Agenda
Draft 2021-2022 Transmission Plan and Draft 20-Year Transmission Outlook

2021-2022 Transmission Planning Process Stakeholder Meeting

February 7, 2022

Reminders

- Stakeholder calls and meetings related to Transmission Planning are not recorded.
  - Given the expectation that documentation from these calls will be referred to in subsequent regulatory proceedings, we address written questions through written comments, and enable more informal dialogue at the call itself.
  - Minutes are not generated from these calls, however, written responses are provided to all submitted comments.
- To ask a question, press #2 on your telephone keypad. Please state your name and affiliation first.
- Calls are structured to stimulate an honest dialogue and engage different perspectives.
- Please keep comments friendly and respectful.

2021-2022 Transmission Planning Process Stakeholder Call – Agenda

Topic	Presenter
Overview & Key Issues	Jeff Billinton
Reliability-driven projects recommended for approval	Binaya Shrestha Preethi Rondla Nikitas Zagoras
Policy-driven projects recommended for approval	Vera Hart Ebrahim Rahimi Meng Zhang
Economic-driven project recommended for approval and Economic Assessment update	Yi Zhang
Other Studies: - Wildfire impact study – Southern areas - Frequency response assessment	David Le Frank Chen Amanda Wong Christopher Fuchs
Draft 20-Year Transmission Outlook	Jeff Billinton
Wrap-up	

Introduction and Overview
Draft 2021-2022 Transmission Plan

Jeff Billinton
Director, Transmission Infrastructure Planning

2021-2022 Transmission Planning Process Stakeholder Meeting
February 7, 2021

Draft 2021-2022 Transmission Plan

- Posted on CAISO website on January 31, 2022
  http://www.caiso.com/InitiativeDocuments/Draft-2021-2022TransmissionPlan.pdf

- The draft transmission plan represents the CAISO's current thinking on system needs over the next 10-years and is an opportunity for stakeholder input before final recommendations are advanced to the CAISO Board of Governors in March

2021-2022 Transmission Planning Process

December 2021 **April 2021** **March 2022**

Phase 1 – Develop detailed study plan

State and federal policy

CEC - Demand forecasts

CPUC - Resource forecasts and common assumptions with procurement processes

Other issues or concerns

Phase 2 - Sequential technical studies

- Reliability analysis
- Renewable (policy-driven) analysis
- Economic analysis

Publish comprehensive transmission plan with recommended projects

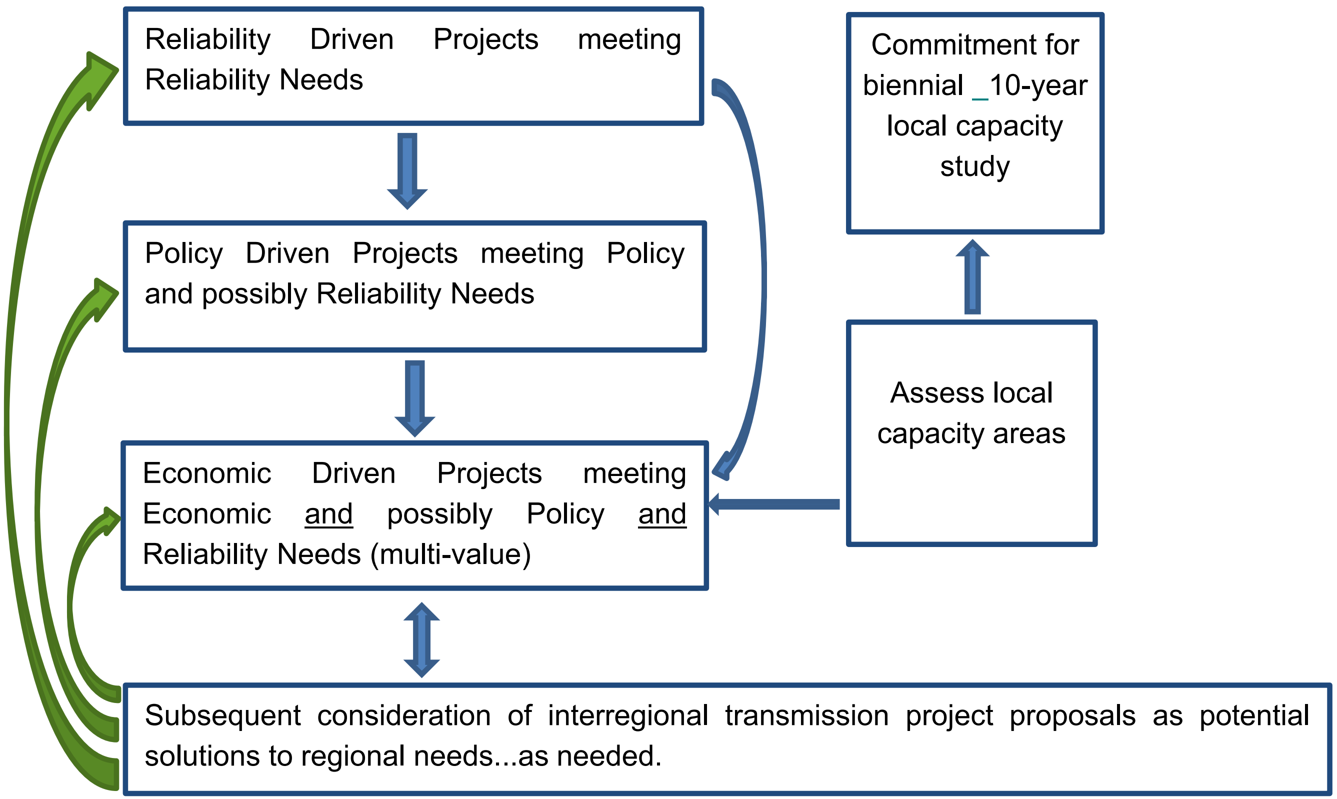
Phase 3 Procurement

CAISO Board for approval of transmission plan

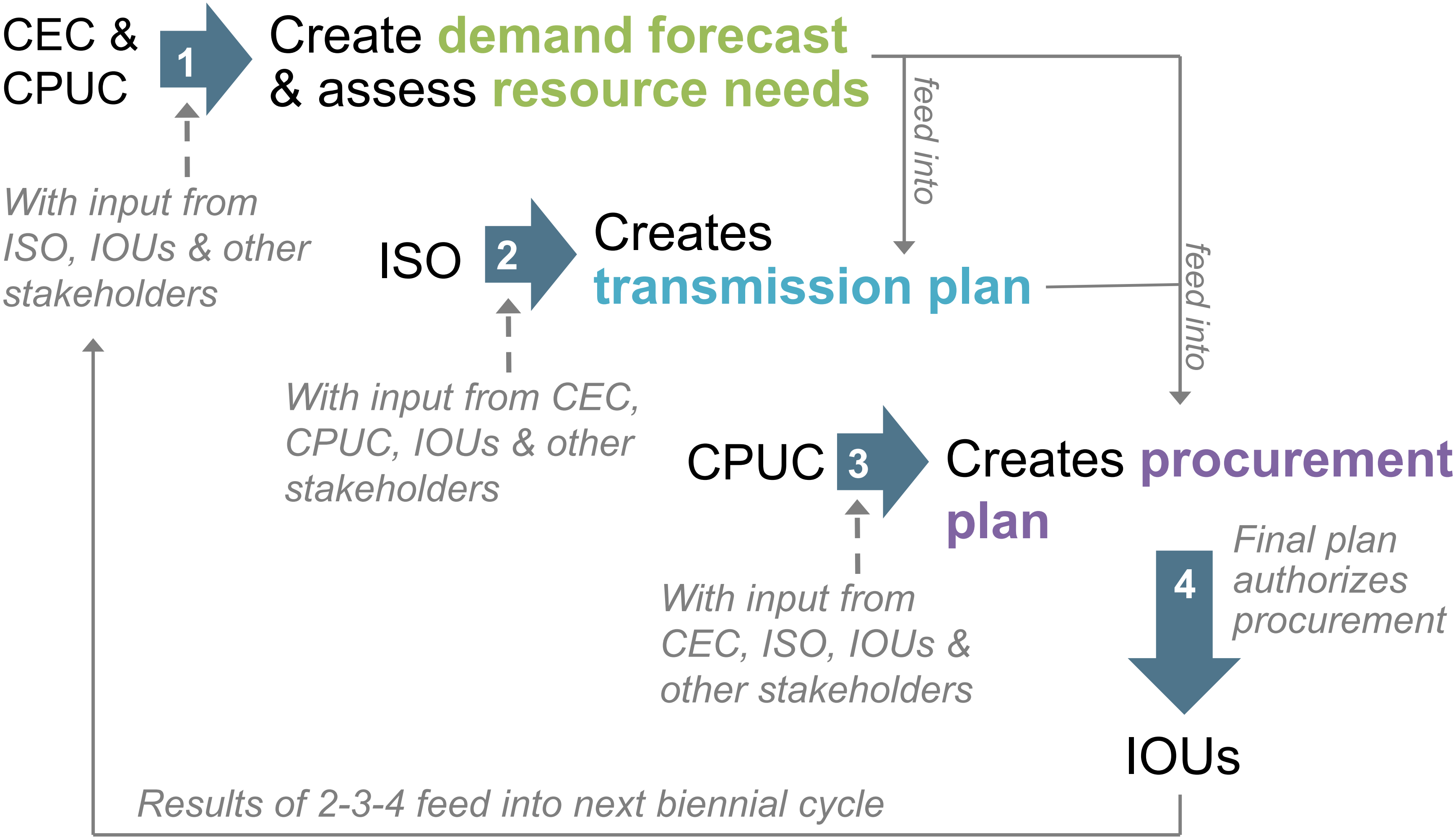
2021-2022 Transmission Plan Milestones

- Draft Study Plan posted on February 18
- Stakeholder meeting on Draft Study Plan on February 25
- Final Study Plan posted on March 31
- Stakeholder meeting May 14
- Stakeholder meeting July 27
- Preliminary reliability study results posted and open Request Window on August 13
- Stakeholder meeting on September 27 and 28
  - Comments to be submitted by October 12
- Request window closes October 15
- Preliminary policy and economic study results on November 18
- Comments to be submitted by December 6
- Draft transmission plan to be posted on January 31, 2022
- Stakeholder meeting February 7, 2022
- Comments to be submitted February 22, 2022
- Revised draft for approval at March Board of Governor meeting

Studies are coordinated as a part of the transmission planning process



Planning and procurement overview



California ISO

Load Forecast Assumptions
Energy and Demand Forecast

- California Energy Demand Updated Forecast 2020-2031 adopted by California Energy Commission (CEC) on January 25, 2021 will be used:
  - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
  - Additional Achievable Energy Efficiency (AAEE)
    - Consistent with CEC 2020 IEPR
    - Mid AAEE will be used for system-wide studies
    - Low AAEE will be used for local studies
  - CEC forecast information is available on the CEC website at:

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

The CPUC transmitted a base portfolio and two sensitivity portfolios for the 2021-2022 TPP

- Base Portfolio – Portfolio based on 46 MMT GHG target to be used to determine transmission investments needed
- Sensitivity-1 Portfolio – Portfolio based on 38 MMT GHG target
- Sensitivity-2 Portfolio– Offshore Wind (OSW) Portfolio based on 30 MMT GHG target intended to test the transmission needs associated with offshore wind
- CPUC provided the portfolios complete with mapping at the substation bus level for both generation and battery storage resources
- The current base portfolio includes significantly more renewables and storage resources than the base portfolio studied in the 2020-2021 TPP

2021-2022 Transmission Plan

- Reliability Assessment to identify reliability-driven needs *(Chapter 2*
- Policy Assessment to identify policy-driven needs *(Chapter 3)*
- Economic Planning Study to identify needed economically-driven elements (Chapter 4)
- Interregional Transmission Planning Process *(Chapter 5)*
  - In year two (odd year) of 2 year planning cycle
- Other Studies *(Chapter 6)*
  - Long-term Congestion Revenue Rights
  - Frequency response
  - Wildfire Assessment – Southern California

The CAISO found the need for 24 projects totaling $2,944 million

- Reliability-driven projects - 16 projects totaling $1,412 million
- Policy-driven projects - 7 projects totaling $1,512 million
- Economic-driven project – 1 project totaling $20 million

Competitive Solicitation

- The following projects are eligible for competitive solicitation:
  - New Collinsville 500 kV substation
  - New Manning 500 kV substation
  - San Jose Area HVDC Lines (Newark to NRS)
  - San Jose Area HVDC Line (Metcalf – San Jose)

- The CAISO will provide a schedule for those processes in March, 2022

Out-of-state wind analysis

- Portfolios provided to the CAISO provided specific direction regarding the treatment of out-of-state wind resources, particularly for the base case

- The CAISO was requested to study the potential requirements and implications of 1,062 MW being injected into the CAISO system from each of Idaho, Wyoming or New Mexico in the base case, but not both simultaneously

Out-of-state wind analysis *(continued)*

- CPUC acknowledged that out-of-state transmission would be needed to deliver these volumes to the existing CAISO boundary, but those were outside of the scope of the policy-driven transmission study request

- In subsequent comments in the CAISO's stakeholder process, CPUC staff comments later requested the CAISO consider, time permitting, on possible out-of-state requirements for information purposes only

Out-of-state wind analysis *(continued)*

- The CAISO addressed these requests, as well as a related economic study request regarding SWIP North:
  - The CAISO focused the policy-driven analysis to be aligned with the CPUC decision regarding transmission implications inside the CAISO footprint
  - The CAISO conducted additional analysis including consideration of out-of-state transmission issues as part of broader economic studies
  - The economic studies showed a wide range of potential benefits between different alternatives accessing different out of state resources and different study assumptions
  - These outcomes will be heavily influenced by procurement interest and different cost recovery options being pursued by different out of state transmission developers

Out-of-state wind analysis *(continued)*

- Regarding the SWIP North economic study request:
  - The CAISO therefore intends to engage further with industry participants to gauge interest in accessing Idaho resources.
  - This process will require more time than is available before the 2021-2022 Transmission Plan is finalized and submitted to the Board for approval in March, 2022. The CAISO intends to consider this as an extension of the 2021-2022 transmission planning cycle, rather than shifting it to the next 2022-2023 planning cycle.
  - The CAISO expects this effort to take the form of an open season-type process to assess the market interest and level of competition that exists for accessing the Idaho resources in support of the project.

Comments
Draft 2021-2022 Transmission Plan

- Comments due by end of day February 22, 2022

- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:
- https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2021-2022-Transmission-planning-process

Comments
Draft 20-Year Transmission Outlook

- Comments due by end of day February 22, 2022

- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:
  https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook

Reliability Assessment Recommendations – PG&E Area Draft 2021-2022 Transmission Plan

Binaya Shrestha/Preethi Rondla

Regional Transmission - North

2021-2022 Transmission Planning Process Stakeholder Meeting

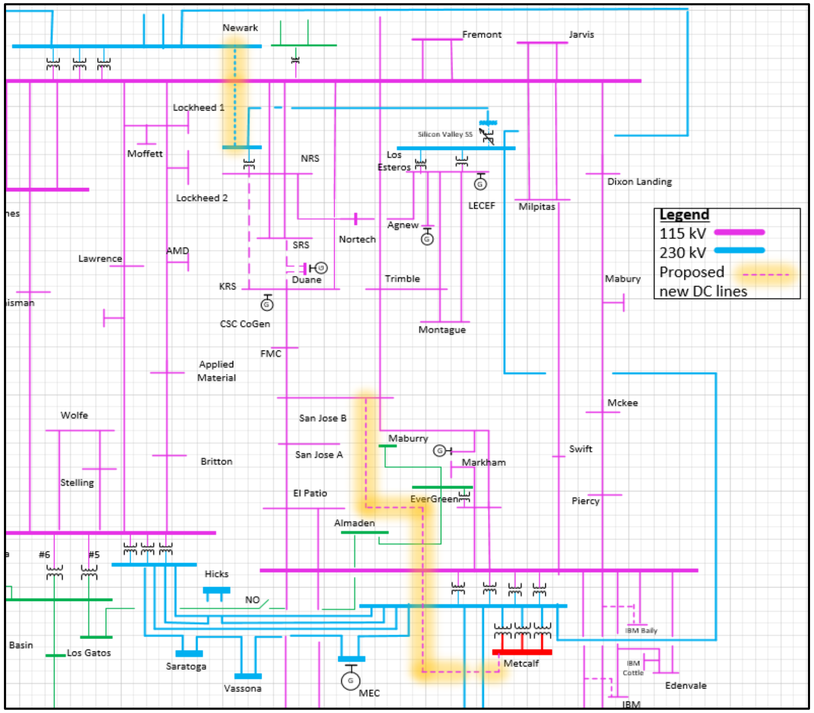
February 7, 2022

New Reliability Projects Recommended for Approval in 2021-2022 TPP - PG&E Area

Projects	Planning Area	Status
Contra Costa 230 kV Line Terminals Reconfiguration	Greater Bay Area	Presented in November meeting
Vasona-Metcalf 230 kV Line Limiting Elements Removal Project	Greater Bay Area	Presented in November meeting
Coppermine 70 kV Reinforcement Project	Greater Fresno Area	Presented in November meeting
Cortina 230/115/60 kV Bank #1 Replacement	Central Valley	Presented in November meeting
Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring	Central Valley	Presented in November meeting
Weber - Mormon Jct 60 kV Line Section Reconductoring	Central Valley	Presented in November meeting
San Jose Area – two HVDC projects	Greater Bay Area	Included in this presentation
Series Compensation on Los Esteros-Nortech 115 kV Line	Greater Bay Area	Included in this presentation
Table Mountain 500/230 kV TB #2 Project	North Valley	Included in this presentation
Atlantic 60 kV Voltage Regulator Project	Central Valley	Included in this presentation
Cooley Landing Substation Circuit Breaker #62 Upgrade	Greater Bay Area	Included in this presentation
Metcalf Substation Circuit Breaker #292 Upgrade	Greater Bay Area	Included in this presentation

