continue the development of a recommendation for the SWIP North project, as a potential regional policy-driven project. This will be conducted as an extension to this planning cycle.

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 addressed.

### 3.7 Offshore Wind

In the Morro Bay area, the base portfolio included 1,588 MW and the sensitivity portfolio included 3,100 MW of offshore wind. For the interconnection of the offshore wind, the existing Diablo 500 kV substation has been identified and is where current offshore wind interconnection requests in the ISO queue are primarily located. The ISO has also considered the alternative of creating a new 500 kV substation on the Diablo-Gates 500 kV for the interconnection of the

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<sup>67</sup> CPUC Decision (D.) 23-02-040 adopted on February 23, 2023.

Morro Bay area offshore wind. The ISO will continue to coordinate with PG&E and the offshore resource developers, which were the successful federal Bureau of Ocean Energy Management (BOEM) lease bidders, for the interconnection point for the Morro Bay area offshore wind.

The base resource portfolio provided by the CPUC for the 2022-2023 Transmission Plan does not support the need for transmission capacity from the North Coast in this year's studies, with 100-150 MW of offshore wind mapped to the Humboldt area. The need for new transmission from the North Coast area was identified in studying the sensitivity portfolio. The ISO also notes that the base portfolio for the 2023-2024 transmission plan will necessitate new transmission, with 1.6 GW of offshore wind mapped to the north coast/Humboldt area.<sup>68</sup>

Given the resource portfolios provided for this year's transmission planning studies and the state's progress of resource development planning activities (supply chains, harbors, etc.) with the CEC AB 525 report due in June 2023, the ISO is not recommending approval of transmission solutions in this planning cycle and will look instead to advancing upgrades in the next planning cycle. The assessment of alternatives in this planning cycle was conducted on the sensitivity portfolio and documented in Appendix F and will assist in being positioned to make a decision for the recommended transmission for the North Coast in the 2023-2024 Transmission Plan.

### 3.8 CPUC Request to CAISO in Accordance with SB 887

The CPUC submitted a letter<sup>69</sup> to the ISO on January 13, 2023 in accordance with SB 887 indicating the following.

*“Pursuant to Senate Bill 887 (Becker, 2022), this letter requests the California Independent System Operator to (1) identify, based as much as possible on studies and projections completed before January 1, 2023, by the CAISO, the CPUC and the California Energy Commission, the highest priority transmission facilities that are needed to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources or zero-carbon resources that are expected to be developed by 2035, and (2) consider whether to approve such transmission projects as part of the CAISO's 2022–23 transmission planning process.”*

The ISO addressed this request, by considering the following sources of relevant information:

- The two-year study process conducted through the 2018-2019 and the 2019-2020 transmission plan specifically undertaken to explore options and opportunities to reduce reliance on – primarily gas-fired – local capacity requirements in the ISO's local capacity areas and sub-areas. That work specifically prioritized areas relying on natural gas and/or petroleum, risk of retirement, and proximity to disadvantaged communities;
- Economic planning studies conducted in the 2020-2021 Transmission Plan (where detailed economic studies explored reducing local capacity requirements in the Greater

<sup>68</sup> CPUC Decision (D.) 23-02-040 adopted on February 23, 2023.

<sup>69</sup> <http://www.caiso.com/InitiativeDocuments/Letter-2022-2023-Transmission-Planning-Process-Jan%2013,%202023.pdf>

Bay area, the LA Basin area and the Big Creek-Ventura area, but no projects were recommended for approval);

- Economic planning studies conducted in 2021-2022 Transmission Plan (where the Pacific Transmission Expansion Project was studied to alleviate Path 26 congestion as well as capture the previously studied benefits in reducing local capacity requirements in the LA Basin area and the Big Creek-Ventura area); and
- The ISO's 20 Year Transmission Outlook released May, 2022.

As noted throughout the ISO's past studies of local capacity requirement reduction opportunities, the study results and corresponding conclusions are heavily influenced, in particular, by the longer term requirements for gas-fired generation for system and flexible capacity requirements. The uncertainty regarding the extent to which gas-fired generation will be needed to meet those system and flexible capacity requirements necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements. The CAISO accordingly has placed values on benefits associated with reducing local gas-fired generation capacity requirements primarily on the difference between the relevant local area capacity price and system capacity prices. This reflects the economic capacity benefit of less generation being needed for local capacity even if it is still needed for system capacity. This conservative assumption was a key difference between the economic benefits calculated in this study, and the economic assessments stakeholders provided in support of their proposed projects. The CAISO 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. As noted in Chapter 1, SB 887<sup>70</sup> 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 2022-2023 Plan.

The ISO then considered these inputs in developing its recommendations in this 2022-2023 Transmission Plan. In this Plan, the ISO has assessed the potential to advance additional projects beyond those approved in this plan to allow for increased capacity into local capacity areas to deliver renewable energy resources expected to be developed by 2035. There are 12 projects recommended for approval as reliability-driven and policy-driven that will increase the transmission capability into local areas. The needs for these projects are to meet identified reliability needs or to provide deliverability for the base and sensitivity resource portfolios.

These projects are as follows:

- Metcalf 230/115 kV Transformers Circuit Breaker Addition project (reliability-driven) – Section 2. This project is recommended to address reliability needs in the Greater Bay area. This project, along with the two HVDC projects in the San Jose area in the 2021-

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<sup>70</sup> SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

2022 Transmission Plan will reduce the local capacity requirements within the San Jose LCR sub-area;

- The seven recommended upgrades to four existing 500 kV lines and three 230 kV lines in the SCE Eastern area (Section 3.5.8) and the addition of the third cable addition to the Mesa-Mira Loma 500 kV underground section (Section 3.5.7) will increase the 500 kV and 230 kV supply to the LA Basin area; and
- The three southern area reinforcement projects (the Imperial Valley–North of SONGS 500 kV Line and Substation, North of SONGS–Serrano 500 kV Line, and Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement projects) will increase the transmission capacity in the LA Basin by establishing a 500 kV source at the existing Del Amo 230 kV substation, and in the San Diego and LA Basin local capacity areas by establishing a new 500 kV source north of San Diego.

The ISO has also reviewed the Pacific Transmission Expansion Project that has been submitted into the Economic Request window in the 2022-2023 transmission planning process. This proposed project is a multi-terminal HVDC project from Diablo Canyon 500 kV substation to multiple 230 kV substations in the LA Basin area. The ISO has been in discussion with LADWP as to its potential interest in project and the possibilities of a joint project; however the ISO is not aware of any decisions by LADWP to move forward at this time<sup>71</sup>. The project can provide improved access to future offshore wind development, offload 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 collaboration opportunities after the Plan has been approved.

### 3.9 Conclusion and Recommendations

The policy assessment has identified 22 new policy-driven projects recommended for approval in this transmission planning cycle for a total estimated cost of \$7.53 billion as listed in Table 3.9-1.

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<sup>71</sup> In the LADWP Power System Strategic Transmission Plan update presentation (dated December 13, 2022), LADWP identifies a potential submarine project from the Diablo Canyon area to the LA Basin area and identifies the next steps being to seek collaboration on potential joint transmission projects.

Table 3.9-1: Recommended Policy-Driven Transmission Projects for Approval

No.	Project Name	PTO Area	Planning Area	Cost (\$M)	
1	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Fresno	25	50
2	Henrietta 230/115 kV Bank 3 Replacement	PG&E	Fresno	12	20
3	Beatty 230 kV	VEA/GLW	East of Pisgah	155	155
4	Trout Canyon/Lugo 500 kV Line	GLW/SCE	East of Pisgah	1,500	2,000
5	Lugo-Victor-Kramer 230 kV Upgrade	SCE	North of Lugo	482	482
6	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	SCE Eastern	50	50
7	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	SCE Eastern	140	140
8	Devers-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	40	40
9	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	60	60
10	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	65	65
11	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	SCE Eastern	18	18
12	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	13	13
13	Mira Loma-Mesa 500 kV Underground Third Cable	SCE	SCE Metro	35	35
14	Imperial Valley-North of SONGS 500 kV Line and Substation	SDG&E	SDG&E	2,288	2,288
15	North of SONGS-Serrano 500 kV line	SDG&E / SCE	SDG&E and SCE Metro	503	503
16	Serrano-Del Amo-Mesa 500 kV Transmission Reinforcement	SCE	SCE Metro	1,125	1,125
17	North Gila-Imperial Valley 500 kV line	SDG&E	SDG&E (Potential Joint Project with IID)	340	340
18	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	APS	27	27
19	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	SDG&E	21	21
20	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	SDG&E	28	28
21	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	SDG&E	8	8
22	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	SDG&E	60	60
			<b>Total</b>	<b>6,995</b>	<b>7,528</b>

As well, the ISO will conduct additional stakeholder and market outreach regarding the SWIP North project, to refine its recommendation regarding the SWIP North project proposed by LS Power to access Idaho wind resources as a potential regional policy-driven transmission project, taking into account participation interest of neighboring transmission service providers. This work will be conducted as an extension of the 2022-2023 Transmission Plan, seeking Board of Governor approval at a later date.



## Chapter 4

# 4 Economic Planning Study

### 4.1 Introduction

The ISO's economic planning study is an integral part of the ISO's transmission planning process and is performed on an annual basis as part of the transmission plan. The economic planning study complements the reliability-driven and policy-driven analysis documented in this transmission plan, exploring economic-driven transmission solutions that may create opportunities to reduce ratepayer costs within the ISO.

Each cycle's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan.

The studies used a production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and to assess benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. 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:

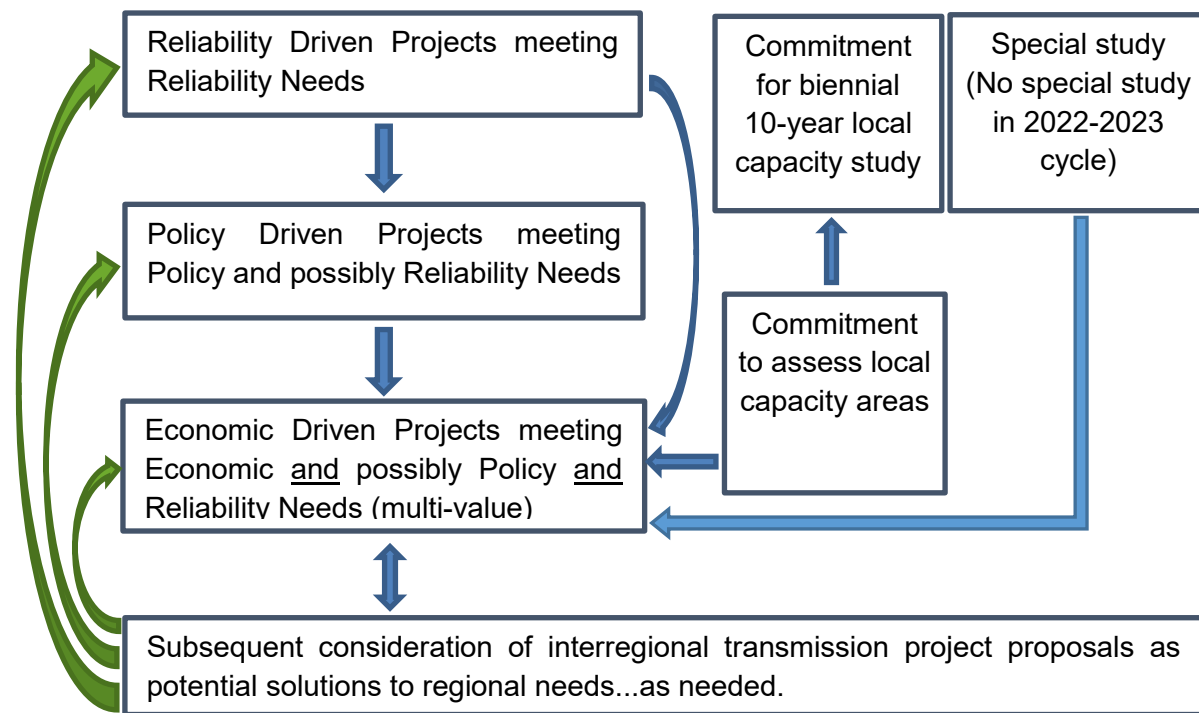
- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling;
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified 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).<sup>72</sup>

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 captured to some extent 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.

<sup>72</sup> Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 [http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2\\_2017.pdf](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.

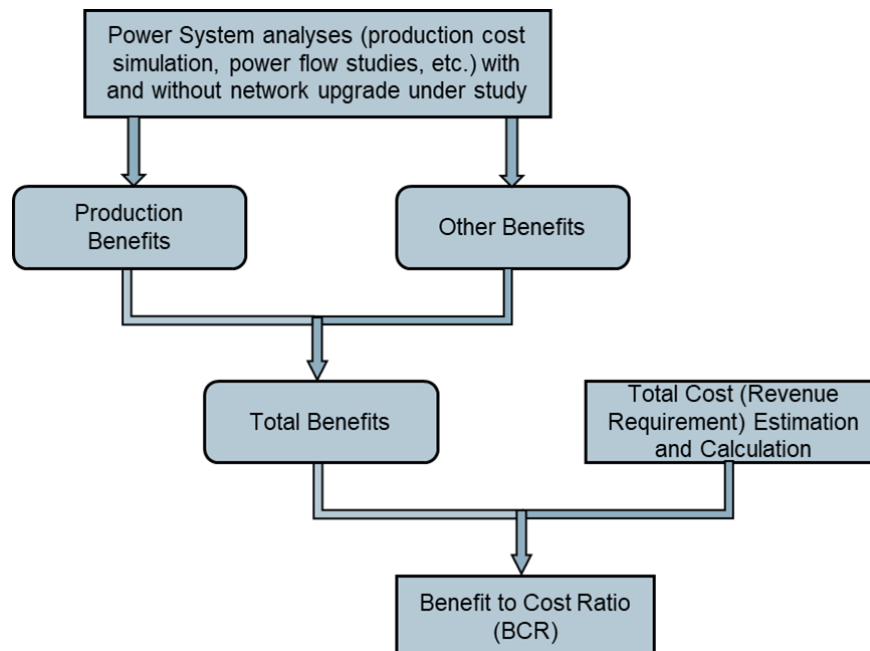
First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and 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, the benefit 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, O&M 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. As noted in Chapter 1, existing legislation<sup>73</sup> 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 2022-2023 Plan.

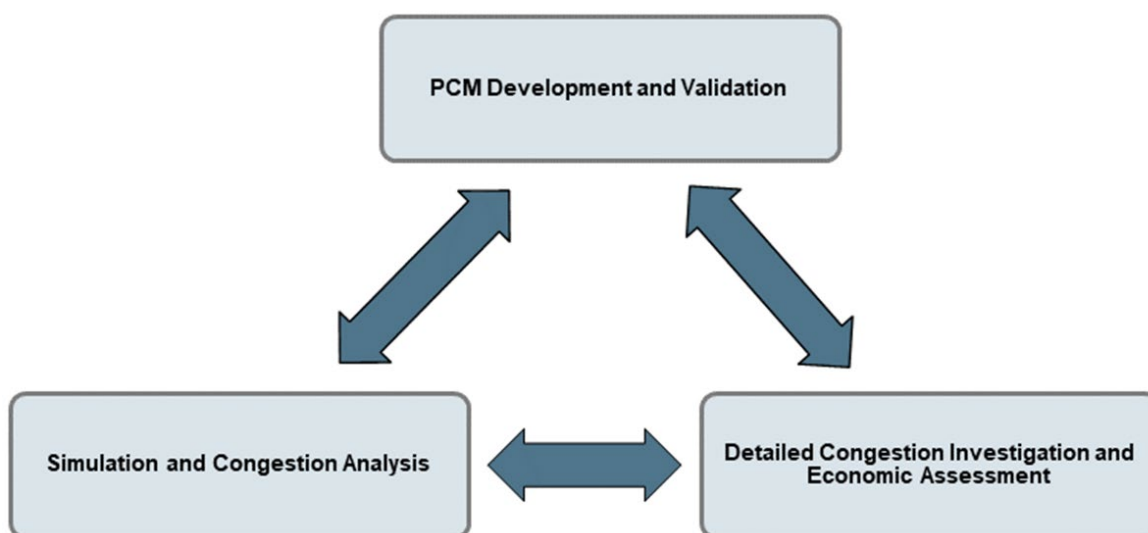
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<sup>73</sup> SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

## 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 10.3.45 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 2022-2023 transmission planning process PCM development started from the ADS PCM 2032 version 2.0, which was released by WECC on August 22, 2022. The ISO then modified the network model for the ISO system to exactly match the 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. The base portfolio PCM used the CEC California Energy Demand Updated Forecast for 2032 with high electrification load, consistent with the demand forecast in the reliability assessment as described in Chapter 2. Different from previous planning cycles, the sensitivity portfolio PCM in this planning cycle used different load forecast from the base portfolio PCM, which is the 2035 energy demand updated forecast with high electrification load. Generator locations and installed capacities in the PCM are consistent with the policy assessment power flow case for 2032, 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 1,062 MW of capacity identified in two alternative locations, Wyoming or 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 as baseline assumption in the base portfolio

PCM. The Idaho wind scenario was also assessed in the SWIP North project assessment as set out in Section 3.6.

The 2022-2023 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
SCE NOL	80.06	6,214	SCE North of Lugo area congestion was observed mostly on the Kramer-Victor 230 kV lines under normal condition and on the Lugo 500/230 kV transformer under N-1 contingency of the Lugo 500/230 kV transformer. Renewable resources in this area, especially in the Kramer area, identified in the CPUC base portfolio, are the driver of the congestion in the SCE NOL area.
COI Corridor	52.83	1,151	COI congestion increased compared with the results in the previous planning cycle. This was mainly caused by the increase of renewable resources in the Northwest regions in the ADS PCM case, especially in the south Oregon area.
Path 26 Corridor	47.32	1,896	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 in Southern CA identified in the CPUC portfolio
GridLiance/VEA	40.37	3,547	The Innovation-Desert 230 kV line was the most congested line in the GridLiance West/VEA area. The relatively low line ratings of the Innovation-Desert 230 kV lines are the main driver of the congestion.
PG&E Panoche/Oro Loma area	32.24	2,213	Congestions on 115 kV and 70 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 115/70 kV system contributed most to the congestion in this area. Congestion was also observed in real system operation in the Panoche/Oro Loma area.
SDGE San Diego Southern	13.91	1,018	Congestion in the San Diego area was observed mainly on the Suncrest-Sycamore 230 kV line and Silvergate-Bay Boulevard 230 kV line. The congestion was attributed to the solar generation in the Imperial area and the import from Arizona through the SWPL and Sunrise 500 kV lines. Reliability and policy upgrades from the Imperial Valley area to the SCE system that were proposed in this planning cycle will help to mitigate the San Diego congestion.
PG&E Fresno	13.81	1,012	PG&E's Fresno area congestion were observed mainly in the Henrietta 115 kV system, specifically the congestion on GWF_HP – Contadina – Jackson under P7 contingency of losing

Constrained area or branch group	Cost (M\$)	Duration (Hours)	Overview of investigation
			the HELM-MCCALL and HENTAP2-MUSTANGSS #1 230 kV lines. Solar generation in the Mustang area and loop flow between the 230 kV and 115 kV systems contributed to the congestion.
SCE W.LA	12.92	197	Congestions were observed in the SCE's Western LA Basin area, mainly on the La Cienega – La Fresa 230 kV line. Potential mitigations were studied in previous planning cycles as part of the LCR reduction study. These congestions will be monitored and investigated in future planning cycles with further clarity of gas-fired generator retirement and battery development at the local areas.
Path 46 WOR	7.86	210	Path 46 congestion was observed mainly as the path rating was derated under scheduled outages on some transmission lines of the path. Reliability and policy upgrades from the Imperial Valley area to the SCE system that were proposed in this planning cycle will help to mitigate the Path 46 congestion.
PG&E Moss Landing-Las Aguilas 230 kV	7.64	334	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 and in the months when the summer line rating was applied. The congestion is attributed to both the PG&E's Fresno area solar generation and the PG&E's Greater Bay Area load. The series reactor, which was approved in the 2021-2022 cycle, can effectively reduce the flow on the Moss Landing – Las Aguilas 230 kV line. The congestion was aggravated as solar generation in the PG&E Fresno area increased.
Path 15 Corridor	7.49	253	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.
SDGE/CFE	6.25	1,528	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 CAISO 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. Other factors that impacted the congestion include future renewable generation development in the Imperial Valley area and its representation in the renewable portfolio, and the CFE's generation and load modeling assumption. Further clarity of such factors will be required before detailed investigations need to be conducted.
SCE EOL	5.56	197	The congestion in the SCE East of Lugo area was observed mainly on the Eldorado-McCullough 500 kV line and the Victorville-Lugo 500 kV line under N-1 contingency of the Eldorado-Lugo 500 kV line. 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.
SCE Antelope 66kV	5.43	1,265	Neenach-Baily 66 kV line congestion was observed in this planning cycle, which was identified in previous planning cycle as well. This congestion was driven by local renewable generators in the CPUC renewable portfolio, and by the loop flow between the 230 kV and 66 kV system in the Antelope area. Congestion in the Antelope 66 kV area was subject to change with further clarity of the interconnection plans of the future resources.
PG&E Collinsville-Pittsburg 230 kV	4.29	532	Collinsville-Pittsburg 230 kV line congestion was correlated with COI congestion, and can also be impacted by future offshore wind development.
PG&E North Valley	3.86	198	PG&E North Valley area congestion (mainly the Round Mountain-Cottonwood 230 kV congestion) was correlated with COI congestion, and can also be impacted by future offshore wind development.
PDCI	1.50	157	PDCI congestion was observed when the flow was in either direction. The congestion in north to south direction was correlated with the COI congestion, and the congestion in south to north direction was correlated with the Path 26 congestion.

#### 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 Tehachapi	31,060	743	31,804	2.34%
PG&E Fresno/Kern	17,924	418	18,342	2.28%
SCE Eastern	15,326	618	15,944	3.88%
SDGE IV	8,296	0	8,296	0.00%
SCE NOL	7,403	403	7,805	5.16%
PG&E Diablo OSW	7,635	98	7,734	1.27%
GridLiance/VEA	7,284	170	7,454	2.28%
NM	6,281	230	6,511	3.53%
AZ	5,621	166	5,786	2.86%
SCE EOL	5,465	125	5,590	2.23%
PG&E Central Valley	5,448	15	5,463	0.27%
WY	3,890	147	4,037	3.64%
PG&E Central Coast	2,797	53	2,849	1.85%
SCE Vestal-Rector	2,349	65	2,414	2.69%
PG&E North Valley	2,240	3	2,242	0.13%
NW	1,876	183	2,059	8.90%
SCE Ventura	1,288	51	1,340	3.83%
SCE Antelope 66 kV	926	23	949	2.39%
PG&E Humboldt OSW	618	2	620	0.30%
SCE LA Basin	315	5	320	1.46%
IID	308	0	309	0.05%
SDGE San Diego	262	0	262	0.01%
PG&E GBA	110	1	110	0.71%
<b>Total</b>	<b>134,719</b>	<b>3,518</b>	<b>138,237</b>	<b>2.54%</b>

Wind and solar curtailment was reduced compared with the results in the previous cycle although total renewable capacity increased. Curtailment was reduced in some areas notably, specifically in the GridLiance/VEA area, the PG&E Fresno area, and the SCE Tehachapi area. This change was mainly attributed to the following factors:

- Battery capacity increased in the CPUC portfolio. Renewable surplus due to either transmission or system constraints can be used to charge battery instead of being curtailed;
- Transmission upgrades approved in the previous cycle helped to reduce renewable curtailment effectively, specifically GridLiance/VEA 230 kV upgrades in the GridLiance/VEA area, Manning, Collinsville, and Moss Landing-Las Aguilas upgrades in the PG&E area; and

- Improved busbar mapping for battery and renewable generators further helped to reduce renewable curtailment, especially in the SCE Tehachapi area.

## 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 through the economic planning studies.

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

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

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

### 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	Selected to receive detailed assessment as a transmission alternative to interconnect Idaho wind generators as proposed in the CPUC portfolio. Also, it can be an alternative to mitigate COI corridor congestion.
2	NGIV2 Project	NGIV2 and IID	AZ/CA	Identified as a component of policy upgrade in southern California.
3	Fresno Avenal Area Congestion	PG&E	PG&E Fresno Avenal area	No significant congestion was observed in this area. No further assessment in this planning cycle
4	Inyokem 230 kV Upgrade	SCE	North of Lugo area	No significant congestion was observed in this area. No further assessment in this planning cycle
5	PTE Project	California Western Grid Development	Northern/Southern CA	Selected to receive detailed assessment as a transmission alternative to mitigate Path 26 corridor congestion
6	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 or the Great Bay Area load increased compared with the solar generation and load in the last planning cycle. The congestion was aggravated in the Sensitivity Portfolio PCM. Long term solution will be needed, but further clarify of load and resource assumptions in the PG&E Fresno and Greater Bay areas is required in order to conduct comprehensive assessment. This congestion will be monitored and reassessed in future planning cycle.
7	GLW 500 kV Upgrade Project	GridLiance West	Southern NV	Policy need was identified in this planning cycle. Significant congestion was observed in the GLW/VEA area. This study request was selected to receive detailed production cost simulation to evaluate the effectiveness of mitigating congestion. Economic assessment was also conducted.
8	GLW Geothermal Upgrade	GridLiance West	Southern NV	Policy upgrade was identified in this area, which is an alternative to this study request. No detailed production cost simulation and economic assessment were conducted 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
Path 26 corridor congestion	Midway-Windhub 500 kV line	ISO	Recurring congestion with large congestion cost. The mitigation alternatives are expected to help to mitigate the congestion
	PTE project	Western Grid	
GLW/VEA area congestion	GLW 500 kV Upgrade	GridLiance West	Congestion with a large congestion cost, although the GLW 230 kV upgrades approved in the last TPP cycle were modeled. The mitigation alternatives are expected to help to mitigate the congestion and reduce renewable curtailment in the GridLiance West/VEA area. Policy need was identified.
PG&E Panoche/Oro Loma area congestion	Multiple alternatives, including SPS, re-rating or reconductoring, and operation summer setup, and the combinations of alternatives	ISO	Significant congestions on the 70 kV and 115 kV in this area were identified in this planning cycle. Some identified congestions are consistent with existing congestion in actual system operation. Detailed analysis on the production cost simulation results can help to understand the issues. The alternatives potentially can help to mitigate the congestion
PG&E Fresno Henrietta 115 kV congestion	Multiple alternatives, including new 115 kV transmission lines and SPS	ISO	Congestion with high congestion cost. It is a critical constraint in the Fresno area that impacts future renewable development in this area. It also indicated potential 230 kV and 115 kV loop flow issue under contingency condition in this area. Potentially mitigate or reduce the identified congestion
Idaho wind scenario with SWIP North	SWIP North	LS Power	Idaho wind scenario with new transmission upgrade was suggested in CPUC portfolio. SWIP North was studied as a potential transmission upgrade alternative for Idaho wind, also it can potentially help to mitigate COI congestion
SCE North of Lugo congestion	Kramer to Victor and Victor to Lugo 230 kV upgrades, including Lugo 500/230 kV transformer	ISO	Significant congestion was observed in the SCE North of Lugo area, especially on the Kramer to Victor 230 kV lines and the Lugo 500/230 kV transformers. Policy need was identified.
	Kramer to Lugo 500 kV upgrade		

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),<sup>74</sup> 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 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 2022-2023 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<sup>75</sup> 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 2022-2023 Plan. As there were no material change in the assumption around the value of

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<sup>74</sup> Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017  
[http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2\\_2017.pdf](http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf)

<sup>75</sup> SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

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 cycle were used in the economic assessment for the transmission projects that potentially had benefit of reducing local capacity. The ISO recognizes that the capacity value of many of these projects will need to be revised when actionable direction on the need for gas-fired generation for system and flexible needs is available.