San Jose Area HVDC Lines

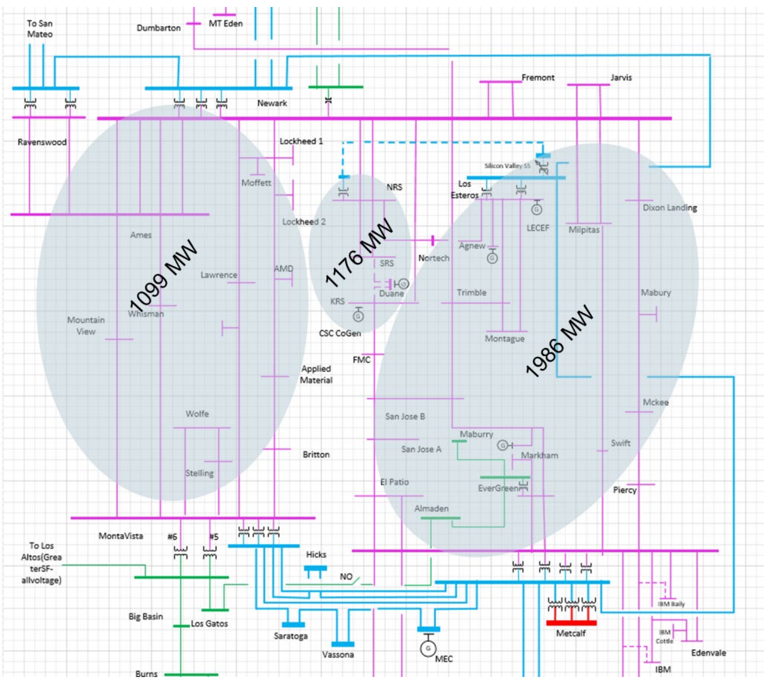
- Reliability Assessment Need
  - The near-term issues driven by P2, P6 and P7 category contingencies and multiple the mid and long-term issues driven by various category contingencies including P1.
- Project Submitter
  - CAISO
- Project Scope
  - To build two HVDC lines, 1) from Newark 230 kV to NRS 230 kV and 2) Metcalf 500 kV to San Jose B 115 kV.
- Estimated Project Cost
  - Newark-NRS: $325M - $510M
  - Metcalf-San Jose B: $425M - $615M
- Estimated In-service Date
  - 2027



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

San Jose Area HVDC Lines (cont’d)

South Bay transmission system and load



- Upgrading individual facilities is uneconomic, complicated to implement and doesn’t setup the system for future load growth or reducing reliance on the local gas generation.
- Due to the electrical proximity of bulk of the area load to the Newark substation, specifically the SVP area load where most of the load increase is, the bulk of the power flows from the Newark side. As such, building new 230 kV AC lines is not very effective.

Facilities identified as overloaded in the 2021-2022 reliability assessment.

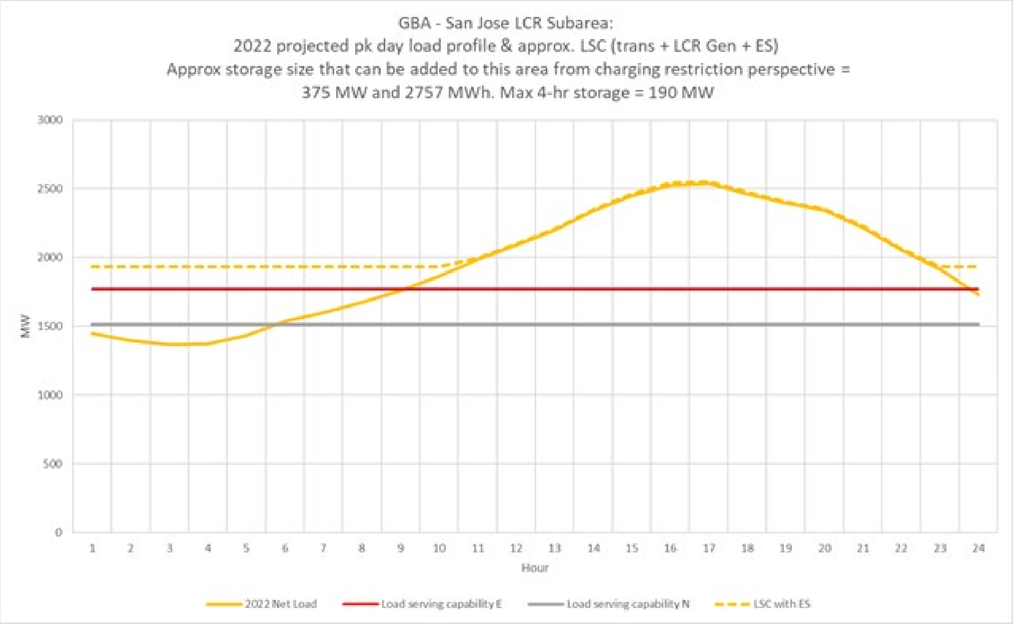
Facility	2023					2026				2031					Sensitivity				
	P1	P2	P5	P6	P7	P1	P2	P5	P7	P0	P1	P2	P5	P7	P0	P1	P2	P5	P7
El Patio-San Jose Sta. 'A' 115 kV Line		X			X			X				X	X	X	X	X	X	X	X
Evergreen-Almaden 60 kV Line	X																		
FMC-San Jose 'B' 115 kV Line		X					X					X							
Kifer-Duane 115 kV Line							X		X							X			X
Kifer-FMC 115 kV Line		X										X							
Los Esteros-Metcalf 230 kV Line												X				X	X		
Los Esteros-Nortech 115 kV Line		X				X				X	X								
Los Esteros-Silicon Switching Station 230 kV Line						X										X			
Los Esteros-Trimble 115 kV Line																	X		
Mckee-Piercy 115 kV Line											X								
Metcalf 230/115 kV Trans No. 1		X																	
Metcalf 230/115 kV Trans No. 2		X																	
Metcalf 230/115 kV Trans No. 3		X																	
Metcalf 230/115 kV Trans No. 4		X															X		
Metcalf 500/230 kV Trans No. 13				X															
Metcalf-El Patio No. 1 115 kV Line							X					X	X	X		X	X	X	X
Metcalf-El Patio No. 2 115 kV Line		X											X	X		X		X	X
Metcalf-Evergreen No. 1 115 kV Line																		X	X
Metcalf-Hicks 230 kV Line																	X		X
Metcalf-Llagas 115 kV Line				X															
Metcalf-Morgan Hill 115 kV Line				X															
Monta Vista-Hicks 230 kV Line												X							X
Monta Vista-Wolfe 115 kV Line						X	X												
Newark-Dixon Landing 115kV Line	X	X			X														
Newark-Jarvis #1 115kV Line	X																		
Newark-Kifer 115kV Line		X		X	X		X	X	X		X		X	X		X			
Newark-Northern Receiving Station #1 115kV Line			X		X	X	X				X	X		X		X			X
Newark-Northern Receiving Station #2 115kV Line			X	X			X		X		X	X	X			X	X		
Newark-Trimble 115kV Line													X					X	X
Nortech-NRS 115 kV Line				X		X	X		X		X			X					
NRS-Scott No. 1 115 kV Line		X																	
NRS-Scott No. 2 115 kV Line		X																	
NRS-Scott No. 3 115 kV Line														X					
San Jose B bus tie							X						X					X	X
San Jose 'B'-Stone-Evergreen 115 kV Line									X				X	X		X	X	X	X
San Jose Sta 'A'-'B' 115 kV Line		X			X		X	X					X						X
Saratoga-Vasona 230 kV Line																			X
Scott-Duane 115 kV Line		X																	
Swift-Metcalf 115 kV Line																		X	
Trimble-San Jose 'B' 115 kV Line							X												
Vasona-Metcalf 230 kV Line		X			X						X	X			X				X

California ISO

San Jose Area HVDC Lines (cont'd)

- Studies show that about 1000 MW of new source is needed to address reliability issues identified in the San Jose transmission system.
- Based on the previous studies related to energy storage assessment, the San Jose system can only accommodate around 375 MW of energy storage from the charging capacity perspective, which is far less compared to the size of energy storage needed to address reliability issues identified in the area.

Result of energy storage assessment performed as part of the 2022 LCR study.



Series Compensation on Los Esteros-Nortech 115 kV Line

- Reliability Assessment Need
  - The near-term issues driven by P2, P6 and P7 category contingencies and multiple the mid and long-term issues driven by various category contingencies including P1.
- Project Submitter
  - CAISO
- Project Scope
  - To install about 2 ohm series reactor on the Los Esteros-Nortech 115 kV line.
- Estimated Project Cost
  - $10M - $15M
- Estimated In-service Date
  - 2023
- Alternatives Considered
  - Reconductoring: This alternative is not recommended due to lack of flow controllability, implementation time and cost.
- Recommendation
  - Approval

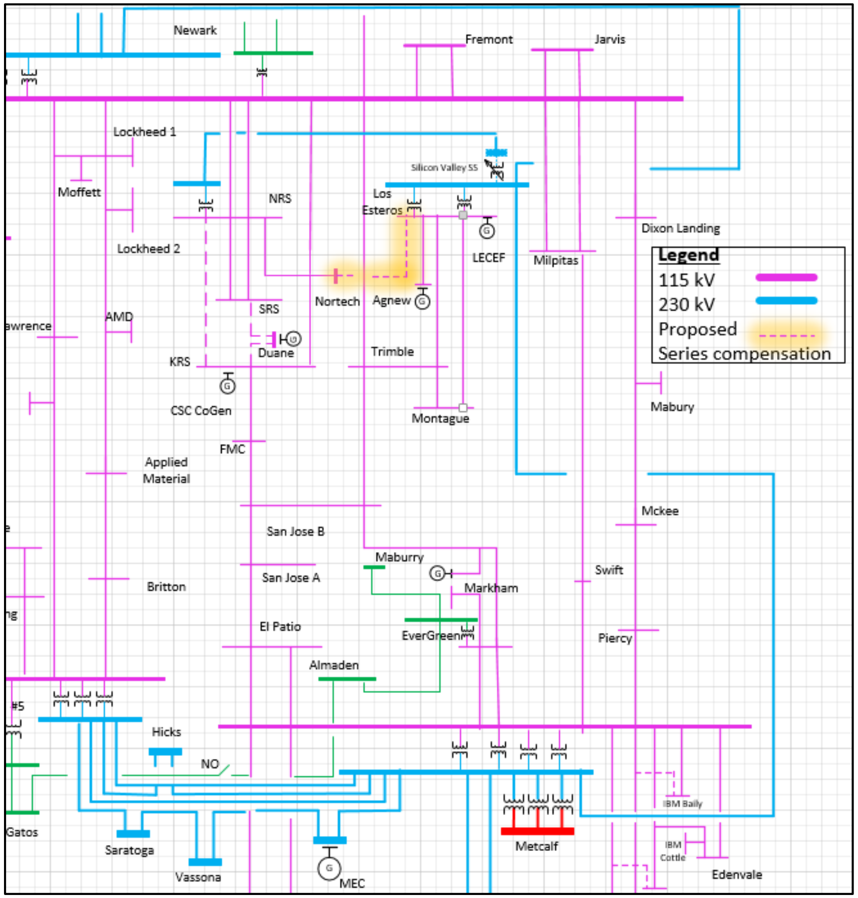
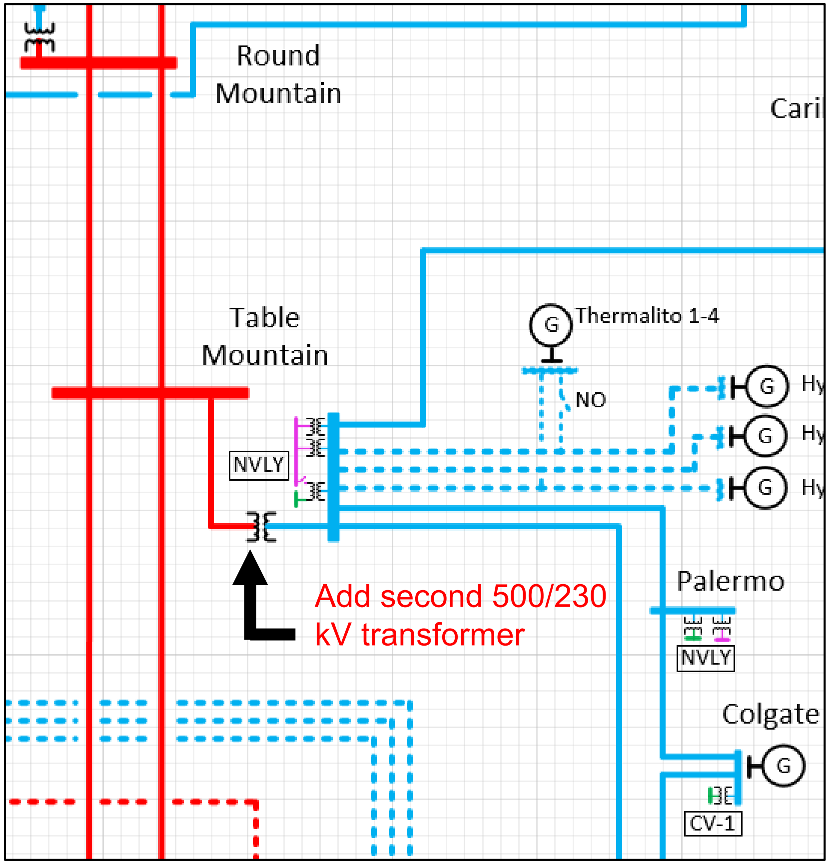


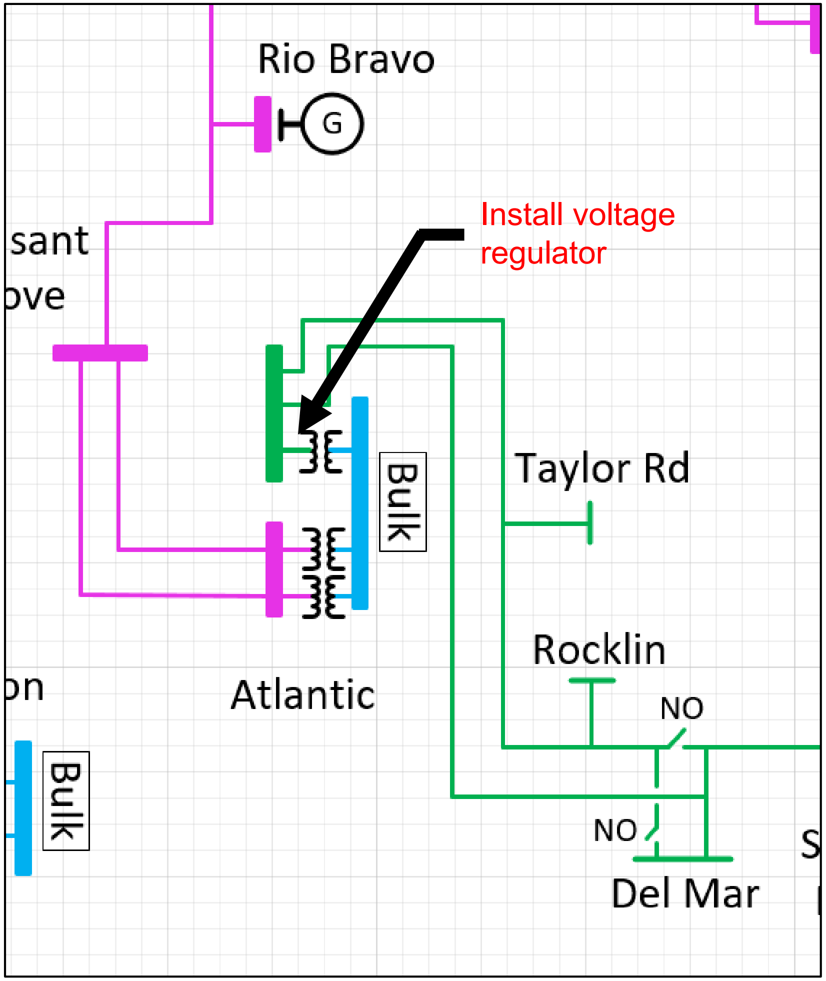
Table Mountain 500/230 kV TB #2 Project

- Reliability Assessment Need
  - High voltage issues in the Table Mountain/Palermo 230 kV area under the maintenance outage or contingency of the existing Table Mountain 500/230 kV transformer.
- Project Submitter
  - CAISO
- Project Scope
  - To install another 500/230 kV transformer bank at the Table Mountain substation.
- Estimated Project Cost
  - $38.4M - $76.8M
- Estimated In-service Date
  - 2027
- Alternatives Considered
  - Do Nothing (Status quo)
  - Install reactive support device.
- Recommendation
  - Approval