Out-of-state wind and transmission upgrades were assessed in this planning cycle using both the Base portfolio, specifically, the scenario with Idaho wind and SWIP North project was studied as an alternative to the scenario of Wyoming wind and TransWest Express project.

The overall economic planning study results in the 2022-2023 planning cycle are summarized in Table 4.9-1, including the Base portfolio out-of-state wind study results.

Table 4.9-1: Summary of economic assessment in the 2022-2023 planning cycle

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
Path 26 corridor congestion	Midway-Windhub 500 kV line	Path 26 corridor congestion was partially mitigated; Ratepayer benefit is not sufficient.	No	No
	PTE project	Path 26 corridor congestion was partially mitigated; Ratepayer benefit is not sufficient.	No	No
GLW/VEA area congestion	GLW 500 kV Upgrade	GLW/VEA congestion was partially mitigated; Ratepayer benefit is not sufficient.	No	Policy need was identified
PG&E Panoche/Oro Loma area congestion	Modify the 70 kV summer setup	70 kV congestion was mitigated, but 115 kV congestion was aggravated; Ratepayer benefits is not sufficient.	No	No
	SPS of tripping local solar generators under the Panoche-Mendota 115 kV line N-1 contingency	Not effective to mitigate either 70 kV or 115 kV congestion.		
	Rerating the 115 kV lines	115 kV congestion was mitigated, but 70 kV congestion was not mitigated; Ratepayer benefit is not sufficient.		
	Modify the 70 kV summer setup plus rerating the 115 kV lines	Most of 70 kV and 115 kV congestion was mitigated; Ratepayer benefit is not sufficient.		
	Modify the 70 kV summer setup plus rerating the 115 kV lines plus SPS of tripping local solar generators	Most of 70 kV and 115 kV congestion was mitigated; Ratepayer benefit is not sufficient.		
PG&E Fresno Henrietta 115 kV congestion	CWF – Contadina – Jackson 115 kV double circuit	Congestion was mitigated; Ratepayer benefits not sufficient.	No	No
	SPS of opening the GWF-Contadina 115 kV line under the Helm-Mc Call and Henrietta Tap2 – Mustang 230 kV lines N-2 contingency	Congestion was mitigated; Recommended PG&E to further evaluate feasibility and reliability implication of implementing the RAS.		
Idaho wind scenario with SWIP North	SWIP North	COI congestion was partially mitigated; Ratepayer benefits not sufficient.	No	No
SCE North of Lugo congestion	Kramer to Lugo 230 kV upgrade	Kramer-Lugo corridor congestion was mitigated; Ratepayer benefits not sufficient.		Policy need was identified
	Kramer to Lugo 500 kV upgrade			

In summary, no transmission solutions were found to have sufficient economic benefits to proceed solely on the merits of the economic study results. Therefore, the CAISO will not recommend any economic-driven transmission upgrades in this planning cycle.

Transmission alternatives assessed in this chapter can help to address transmission congestion or renewable curtailment issues in respective study areas. Based on the results of the economic assessment and the production cost simulation, the ISO will coordinate with PG&E to further investigate summer setup and other feasible operation and transmission solution to mitigate the Panoche/Oro Loma area congestion and renewable curtailment issue. The ISO will also coordinate with PG&E to investigate the feasibility of the SPS solution or other potential transmission solution to mitigate Henrietta 115 kV congestion.

The ISO performed additional economic studies of the SWIP North project. The detailed studies conducted in the 2020-2021 Transmission Plan demonstrated that – without clear policy support for accessing Idaho resources for resource planning purposes – the project on its own provided significant economic benefits, but not sufficient to warrant the cost of the project to ISO ratepayers. These circumstances are now evolving, as there is greater support for accessing Idaho wind resources based on the renewable generation portfolios provided by the CPUC for this year’s studies, as well as the portfolios that have already been provided for the 2023-2024 transmission plan. The ISO did conduct an additional study of the SWIP North project by comparing production cost results with and without the SWIP North project, and with incremental Idaho wind resources modeled in both cases. The analysis provides useful complementary insights. Please refer to Chapter 3.

Two policy transmission upgrades identified in Chapter 3 were assessed in this chapter to compare economic benefits of different transmission alternatives. They are the GLW 500 kV Upgrade and the SCE North of Lugo area Kramer to Lugo Upgrade. All proposed transmission alternatives showed economic benefit greater than zero to the CAISO ratepayers, which provide additional justification for these transmission upgrades.

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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 2022-2023 transmission planning cycle was completed during the even-year portion of the 2022-2023 interregional transmission coordination cycle.

The ISO opened its 2022-2023 ITP submission window in the first quarter of 2022, during 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 project sponsors. However, as part of the submission validation process, it was determined that only one project met the requirement of an interregional transmission project. The project only connects the ISO and WestConnect. With WestConnect not finding a regional need for this project, it will not be considered an Order 1000 interregional transmission project and no interregional projects will be moving into year two.

#### 5.1 Interregional Transmission Coordination per FERC Order No. 1000

The ISO's interregional coordination and interregional transmission project study process was developed to align with FERC Order No. 1000 requirements. The FERC Order No. 1000 broadly reformed the regional and interregional planning processes of public utility transmission providers, and as part of that reform, also required improved coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. For the ISO, these coordination processes are in place with our neighboring planning entities, WestConnect and Northern Grid, and they and the ISO are referred to collectively as the Western Planning Regions (WPRs). While FERC Order No. 1000 only requires comment tariff provisions between pairs of neighboring planning entities, enabling for example the ISO to have different coordination provisions with WestConnect than with Northern Grid, the ISO is fortunate that a common set of coordination provisions have been established across all three. This greatly simplifies the coordination process.

In addition to tariff provisions establishing the 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.

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 planning data and information among the WPRs, at least annually; and
- (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.

### **5.1.1 Procedure to Coordinate and Share ISO Planning Results with other WPRs**

The ISO exchanges its interregional information with the other WPRs in two ways: an annual coordination meeting hosted by the WPRs, and 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 would be responsible for facilitating the meeting. The annual coordination meetings are generally held in February of each year, but no later than March 31. Hosting responsibilities are shared by the WPRs in a rotational arrangement that has been agreed to by the WPRs. The ISO hosted the 2022 meeting and WestConnect is hosting the 2023 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, an update on ITP evaluation activities, and other related issues. It is important to note that the ISO's planning processes are annual while the planning processes of NorthernGrid and WestConnect are biennial. To address this difference in planning cycles, the WPRs have agreed to annually share the planning data and information that is available at the time the annual interregional coordination meeting is held, divided into an "even" and "odd"-year framework. Specifically, the information which the ISO shares is shown in Table 5.1-1.

Table 5.1-1: Annual Interregional Coordination Information

Even Year	Odd Year
Most recent draft transmission plan	Most recent draft transmission plan
ITPs that: <ul style="list-style-type: none"> <li>• Were being considered within the previous odd year draft transmission plan;</li> <li>• Are being considered within the previous odd-year draft transmission plan for approval and/or awaiting “final approval” from the relevant planning regions; and</li> <li>• Have been submitted for consideration in the even-year transmission plan.</li> </ul>	ITPs that: <ul style="list-style-type: none"> <li>• Were being considered within the previous even year draft transmission plan; and</li> <li>• Were considered in the even-year draft transmission plan and approved by the ISO Board for further consideration within the odd-year draft transmission plan.</li> </ul>

**5.1.2 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 1 through March 31 of every even-numbered year. Interregional Transmission Projects will be considered by the WPRs on the basis identified in Section 5.2.

An ITP submission must include specific technical and cost information for the ISO to consider during its validation/selection process of the ITP. For the ISO to consider a proponent’s project as an ITP, it must have been submitted to and validated by at least one other WPR. Once the validation process has been completed, each WPR is then considered to be a Relevant Planning Region. All Relevant Planning Regions consider the proposed ITP in their regional process. For the ISO, validated ITPs will be included in the ISO’s Transmission Planning Process Unified Planning Assumptions and Study Plan for the current planning cycle and evaluated in that year’s transmission planning process.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

**5.1.3 Interregional Transmission Project Submittal Requirements**

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

- The ITP must electrically interconnect at least two Order 1000 planning regions;
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO’s transmission planning process;

- When a sponsor submits an ITP into the regional process of an Order 1000 planning region, it must indicate whether it is seeking cost allocation from that Order 1000 planning region; and
- When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

#### **5.1.4 Evaluation of Interregional Transmission Projects by the ISO**

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

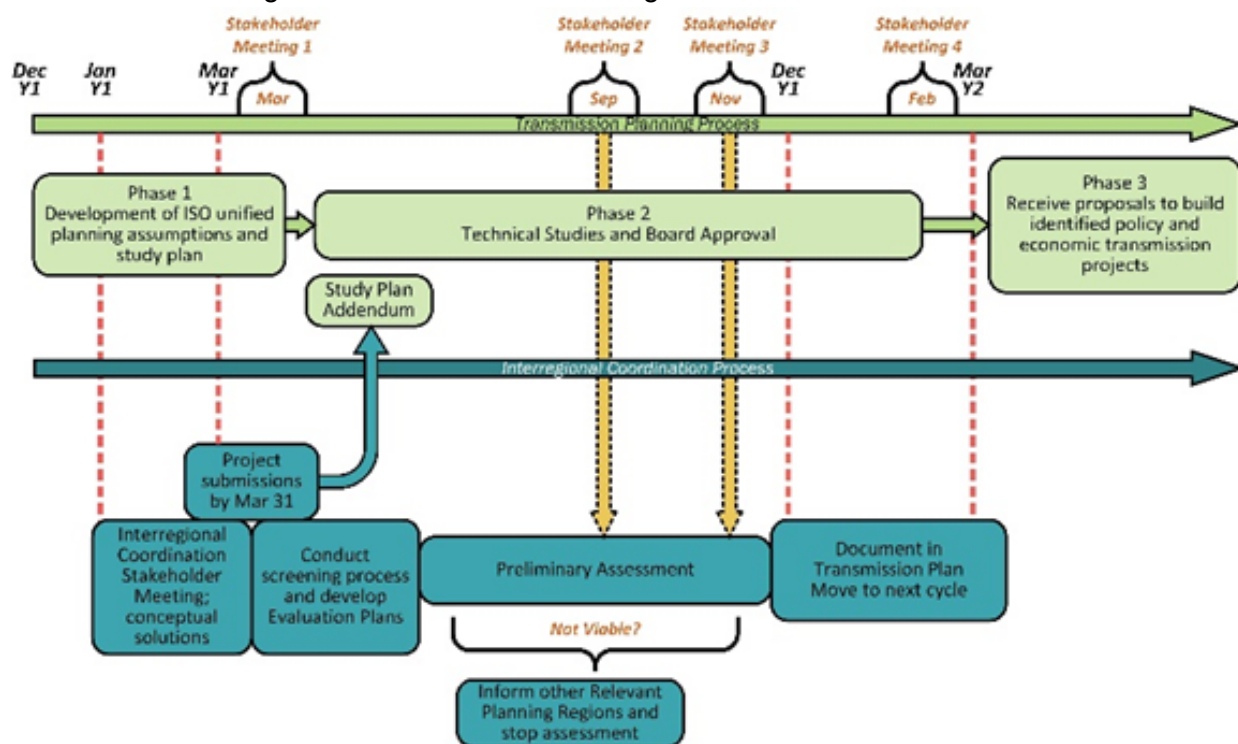
##### **5.1.4.1 Even Year ITP Assessment**

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 where 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 submission 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 Figure 5.1-1, the ISO shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the ISO manages its assessment of an ITP proposal across the two-year interregional coordination cycle in two steps. During the even year, the ISO makes a preliminary assessment of the ITP and once it completes that task, the ISO must evaluate 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, public policy considerations, and whether the project continues to be considered by at least one other planning region

Figure 5.1-1: Even Year Interregional Coordination Process

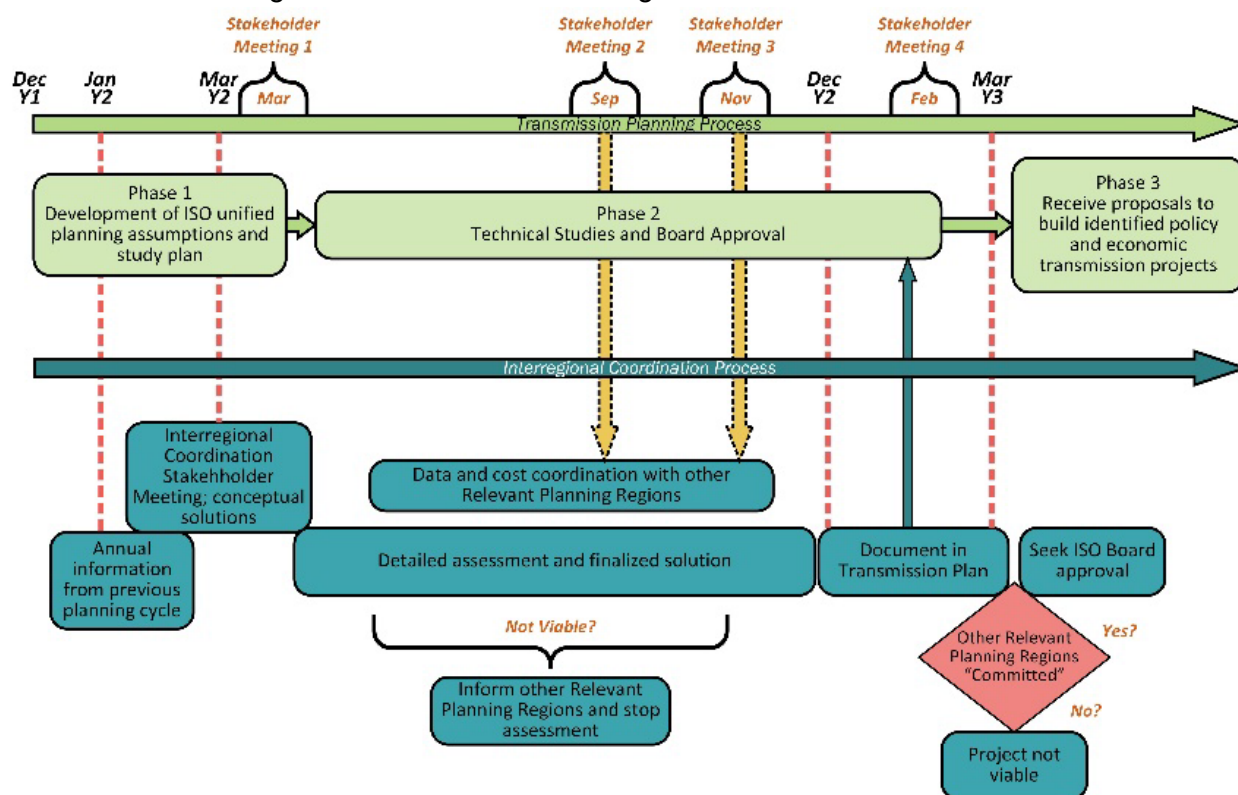


The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation whether the assessment of the ITP should continue in the odd year. The ISO Board’s approval of the transmission plan is sufficient to enact its recommendations.

### 5.1.4.2 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 will be documented in the odd-year transmission planning process, unified planning assumptions, and study plan. Similar to the even-year coordination process shown in Figure 5.1-1, the ISO will follow the odd-year interregional coordination process shown in Figure 5.1-2.

Figure 5.1-2: Odd Year Interregional Coordination Process



During the odd-year planning cycle, the ISO will conduct a more in-depth analysis of the project proposal, which will include consideration of the timing in which the regional solution is needed and the likelihood that the proposed interregional transmission project will be constructed and operational in the same timeframe as the regional solution(s) it is replacing. The ISO may also determine the regional benefits of the interregional transmission project to the ISO that will be used for purposes of allocating any costs of the ITP to the ISO.

If the ISO determines that the proposed ITP is a more efficient or cost-effective solution to meet an ISO-identified regional need and the ITP can be constructed and operational in the same timeframe as the regional solution, the ISO will then consider the ITP as the preferred solution in the ISO transmission plan. The ISO will document its analysis of the ITP and the other regional transmission solutions.

Once the ISO selects an ITP in the ISO transmission plan, the ISO will coordinate with the other relevant planning regions to determine if the ITP will be selected in their regional plans and whether a project sponsor has committed to pursue or build the project. Based on the information available, the ISO may inform the ISO Board on the status of the ITP proposal and if appropriate, seek approval from the board to continue working with all relevant parties associated with the ITP to determine if the ITP can viably be constructed. Determining viability may take several years during which time the ISO will continue to consider the ITP in its transmission planning process and if appropriate, select it as the preferred solution. The ISO may seek ISO Board approval to build the ITP once the ISO receives a firm commitment to construct the ITP.

## 5.2 2022-2023 Interregional Transmission Coordination ITP Submissions to the ISO

The ISO opened its 2022-2023 ITP submission window in the first quarter of 2022, when proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2022-2023 transmission planning process. The submission period began on January 1 and closed on March 31. Seven projects and their documentation<sup>76</sup> were submitted by their project sponsors for consideration by the ISO. The submitted projects are shown in Table 5.2-1

Table 5.2-1: ITPs Submitted into the 2020-2021 Submission Period

Project Name	Company	Project Submitted to	Relevant Planning Regions	Cost Allocation Requested From	Description	In Service Date
North Gila – Imperial Valley #2 (NGIV2)	NGIV2, LLC	CAISO, WC	CAISO, WC	CAISO	500 kV line from North Gila to Imperial Valley with 500/230 kV Connection to IID system at new Dunes substation.	2026
SWIP-North	Great Basin Transmission LLC	CAISO, NG	CAISO, NG	CAISO, NG	Midpoint to Robinson Summit 500 kV line.	2025
Del Norte HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Del Norte area in the Pacific Ocean to Pittsburg substation.	2035
Humboldt HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Humboldt area in the Pacific Ocean to Potrero substation.	2030
Cape Mendocino HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Cape Mendocino area in the Pacific Ocean to Moss Landing substation.	2040
Diablo Canyon HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Diablo Canyon call area in the Pacific Ocean to Diablo Canyon substation.	2030
Morro Bay HVDC Transmission Collector	Premium Energy Holdings, LLC	CAISO	CAISO	Not requested	HVDC project to connect Morro Bay call area in the Pacific Ocean to Morro Bay substation.	2030

Following the submission and the screening of the ITP submittals, it was determined that only North Gila – Imperial Valley #2 (NGIV2) project is qualified as an interregional project. More details on the NGIV2 project is provided in Section 5.2.1. Regarding the SWIP-North project, NorthernGrid indicated that since the proposed project is entirely within the NorthernGrid system, it is not qualified as an Order 1000 interregional transmission project. The ISO agreed with the NorthernGrid's assessment and therefore the project was not further studied in the

<sup>76</sup> <http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx>

Order 1000 process. Regarding the five HVDC projects, since the projects were only submitted to the ISO, they are not qualified as an Order 1000 interregional transmission project which requires a project connect at least two western planning regions. The ISO developed its ITP evaluation for the NGIV2 project in coordination with the other relevant planning regions. Given the intent of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP, the NGIV2 evaluation plan satisfy that intent and as such, fulfills Order 1000's requirement of the relevant planning regions to jointly coordinate regional planning processes that evaluate an ITP. In doing so, the NGIV2 evaluation plan documents a common framework, coordinated by the WPRs, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process. The ISO then utilizes this information in its development of all planning data and information that is required for the ISO to assess the ITP in its transmission planning process. Specifically, the information in the evaluation plan is considered an addendum to the approved Transmission Planning Process Unified Planning Assumptions and Study Plan.<sup>77</sup>

## 5.2.1 North Gila – Imperial Valley Transmission Project and Assessment Results

### Project Description

The NGIV2, LLC submitted the North Gila-Imperial Valley #2 (NGIV2) Transmission Project for consideration as an Interregional Transmission Project. The NGIV2 is a proposed 500 kV AC transmission project that will extend approximately 90 miles and will be constructed between southwest Arizona and southern California (see Figure 5.2-1). The line will parallel the existing North Gila-Imperial Valley line, also known as the Southwest Power Link (SWPL), and will connect the existing 500 kV North Gila substation (in the WestConnect planning region) with the existing 500 kV Imperial Valley substation (in the California ISO planning region). NGIV2 would be constructed to loop in a new 500/230 kV Dunes substation (in the WestConnect planning region) and would also include construction of a new 230 kV line from Dunes into the existing IID Highline 230 kV substation. A new 500/230 kV transformer would be installed in the Dunes substation as part of the NGIV2 project. This project will become an additional component of the West of Colorado River path (Western Electricity Coordination Council (WECC) path 46) and is expected to increase the East of Colorado River path (WECC path 49) transfer capability by 1,250 MW. Series compensation may be added to the project to balance flows on this new circuit and the existing SWPL line.

NGIV2, LLC completed the WECC 3-phase rating process on September 5, 2019. The NGIV2, LLC is currently evaluating potential alternative routes and working with the responsible regulatory agencies to obtain all necessary project approvals. According to NGIV2, LLC, the project is expected to be in-service by December 2026.

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<sup>77</sup> <http://www.caiso.com/InitiativeDocuments/FinalStudyPlan-2022-2023TransmissionPlanningProcess.pdf>





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## Chapter 6

### 6 Other Studies and Results

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan and are either set out in the ISO tariff or form part of the ongoing collaborative study efforts taken on by the ISO to assist the CPUC with state regulatory needs. The studies have not been addressed elsewhere in the transmission plan. These presently include the reliability requirements for resource adequacy, simultaneous feasibility test studies, a system frequency response assessment, and a flexible capacity deliverability assessment.

#### 6.1 Reliability Requirement for Resource Adequacy

Section 6.1.1 summarizes the technical studies conducted by the ISO to comply with the reliability requirements initiative in the resource adequacy provisions under Section 40 of the ISO tariff. 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 2023. 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 2022. A short-term analysis was conducted for the 2023 system configuration to determine the minimum local capacity requirements for the 2023 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the ISO tariff Section 40.3. This study was conducted in January through April through a transparent stakeholder process with a final report published on April 28, 2022. For detailed information on the 2023 LCT Study Report please visit:

<http://www.caiso.com/InitiativeDocuments/Final2023LocalCapacityTechnicalReport.pdf>

One long-term analysis was also performed identifying the local capacity needs in the 2027 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years respectively. The 2027 LCT Study Report was published on April 28, 2022. For detailed information please visit:

<http://www.caiso.com/InitiativeDocuments/Final2027Long-TermLocalCapacityTechnicalReport.pdf>

The ISO also conducts a 10-year local capacity technical study every second year, as part of the annual transmission planning process. The 10-year LCT studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide an indication of

whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding. 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 7,500 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 2023, 2027 and 2032

LCR Area	LCR Capacity Need (MW)		
	2023	2027	2032
Humboldt	141	147	154
North Coast/North Bay	857	911	911
Sierra	1,150	1,345	1,450
Stockton	579	555	755
Bay Area	7,312	7,540	7,936
Fresno	1,870	2,179	2,750
Kern	439	320	424
Big Creek/Ventura	2,240	1126	1,366
Los Angeles Basin	7,529	6,131	7,388
San Diego/Imperial Valley	3,332	3,369	4,849
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	25,449	23,623	27,983
<b>Notes:</b>			
For more information about the LCR criteria, methodology and assumptions, please refer to the ISO LCR manual. <sup>78</sup>			
For more information about the 2023 LCT study results, please refer to the report posted on the ISO website.			
For more information about the 2027 LCT study results, please refer to the report posted on the ISO website.			

<sup>78</sup> "Final Manual 2023 Local Capacity Area Technical Study," January 14, 2022, <http://www.caiso.com/InitiativeDocuments/2023LocalCapacityRequirementsFinalStudyManual.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 2023 in accordance with the ISO tariff Section 40.4.6.2.1. These data can be found on the ISO website.<sup>79</sup> The entire import allocation process<sup>80</sup> 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/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2023-2032.pdf>

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW 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. In order to achieve an increase to 702 MW total MIC from IID, upgrades on the ISO system are currently complete, awaiting the completion of the IID-owned 230 kV S Line.

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 base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2032.

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 6.1-6.1-3: TPP deliverability study results regarding CPUC main portfolio

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
2	MEAD_ITC (MEAD 230)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
3	IID-SCE_ITC (MIR2)	Failed	For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
4	IID-SDGE_ITC (IVLY2)	Failed	For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
5	MCCULLGH_ITC (ELDORADO500)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
6	PALOVRDE_ITC (PVWEST)	Failed	For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.

<sup>79</sup> "California ISO Maximum RA Import Capability for year 2023," available on the ISO's website at <http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2023.pdf>.

<sup>80</sup> See general the Reliability Requirements page on the ISO website <http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx>.

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.

### 6.1.2.2 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 CAISO within 2 weeks after the first stakeholder meeting and not later than the time that the study plan comments were due. The valid maximum import capability expansion requests have identified the intertie(s) (branch group(s)) that require expansion.