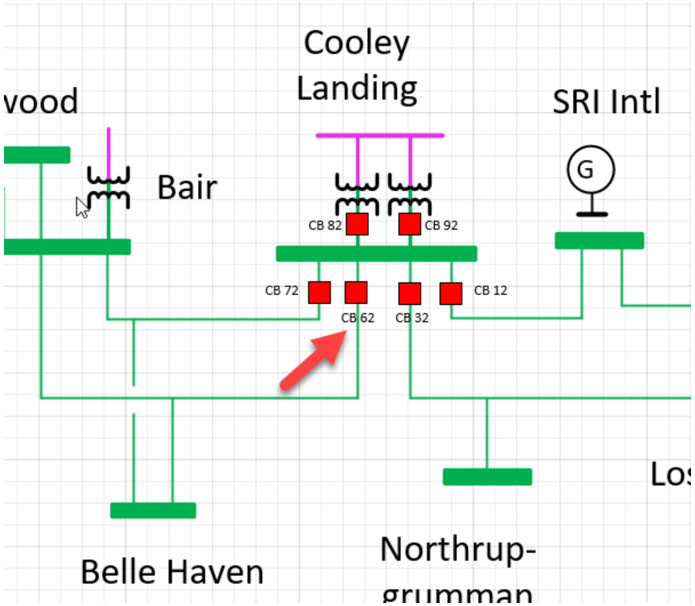
Atlantic 60 kV Voltage Regulator Project

- Reliability Assessment Need
  - High voltage issues on the 60 kV system which is radially supplied by the Atlantic 230/60 kV transformer starting 2026. The transformer does not have LTC and there are no means for operators to control the voltage.
- Project Submitter
  - CAISO
- Project Scope
  - To install a voltage regulator on the existing Atlantic 230/60 kV transformer.
- Estimated Project Cost
  - $5M - $10M
- Estimated In-service Date
  - 2026
- Alternatives Considered
  - Do Nothing (Status quo)
  - Replace the transformer with another one with LTC.
- Recommendation
  - Approval



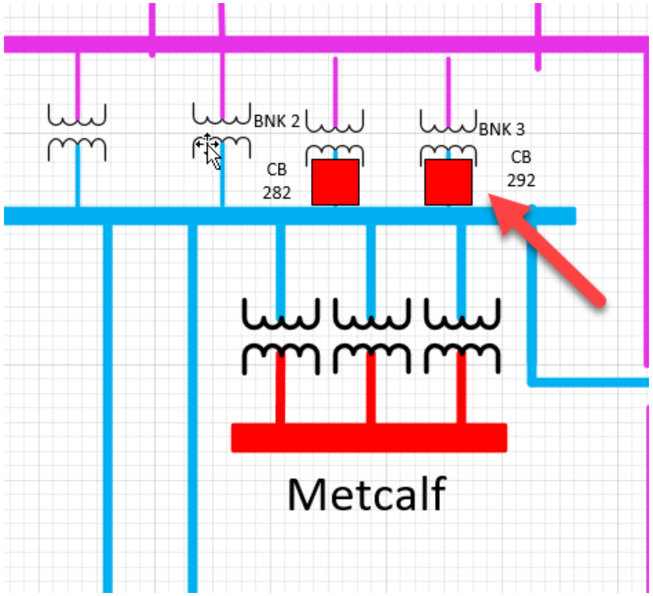
Cooley Landing Substation Circuit Breaker #62 Upgrade

- Reliability Assessment Need
  - Circuit Breaker overstress issues starting 2023
- Project Submitter
  - CAISO
- Project Scope
  - Upgrade Cooley Landing Circuit Breaker #62
- Estimated Project Cost
  - $750k - $1.13M
- Estimated In-service Date
  - 2026
- Alternatives Considered
  - None.
- Recommendation
  - Approval



Metcalf Substation Circuit Breaker #292 Upgrade

- Reliability Assessment Need
  - Circuit Breaker overstress issues starting 2023
- Project Submitter
  - CAISO
- Project Scope
  - Upgrade Metcalf Circuit Breaker #292
- Estimated Project Cost
  - $900k - $1.13M
- Estimated In-service Date
  - 2026
- Alternatives Considered
  - None.
- Recommendation
  - Approval



Reliability Assessment Recommendations – SCE Area
Draft 2021-2022 Transmission Plan

Nikitas Zagoras
Regional Transmission - South

2021-2022 Transmission Planning Process Stakeholder Meeting
February 7, 2022

New Reliability Projects Recommended for Approval in 2021-2022 TPP - SCE Area

Projects	Planning Area	Status
Devers 230 kV Reconfiguration Project	SCE Eastern	Included in this presentation
Victor 230 kV Switchrack Reconfiguration	SCE North of Lugo	Included in this presentation
Antelope 66 kV Short Circuit Duty Mitigation Project	SCE Big Creek Area	Included in this presentation

Devers 230 kV Reconfiguration Project

Scope:

- This project would be located at the Devers substation, and the proposed scope involves the following rearrangements:
- Create positions 1XS and 7S at the 230 kV Bus (breaker-and-a-half configuration)
- Move the Devers - Mirage No. 2 line from position 1S to position 1XS
- Move the Devers - Vista No. 2 line from position 8S to position 7S

Project cost:

- $6M

In-service Date:

- 2023

Reliability Assessment Need:

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

Alternatives under consideration

- Do Nothing (Status quo)

Recommendation

- Approve

Victor 230 kV Switchrack Reconfiguration

Scope:

- Convert two bus positions from the existing double bus double breaker configuration to breaker-and-a-half configuration by adding a tie breaker and relocate two lines.

Project cost:

- Original cost: $5M

In-service Date:

- 2023

Reliability Assessment Need:

- Potential post contingency voltage collapse risk was identified in the Victor/Kramer/Control area during planned or forced Victor 230kV bus. The project would mitigate the identified voltage instability risk, provide operational flexibility and enhance reliability in the area.

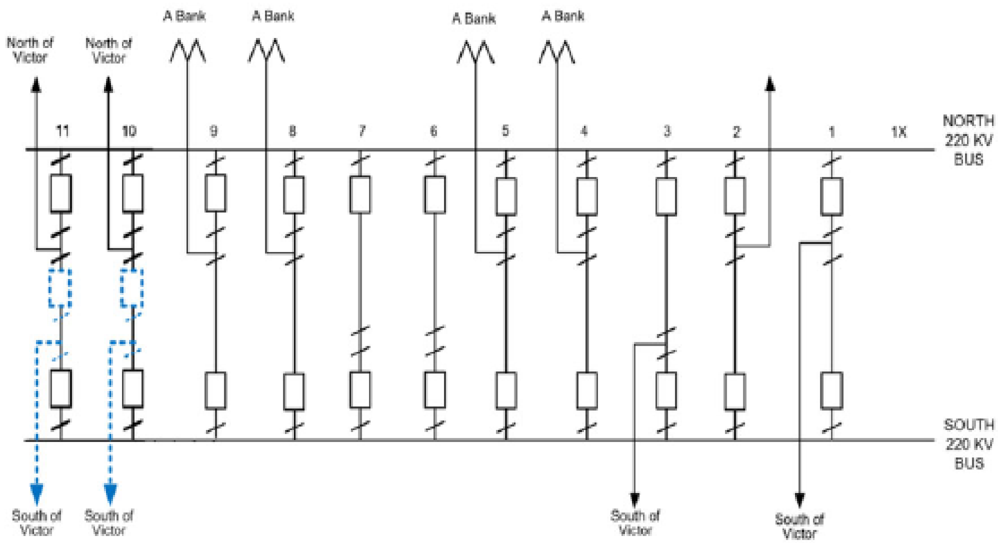
Alternatives under consideration

- Do Nothing (Status quo) This alternative is not recommended due to the post contingency voltage instability risk

Recommendation

- Approve

Proposed Configuration



Antelope 66 kV Short Circuit Duty Mitigation Project

Scope:

- To upgrade the existing Antelope 66 kV switchrack to a 50 kA short circuit duty rating by replacing (41) 66 kV circuit breakers, (101) 66 kV ground disconnect switches, (45) 66 kV potential transformers, performing a ground grid study, and removing (15) steel lattice structures and installing (15) new dead-end structures.

Project cost:

- Original cost: $55M

In-service Date:

- 2026

Reliability Assessment Need:

- The existing circuit breakers are currently operating at 96 percent of their 40 kA short circuit duty rating and our preliminary analyses show that adding the CPUC portfolio generation at the Antelope Substation 230 kV bus alone will trigger the need for circuit breaker replacement.

Alternatives considered

- Do nothing

Recommendation

Approve

Policy Assessment Recommendations – PG&E Area
Draft 2021-2022 Transmission Plan

Vera Hart – Lead Engineer

Ebrahim Rahimi – Sr. Advisor

Regional Transmission - North

2021-2022 Transmission Planning Process Stakeholder Meeting

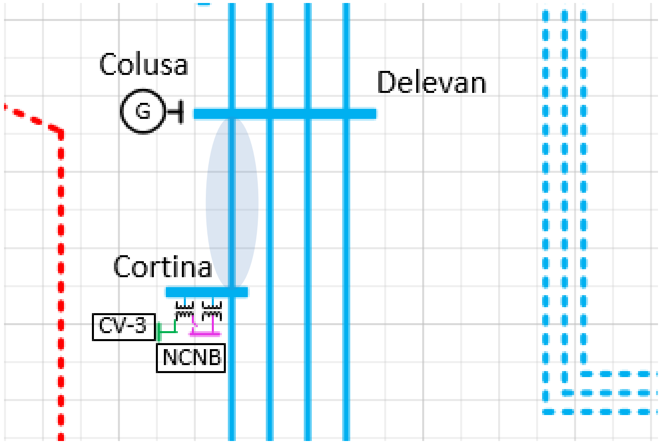
February 7, 2022

New Policy Projects Recommended for Approval in 2021-2022 TPP - PG&E Area

Projects	Planning Area	Status
Delevan Cortina 230kV Reconductoring	North of Greater Bay Area	Included in this presentation
Rio Oso-SPI Jct-Lincoln 115kV line	Greater Bay Area	Included in this presentation
Collinsville 500/230 kV Substation	North of Greater Bay Area	Included in this presentation
Manning 500/230 kV Substation	Fresno Area	Included in this presentation

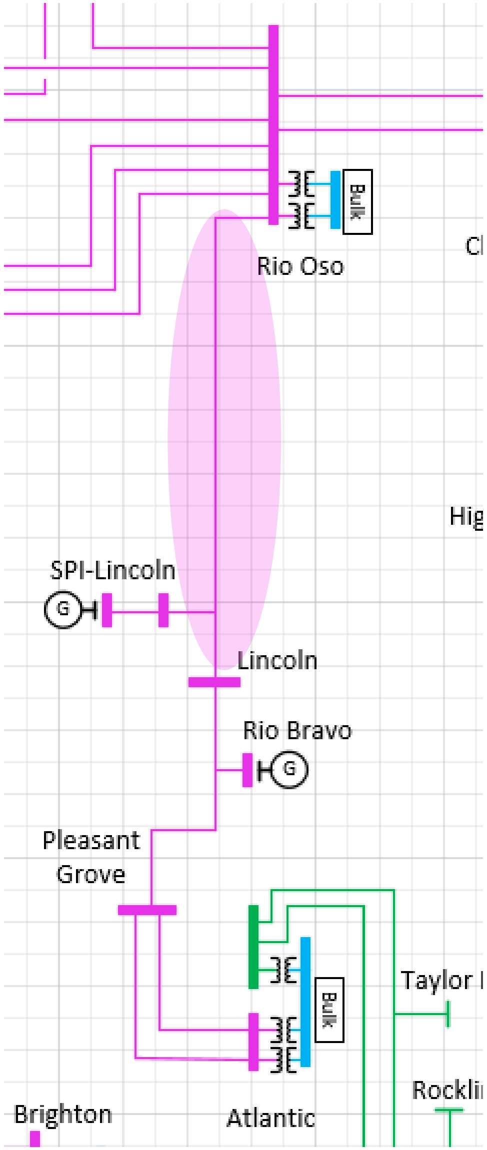
Delevan-Cortina 230kV line Reconductoring Project

- Policy Assessment Need
  - Base case and contingency overloads in baseline and sensitivity scenarios in on-peak deliverability assessment.
- Project Submitter
  - CAISO
- Project Scope
  - Reconductor Delevan-Cortina 230kV line
- Estimated Project Cost
  - $17.7M - $35.4M
- Estimated In-service Date
  - 2028
- Alternatives considered
  - RAS - not feasible due to base case overload.
  - Re-locating portfolio battery storage – no portfolio storage behind this constraint.
- Recommendation
  - Approve



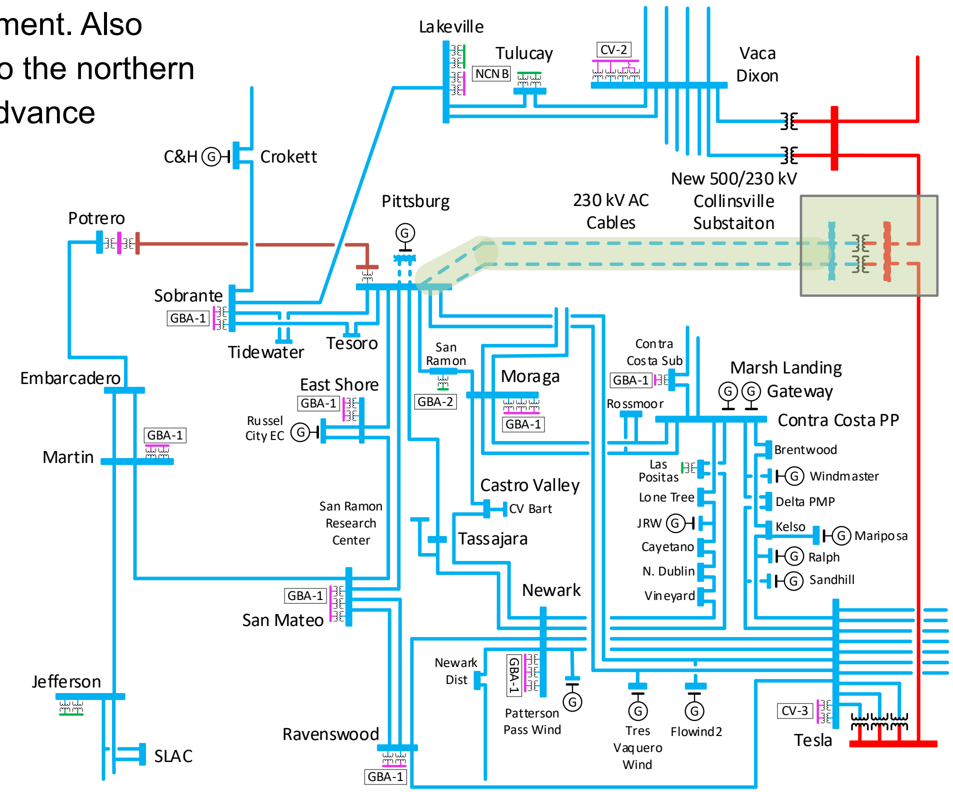
Rio Oso-SPI Jct-Lincoln 115kV line Reconductoring Project

- Policy Assessment Need
  - N-2 contingency overloads in baseline and sensitivity scenarios in on-peak deliverability assessment
- Project Submitter
  - CAISO
- Project Scope
  - Reconductor Rio Oso-SPI Jct-Lincoln 115kV line
- Estimated Project Cost
  - $10.6M - $21.2M
- Estimated In-service Date
  - 2028
- Alternatives considered
  - RAS – not feasible due to need for remote monitoring.
  - Re-locating portfolio battery storage – no portfolio storage behind this constraint.
- Recommendation
  - Approve



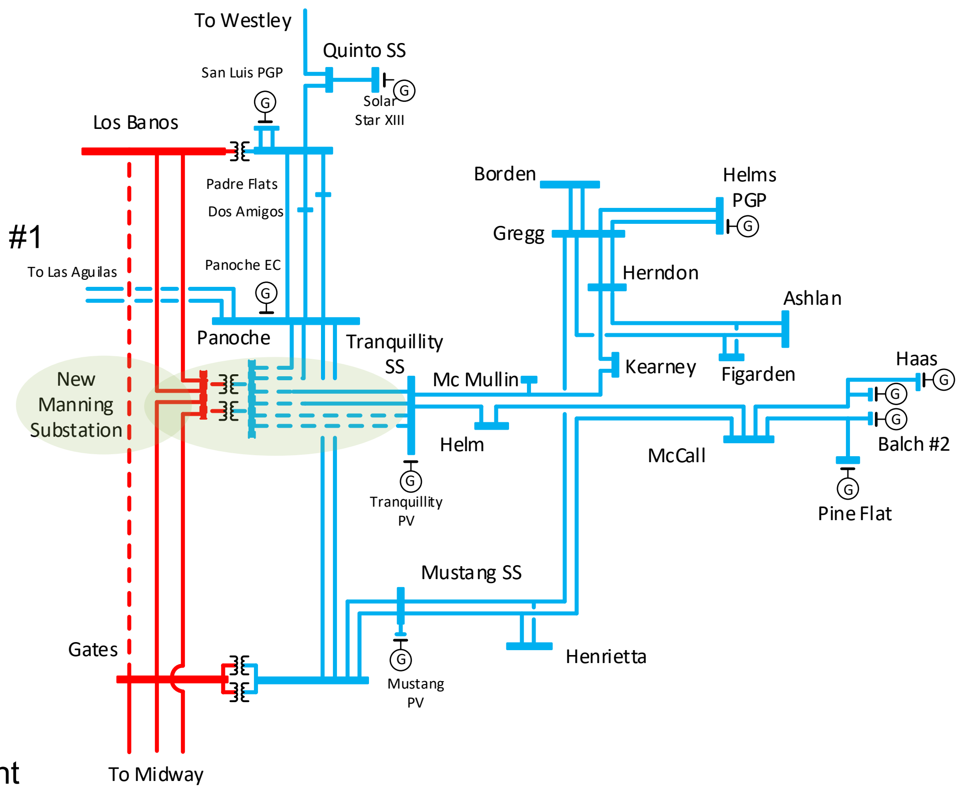
Collinsville 500/230 kV Substation Project