The CAISO 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 6.1-6.1-4: Valid Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource Type
1-4	San Diego Community Power	IID-SCE_ITC (MIR2)	150	Hybrid (Solar/Battery)
		ELDORADO_ITC (WILLOWBEACH)	333	Wind
2-5	Valley Electric Association	MEAD_ITC (MEAD 230)	33	Hydro
			90	Solar
9-10	Sonoma Clean Power	GONDIPDC_ITC (GONIPP)	68	Geothermal
		MERCHANT_ITC (ELDORADO230)	40	
		IID-SDGE_ITC (IVLY2)	50	
		SILVERPK_ITC (SILVERPEAK55)	13	
11	East Bay Community Energy	SUMMIT_ITC (SUMMIT120)	40	Geothermal
		SILVERPK_ITC (SILVERPEAK55)		
12	Peninsula Clean Energy	IID-SCE_ITC (MIR2)	26	Geothermal
13	Southwestern Power Group II	PALOVPRD_ITC (PVWEST)	1257	Wind

The CAISO has received 12 submissions with requests for MIC expansion. They contained 29 distinct requests (a few were duplicates – the LSE provided the request and the supplier provided a requests for the same resource).

Based on the CAISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) requirements, 13 distinct requests qualify as valid requests based on the following factors:

1. LSEs with valid RA contracts not already accounted for as Pre-RA Import Commitments or New Use Import Commitment.
2. Submittals by transmission owners – with connection in a neighboring Balancing Authority Area immediately adjacent to the CAISO Controlled Grid.



For the following reasons, 16 distinct requests do not qualify at this time:

1. Submissions by LSEs and/or resource owners with “shortlisted” contracts - since they do not have an existing RA contract with a CAISO LSE.
2. Submissions by resource owners with resources in other Balancing Authority Area (BAA) queue including site exclusivity - since they do not have an existing RA contract with a CAISO LSE.
3. Submissions by owners of Pseudo-ties or Dynamic schedules with Transmission Service Agreements (TSA) to the CAISO border – since they do not have an existing RA contract with a CAISO LSE. The TSA is required to participate in the CAISO energy market as an energy only resource (see Tariff Section 40.8.1.12.1) plus the TSAs are given out on non-simultaneous bases (incompatible with the MIC calculation).

The CAISO 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 6.1-6.1-5: Assessment of valid Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Triggers expansion	Comments:
1-4	San Diego Community Power	IID-SCE_ITC (MIR2)	150	No	CPUC portfolio triggers MIC expansion.
		ELDORADO_ITC (WILLOWBEACH)	333	In CPUC portfolio	CPUC portfolio triggers MIC expansion.
2-5	Valley Electric Association	MEAD_ITC (MEAD 230)	33	Potentially	Together with CPUC portfolio triggers MIC expansion.
			90		
9-10	Sonoma Clean Power	GONDIPDC_ITC (GONIPP)	68	Yes	
		MERCHANT_ITC (ELDORADO230)	40	No	
		IID-SDGE_BG (IVLY2)	50	No or in CPUC portfolio	CPUC portfolio triggers MIC expansion.
		SILVERPK_ITC (SILVERPEAK55)	13	Yes	
11	East Bay Community Energy	SUMMIT_ITC (SUMMIT120)	40	Yes	
		SILVERPK_ITC (SILVERPEAK55)		Yes	
12	Peninsula Clean Energy	IID-SCE_ITC (MIR2)	26	No	CPUC portfolio triggers MIC expansion.
13	Southwestern Power Group II	PALOVRDE_ITC (PVWEST)	1257	No	CPUC portfolio triggers MIC expansion.

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

NQC deliverability study:

Only 4 scheduling points had a MIC expansion requests that triggered an increase applicable to the 2023 RA year.

Table 6.1-6.1-6: 2023 NQC deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Pass	Temporary expansion included in 2023 MIC.
2	MEAD_ITC (MEAD 230)	Pass	Temporary expansion included in 2023 MIC.
3	IID-SCE_ITC (MIR2)	Failed	Due to delay in "S" line upgrade.
4	IID-SDGE_ITC (IVLY2)	Failed	Due to delay in "S" line upgrade.

The appropriate amount of MWs to the scheduling points that passed the test of the 2023 NQC deliverability study were given to the LSEs as a temporary MIC increase for RA year 2023.

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 CAISO.

Table 6.1-6.1-7: TPP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
2	MEAD_ITC (MEAD 230)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
3	IID-SCE_ITC (MIR2)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
4	IID-SDGE_ITC (IVLY2)	Failed	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
5	GONDIPPDC_ITC (GONIPP)	Failed	For potential increase see mitigation for Lugo-Victorville constraint.
6	SILVERPK_ITC (SILVERPEAK55)	Failed	For potential partial increase see upgrades under SCE North of Lugo area constraints.
7	SUMMIT_ITC (SUMMIT120)	Failed	For potential increase see Drum-Higgins constraint in PG&E Sierra area.

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. Remainder – the MIC expansion requests on their own cannot trigger transmission expansion however some of the MIC expansion requests may end up passing at a later date 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 CAISO 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 6.1-6.1-8: GIP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	ELDORADO_ITC (WILLOWBEACH)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
2	MEAD_ITC (MEAD 230)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for Lugo-Victorville constraint.
3	IID-SCE_ITC (MIR2)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
4	IID-SDGE_ITC (IVLY2)	Failed*	Included in the CPUC portfolio. For potential increase see mitigation for SCE Eastern and San Diego areas as well as Lugo-Victorville constraint.
5	GONDIPPDC_ITC (GONIPP)	Failed*	For potential increase see mitigation for Lugo-Victorville constraint.
6	SILVERPK_ITC (SILVERPEAK55)	Failed*	For potential partial increase see upgrades under SCE North of Lugo area constraints.
7	SUMMIT_ITC (SUMMIT120)	Failed*	For potential increase see Drum-Higgins constraint in PG&E Sierra area.

\* 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. 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 2022 LT CRR study leveraged the base case network topology used for the annual 2023 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 2022-2023 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 was used to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs SFT is completed successfully:

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

### 6.2.3 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

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

### 6.2.4 Conclusions

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

The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as planned. In compliance with Section 24.4.6.4 of the ISO tariff, the ISO followed the LTCRR SFT study steps outlined in Section 4.2.2 of the BPM for the Transmission Planning Process to determine whether there are any existing released LT CRRs that could be at risk and for which mitigation measures should be developed. Based on the results of this analysis, the ISO determined in December of 2022 that there are no existing released LT CRRs “at-risk” that require further analysis. Thus, the transmission projects and elements approved in the 2022-2023 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.

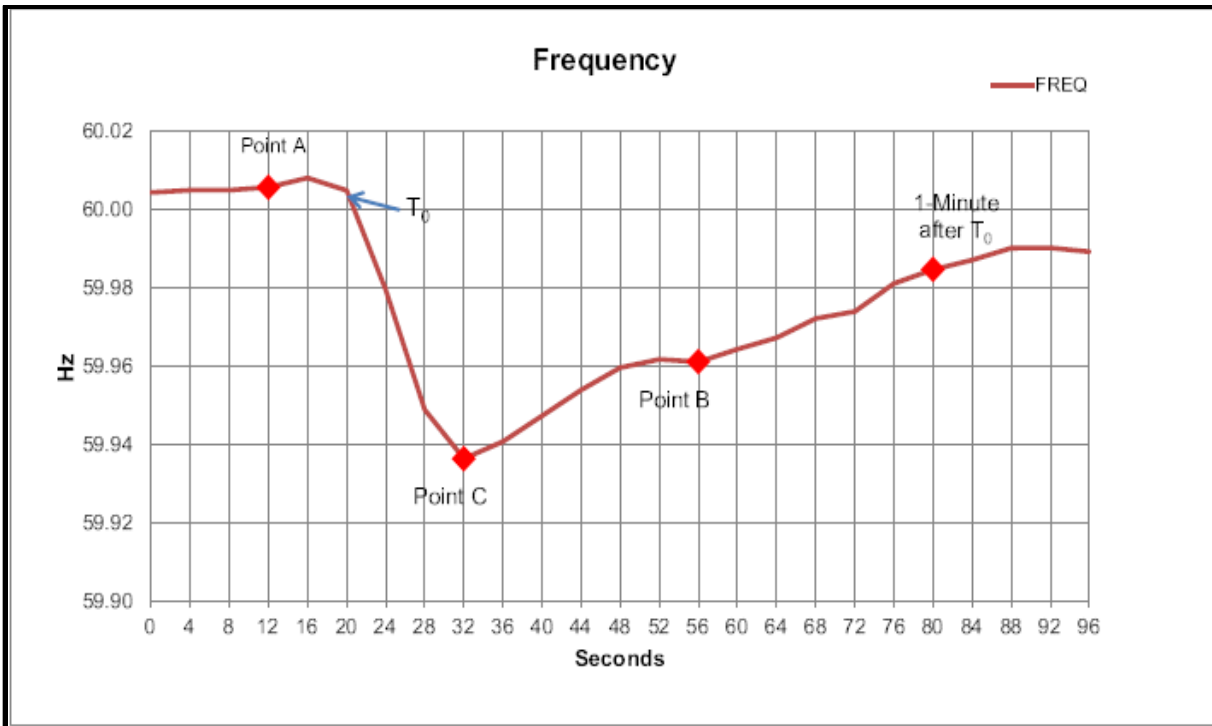
#### Background on Frequency Response and Frequency Bias Setting Methodology

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  $Kt^{81}$ ; 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

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<sup>81</sup> 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 prior 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 CAISO 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

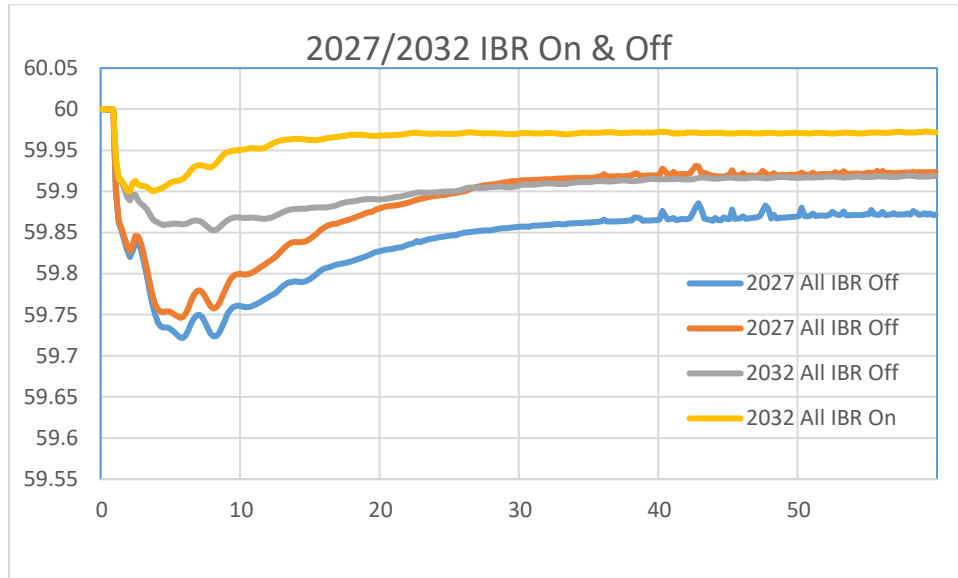


Figure 6.3-3: 2027 & 2032 Scenarios 2&3: System Frequency for all IBR Plants On and BESS Plants at 10% Headroom

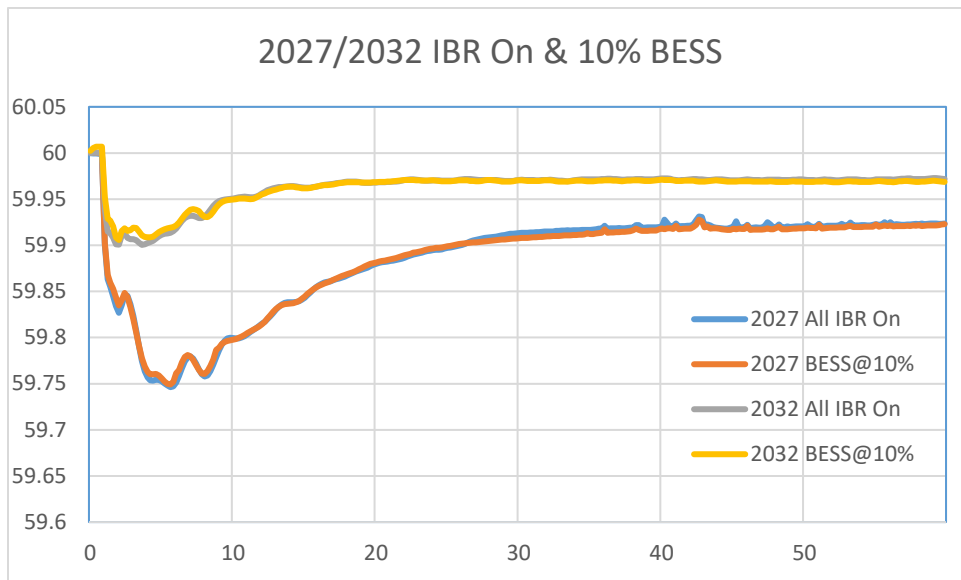


Figure 6.3-4: 2027 & 2023 Scenarios 2 & 4: System Frequency for all IBR Plants On and the ISO at Minimum Spinning Reserve