- Policy Assessment Need
  - Multiple overloads on the 230 kV corridor between Contra Costa and Newark under normal, N-1, and N-2 contingency conditions in baseline and sensitivity scenarios in on-peak deliverability assessment. Also provides an additional supply from the 500 kV system into the northern Greater Bay Area to increase reliability to the area and advance additional renewable generation in the northern area.
- Project Submitter
  - CAISO
- Project Scope
  - New Collinsville 500/230 kV substation
  - Loop in the Vaca Dixon – Tesla 500 kV line
  - Two 230 kV cables from Collinsville to Pittsburg
- Estimated Project Cost
  - $475M - $675M
- Estimated In-service Date
  - 2028
- Alternatives under consideration
  - RAS – not feasible due to large number of facilities to be monitored and due to complexity.
  - 230 kV lines reconductor – not recommended as it doesn't provide additional supply needed for the northern GBA for increased reliability and to advance renewable generation addition.
- Recommendation
  - Approve



Manning 500/230 kV Substation Project

- Policy Assessment Need
  - Overloads on the Borden-Storey 230 kV lines under normal and N-1 contingency conditions in baseline and sensitivity scenarios in on-peak deliverability assessment. Also provides benefit in allowing for the advancement of renewable generation within the Westlands / San Joaquin area.
- Project Submitter
  - CAISO
- Project Scope
  - New Manning 500/230 kV substation
  - Loop in Los Banos – Midway #2 and Los Banos – Gates #1 500 kV lines
  - Loop in two existing Panoche – Tranquility 230 kV line
  - Build a new double circuit 230 kV line between Manning and Tranquility substations.
- Estimated Project Cost
  - $325M - $485M
- Estimated In-service Date
  - 2028
- Alternatives under consideration
  - RAS – not feasible due need for remote monitoring.
  - 230 kV lines reconductor – not recommended as it doesn't provide benefit in allowing for the advancement of renewable generation within the Westlands or San Joaquin area.
- Recommendation
  - Approve



Policy Assessment Recommendations – Southern California Draft 2021-2022 Transmission Plan

Meng Zhang – Senior Engineer
Regional Transmission - South

2021-2022 Transmission Planning Process Stakeholder Meeting
February 7, 2022

New Policy Projects Recommended for Approval in 2021-2022 TPP – Southern California

Projects	Planning Area	Status
GLW/VEA Area Upgrades	GLW/VEA	Seeking approval
Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project	SCE	Seeking approval

GLW/VEA Area Upgrades Project

- **Recap of November Stakeholder Meeting**
  - 2,024 MW CPUC base portfolio resources were allocated to the GLW system in 2021/22 TPP Policy Assessment.
  - The solar resources connecting to GLW's Trout Canyon, Innovation and Desert View 230kV buses are subject to curtailment in the Base Portfolio off-peak deliverability assessment due to normal loading limitations of multiple 230kV and 138kV lines in GLW and VEA areas and the tie-lines to the neighboring system.
  - During the Request Window Submission process, GridLiance West LLC submitted a GLW Upgrade Project. The project scope includes rebuilding existing 230kV lines to double circuit lines; adding a new 500/230 kV transformer; an upgrade to VEA's Amargosa 230/138 kV transformer located at WAPA's Amargosa substation and a tentatively planned NV Energy upgrade on the Mercury SW – Northwest 138 kV tie line. The estimated cost of the project is $213M with an expected in-service date of 2025.

GLW/VEA Area Upgrades Project *(continued)*

- **ISO Transmission Capacity Limit**
  - The VEA/GLW system is connected to the rest of ISO grid through the Innovation – Pahrump – Gamebird - Trout Canyon – Sloan Canyon – Eldorado 230 kV single path and the path doesn't have enough capacity to deliver the majority of the generation to the ISO load without relying on the neighboring system.
  - The submitted GLW Upgrade Project would mitigate the Pahrump – Gamebird – Trout Canyon – Sloan Canyon capacity constraints, but it didn't address the Innovation – Pahrump ISO transmission capacity limit.
  - Innovation – Pahrump 230kV upgrade was added to the scope of the project.

- **138kV NVE Tie-line Constraint**
  - The Mercury SW – Northwest 138kV tie-line that NV Energy had preliminary plans to rebuild is no longer under consideration by NV Energy.
  - Subsequent analysis demonstrated that a phase shifter would mitigate the 138kV tie-line constraints.

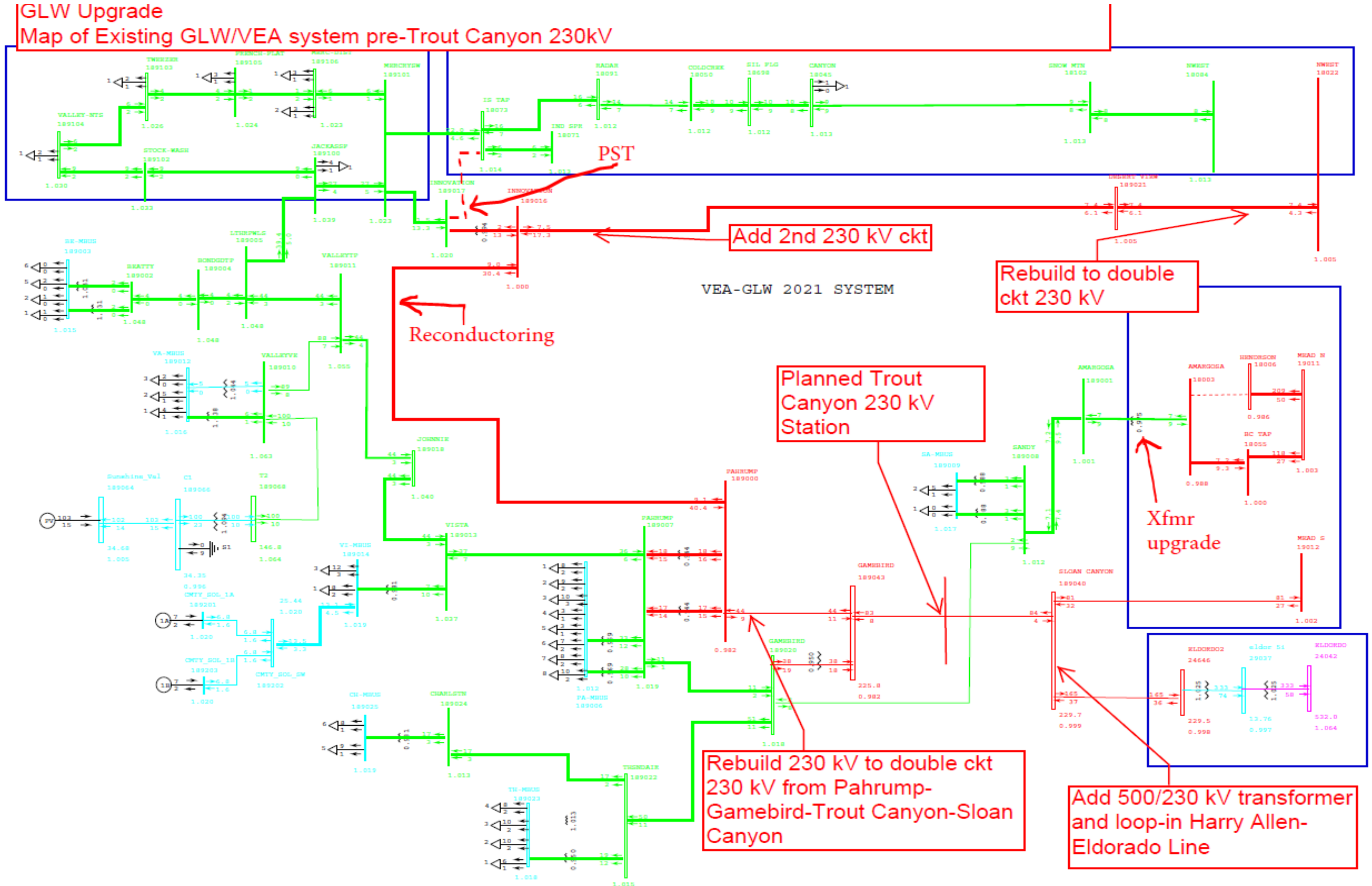
- **Coordination with Eldorado SCD Mitigation**
  - With the queued generation projects development in the Eldorado area on the GLW, SCE, NVE and LADWP system, the short circuit duty capability on the 230kV and 500kV equipment at Eldorado Substation is expected to be exceeded in the near term and must be mitigated.
  - A mitigation will need to be in place before the GLW upgrade project can be fully utilized.
  - SCE is working with key stakeholders such as LADWP, NVE and the CAISO to develop both interim and permanent mitigations.

GLW/VEA Area Upgrades Project *(continued)*

- **Project Scope for Approval:**
  - Rebuild Desert View – Northwest 230 kV, Pahrump – Gamebird 230 kV, Gamebird – Trout Canyon 230kV and Trout Canyon – Sloan Canyon 230 kV to double circuit lines;
  - Add 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 138kV phase shifter at Innovation on the planned tie-line to NVE
  - Upgrade VEA's Amargosa 230/138 kV transformer
- **Estimated Project cost:**
  - $278 M*

  *The ISO recommends that the cost of the Amargosa transformer upgrade and the Innovation 138kV phase shifter should be recoverable through the ISO Regional Transmission Access charge pursuant to ISO Tariff Section 24.10
- **Estimated In-service Date:**
  - 2025
- **Alternatives Considered:**
  - GLW Conversion Project: the project consisted of a new Gamebird – Arden 230kV line and a second Innovation – Desert View and Desert View – Northwest 230kV line. While the project would mitigate the identified constraints, it did not help with commercial issues of whether the ISO system had enough capacity without relying on the neighboring transmission system.
- **Recommendation**
  - Approve

GLW/VEA Area Upgrades Project *(continued)*



California ISO

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

Approved Cycle:
- 2021-2022 TPP

Original Scope:
- Reconductor the Laguna Bell-Mesa No. 1 230kV transmission circuit

Estimated Project Cost:
- $17.3 M

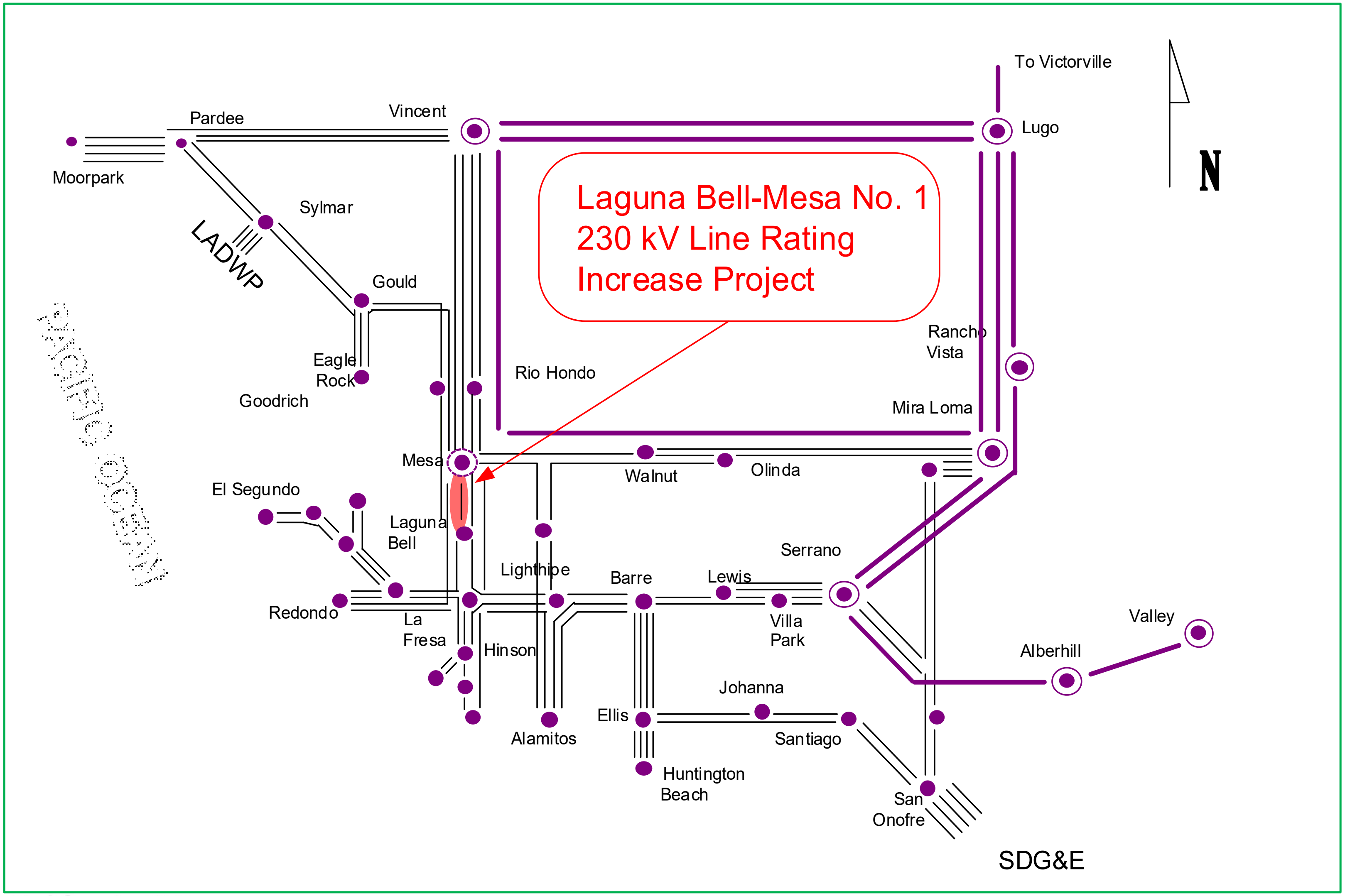
Estimated In-service Date:
- 2023

Reliability Assessment Need:
- The line loads to 114% due to the Mesa–Lighthipe & Mesa - Laguna Bell No.2 230 kV (P7) based on the on-peak deliverability assessment methodology of the Base Portfolio

Alternatives Considered:
- Laguna Bell – Mesa Series Compensation Project ($18.1 M)

Recommendation
- Approve

Laguna Bell-Mesa No. 1 230 kV Line Rating Increase Project *(Continued)*



Economic Assessment and Production Cost Simulation
Draft 2021-2022 Transmission Plan

Yi Zhang

2021-2022 Transmission Planning Process Stakeholder Meeting
February 7, 2022

Summary of key steps in database development since November stakeholder session

- Continued to update the Planning PCMs
  - Updated SCE area BTM PV bus mapping based on the new data provided by SCE
  - Updated SDGE SPS models for a number of contingencies
- PCM cases were posted on the CAISO's MPP
  - Base portfolio PCM with NM wind for economic assessment
  - Base portfolio and Sensitivity 1 portfolio out of state wind PCM for out of state wind study
  - Sensitivity 2 portfolio PCM for offshore wind study

Economic Assessment

Base Portfolio - summary of congestions

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	Path 26 Corridor	116.33	3,285
2	GridLiance West/VEA	39.92	3,158
3	SDGE DOUBLTTP-FRIARS 138 kV	37.63	1,772
4	COI Corridor	14.63	332
5	PG&E Moss Landing-Las Aguilas 230 kV	14.44	261
6	Path 42 IID-SCE	7.74	296
7	PDCI	6.81	663
8	Path 60 Inyo-Control 115 kV	6.35	1,888
9	Path 15 Corridor - Panoche-Gates 230 kV	6.21	388
10	Path 45	4.99	688
11	Path 61/Lugo-Victorville	4.28	315
12	PG&E Fresno	3.96	446
13	SCE LCIENEGA-LA FRESA 230 kV	3.96	34
14	Path 15 Corridor	3.53	105
15	PG&E Tesla 500 kV Transformer	3.43	22
16	SCE RedBluff-Devers 500 kV	3.22	31
17	Path 46 WOR	2.64	49
18	SCE Antelope 66 kV system	2.57	1,108
19	PG&E Las Positas- Newark 230 kV	1.81	46
20	Path 25 PACW-PG&E 115 kV	1.76	193
21	SCE Alberhill-Valley 500 kV	1.71	125
22	PG&E Sierra	1.41	167
23	SDGE N.Gila-Imperial Valley 500 kV	1.00	53

- Only listed congestions with more than $1 million congestion cost. More details can be found in the draft TPP report
- No significant changes from the preliminary results presented in the Nov. stakeholder meeting, except for the SDG&E Doublet Tap – Friars 138 kV congestion and SCE North of Lugo congestion

Constrained areas selected for detailed investigation and economic assessment

Detailed investigation\	Alternative	Proposed by	Reason
Path 26 corridor congestion	Re-rate the Midway-Whirlwind 500 kV line rating and bypass series cap of the line	CAISO	Expected to reduce or eliminate the Midway – Whirlwind congestion
	PTE project	Western Grid	Potentially reduce Path 26 corridor congestion
GLW/VEA area congestion	GLW upgrade	GridLiance West	Expected to reduce or eliminate the congestion and reduce renewable curtailment
PG&E Moss Landing – Las Aguilas 230 kV congestion	Series reactor on the Moss Landing – Las Aguilas 230 kV line	CAISO	Potentially mitigate or reduce the identified congestion
PG&E Panoche – Gates 230 kV congestion	Series reactor on the Panoche – Gates 230 kV lines	CAISO	Potentially mitigate or reduce the identified congestion

Path 26 corridor congestion

- Congestion on Path 26 corridor was observed mainly when the flow was from south to north
- Solar generation and battery in Southern California identified in the CPUC renewable portfolio were the main driver of the Path 26 corridor congestion
- The low summer line rating of the Midway – Whirlwind 500 kV line contributed to the line congestion
- Resources in the CPUC portfolio at Whirlwind contributed to the Midway – Whirlwind congestion as well
- Path 26 corridor was also identified as off-peak deliverability constraint in the policy assessment

Path 26 corridor congestion - Occurrences of Midway – Whirlwind 500 kV Line Congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	15	19	10	6	5	4	3	4	5	4	13	25	27	22	15	12
May	0	0	0	0	0	0	0	5	25	18	12	10	5	7	7	7	7	8	11	16	14	13	9	5
Jun	0	0	0	0	0	0	0	2	16	23	22	12	10	4	6	7	7	8	3	5	8	7	5	4
Jul	0	0	0	0	0	0	0	0	14	28	21	17	14	15	15	17	14	9	10	9	8	8	3	2
Aug	0	0	0	0	0	0	0	0	6	28	25	18	14	14	15	17	15	14	12	13	15	10	7	7
Sep	0	0	0	0	0	0	0	0	4	26	21	6	4	8	13	8	6	8	12	14	8	5	5	5
Oct	0	0	0	0	0	0	0	0	2	19	9	9	4	3	7	10	2	7	20	22	13	5	4	3
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Path 26 corridor congestion - Occurrences of Midway – Whirlwind 500 kV Line Congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	2	3	1	1	3	2	3	3	17	29	31	23	15	13	11	12	4	4	22	22	16	11	4	5
Feb	4	2	2	2	1	0	4	8	17	21	20	20	18	17	17	16	12	5	16	18	17	14	16	16
Mar	6	4	3	4	2	3	7	15	20	29	26	20	14	9	10	10	10	5	22	26	25	27	25	23
Apr	0	0	0	0	0	0	0	5	10	15	14	6	5	2	2	2	3	1	2	1	2	3	7	0
May	0	0	0	0	0	0	0	1	0	3	3	2	2	2	3	2	2	1	0	2	0	1	1	0
Jun	0	0	0	0	0	0	0	0	3	3	1	0	0	0	0	1	0	0	1	1	0	0	0	0
Jul	0	0	0	0	0	0	0	5	9	5	4	3	0	0	0	3	0	0	0	0	0	0	1	0
Aug	2	1	0	0	0	0	2	17	21	6	7	4	3	4	3	2	0	1	0	0	1	2	3	5
Sep	4	3	3	6	5	4	5	19	24	16	13	2	2	1	0	1	0	1	4	1	1	3	4	4
Oct	0	0	0	0	0	0	1	9	18	14	23	15	11	4	6	7	1	1	4	4	1	1	1	0
Nov	1	0	2	2	3	1	3	12	27	30	29	22	15	12	10	6	0	13	22	23	17	14	9	2
Dec	7	4	5	3	5	2	3	4	22	28	28	27	18	19	19	15	4	9	16	16	10	10	9	7

Path 26 corridor congestion – Southern California Battery Output

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	-425	-4,587	-8,263	-8,855	-6,966	-2,481	0	3,452	7,285	6,952	5,583	2,174	879	514
Feb	-1	0	0	0	0	0	1	1	0	-6	-1,220	-5,684	-8,090	-7,959	-6,863	-3,601	-389	1,457	6,743	7,061	6,317	4,104	1,833	1,224
Mar	0	0	-6	-1	0	0	0	0	0	-141	-2,656	-7,557	-10,216	-10,999	-10,218	-7,713	-1,881	417	7,353	10,213	10,134	8,188	4,714	2,659
Apr	0	0	0	0	0	0	0	0	0	-444	-3,836	-7,952	-9,538	-10,241	-9,620	-7,078	-1,581	423	4,573	9,104	9,687	8,240	6,303	4,417
May	0	0	0	0	0	0	0	-1	-22	-1,265	-4,581	-7,624	-9,172	-8,908	-7,389	-3,903	-548	1,093	4,575	8,221	8,822	6,925	4,560	2,696
Jun	0	0	0	0	0	0	0	0	-39	-656	-2,357	-5,023	-6,747	-7,270	-6,410	-4,419	-1,346	731	3,196	6,466	7,589	5,636	3,382	2,122
Jul	0	0	0	0	0	0	0	-6	-2	-841	-3,242	-6,256	-7,140	-6,380	-4,540	-2,387	-312	2,084	4,881	6,047	5,777	3,726	2,282	1,634
Aug	0	0	0	0	0	0	0	0	0	-686	-3,201	-6,903	-8,392	-7,799	-5,646	-2,475	-204	3,076	6,096	7,003	6,695	3,397	2,098	1,640
Sep	0	-19	-50	-81	-66	0	0	-7	-11	-890	-4,593	-7,811	-8,471	-6,375	-3,410	-1,004	1,231	4,445	6,635	7,060	4,375	1,875	1,233	1,011
Oct	0	0	0	0	0	0	-1	-8	-14	-600	-4,168	-8,168	-9,839	-9,080	-6,141	-2,395	447	5,409	8,450	8,203	6,228	3,001	1,430	1,179
Nov	0	0	0	0	0	0	0	0	0	-117	-3,470	-8,251	-9,668	-8,803	-5,484	-988	365	6,815	7,986	7,258	5,226	2,016	926	672
Dec	0	-1	0	0	0	0	0	0	-8	-2	-575	-4,184	-7,190	-6,890	-4,190	-570	51	4,645	5,483	5,016	3,417	771	401	285

Path 26 corridor congestion – Mitigation alternatives

- Alternatives without capital cost, which were also identified effective to address off-peak deliverability problem in the policy assessment
  - Rerate the summer rating of the Midway-Whirlwind 500 kV line, and adjust the emergency rating accordingly
  - Bypass the series capacitor on the Midway-Whirlwind 500 kV line, which was expected to balance flow among the three 500 kV lines of Path 26
- The Pacific Transmission Expansion (PTE) project – an economic study request with multi-terminals offshore HVDC lines between the northern and southern California systems

Path 26 corridor congestion – Midway – Whirlwind mitigation with re-rating and bypassing series cap

- Re-rate the summer rating and bypass the series cap of the Midway – Whirlwind line can effectively reduce congestion of the line
  - Path 26 path rating would be binding more frequently
    - It is expected that path rating increase can help to mitigate or reduce Path 26 congestion
    - Path rating change requires to go through the WECC path rating process

Path 26 corridor congestion – Production benefit of Midway – Whirlwind re-rate and series cap bypass

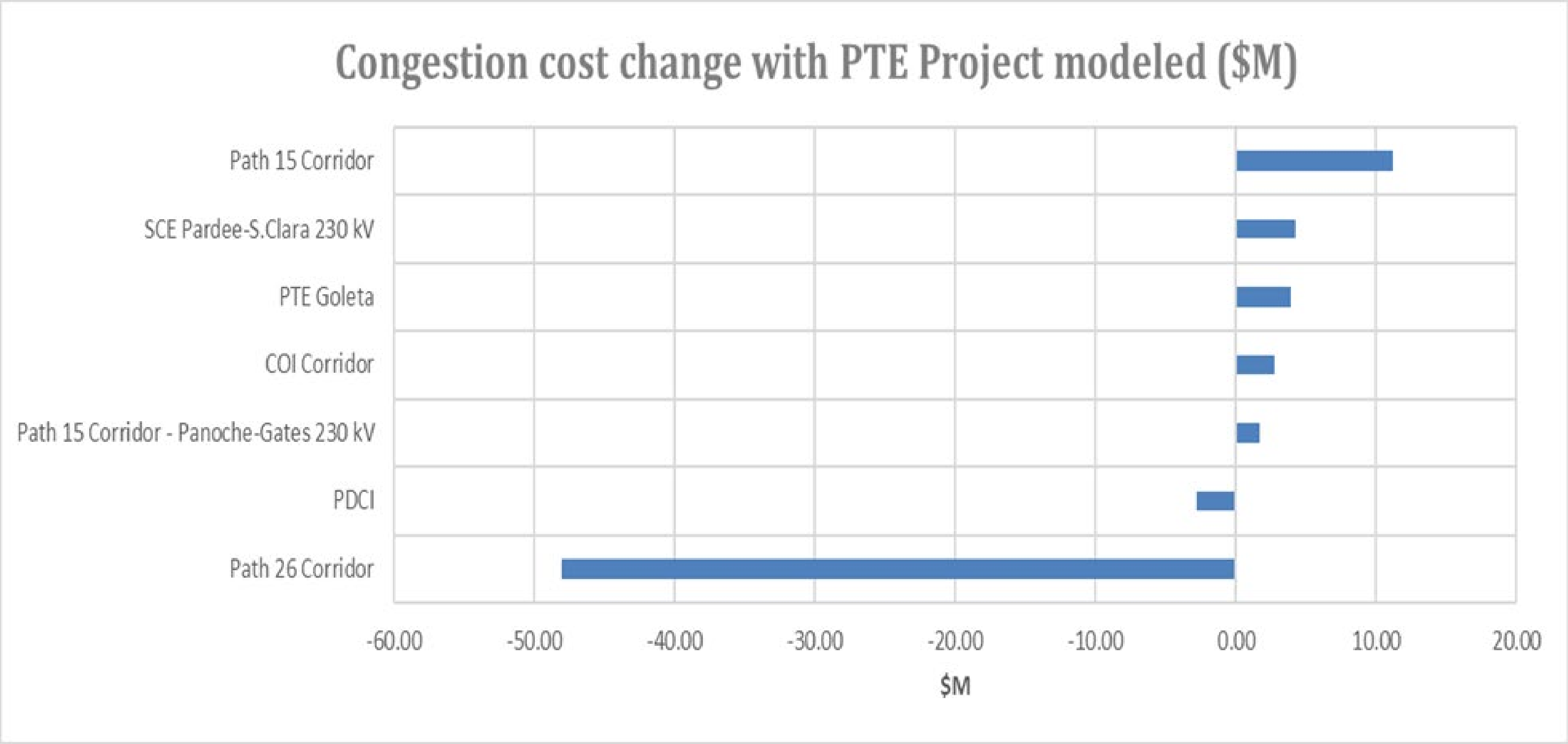
	Base case	Midway-Whirlwind re-rate		MW-WW Re-rate and bypass series cap	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
CAISO load payment	9,265	9,259	6	9,258	7
CAISO generator net revenue benefiting ratepayers	4,206	4,228	22	4,226	20
CAISO transmission revenue benefiting ratepayers	484	460	-24	464	-20
CAISO Net payment	4,575	4,572	3	4,569	6
WECC Production cost	13,184	13,182	2	13,173	11

As these two mitigations do not require capital cost, positive production benefit provided sufficient economic justification to recommend these to mitigate the constraints

Path 26 corridor congestion – PTE project

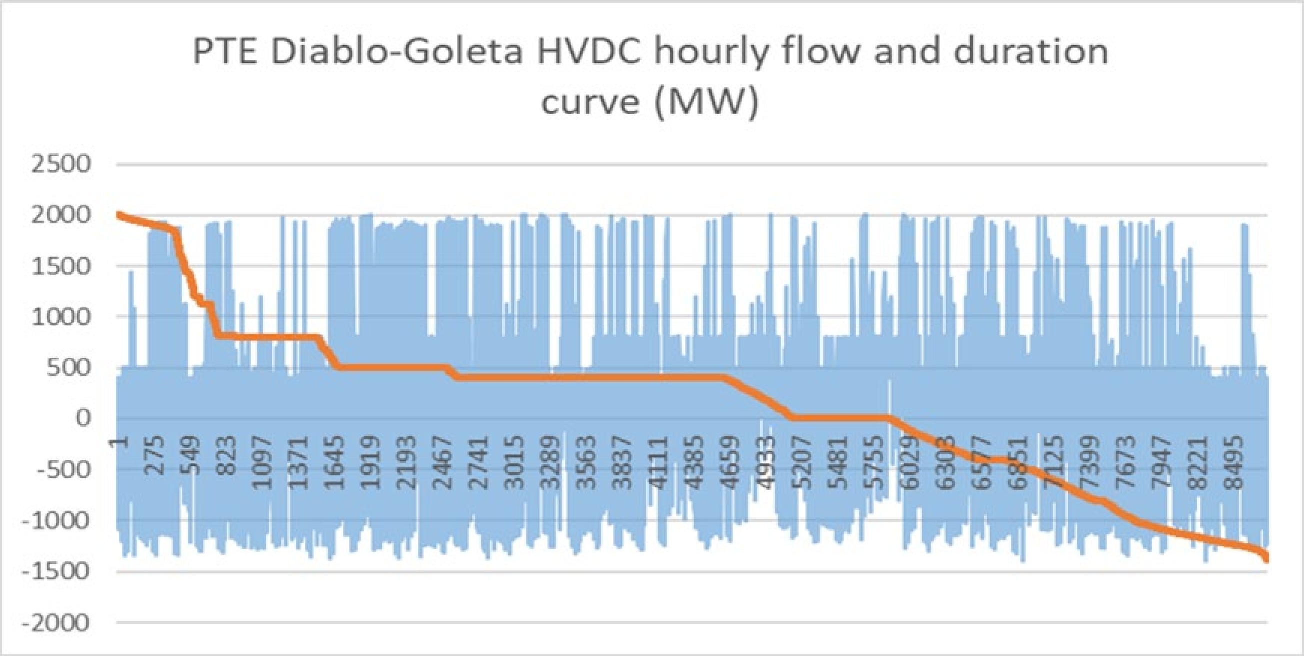
- PTE project consists of a 2,000 MW controllable HVDC subsea transmission cable that connects northern and southern California
  - Submitted by Western Grid Development LLC (Western Grid) as both economic study request and reliability request window submission
  - HVDC with multi-terminals:
    - PG&E Diablo Canyon substation
    - SCE Goleta substation
    - SCE El Segundo substation
    - SCE Huntington Beach substation

Path 26 corridor congestion – Congestion changes with PTE modeled



- Path 26 corridor congestion reduced significantly compared with the study results for the PTE project in the last planning cycle
- Path 15 corridor congestion increased

Path 26 corridor congestion – PTE HVDC flow



- The HVDC flow was from north to south in more hours than from south to north.
- Consequently, the total congestion hours of the Path 26 corridor congestion increased to 4023 hours with the PTE modeled, from the 3285 congestion hours in the base PCM

Path 26 corridor congestion – PTE project production cost benefit

	Base case	PTE case	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,262	3
ISO generator net revenue benefiting ratepayers	4,206	4,233	27
ISO transmission revenue benefiting ratepayers	484	469	-15
ISO Net payment	4,575	4,560	15
WECC Production cost	13,184	13,155	29

- LCR reduction benefit identified in the last planning cycle was considered as well in the BCR calculation
- Did not show sufficient benefit to justify as economic driven upgrade in this planning cycle

GridLiance West/VEA area congestion

Constraints Name	Costs_F (K$)	Duration_ F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration_ T (Hrs)
TROUT CANYON-SLOAN CANYON 230 kV line #1	30,449	2,144	0	0	30,449	2,144
GAMEBIRD-TROUT CANYON 230 kV line #1	0	0	8,816	838	8,816	838
NWEST-DESERT VIEW 230 kV line #1	0	0	595	147	595	147
INNOVATION-DESERT VIEW 230 kV line #1	46	27	0	0	46	27
MEAD S-SLOAN CANYON 230 kV line #1	0	0	11	2	11	2

- Congestions in the GridLiance West/VEA area were observed mainly on the 230 kV lines under normal condition and when solar generation output was high
- Off-peak deliverability problems were also identified in the policy assessment

GridLiance West/VEA area congestion – Mitigation

- The CAISO identified the GLW Upgrade as the mitigation for the off-peak constraints in the GridLiance West/VEA area
- The GLW Upgrade reinforces the 230 kV lines in the GridLiance West/VEA area, and provides a new 500 kV connection to the Harry Allen – Eldorado 500 kV line
  - The upgrade can mitigate most of the congestions in the GridLiance West/VEA area
  - Solar curtailment in GridLiance West/VEA area can also be relieved
  - Congestion in the downstream system may increase, such as Path 26 corridor

GridLiance West/VEA area congestion – Congestion mitigation and production benefit with the GLW Upgrade

Area or Branch Group	Base case - Congestion Cost ($M)	GLW Upgrade case - Congestion Cost ($M)	Congestion cost change (>$2M)
GridLiance West/VEA	39.92	4.13	-35.79
Path 46 WOR	2.64	4.82	2.18
PDCI	6.81	9.22	2.41
Path 26 Corridor	116.33	121.59	5.26

	Base case	GLW Upgrade case	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,265	9,184	81
ISO generator net revenue benefiting ratepayers	4,206	4,186	-20
ISO transmission revenue benefiting ratepayers	484	467	-17
ISO Net payment	4,575	4,530	45
WECC Production cost	13,184	13,159	25

GridLiance West/VEA area congestion – BCR of the GLW Upgrade

GLW Upgrade	
Production cost savings ($million/year)	45
Capacity saving ($million/year)	0
Capital cost ($million)	273
Discount Rate	7%
PV of Production cost savings ($million)	642
PV of Capacity saving ($million)	0
Total benefit ($million)	642
Total cost (Revenue requirement) ($million)	355
Benefit to cost ratio (BCR)	1.81

The GLW Upgrade has 1.81 of benefit to cost ratio, also supporting the policy-driven recommendation for approval.

PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion

- Congestion on the Moss Landing – Las Aguilas 230 kV line was observed when the flow was from Las Aguilas to Moss Landing
- Congestion on the Panoche – Gates 230 kV lines was observed when the flow was from Gates to Panoche
- Most of the congestions on these 230 kV lines occurred in summer months and within solar hours

PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion

Constraints Name	Costs_F (K$)	Duration_ F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration_T (Hrs)
MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Moss Landing-LosBanos 500 kV	0	0	13,836	235	13,836	235
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	4,461	244	4,461	244
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	1,129	44	1,129	44
MOSSLNSW-LASAGUILASS 230 kV line #2	0	0	604	26	604	26
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	484	71	484	71
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	89	17	89	17
PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Henrieta1-Gregg 230 kV	0	0	33	1	33	1
PANOCHE-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	11	11	11	11

PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion – Occurrences of conestions

Moss Landing – Las Aguilas

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	2	4	4	2	2	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	3	8	7	6	5	3	3	1	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	8	15	10	4	4	3	4	1	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	1	14	14	7	5	4	4	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	9	19	12	7	7	2	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	1	8	3	4	2	2	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	1	3	1	2	4	0	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Panoche - Gates

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	2	6	6	3	2	3	2	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	2	3	4	3	3	2	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	1	11	5	4	4	2	1	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	3	7	5	7	7	6	2	0	1	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	16	10	11	9	8	4	0	2	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	1	6	5	4	5	5	4	1	1	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	5	11	12	4	4	3	2	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion - Mitigation

- Series reactors are effective to mitigate the congestions
  - Add 10 ohms series reactor on the Moss Landing – Las Aguilas 230 kV line
  - Add 20 ohms series reactor on each of the Panoche – Gates 230 kV lines

PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion – BCR of adding series reactors switched in for whole year

	10 ohms Reactors on Moss Landing – Las Aguilas	20 ohms Reactors on Panoche - Gates	Reactors on Moss Landing – Las Aguilas and Panoche - Gates
Production cost savings ($million/year)	5.6	11.1	-0.7
Capacity saving ($million/year)	0	0	0
Capital cost ($million)	20	80	100
Discount Rate	7%	7%	7%
PV of Production cost savings ($million)	82.9	164.2	-10.52
PV of Capacity saving ($million)	0	0	0
Total benefit ($million)	82.9	164.2	-10.52
Total cost (Revenue requirement) ($million)	26	104	130
Benefit to cost ratio (BCR)	3.19	1.58	-0.08

PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion – BCR of adding series reactors switched in for summer only

	10 ohms Reactors on Moss Landing – Las Aguilas	20 ohms Reactors on Panoche - Gates	Reactors on Moss Landing – Las Aguilas and Panoche - Gates
Production cost savings ($million/year)	8.5	-3.4	5.0
Capacity saving ($million/year)	0	0	0
Capital cost ($million)	20	80	100
Discount Rate	7%	7%	7%
PV of Production cost savings ($million)	125.9	-50.4	73.7
PV of Capacity saving ($million)	0	0	0
Total benefit ($million)	125.9	-50.4	73.7
Total cost (Revenue requirement) ($million)	26	104	130
Benefit to cost ratio (BCR)	4.84	-0.48	0.57

PG&E Moss Landing – Las Aguilas and Panoche - Gates Congestion – Recommended upgrades

- The CAISO recommended the 10 ohms series reactor on the Moss Landing – Las Aguilas 230 kV line for approval as an economic-driven upgrade,
  - Had the greatest benefit to cost ratio among the studied scenarios
  - Helped to balance the impedances and flow between the Moss Landing – Las Aguilas line and the parallel Las Aguilas – Coburn – Moss Landing 230 kV line
  - Flexible to be switched in for whole year or for summer, without impacting economic benefit
- Recommended deferring approval of the mitigation for the Panoche – Gates 230 kV line congestion

Summary of economic studies

- One transmission upgrade is recommended for approval as an economically-driven upgrade in this planning cycle
  - Installing 10 ohms series reactors on the PG&E’s Moss Landing – Las Aguilas 230 kV line
- The benefit to cost ratio also supports the following two policy-driven upgrades
  - GLW Upgrade project
  - Rerating the Midway-Whirlwind 500 kV line and bypassing its series compensation

Out of state wind study

Out of state wind in CPUC IRP portfolios

- Base portfolio
  - Requiring new transmission
    - 1062 MW of NM or WY wind, Idaho wind was considered as an alternative to the WY wind
  - Using existing transmission
    - 530 MW of Pac NW wind
- Sensitivity 1 portfolio
  - Requiring new transmission
    - 1500 MW of NM, and
    - 1500 MW of WY wind, or Idaho wind as an alternative
  - Using existing transmission
    - 1500 MW of Pac NW wind
    - 500 MW of NM wind

Alternative transmission upgrades for out-of-state wind

- Alternative transmission upgrades for out-of-state wind considered in this planning cycle include:
  - Cross-Tie project
  - SWIP North project
  - TransWest Express project
- Detailed information of these projects were discussed in the November stakeholder meeting
- The only change is to consider 1500 MW of transmission right that the TransWest Express project can provide to the CAISO
  - Consider the corresponding portion of the congestion revenue and the project cost in benefit and BCR calculation, respectively.

Out-of-state wind study approach and study scenarios

- Base portfolio OOS wind study
  - NM wind scenario as the reference case for ratepayer benefit calculations
  - Baseline BCR without considering avoided cost
  - Alternative BCR assuming an added benefit of avoiding half of the cost of the SunZia project
- Sensitivity 1 portfolio OOS wind study only compared the CAISO net payment between alternatives
- Two sensitivity studies conducted on the Base and Sensitivity 1 portfolio PCM cases:
  - Without Gateway West Bridger – Hemmingway segments
  - With GLW upgrade

Base portfolio OOS study – Benefit to cost ratio

OOS Wind Scenario	Alternative	Production Benefit ($M)	PV of Production Benefit ($M)	Capital Cost ($M)	Total cost ($M)	BCR not considering avoided cost of SunZia	Avoided cost for 50% of SunZia ($M)	BCR considering avoided cost of SunZia
01-Base-WY	01-CrossTie-0cost	-4.9	-71.9	727	945	-0.08	1,690	1.71
01-Base-WY	02-CrossTie-Neg48	39.9	588.8	727	945	0.62	1,690	2.41
01-Base-WY	03-CrossTie-0deg	2.7	39.3	727	945	0.04	1,690	1.83
01-Base-WY	04-SWIPN-0cost	-2.0	-29.7	635	826	-0.04	1,690	2.01
01-Base-WY	05-SWIPN-Neg48	15.5	228.5	635	826	0.28	1,690	2.32
01-Base-WY	06-SWIPN-0deg	20.1	296.4	635	826	0.36	1,690	2.41
01-Base-WY	07-TWE-IPPPST-0cost	-40.3	-594.4	1,710	2,223	-0.27	1,690	0.49
01-Base-WY	08-TWE-IPPPST-Neg45	101.5	1498.7	1,710	2,223	0.67	1,690	1.43
01-Base-WY	09-TWE-IPPPST-0deg	-5.9	-87.0	1,710	2,223	-0.04	1,690	0.72
02-Base-ID	01-CrossTie-0cost	-14.1	-208.3	727	945	-0.22	1,690	1.57
02-Base-ID	02-CrossTie-Neg48	22.6	333.3	727	945	0.35	1,690	2.14
02-Base-ID	03-CrossTie-0deg	-8.7	-129.0	727	945	-0.14	1,690	1.65
02-Base-ID	04-SWIPN-0cost	4.7	68.8	635	826	0.08	1,690	2.13
02-Base-ID	05-SWIPN-Neg48	18.4	271.6	635	826	0.33	1,690	2.38
02-Base-ID	06-SWIPN-0deg	-5.9	-86.6	635	826	-0.10	1,690	1.94
02-Base-ID	07-TWE-IPPPST-0cost	-54.4	-803.5	1,710	2,223	-0.36	1,690	0.40
02-Base-ID	08-TWE-IPPPST-Neg45	60.0	886.0	1,710	2,223	0.40	1,690	1.16
02-Base-ID	09-TWE-IPPPST-0deg	-26.0	-383.2	1,710	2,223	-0.17	1,690	0.59

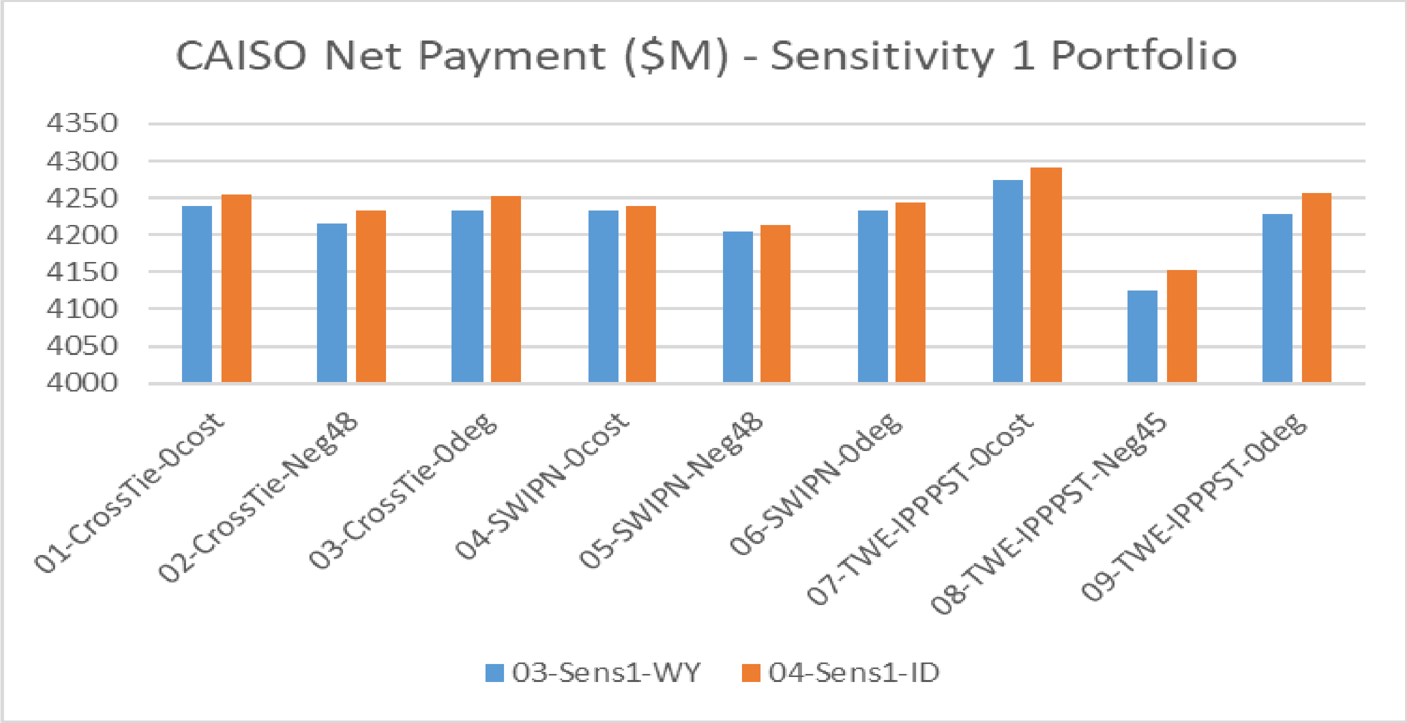
Base portfolio OOS study without Gateway West – Benefit to cost ratio

OOS Wind Scenario	Alternative	Production Benefit ($M)	PV of Production Benefit ($M)	Capital Cost ($M)	Total cost ($M)	BCR not considering avoided cost of SunZia	Avoided cost for 50% of SunZia ($M)	BCR considering avoided cost of SunZia
01-Base-WY	01-CrossTie-0cost	-42.1	-622.2	727	945	-0.66	1,690	1.13
01-Base-WY	02-CrossTie-Neg48	-25.9	-382.6	727	945	-0.40	1,690	1.38
01-Base-WY	03-CrossTie-0deg	-48.6	-717.0	727	945	-0.76	1,690	1.03
01-Base-WY	04-SWIPN-0cost	-40.5	-597.4	635	826	-0.72	1,690	1.32
01-Base-WY	05-SWIPN-Neg48	-12.5	-184.0	635	826	-0.22	1,690	1.82
01-Base-WY	06-SWIPN-0deg	-29.0	-428.0	635	826	-0.52	1,690	1.53
01-Base-WY	07-TWE-IPPPST-0cost	-45.8	-676.2	1,710	2,223	-0.30	1,690	0.46
01-Base-WY	08-TWE-IPPPST-Neg45	53.9	796.4	1,710	2,223	0.36	1,690	1.12
01-Base-WY	09-TWE-IPPPST-0deg	-9.8	-144.2	1,710	2,223	-0.06	1,690	0.70
02-Base-ID	01-CrossTie-0cost	-16.8	-247.9	727	945	-0.26	1,690	1.53
02-Base-ID	02-CrossTie-Neg48	6.1	90.7	727	945	0.10	1,690	1.88
02-Base-ID	03-CrossTie-0deg	-8.2	-120.6	727	945	-0.13	1,690	1.66
02-Base-ID	04-SWIPN-0cost	8.9	131.0	635	826	0.16	1,690	2.21
02-Base-ID	05-SWIPN-Neg48	14.3	210.9	635	826	0.26	1,690	2.30
02-Base-ID	06-SWIPN-0deg	2.7	39.4	635	826	0.05	1,690	2.09
02-Base-ID	07-TWE-IPPPST-0cost	-48.8	-721.2	1,710	2,223	-0.32	1,690	0.44
02-Base-ID	08-TWE-IPPPST-Neg45	34.3	506.1	1,710	2,223	0.23	1,690	0.99
02-Base-ID	09-TWE-IPPPST-0deg	-16.2	-239.8	1,710	2,223	-0.11	1,690	0.65

Base portfolio OOS study with GLW Upgrade – Benefit to cost ratio

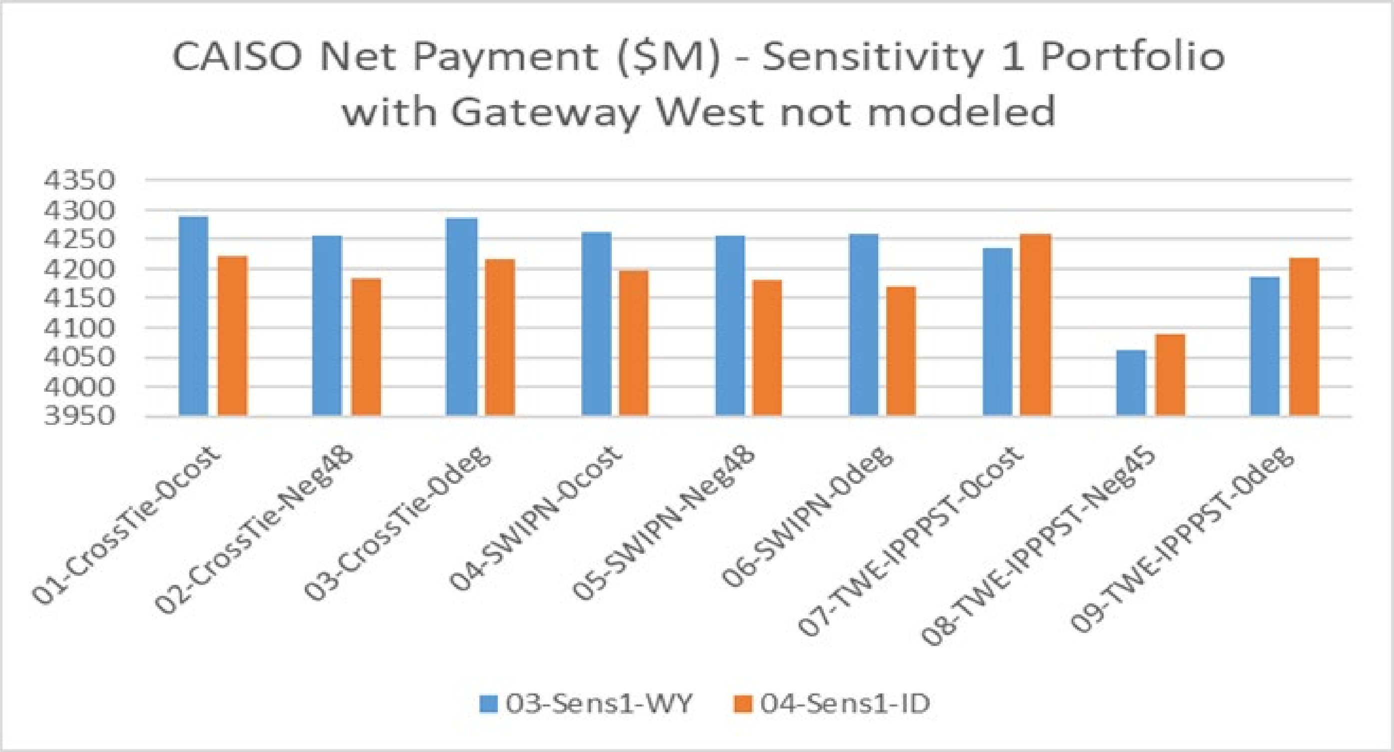
OOS Wind Scenario	Alternative	Production Benefit ($M)	PV of Production Benefit ($M)	Capital Cost ($M)	Total cost ($M)	BCR not considering avoided cost of SunZia	Avoided cost for 50% of SunZia ($M)	BCR considering avoided cost of SunZia
01-Base-WY	01-CrossTie-0cost	-9.1	-134.9	727	945	-0.14	1,690	1.65
01-Base-WY	02-CrossTie-Neg48	43.0	634.7	727	945	0.67	1,690	2.46
01-Base-WY	03-CrossTie-0deg	-1.0	-14.8	727	945	-0.02	1,690	1.77
01-Base-WY	04-SWIPN-0cost	17.8	262.6	635	826	0.32	1,690	2.37
01-Base-WY	05-SWIPN-Neg48	32.7	483.4	635	826	0.59	1,690	2.63
01-Base-WY	06-SWIPN-0deg	28.7	423.2	635	826	0.51	1,690	2.56
01-Base-WY	07-TWE-IPPPST-0cost	-44.2	-652.0	1,710	2,223	-0.29	1,690	0.47
01-Base-WY	08-TWE-IPPPST-Neg45	96.0	1417.7	1,710	2,223	0.64	1,690	1.40
01-Base-WY	09-TWE-IPPPST-0deg	-8.1	-119.5	1,710	2,223	-0.05	1,690	0.71
02-Base-ID	01-CrossTie-0cost	7.2	106.7	727	945	0.11	1,690	1.90
02-Base-ID	02-CrossTie-Neg48	30.0	442.9	727	945	0.47	1,690	2.26
02-Base-ID	03-CrossTie-0deg	6.7	98.8	727	945	0.10	1,690	1.89
02-Base-ID	04-SWIPN-0cost	18.8	277.1	635	826	0.34	1,690	2.38
02-Base-ID	05-SWIPN-Neg48	24.7	364.6	635	826	0.44	1,690	2.49
02-Base-ID	06-SWIPN-0deg	20.2	298.7	635	826	0.36	1,690	2.41
02-Base-ID	07-TWE-IPPPST-0cost	-41.0	-605.5	1,710	2,223	-0.27	1,690	0.49
02-Base-ID	08-TWE-IPPPST-Neg45	103.3	1,525.4	1,710	2,223	0.69	1,690	1.45
02-Base-ID	09-TWE-IPPPST-0deg	-6.5	-95.4	1,710	2,223	-0.04	1,690	0.72