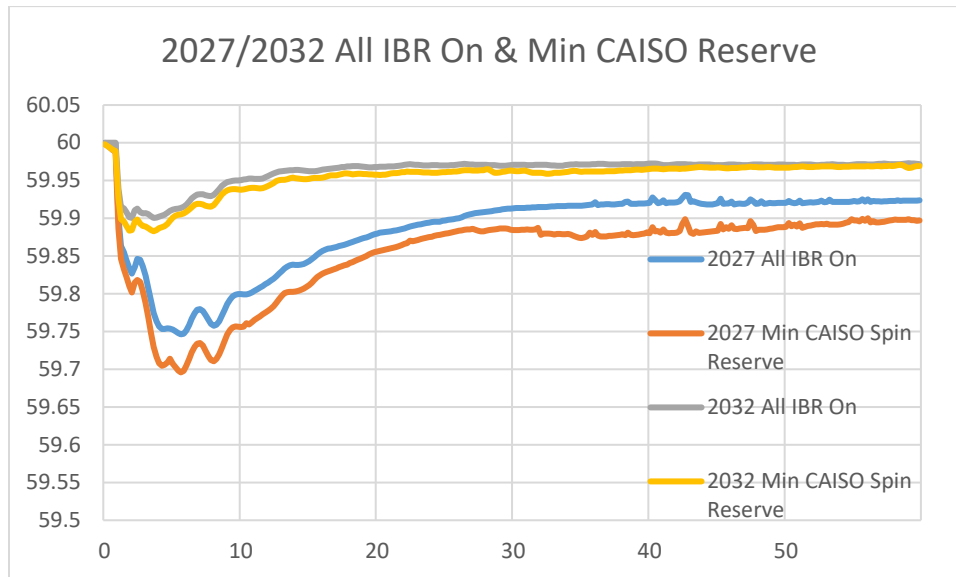
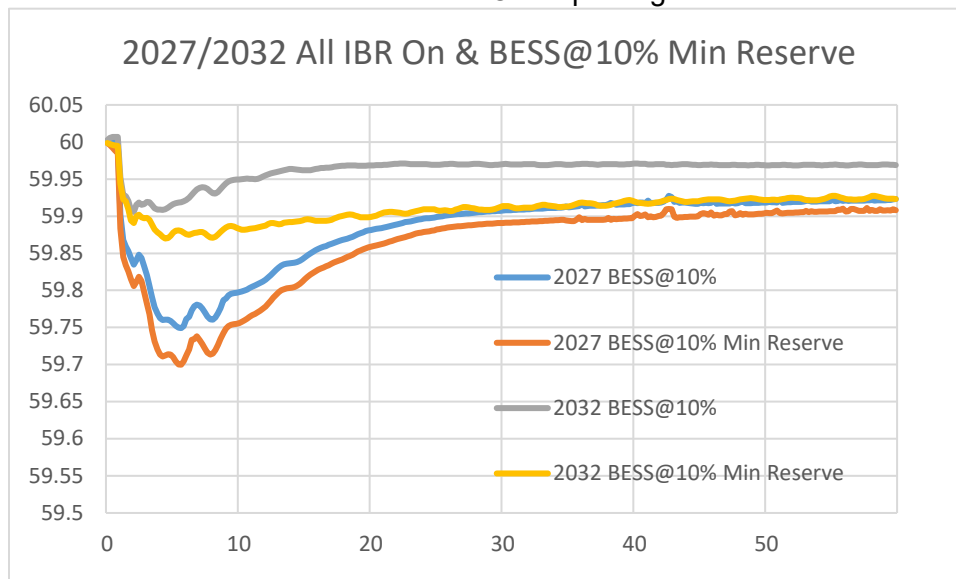


Figure 6.3-5: 2027 & 2023 Scenario 3 & 5: System Frequency Response with BESS@10% without and with the ISO at Spinning Reserve



**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.<sup>82</sup> A whitepaper released in September 2021 entitled 'Dynamic Model Review Guideline for Inverter based Interconnection Requests'<sup>83</sup> 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.

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<sup>82</sup> <https://www.aiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx>

<sup>83</sup> <http://www.aiso.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. In the 2022-2023 transmission planning cycle, the ISO performed the following two "special studies":

- Transmission reliability study for the LA Basin and San Diego-Imperial Valley local capacity areas with reduced reliance on Aliso Canyon gas storage; and
- Policy-driven assessment of the high electrification sensitivity scenario.

Only the summary of key findings is included in this chapter for the transmission reliability study for the reduced reliance on Aliso Canyon gas storage. For further details of the study findings, please refer to Appendix K of the Transmission Plan.

#### 7.1 Information Only, Transmission Reliability Study of the LA Basin and San Diego-Imperial Valley Local Capacity Areas with Reduced Reliance on Aliso Canyon Gas Storage

The Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) located in the Santa Susana Mountains of Los Angeles County is the largest natural gas storage facility in California. The facility provides gas support to the core and non-core customers, including electric generation located in the LA Basin between the ISO and the Los Angeles Department of Water and Power (LADWP) Balancing Authority Areas. On October 23, 2015, Southern California Gas Company (SoCalGas) crews discovered a leak at the natural gas storage well at Aliso Canyon. The leak was stopped and the well was sealed in February 2016. Subsequently, the California Public Utility Commission (CPUC)<sup>84</sup> has capped the inventory level at Aliso Canyon at various levels, and most recently, at 41.16 Bcf<sup>85</sup> in November 2021.

In the 2022-2023 transmission planning cycle, the ISO undertook an information only transmission study to evaluate the potential reliability impacts to the transmission facilities in the

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<sup>84</sup> The CPUC has jurisdiction over the above ground infrastructure beginning where the storage facility connects to the pipeline, or "at the wellhead." In addition, the CPUC has jurisdiction over the recovery of costs related to the storage facility as well as ensuring that Southern California Gas Company provides safe, reliable service at just and reasonable rates. The California Geologic Energy Management Division, (CalGEM), has primary jurisdiction over Aliso Canyon's underground facilities, and decided the maximum allowable operating pressure in the field to be 2,926 psi, which translates to an inventory of 68.6 billion cubic feet (Bcf) of natural gas.

<sup>85</sup> <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K086/421086399.PDF>

LA Basin and to some extent the San Diego-Imperial Valley local capacity areas in the ISO Balancing Authority Area due to strong interaction between these two areas. The ISO worked with the CPUC to obtain potential ranges of gas-fired generation capacity impacts, and to the extent possible, the generating units that are associated with these ranges.<sup>86</sup> The ISO also evaluated various potential transmission upgrades needed to maintain transmission reliability in the LA Basin and to some extent the San Diego-Imperial Valley area, as necessary, based on applicable NERC, WECC and ISO reliability standards. These study results are for informational purposes only at this time as further confirmation is needed on the specific gas generating units that may need to be curtailed under the summer peak load condition without Aliso Canyon gas storage availability. In addition, further clarity on the future operational need of Aliso Canyon gas storage from the CPUC would be needed for the ISO to plan for specific electric transmission upgrades that may be needed.

The ISO presented the following study scope to the stakeholders at the July 6, 2022 meeting. The following section provides further details on the study scope.

### 7.1.1 Study Scope

#### Study Objective

- Performing the local reliability assessment for the LA Basin and San Diego-Imperial Valley areas in the absence of Aliso Canyon gas storage.

#### Study Scopes

- Performing reliability assessments for the LA Basin and San Diego-Imperial Valley local capacity requirement areas with the gas-fired generation curtailment due to absence of the Aliso Canyon gas storage; and
- Identifying reliability concerns and evaluating potential transmission upgrade options.

The single line diagram of the study areas of the LA Basin and San Diego-Imperial Valley local capacity areas is illustrated in Figure 7.1-1.

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<sup>86</sup> The list of gas-fired generation that was curtailed for the study is obtained from FTI Consulting (CPUC's consultant) study that is part of the CPUC Aliso Canyon OII Phase 3 (I.17-02-002), as further explained below.



Figure 7.1-1: LA Basin and San Diego-Imperial Valley Local Capacity Areas

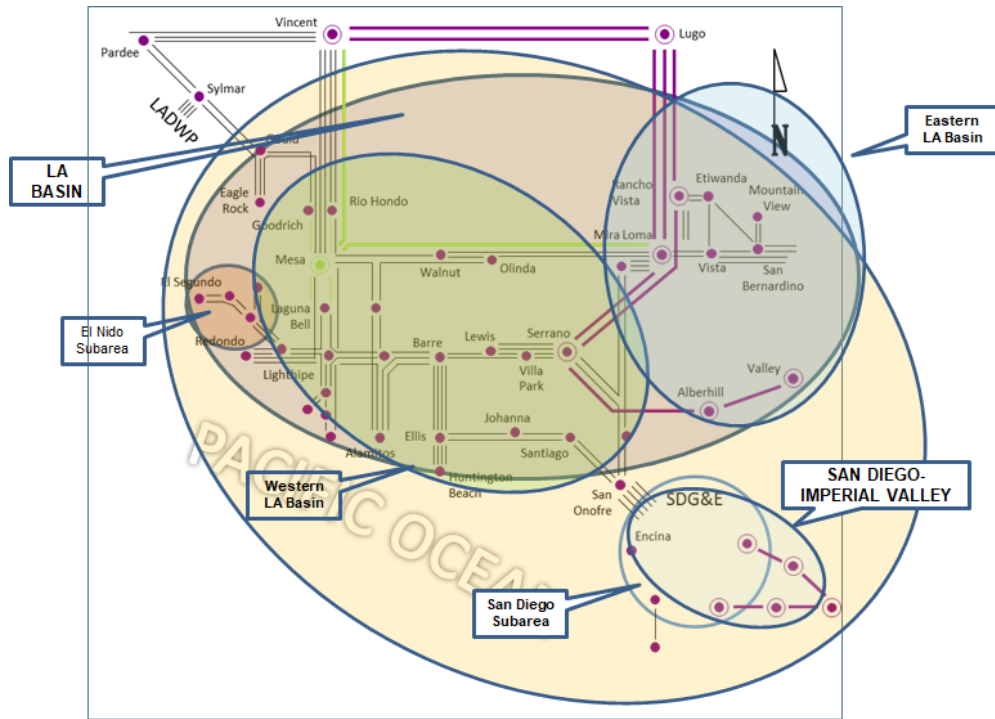
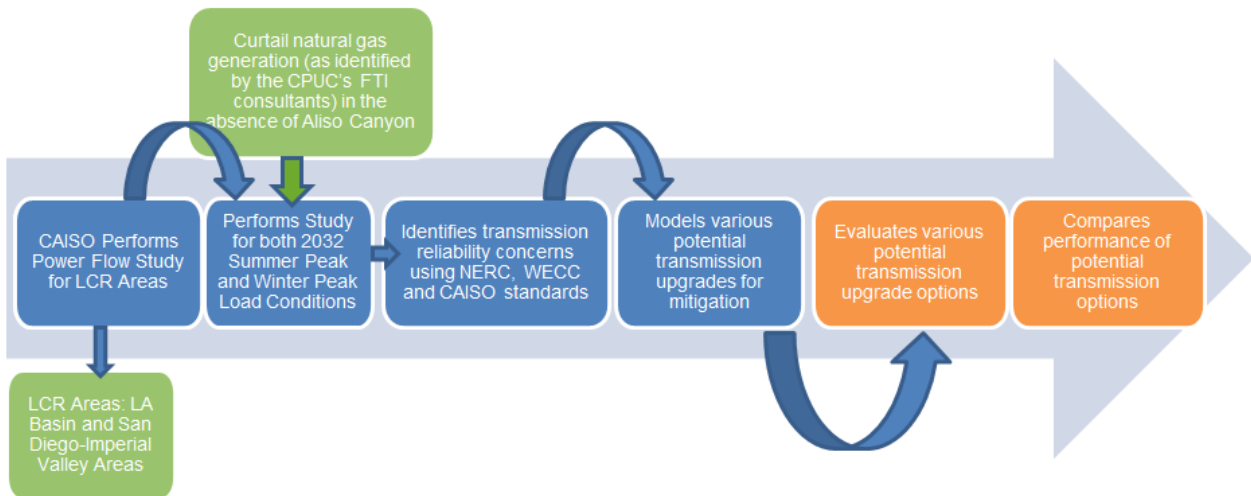


Figure 7.1-2 provides the summary of the study process used for the assessment.

Figure 7.1-2: Summary of Study Process



LCR Area: Local Capacity Requirement Area

A summary of the study base cases is provided in Table 7.1-1.

Table 7.1-1: Study Base Cases

	Power Flow Cases	Study Case Descriptions
1	2032 Summer peak	Models 1-in-10 AAEE 2 & AAFS 4 demand with Additional Transportation Electrification (ATE) forecasts
2	2032 Winter peak	67% of the Summer peak load condition

### Gas-fired Generation Curtailment

The list of gas-fired generation that was curtailed for the study is obtained from FTI Consulting (CPUC's consultant) study that is part of the CPUC Aliso Canyon OII Phase 3 (I.17-02-002) is provided in Appendix K, Section K1. A summary of the number of generation facilities and the total curtailment capacity for the facilities in the ISO Balancing Authority Area is provided in Table 7.1-2.

Table 7.1-2: Number of Generator Facilities and Total Curtailment Capacity

PTO Area	Number of Generation Facilities	Total Curtailment (MW)
SCE	41	3,083
SDG&E	15	645
Total	56	3,728

### 7.1.2 Study Process

- Both summer peak load and winter peak load assessments were performed for the ten-year study cases (i.e., 2032 summer peak and winter peak);
- As part of the study, the ISO identified potential reliability concerns due to curtailment of gas-fired generation in the LA Basin and San Diego-Imperial Valley LCR areas in the absence of Aliso Canyon gas storage; and
- The ISO also evaluated various potential transmission upgrade options to mitigate identified reliability concerns:
  - As part of this process, the ISO leveraged the information from the potential transmission upgrades that were identified in the 20-Year Transmission Outlook<sup>87</sup> as a guide in evaluating potential mitigations in the LA Basin and San Diego LCR areas.