Sensitivity 1 portfolio OOS study – CAISO net payment



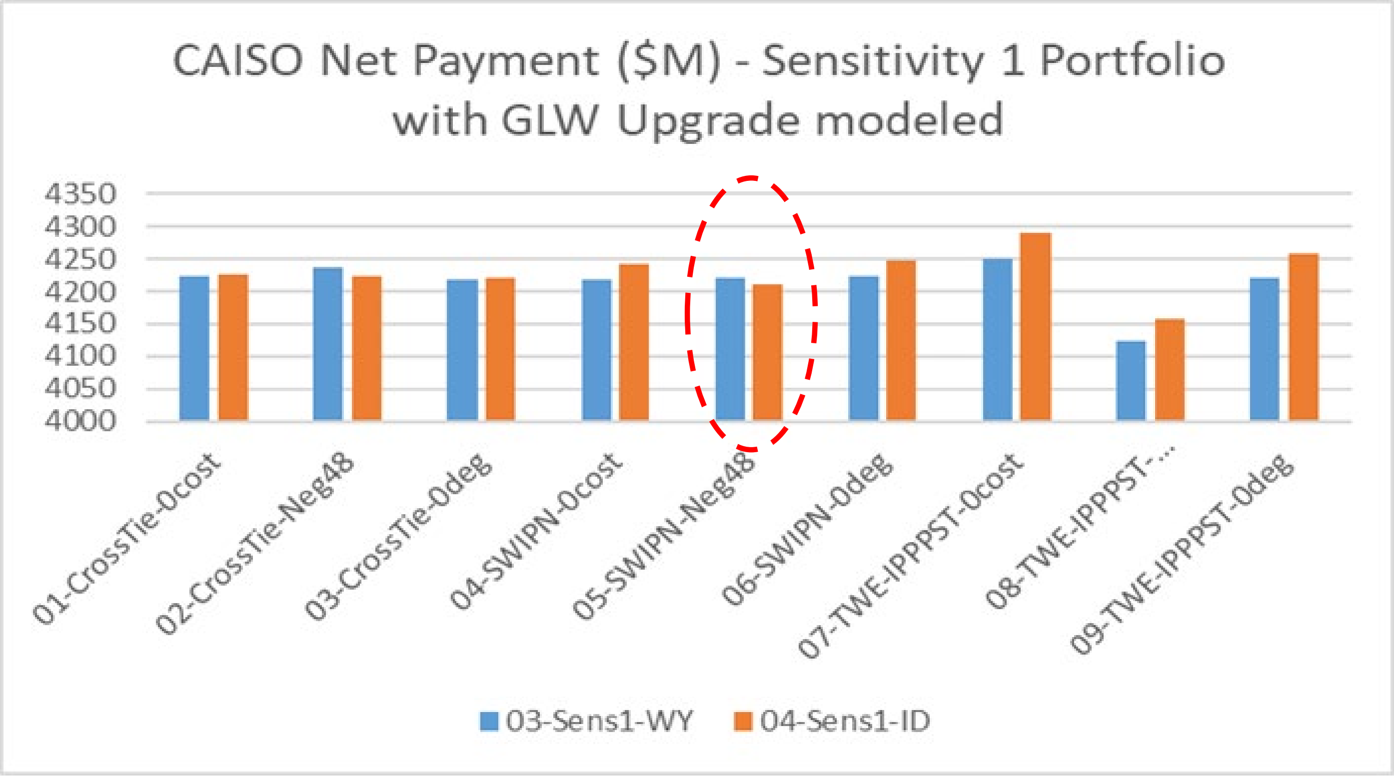
- Out-of-state wind location and the phase shifter setup impacted the CAISO net payment.
- CAISO net payments in the Wyoming wind scenarios were generally less than the net payment in the Idaho wind scenarios in the Sensitivity 1 portfolio OOS study

Sensitivity 1 portfolio OOS study without Gateway West – CAISO net payment



All studied scenarios with Wyoming wind had higher net payment than the scenarios with Idaho wind for the Cross Tie and SWIP North projects

Sensitivity 1 portfolio OOS study with GLW Upgrade – CAISO net payment



The Wyoming wind scenario was not always better than the Idaho wind scenario in terms of the CAISO net payment in this sensitivity study

High level summary of OOS wind study (1)

- Congestion and renewable curtailment were similar to the preliminary results presented in the November stakeholder meeting
- The Base portfolio OOS study showed that
  - The baseline BCR, which did not consider the SunZia avoided cost, were less than 1.0 for all studied scenarios
  - With considering the SunZia avoided cost, the alternative BCR became greater than 1.0
  - Sensitivity studies on the base case without Gateway West or with GLW Upgrade showed large variations in BCR as the key transmission assumptions changed

High level summary of OOS wind study (2)

- The Sensitivity 1 portfolio OOS wind study and the sensitivity studies on the Sensitivity 1 portfolio PCM cases without Gateway West or with the GLW Upgrade modeled further demonstrated the impact of the changes in out-of-state wind capacity in the portfolio and the transmission topology change on the assessment results
- The results were therefore found to be very sensitive to a host of assumptions, *e.g.*:
  - Out of state transmission assumptions
  - Resources assumptions
  - Cost and cost recovery of transmission upgrades
  - Industry interest in accessing OOS wind generation

Regarding the SWIP North economic study request, given the sensitivity to market interest:

- The CAISO recommends to engage further with industry participants to gauge interest in accessing Idaho resources.
- This process will require more time than is available before the 2021-2022 Transmission Plan is finalized and submitted to the Board for approval in March, 2022. The CAISO intends to consider this as an extension of the 2021-2022 transmission planning cycle, rather than shifting it to the next 2022-2023 planning cycle.
- The CAISO expects this effort to take the form of an open season-type process to assess the market interest and level of competition that exists for accessing the Idaho resources in support of the project.

Sensitivity 2 Offshore wind PCM study

California ISO

Studied scenarios

- Offshore wind were modeled in the same way as presented in the November stakeholder meeting
- Transmission upgrades for offshore wind interconnection
  - Three alternatives for Humboldt offshore wind
  - Three alternatives for Diablo and Morro Bay offshore wind
- All nine combinations were studied:

Transmission alternatives for Diablo and Morro Bay offshore wind	Humboldt offshore wind at Fern Road	Humboldt offshore wind at Collinsville	Humboldt offshore wind at Bay Hub
PTE	X	X	X
Morro Bay HVDC	X	X	X
New Diablo-Gates 500 kV line	X	X	X

Offshore wind PCM study summary - curtailment

- The Fern Road scenario had the least Humboldt offshore wind curtailment among the three transmission scenarios for Humboldt offshore wind
- The PTE scenario had less Diablo and Morro Bay offshore wind curtailment than the Morro Bay DC scenario and the Diablo-Gates 500 kV line scenario
- Offshore wind generation impacted curtailment at different local areas depending on offshore wind injection points and transmission upgrade alternatives, but the CAISO system overall curtailment ratios were similar among all scenarios

Offshore wind PCM study summary – congestion (1)

- Table Mountain 500/230 kV transformer was congested when the flow was from 230 kV to 500 kV and the COI flow was from south to north. The congestion mainly happened in spring months
- The Humboldt offshore wind aggravated the congestion of the Vaca Dixon-Tesla 500 kV line, as the Fern Road scenario had the largest and the Bay Hub scenario had the least congestion of this line among all three transmission scenarios for Humboldt offshore wind

Offshore wind PCM study summary – congestion (2)

- The offshore wind at Diablo and Morro Bay resulted in congestion on the 500 kV lines coming out of the Diablo 500 kV bus
- The offshore wind at Diablo and Morro Bay aggravated Path 15 congestion. The scenarios with the PTE project or with the new Diablo-Gates 500 kV line had higher Path 15 congestion cost than the scenario with Morro Bay HVDC
- The offshore wind helped to reduce Path 26 congestion. The PTE project is more effective to reduce Path 26 congestion than the other two transmission alternatives for the Diablo and Morro Bay offshore wind

2021-2022 TPP PSPS/Wildfire Impact Assessment Results and Conclusion – Southern California

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2021-2022 Transmission Planning Process Stakeholder Meeting
February 7, 2022

Outline

- Study scope and objective
- Wildfire related information
- Study approach
- Study scenario development
- Summary of study scenarios for SCE and SDG&E service areas
- Scenario study results
- Identification of critical facilities
- Conclusions

Study scenarios & number of lines de-energized – SCE Service Area

Scenario ID	Scenario Description	Wildfire Event?	PSPS Event?	Number of 500 kV Lines De-Energized?	Number of 230 kV Lines De-Energized?	Study Base Cases
1	Ventura PSPS event	No	Yes	0	2	Spring 2023 off-peak
2	Ventura & Los Angeles PSPS event	No	Yes	0	2	Spring 2023 off-peak
3	Kern localized PSPS event	No	Yes	1	2	Spring 2023 off-peak
4	San Bernardino & Orange PSPS event	No	Yes	2	2	Summer 2026 peak
5	Los Angeles PSPS event	No	Yes	1	5	Summer 2026 peak
6	San Bernardino PSPS event	No	Yes	0	2	Summer 2026 peak
7	SCE Main system-wide PSPS event	No	Yes	9	5	Spring 2023 off-peak
8	Big Creek fire scenario	Yes	No	0	4	Summer 2026 peak
9A	Bond fire scenario (joint SCE/SDG&E study scenario #1)	Yes	No	1	2	Spring 2023 off-peak
9B	Bond fire scenario (joint SCE/SDG&E study scenario #2)	Yes	No	1	4	Spring 2023 off-peak

Study scenarios & number of lines de-energized – SDG&E Service Area

	Scenario Description	Wildfire Event?	PSPS Event?	Number of 500kV Lines De-Energized?	Number of 230kV Lines De-Energized?	Number of 138kV Lines De-Energized?	Number of 69kV Lines De-Energized?	Study Base Cases
1	SDG&E 2007 fire event	Yes	No	2	9	4	19	Summer 2026 peak
2	Eastern 69kV PSPS event	No	Yes	0	0	0	4	Spring 2023 off-peak
3	Southeastern fire event	Yes	No	1	1	0	1	Summer 2026 peak
4	Northern and Southeastern localized PSPS event	No	Yes	0	1	0	2	Summer 2026 peak
5	Various Eastern 69kV lines PSPS event	No	Yes	0	0	0	12	Spring 2023 off-peak
6	Various Eastern 69kV lines PSPS event (different than event #5)	No	Yes	0	0	0	5	Spring 2023 off-peak
7A	Bond fire scenario #1 (joint SCE/SDG&E study scenario #1)	Yes	No	1	2	0	0	Spring 2023 off-peak
7B	Bond fire scenario #2 (joint SCE/SDG&E study scenario #2)	Yes	No	1	4	0	0	Spring 2023 off-peak

Study results – General study observations for scenario studies in SCE service area

Scenario No.	Scenario Description	Scenario Impact Summary
1	Ventura PSPS event	There is no direct or indirect impact load loss impact for this scenario
2	Ventura & Los Angeles PSPS event	There is no direct or indirect impact load loss impact for this scenario
3	Kern localized PSPS event	There is no direct or indirect impact load loss impact for this scenario
4	San Bernardino & Orange PSPS event	There is no direct or indirect impact load loss impact for this scenario
5	Los Angeles PSPS event	1000 MW of load loss is identified to address the P0 overloading concerns on Mesa 500/230 kV bank No.2 and Mesa – Laguna Bell 230 kV No.2 line, after dispatching available non-storage resources in the Western LA Basin, San Bernardino, and San Diego areas. No load loss is identified for P1 contingencies. In addition, if Alamitos Energy Storage System could be dispatched, the load loss would be reduced to 900 MW from 1000 MW. As alternative, if the short circuit current duties allow, closing the bus-tie at Mesa 230 kV could drastically reduce the load loss to as low as 50 MW from 1000 MW

Study results – General study observations for scenario studies in SCE service area (cont'd)

Scenario No.	Scenario Description	Scenario Impact Summary
6	San Bernardino PSPS event	751 MW direct impact load loss impact identified as a result of an island created due to the PSPS facilities de-energized. No indirect impact load loss impact is identified for P1 contingencies
7	SCE Main system-wide PSPS event	751 MW direct impact load loss impact identified as a result of an island created due to the PSPS facilities de-energized. The P0 overload on Mesa – Laguna Bell No.1 230 kV line could be mitigated by operational mitigations dispatching available non-storage resources in the Western LA Basin, San Bernardino, and San Diego areas. The Mesa – Laguna Bell 230 kV No.1 reconductoring could alleviate the need for the generation dispatch. No indirect impact load loss impact is identified for P1 contingencies
8	Big Creek fire scenario	There are about 7 MW of direct load loss and 900 MW of generation loss as a result of an island created due to the PSPS facilities de-energized. No indirect impact load loss impact is identified for P1 contingencies
9A	Bond fire scenario (joint SCE/SDG&E study scenario #1)	See results in the table for SDG&E service area
9B	Bond fire scenario (joint SCE/SDG&E study scenario #2)	See results in the table for SDG&E service area

Study results – General study observations for scenario studies in SDG&E service area

Scenario No.	Scenario Description	Scenario Impact Summary
1	SDG&E 2007 fire event	Majority of the load losses in the study includes indirect impact load loss to mitigate normal overloads and voltage stability related issue (1,577 MW). Another 962 MW of indirect impact load loss is related to mitigation for P1 contingency related overloading concerns.
2	Eastern 69kV PSPS event	About 10 MW of direct impact load loss as a result of islanded facilities. There is no indirect impact load loss for this scenario.
3	Southeastern fire event	There is no direct impact load loss impact. About 420 MW of load loss is related to indirect load loss impact for mitigation of P1 and P7 contingency overloading concern.
4	Northern and Southeastern localized PSPS event	About 2 MW of direct impact load loss as a result of islanded facilities. Another 80 MW of indirect impact load loss is related to mitigation of P7 contingency overloading concerns.
5	Various Eastern 69kV lines PSPS event	About 56 MW of direct impact load loss as a result of islanded facilities. There is no indirect impact load loss for this scenario.

Study results – General study observations for scenario studies in SDG&E service area (cont'd)

Scenario No.	Scenario Description	Scenario Impact Summary
6	Various Eastern 69kV lines PSPS event (different than event #5)	About 10 MW of direct impact load loss as a result of islanded facilities. There is no indirect impact load loss for this scenario.
7A	Bond fire scenario #1 (joint SCE/SDG&E study scenario #1)	There is no direct or indirect load loss impact for this scenario.
7B	Bond fire scenario #2 (joint SCE/SDG&E study scenario #2)	There is no direct impact load loss. Approximately 146 MW of indirect load loss impact is attributed to mitigation of P1 contingency related loading concerns.