<sup>87</sup> <http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf>

### 7.1.3 Study Results

The following is a summary of information only reliability study results:

- Extensive thermal overloading concerns under critical contingencies in the LA Basin and San Diego areas under summer peak load conditions;
- Several IID transmission facilities are also impacted due to contingencies in the San Diego-Imperial Valley area;
- 2032 Winter peak load conditions did not result in transmission reliability concerns in the LA Basin and San Diego-Imperial Valley area, provided that the remaining gas-fired generation resources are available; and
- As transportation and building fuel substitution become more electrified in the future, the winter peak load is also increasing (winter peak load for 2035 increases 6% over the 2032 winter peak load (73% of summer peak vs. 67% summer peak).

For further details on specific transmission facilities and identified reliability concerns, please refer to the report in Appendix K, Section K2.

### 7.1.4 Transmission Alternatives

A summary of transmission the alternatives that were evaluated for efficacy in mitigating the identified transmission reliability constraints is provide in Table 7.1-3.

Table 7.1-3: Transmission Alternatives

Options	Description of Alternatives	Areas
1A	<ul style="list-style-type: none"> <li>• Diablo South Multi-Terminal HVDC VSC Line (2000 MW at Diablo Canyon, 1000 MW at Alamitos and 1000 MW at Huntington Beach;</li> <li>• Additional upgrades in LA Basin (La Fresa-Hinson 230 kV, South of Ellis 230 kV lines); and</li> <li>• Imperial Valley-N.Gila #2 500 kV line, Sycamore-Suncrest 230 kV #3 line, Suncrest 500/230 kV #3 transformer, Miguel 500/230 kV #3 transformer.</li> </ul>	Western LA Basin & San Diego
1B	<ul style="list-style-type: none"> <li>• Diablo South Multi-Terminal HVDC VSC Line (same as in Option 1A);</li> <li>• Imperial Valley – N.Gila 500 kV #2 line; and</li> <li>• Alberhill – Suncrest 500 kV HVDC VSC line (1000 MW).</li> </ul>	Western and Eastern LA Basin, San Diego
2A	<ul style="list-style-type: none"> <li>• Diablo South Multi-Terminal HVDC VSC Line (2000 MW at Diablo Canyon, 1000 MW at Redondo Beach, 1000 MW at Encina).</li> </ul>	Western LA Basin and San Diego
2B	<ul style="list-style-type: none"> <li>• Diablo South (same as Option 2A);</li> <li>• Third Sycamore-Suncrest 230 kV line; and</li> <li>• Fourth Serrano AA 500/230 kV transformer</li> </ul>	Western LA Basin and San Diego
2C	<ul style="list-style-type: none"> <li>• Diablo South (same as Option 2A); and</li> <li>• Alberhill-Suncrest HVDC VSC Line (1000 MW).</li> </ul>	Western LA Basin and San Diego

Options	Description of Alternatives	Areas
3	<ul style="list-style-type: none"> <li>Diablo South (2000 MW at Diablo Canyon, 500 MW at Redondo Beach, 750 MW at Alamitos, 750 MW at San Onofre).</li> </ul>	Western LA Basin and San Diego
4	<ul style="list-style-type: none"> <li>Vincent-Del Amo HVDC VSC line (1000 MW).</li> </ul>	Western LA Basin
5	<ul style="list-style-type: none"> <li>Imperial Valley – Serrano HVDC VSC line (2000 MW).</li> </ul>	San Diego, Western LA Basin
6	<ul style="list-style-type: none"> <li>Devers – La Fresa HVDC VSC line (1000 MW).</li> </ul>	Eastern and Western LA Basin
7A	<ul style="list-style-type: none"> <li>Imperial Valley-Del Amo HVDC VSC line (2000 MW); and</li> <li>Imperial Valley-N.Gila #2 500 kV line</li> </ul>	San Diego Western LA Basin
7B	<ul style="list-style-type: none"> <li>Option 7A, plus the following upgrades: <ul style="list-style-type: none"> <li>Additional upgrades in the LA Basin (La Fresa-Hinson 230 kV line, Lighthipe-Mesa 230 kV line, Mesa-Redondo 230 kV, Midway-Whirlwind (check for applicability and adequacy of Path 26 RAS);</li> <li>Serrano AA 500 kV Bank #4;</li> <li>Additional Suncrest and Miguel 500/230 kV transformer banks; and</li> <li>Additional dynamic reactive support in San Diego.</li> </ul> </li> </ul>	Western LA Basin San Diego
8A	<ul style="list-style-type: none"> <li>Multi-terminal HVDC VSC (Imperial Valley (2000 MW)-Inland (normal flow at 1000 MW with converter capability up to 2000 MW for emergency condition)-Del Amo (1000 MW normal flow with converter capability up to 2000 MW for emergency condition)), plus the following upgrades: <ul style="list-style-type: none"> <li>Del Amo-Mesa 500 kV line (new);</li> <li>Del Amo-Serrano 500 kV line (new); and</li> <li>Del Amo new 500 kV substation with 3 new AA-banks.</li> </ul> </li> </ul>	Western LA Basin San Diego
8B	<ul style="list-style-type: none"> <li>Multi-terminal HVDC VSC (Imperial Valley (2000 MW) – Sycamore Canyon (1000 MW normal flow with converter capability up to 2000 MW for emergency condition) - Del Amo (1000 MW normal flow with converter capability up to 2000 MW for emergency condition)), plus the following upgrades: <ul style="list-style-type: none"> <li>Del Amo-Mesa 500 kV line (new);</li> <li>Del Amo-Serrano 500 kV line (new); and</li> <li>Del Amo new 500 kV substation with 3 new AA-banks.</li> </ul> </li> </ul>	Western LA Basin San Diego

For further details on each transmission alternative’s performance and its effectiveness in mitigating identified reliability concerns, please refer to Appendix K, Section K3.

## Conclusions

The study is an informational study to continue the assessment of transmission alternatives that may potentially be required with reduced reliance on Aliso Canyon gas storage. Further work on the input assumptions on the impact of available gas in the LA Basin is required for the summer months when the load is at peak energy demand.

The following provides a summary and comparison analysis of the studies undertaken in this informational assessment:

- Alternatives 1A, 2B and 2C are effective at mitigating reliability concerns in the LA Basin and San Diego-Imperial Valley areas.
  - These alternatives include a multi-terminal HVDC VSC line south of Diablo Canyon to the LA Basin and San Diego areas. The studies include power flow analysis only. The ISO is in the process of assessing applicable dynamic models that will be required for dynamic stability analysis.
  - The alternatives take advantage of locating the terminal HVDC VSC lines where once-through cool gas generation retires.
  - The alternatives also provide loading relief to Path 26 line flow under contingency conditions.
  - Variation of HVDC VSC terminals to be connected to the LA Basin and San Diego areas were included.
  - Depending on where these terminals are connected to, other transmission upgrades may be required to provide further mitigations.
- Alternatives 7B and 8B are also effective at mitigating reliability concerns in the LA Basin and San Diego-Imperial Valley areas.
  - These alternatives do not provide loading relief to line flows on Path 26 under contingency conditions when compared to alternatives 1A, 2B and 2C. However, these alternatives provide policy-driven benefits of accessing renewable resources in the Imperial Valley Substation.
  - Both of these alternatives include 500 kV HVDC VSC transmission lines in the LA Basin and San Diego-Imperial Valley areas.
  - Alternative 8B provides better performance in mitigating voltage stability concern due to loss of two major 500 kV transmission lines in San Diego areas when compared to Alternative 7B.
  - 500 kV AC alternatives from the Imperial Valley into the LA Basin with an interconnection into the 230 kV at a new 500/230 kV station at North of SONGS or Inland, as illustrated in Chapter 3 and Appendix, will also provide reduction in local capacity gas requirements in the LA Basin as the HVDC alternatives F have demonstrated.

## 7.2 Policy Driven Assessment of the High Electrification Sensitivity Scenario

In the 2022-2023 transmission planning cycle, the ISO undertook a special study to evaluate the potential reliability impacts to the transmission facilities based on a high electrification scenario. The CEC, in collaboration with the CPUC and the ISO, developed a demand scenario that placed a greater emphasis on electrification than was embedded within the CEC's 2021 IEPR energy demand forecast. The CPUC also developed a resource portfolio based upon the high electrification scenario. The CEC and CPUC provided the high electrification scenario load forecast and resource portfolio to the ISO during the course of summer 2022. For this effort, the ISO engaged stakeholders via webinar meetings that were part of the ISO transmission planning process as well as performed reliability assessment, policy analysis and production cost simulation for the high electrification sensitivity scenario.

The following study assumptions were included as part of the high electrification sensitivity scenario:

- 2035 for study year;
- 2021 Integrated Energy Policy Report (IEPR) Additional Transportation Electrification demand scenario; and
- 30 MMT High Electrification policy-driven sensitivity portfolio.

The study results for the high electrification sensitivity scenario are included in Chapter 2 (Reliability Assessment), Chapter 3 (Policy Assessment) and Chapter 4 (Economic Assessment).

## 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 <sup>88</sup>	Current Expected In-service date <sup>89</sup>
1	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	2008	In-Service Q4-2022
2	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Kern PP 230 kV Area Reinforcement Project)	PG&E	2010-2011	In-Service Q1-2021
3	Oakland Clean Energy Initiative (Oakland X 115 kV Bus Upgrade)	PG&E	2017-2018	In-Service Q2-2022
4	Palermo – Wyandotte 115 kV Line Section Reconductoring Project	PG&E	2020-2021	In-Service Q3-2021
5	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	2017-2018	In-Service Q4-2022
6	Vaca Dixon Area Reinforcement (Replace Bank 5)	PG&E	2017-2018	In-Service Q3-2022
7	Atlantic 230/60 kV transformer voltage regulator	PG&E	2021-2022	Q2-2026
8	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	2019-2020	Q4-2027
9	Cascade 115/60 kV No.2 Transformer Project	PG&E	2010-2011	Q4-2024
10	Christie-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	Q2-2028
11	Clear Lake 60 kV System Reinforcement	PG&E	2009	Q4-2028

<sup>88</sup> 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>

<sup>89</sup> Draft Transmission Plan in-service dates based on January Transmission Development Forum. Revised draft will be updated based on the in-service dates of the April Transmission Development Forum

No	Project	PTO	Transmission Plan Approved <sup>88</sup>	Current Expected In-service date <sup>89</sup>
12	Coburn-Oil Fields 60 kV system project	PG&E	2017-2018	Q2-2029
13	Contra Costa PP 230 kV Line Terminals Reconfiguration Project	PG&E	2021-2022	Q2-2025
14	Cooley Landing 60 kV Substation Circuit Breaker No #62 Upgrade	PG&E	2021-2022	Q4-2026
15	Coppermine 70 kV Reinforcement Project	PG&E	2021-2022	Q4-2027
16	Cortina 230/115/60 kV Transformer Bank No. 1 Replacement Project	PG&E	2021-2022	Q2-2027
17	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	2018-2019	Q1-2026
18	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	2017-2018	Q3-2025
19	East Marysville 115/60 kV Project	PG&E	2018-2019	Q1-2028
20	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	2019-2020	Q4-2025
21	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	2011-2012	Q4-2023
22	Estrella Substation Project	PG&E	2013-2014	Q2-2028
23	Giffen Line Reconductoring Project	PG&E	2018-2019	Q1-2024
24	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	2013-2014	Q4-2023
25	Gold Hill 230/115 kV Transformer Addition Project	PG&E	2018-2019	Q2-2028
26	Herndon-Bullard 115 kV Reconductoring Project	PG&E	2017-2018	Q4-2026
27	Ignacio Area Upgrade	PG&E	2017-2018	Q4-2028
28	Jefferson 230 kV Bus Upgrade	PG&E	2018-2019	Q4-2026
29	Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Q4-2026
30	Lakeville 60 kV Area Reinforcement	PG&E	2017-2018	Q4-2028
31	Manteca #1 60 kV Line Section Reconductoring Project	PG&E	2020-2021	Q1-2025
32	Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project	PG&E	2021-2022	Q2-2026
33	Maple Creek Reactive Support	PG&E	2009	Q4-2027
34	Metcalf 230 kV Substation Circuit Breaker No# 292 Upgrade	PG&E	2021-2022	2025



No	Project	PTO	Transmission Plan Approved <sup>88</sup>	Current Expected In-service date <sup>89</sup>
35	Metcalfe-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	2003	Q4-2027
36	"Midway – Kern PP #2 230 kV Line (Bakersfield-Kern Reconductor)"	PG&E	2013-2014	Q1-2028
37	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Midway 230 kV Bus Section D Upgrade Project)	PG&E	2010-2011	Q2-2025
38	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	2012-2013	Q4-2028
39	Monta Vista 230 kV Bus Upgrade	PG&E	2012-2013	Q3-2025
40	Moraga 230 kV Bus Upgrade	PG&E	2019-2020	Q4-2028
41	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	2010-2011	Q2-2024
42	Moraga-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	On Hold
43	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	2013-2014	Q3-2027
44	Mosher Transmission Project	PG&E	2013-2014	Q4-2027
45	Moss Landing – Las Aguilas 230 kV Series Reactor Project	PG&E	2021-2022	Q4-2026
46	"Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition"	PG&E	2019-2020	Q4-2026
47	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	2017-2018	Q4-2024
48	North Tower 115 kV Looping Project	PG&E	2011-2012	Q1-2030
49	Oakland Clean Energy Initiative (MORAGA 115 KV BUS UPGRADE & BK 3 SW)	PG&E	2017-2018	Q4-2023
50	Oro Loma 70 kV Area Reinforcement	PG&E	2010-2011	Q4-2026
51	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	2015-2016	Q2-2024
52	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	2007	Q1-2025
53	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	2018-2019	Q4-2025
54	Reconductor Delevan-Cortina 230 kV line	PG&E	2021-2022	Q4-2028
55	Reconductor Rio Oso–SPI Jct–Lincoln 115 kV line	PG&E	2021-2022	Q4-2029
56	Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects)	PG&E	2017-2018	Q4-2025
57	Rio Oso 230/115 kV Transformer Upgrades	PG&E	2007	Q4-2025
58	Rio Oso Area 230 kV Voltage Support	PG&E	2011-2012	Q2-2025

No	Project	PTO	Transmission Plan Approved <sup>88</sup>	Current Expected In-service date <sup>89</sup>
59	Salinas-Firestone #1 and #2 60 kV Lines	PG&E	2019-2020	Q4-2026
60	Series Compensation on Los Esteros-Nortech 115 kV Line	PG&E	2021-2022	Q4-2024
61	South of Mesa Upgrade	PG&E	2018-2019	Q2-2027
62	South of San Mateo Capacity Increase	PG&E	2007	Q2-2027
63	Tesla 230 kV Bus Series Reactor project	PG&E	2018-2019	Q4-2023
64	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
65	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	Q4-2023
66	Tie line Phasor Measurement Units	PG&E	2017-2018	Q4-2026
67	Tulucay-Napa #2 60 kV Line Capacity Increase	PG&E	2019-2020	Q4-2025
68	Tyler 60 kV Shunt Capacitor	PG&E	2018-2019	Q2-2026
69	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	2017-2018	Q2-2026
70	Vasona-Metcalf 230 kV Line Limiting Elements Removal Project	PG&E	2021-2022	Q2-2025
71	Vierra 115 kV Looping Project	PG&E	2010-2011	Q3-2025
72	Warnerville-Bellota 230 kV line reconductoring	PG&E	2012-2013	Q2-2024
73	Weber-Mormon Jct 60 kV Line Section Reconductoring Project	PG&E	2021-2022	Q2-2026
74	Wilson 115 kV Area Reinforcement	PG&E	2010-2011	Q1-2028
75	Wilson-Le Grand 115 kV line reconductoring	PG&E	2012-2013	Q4-2023
76	Wilson-Oro Loma 115 kV Line Reconductoring	PG&E	2019-2020	Q4-2028
77	Moorpark-Pardee No. 4 230 kV Circuit	SCE	2018	In Service May-2022
78	Devers 230 kV Reconfiguration Project	SCE	2021-2022	Jun-25
79	Laguna Bell - Mesa No. 1 230 kV Line Rating Increase Project	SCE	2021-2022	Apr-24
80	Lugo - Victorville 500 kV Upgrade (SCE portion)	SCE	2017	Jan-25
81	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	2008	Dec-25
82	Method of Service for Wildlife 230/66 kV Substation	SCE	2007	Oct-27

No	Project	PTO	Transmission Plan Approved <sup>88</sup>	Current Expected In-service date <sup>89</sup>
83	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	2020	Jun-25
84	Tie line Phasor Measurement Units	SCE	2017-2018	Dec-25
85	Victor 230 kV Switchrack Reconfiguration	SCE	2021-2022	Apr-25
86	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	2013-2014	Close-Out
87	Rose Canyon-La Jolla 69 kV T/L	SDG&E	2013-2014	Completed
88	2nd Escondido-San Marcos 69 kV T/L	SDG&E	2013-2014	Feb-23
89	Reconductor TL 605 Silvergate – Urban	SDG&E	2015-2016	Jun-24
90	Sweetwater Reliability Enhancement	SDG&E	2012-2013	Nov-27
91	TL623C Reconductor (San Ysidro - Otay Tap)	SDG&E	2017-2018	Feb-29
92	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	2013-2014	Jun-26
93	TL644, South Bay-Sweetwater: Reconductor	SDG&E	2010-2011	May-22
94	TL649D Reconductor (San Ysidro - Otay Lake Tap)	SDG&E	2017-2018	Dec-24
95	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	2012-2013	Nov-22
96	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	2013-2014	Nov-26
97	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	2011-2012	Feb-23
98	Tie Line Phasor Measurement Units	VEA	2017-2018	Jun-23
99	IID S-Line Upgrade	Citizens Energy	2017-2018	2023

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

<b>No</b>	<b>Project</b>	<b>PTO</b>	<b>Transmission Plan Approved</b>	<b>Current Expected</b>
1	Kern PP 115 kV Area Reinforcement	PG&E	2011-2012	Aug-23
2	Lockeford-Lodi Area 230 kV Development	PG&E	2012-2013	Jun-23
3	Martin 230 kV Bus Extension	PG&E	2014-2015	May-23
4	Midway – Kern PP #2 230 kV Line	PG&E	2013-2014	Jun-23
5	New Collinsville 500 kV substation	PG&E	2021-2022	Q4-2028
6	New Manning 500 kV substation	PG&E	2021-2022	Q4-2028
7	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)	PG&E	2012-2013	On Hold
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	Dec-23
9	San Jose Area HVDC 230 kV Line (Newark - NRS)	PG&E	2021-2022	Q4-2028
10	San Jose Area HVDC 500 kV Line (Metcalf – San Jose)	PG&E	2021-2022	Q4-2028
11	Table Mountain Second 500/230 kV Transformer	PG&E	2021-2022	Q4-2027
12	Vaca Dixon Area Reinforcement (Original project was the "Vaca – Davis Voltage Conversion Project" approved in 2010-2011 Transmission Plan. The project was rescoped and renamed in 2017-2018 Transmission Plan)	PG&E	2017-2018	Jul-23
13	Wheeler Ridge Junction Substation	PG&E	2013-2014	On Hold
14	Alberhill 500 kV Method of Service	SCE	2009	Jun-23
15	Antelope 66 kV Circuit Breaker Duty Mitigation Project	SCE	2021-2022	Jul-05
16	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	2012-2013	Dec-23
17	Lugo-Mohave series capacitor upgrade	SCE	2012-2013	Dec-23
18	Mesa 500 kV Substation Loop-In	SCE	2013-2014	In-Service May-2022
19	Southern Orange County Reliability Upgrade Project – Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	2010-2011	Nov-23
20	Artesian 230 kV Sub & loop-in TL23051	SDG&E	2013-2014	Jun-23
21	GLW/VEA Area Upgrades	VEA/GLW	2021-2022	TBD
22	Delaney-Colorado River 500 kV line	DCR Transmission	2013-2014	Apr-23
23	Gates 500 kV Dynamic Voltage Support	LS Power	2018-2019	Jun-23
24	Round Mountain 500 kV Dynamic Voltage Support	LS Power	2018-2019	Dec-23

## 8.2 Transmission Projects found to be needed in the 2022-2023 Planning Cycle

In the 2022-2023 transmission planning process, the ISO determined that 24 transmission projects were needed to mitigate identified reliability concerns; 21 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 2022 Request Window can be found in Appendix E.

Additional details of new 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	Garberville area reinforcement project	Humboldt	2032	204
2	Tulucay-Napa #2 60 kV line Reconductoring project	NCNB	2028	14.6
3	Santa Rosa 115 kV lines Reconductoring project	NCNB	2028	74
4	Tesla 115 kV Bus Reconfiguration Project	CVLY	2030	55
5	Banta 60 kV Bus Voltage Conversion	CVLY	2024	17.5
6	Metcalf 230/115 kV Transformers Circuit Breaker Addition	GBA	2026	15
7	South Bay Area Limiting Elements Upgrade	GBA	2027	11
8	Redwood City Area 115 kV System Reinforcement	GBA	2030	110.8
9	Lone Tree – Cayetano – Newark Corridor Series Compensation	GBA	2027	25
10	Pittsburg 115 kV Bus Reactor project	GBA	2032	26
11	Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation	Fresno	2024	1.6
12	Los Banos 70 kV Area Reinforcement Project	Fresno	2029	60
13	Los Banos 230 kV Circuit Breaker Replacement	Fresno	2032	66
14	Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	Fresno	2032	184
15	North East Kern 115 kV Line Reconductoring Project	Kern	2032	256
16	Mesa 230/115 kV spare transformer	CCLP	2032	24

17	Barre 230 kV Switchrack Conversion to Breaker-and-a-Half	SCE - Main	2026	45
18	Mira Loma 500 kV Circuit Breaker Upgrade	SCE - Main	2026	10
19	Serrano 4AA 500/230 kV Transformer Bank Addition	SCE - Main	2027	120
20	Sylmar Transformer Replace	SCE - Main	2026	23
21	Antelope-Whirlwind 500 kV Line Upgrade Project	SCE - Main	2025	6
22	Coolwater 1A 230/115 kV Bank Project	SCE - NOL	2026	47
23	Control 115 kV Shunt Reactor	SCE - NOL	2026	4
24	Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Project	SDG&E	2032	375

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	Borden-Storey 230 kV 1 and 2 Line Reconductoring	Fresno	2032	\$50
2	Henrietta 230/115 kV Bank 3 Replacement	Fresno	2032	\$20
3	Beatty 230 kV	VEA/GLW	2027	\$155
4	Lugo-Victor-Kramer 230 kV Upgrade	North of Lugo	2032	\$482
5	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE Eastern	2028	\$50
6	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE Eastern	2028	\$140
7	Devers-Valley 500 kV 1 Line Upgrade	SCE Eastern	2028	\$40
8	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE Eastern	2028	\$60
9	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE Eastern	2031	\$65
10	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE Eastern	2028	\$18
11	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE Eastern	2031	\$13
12	Mira Loma-Mesa 500 kV Underground Third Cable	SCE Metro	2026	\$30
13	Imperial Valley-North of SONGS 500 kV Line and Substation	SDG&E	2034	\$2,288
14	North of SONGS-Serrano 500 kV line	SDG&E and SCE Metro	2034	\$503

15	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE Metro	2033	\$1,125
16	North Gila–Imperial Valley 500 kV line	SDG&E (Potential Joint Project with IID)	2028	\$340
17	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	2032	\$27
18	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	2032	\$21
19	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	2032	\$28
20	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	2032	\$8
21	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	2032	\$60

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

### 8.3 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2022-2023 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 2022-2023 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.

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" 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. This continues to satisfy the local area need in absence of the local thermal generation. The approved project is expected to be in-service in 2024.



### Central Coast & Los Padres Area

To provide a sufficient maintenance window within winter months for facilities in the area as required by the ISO planning standards, in the 2020-2021 transmission planning process, the ISO recommended the mitigation plan for procurement of approximately 50 MW 4-hour BESS at Mesa 115 kV substation to address the maintenance requirements and for the North of Mesa upgrade project to remain on hold pending procurement of the battery storage. In this cycle, due to the complications associated with the 115 kV interconnection, which will result in high interconnection costs and commercial interest, the scope of the previously recommended procurement solution is recommended to be changed by moving the POI for the BESS to 230 kV and installing a new spare 230/115 kV transformer at Mesa substation.

### 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.

## **8.4 Competitive Solicitation for New Transmission Elements**

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the ISO selects a regional transmission solution to meet an identified need in one of the three 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 2022-2023 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

- Imperial Valley–North of SONGS 500 kV Line and Substation;
- North of SONGS–Serrano 500 kV line;
- North Gila–Imperial Valley 500 kV line; and

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

## 8.5 Capital Program Impacts on Transmission High-Voltage Access Charge

### 8.5.1 Background

The purpose of the ISO's internal High-Voltage Transmission Access Charge (HV TAC) estimating tool is to provide an estimation of the impact of the capital projects identified in the ISO's annual transmission planning processes on the access charge. The ISO is continuing to update and enhance its model since the tool was first used in developing results documented in the 2012-2013 transmission plan, and the model itself was released to stakeholders for review and comment in November 2018. Additional upgrades to the model have been made reflecting 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.

### 8.5.2 Input Assumptions and Analysis

The ISO’s rate-impact model is based on publicly available information or ISO assumptions as set out below, with clarifications provided by several utilities.

Each PTO’s most recent FERC revenue requirement approvals are relied upon for revenue requirement consisting of capital-related costs and operating expense requirements, as well as plant and depreciation balances. Single tax and financing structures for each PTO are utilized, which necessitates some adjustments to rate base. These adjustments are “back-calculated” such that each PTO’s total revenue requirement aligned with the filing.

Total existing costs are then adjusted on a going-forward basis through escalation of O&M costs, adjustments for capital maintenance costs, and depreciation impacts. PTO input is sought each year regarding these values, recognizing that the ISO does not have a role regarding those costs. The 2023 model uses the average annual 1% energy growth rate based on the CEC 2021 IPER 2021-2035 California Energy Demand baseline forecast, which is also used in the 2022-2023 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 2023 TAC value for the 2023 projection remains relatively consistent with the 2022 projection. The projection also includes capital projects in this year’s plan and all other transmission plan projects not already energized. The decrease of \$2.01 from last year’s projection for January 1, 2023 to this year’s actuals reflects the decrease in Transmission Revenue Balancing Account Adjustments (TRBAA) and Standby Credit contribution below the historical projections. Together with a higher Gross Load growth, the lower starting values in this year’s model result in lower overall TAC Rates across all years. The higher Growth Load growth rate also reduces the impact of the TAC Rates due to the recommended projects in this year’s plan.

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