Study results – SCE service area

Scenario No.	Scenario Description	Direct Load Impact (MW)	Indirect Load Impact Due to P0 Overloads/Voltage Stability Issue (MW)	Indirect Load Impact Due to P1 (MW)	Count of Base Case Overloads	Count of P1 Overloads
1	Ventura PSPS event	0	0	0	0	0
2	Ventura & Los Angeles PSPS event	0	0	0	0	0
3	Kern localized PSPS event	0	0	0	0	0
4	San Bernardino & Orange PSPS event	0	0	0	0	0
5	Los Angeles PSPS event	0	1000 MW or 900 MW if the Alamitos energy storage could be dispatched	0	2	0

Study results – SCE service area (cont'd)

Scenario No.	Scenario Description	Direct Load Impact (MW)	Indirect Load Impact Due to P0 Overloads/Voltage Stability Issue (MW)	Indirect Load Impact Due to P1 (MW)	Count of Base Case Overloads	Count of P1 Overloads
6	San Bernardino PSPS event	751	0	0	an island created due to the PSPS facilities de-energized	0
7	SCE Main system-wide PSPS event	442	0	0	1 along with the same island created in Scenario #6	0
8	Big Creek fire scenario	7	0	0	an island created due to the PSPS facilities de-energized	0
9A	Bond fire scenario #1 (joint SCE/SDG&E study scenario #1)	See study results under SDG&E				
9B	Bond fire scenario #2 (joint SCE/SDG&E study scenario #2)	See study results under SDG&E				

Study results – SDG&E service area

Scenario No.	Scenario Description	Direct Load Impact (MW)	Indirect Load Impact Due to P0 Overloads/Voltage Stability Issue (MW)	Indirect Load Impact Due to P1/P7 (MW)	Count of Base Case Overloads	Count of P1/P7 Overloads
1	SDG&E 2007 fire event	51	1,577	962	6	3
2	Eastern 69kV PSPS event	10	0	0	0	0
3	Southeastern fire event	0	0	420	0	3
4	Northern and Southeastern localized PSPS event	2	0	80	0	2
5	Various Eastern 69kV lines PSPS event	56	0	0	0	0

Study results – SDG&E service area (cont'd)

Scenario No.	Scenario Description	Direct Load Impact (MW)	Indirect Load Impact Due to P0 Overloads/Voltage Stability Issue (MW)	Indirect Load Impact Due to P1/P7 (MW)	Count of Base Case Overloads	Count of P1/P7 Overloads
6	Various Eastern 69kV lines PSPS event (different than event #5)	10	0	0	0	0
7A	Bond fire scenario #1 (joint SCE/SDG&E study scenario #1)	0	0	0	0	0
7B	Bond fire scenario #2 (joint SCE/SDG&E study scenario #2)	0	0	146	0	1

Identification of Critical Facilities – SCE Service Area

No.	Scenario	Scenario Study Impact		Critical Facilities
		Direct Load Impact (MW)	System Performance Impact (MW)	
1	Ventura PSPS event	0	0	None
2	Ventura & Los Angeles PSPS event	0	0	None
3	Kern localized PSPS event	0	0	None
4	San Bernardino & Orange PSPS event	0	0	None
5	Los Angeles PSPS event	1000 MW or 900 MW if the Alamitos energy storage could be dispatched	generation re-dispatch to mitigate the P0 normal overloads in addition to the load loss	Mesa-Vincent No.1 or No.2 230 kV, Eagle Rock-Sylmar 230 kV, or Goodrich-Gould, and Gould-Sylmar 230 kV
6	San Bernardino PSPS event	751 MW	0	Information shared with PTO
7	SCE Main system-wide PSPS event	442 MW	generation re-dispatch in a wide area to mitigate the P0 normal overload	Information shared with PTO
8	Big Creek fire scenario	7 MW	900 MW of generation loss	Big Creek 3-Rector No. 1 230 kV, Big Creek 3-Rector No. 2 230 kV, or Big Creek 1-Rector 230 kV
9A & 9B	Bond fire scenario #1 & 2	See notes under SDG&E on the next table		

there could be a significant amount of load loss and generation loss, along with system performance concerns in scenarios #5, #6, #7, and #8

Identification of Critical Facilities – SCE Service Area & Conclusions (cont'd)

- Significant amount of load losses and system performance concerns including generation loss were identified in Scenarios #5, #6, #7, and #8
- Exclusion of one or multiple of the identified critical facilities de-energized for Scenarios #5, #6, #7, #8, if feasible, would address about 100% of the identified load impacts and most system performance concerns in the affected areas
- The internal gas fired generation resources in the Western LA Basin, San Bernardino, and San Diego areas was relied upon to eliminate additional lost load and mitigating the system performance concerns in Scenarios #5 and #7
- The Mesa – Laguna Bell 230 kV No.1 line reconductoring identified as needed as a policy-driven project could alleviate the need for re-dispatching generation under Scenario #7 when implemented
- The ISO will continue to coordinate with SCE to evaluate potential mitigation options for the critical facilities to reduce the risk of future PSPS outages on these facilities.

Identification of Critical Facilities – SDG&E Service Area & Conclusions

No.	Scenario	Scenario Study Impact		Critical Facilities
		Direct Load Impact (MW)	System Performance Impact (MW)	
1	SDG&E 2007 fire event	51	2,539	ECO-Miguel and Ocotillo-Suncrest 500kV Lines, OR South of San Onofre 230kV lines (between San Luis Rey and San Onofre and Otay Mesa-Miguel-Sycamore)
2	Eastern 69kV PSPS event	10	0	TL625 Descanso - Loveland 69 kV line OR TL6923 Barrett - Cameron 69 kV line
3	Southeastern fire event	0	420	Ocotillo-Suncrest 500kV Line
4	Northern and Southeastern localized PSPS event	2	80	TL23030 Escondido - Talega - Capistrano 230 kV line
5	Various Eastern 69kV lines PSPS event	56	0	TL6904 Alpine - Loveland 69 kV line TL6957 Barrett - Loveland 69 kV line TL6923 Barrett - Cameron 69 kV line TL629 Descanso - Crestwood - Glencliff 69 kV line TL625 Descanso - Loveland 69 kV line TL637 Creelman - Santa Ysabel 69 kV line TL685 Santa Ysabel - Warners 69 kV line

Identification of Critical Facilities – SDG&E Service Area & Conclusions

No.	Scenario	Scenario Study Impact		Critical Facilities
		Direct Load Impact (MW)	System Performance Impact (MW)	
6	Various Eastern 69kV lines PSPS event (different than event #5)	10	0	TL686 Narrows - Warners 69 kV line TL682 Rincon - Warners 69 kV line OR TL685 Santa Ysabel - Warners 69 kV line
7A	Bond fire scenario #1 (joint SCE/SDG&E study scenario #1)	0	0	None
7B	Bond fire scenario #2 (joint SCE/SDG&E study scenario #2)	0	146	North of San Onofre 230kV Lines, or Imperial Valley – North Gila 500kV Line

Identification of Critical Facilities – SDG&E Service Area & Conclusions (cont'd)

- Exclusion of identified critical facilities from future PSPS scope or similar fire events, if feasible, would address most load impacts.
- The ISO will continue to coordinate with SDG&E to evaluate potential mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS or similar fire events.
- SDG&E-proposed small transmission upgrade of looping the Otay Mesa-Miguel-Sycamore 230kV line into Miguel substation helps reduce indirect load impact under Wildfire Scenario #1. This can be considered further in future transmission planning processes.
- A previous ISO Board-approved project (i.e., S-Line Upgrade) is expected to alleviate the system performance issue for Scenario 7B (joint SCE/SDG&E fire study event #2) when implemented.

Frequency Response Assessment and Data Requirements Draft 2021-2022 Transmission Plan

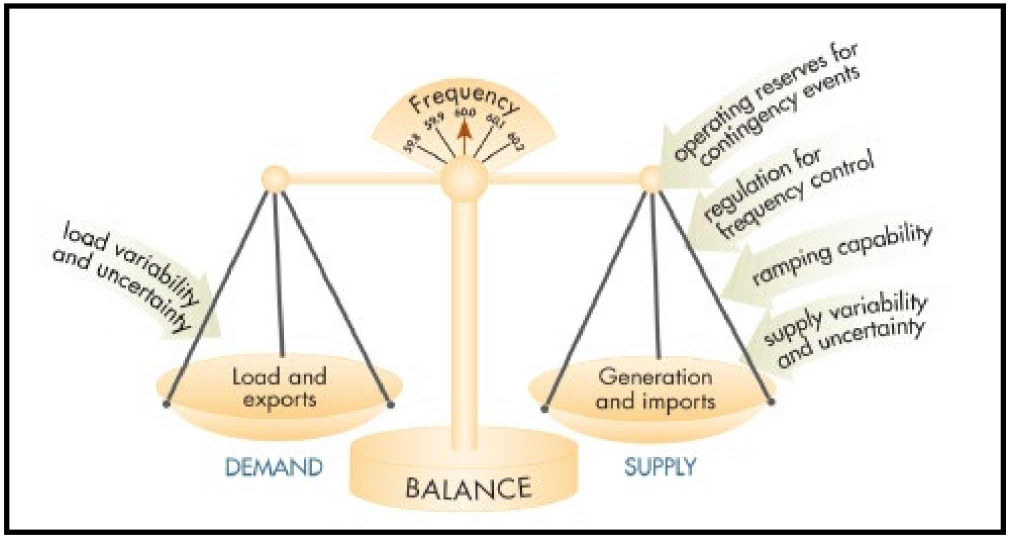
Christopher Fuchs
Regional Transmission North

2021-2022 Transmission Planning Process Stakeholder Meeting
February 7, 2022

Overview

- Basics of frequency response (will focus on under-frequency events)
- ISO frequency response study results in previous TPPs
- ISO frequency response study results 2021-2022 TPP - impact of frequency response from Inverter Based Resources (IBRs) and Battery Energy Storage Systems (BESS)
- Data collection, model improvement efforts and validation

Continuous Supply and Demand Balance



Load-Resource balance must be maintained at all time scales:

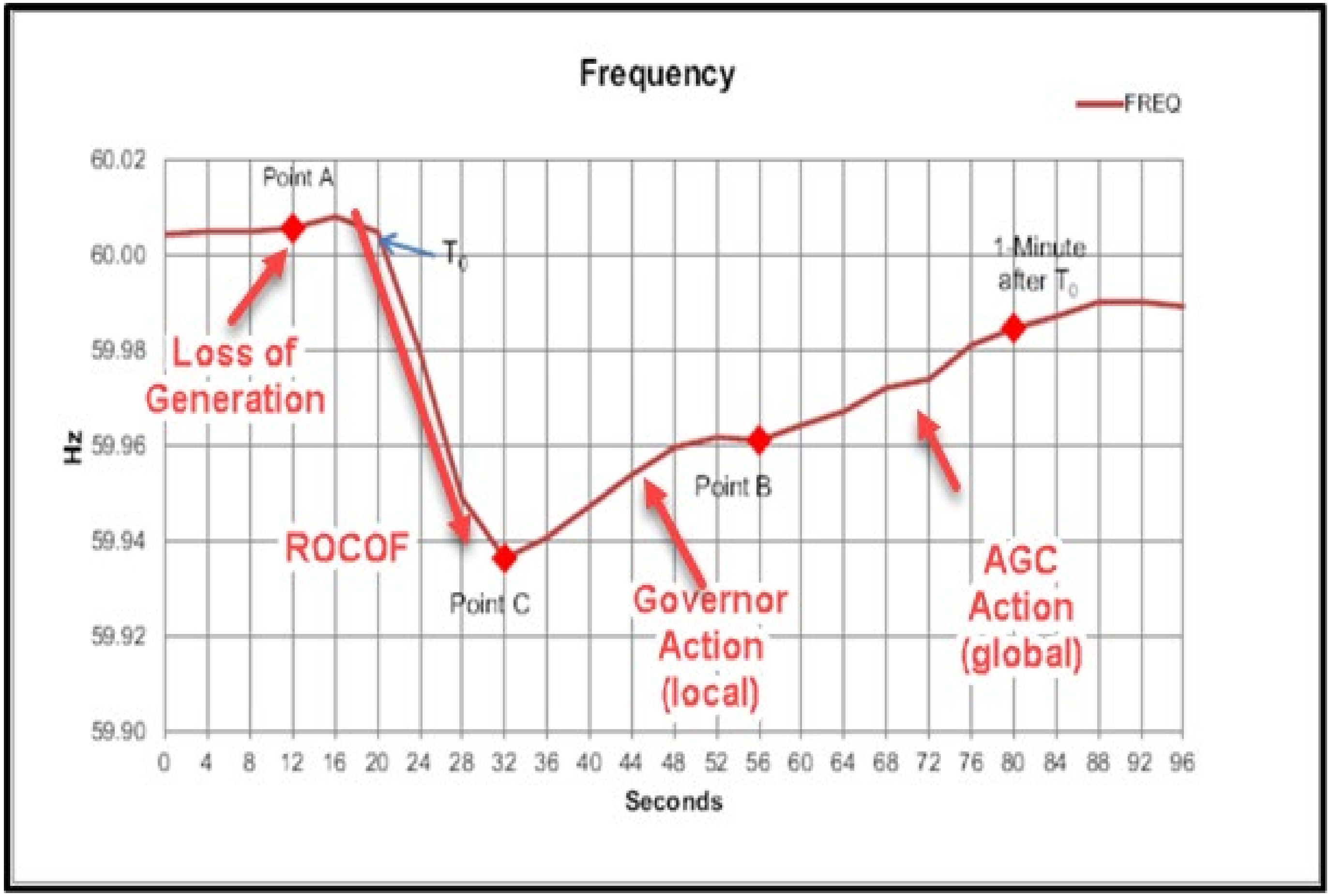
$$\sum Load = \sum Generation$$

During system disturbances/outages this balance is upset

For example on the loss of a large generator we have:

$$\sum Load > \sum Generation \Rightarrow \text{Underfrequency } (< 60 \text{ Hz})$$

Standard Frequency Event Progression



Point C – nadir
Point B – settling frequency

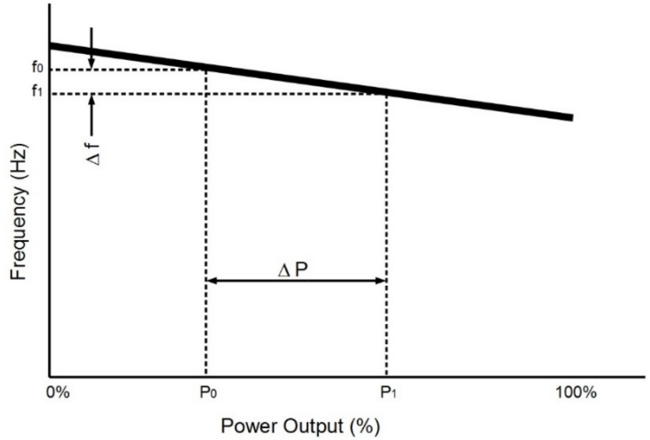
Nadir needs to be higher than the 1st set-point for Under Frequency Load Shedding (59.5 Hz)

Generator Response to Frequency Events

- Generating units play a major role in controlling system frequency through their governors.
- Governors are the 1st line of defense for system frequency control.
- A governor controls the generator MW output to a preset output subject to a deliberate steady state error called droop control.
- Droop is a means of getting all system generators to proportionally share an increase in output power to frequency excursions based on the capacity of the contributing machines
- The headroom of the generator and the droop and deadband of the governor determine a generator response to frequency events.

Governor Droop Curve

- Droop is the ratio of the frequency change to generator output change. The smaller the droop, the higher the individual response, but system-wide generation response becomes erratic and uncoordinated if it is too small. Droop is typically in the 4%-5% range.



  - *Example: for a drop in system frequency to 59.9 Hz, with 5% droop setting, unit responds with ([60-59.9]/60)/0.05 = 3.33% increase of the machines' rated power*

Generator Headroom

- Headroom is the difference between the maximum capacity of the unit and the unit's output. Units that don't respond to changes in frequency are considered not to have headroom.
- Solar and Wind plants are designed to extract as much energy from the environment as possible and prefer to operate at capacity if possible. ⇒ minimal headroom.
- Battery Energy Storage Systems (BESS) plants when charging have a large headroom for under-frequency events.

Governor Frequency Deadband

- Frequency Deadband is a margin (high/low) around 60 Hz and is a means of restricting excessive and usually unrequired control action
- the minimum frequency deviation from 60 Hz before governor responds. Deadband is typically 0.036 Hz.

Frequency Response Characterization

- For studies of off-nominal frequency events, it is essential to properly characterize the response of each generator
- System inertia and determines how fast the frequency will decrease with loss of generation. As the penetration of inverter-based resources increases, on-line synchronous inertia may decrease and rate-of-change of frequency (ROCOF) may continue to increase
- Frequency response of all units in the system determines at which value frequency will settle before the AGC action engages.

Frequency Response Obligation (FRO) and Measure (FRM)

- Frequency Response (FR), or Frequency Response Measure (FRM)

- $$FR = \frac{\Delta P}{\Delta f} \left[\frac{MW}{0.1Hz}\right]$$

- FRO for the Interconnection is established in NERC BAL-003-2 Frequency Response & Frequency Bias Setting Standard
- For WECC, FRO is 858 MW/0.1Hz
- Balancing Authority FRO allocation

$$FRO_{BA} = FRO_{Int} \frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

- For the CAISO, FRO is approximately 30% of WECC FRO (257.4 MW/0.1Hz)

ISO Frequency Response Study Results in Previous TPPs

- All studies assessed primary frequency response for the most severe credible contingency involving frequency disturbance: outage of two Palo Verde nuclear units
- Off-peak cases appeared to be more severe than peak cases because of lower generation dispatch and less frequency-responsive units on-line
- Under off-peak spring conditions (weekend afternoon) there is more solar generation on-line, which historically did not participate in primary frequency response

Studies of the 2018-2019 TPP – Conclusions

- The ISO system meets BAL-003-1.1 requirements under the assumptions studied (latest is no v2).
- With lower commitment of the frequency-responsive units, frequency response from the ISO could go below the FRO specified by NERC.
- With more inverter-based resources (IBR) online without frequency control, frequency response from the ISO will most likely become insufficient.
- Compared to the ISO's actual system performance during disturbances, the simulation results seemed optimistic. A thorough validation of the models was needed.

Frequency Response of IBRs in 2019-2020 TPP Study

- NERC has number of standards related to resource and demand balancing which is becoming challenging for the ISO to meet due to the variability of wind and solar generation.
- FERC Order 842 requires all new IBRs to have frequency response capability.
- This study evaluated the potential impact of activating the FR of the existing IBRs and changing the droop and frequency deadband settings of the new IBRs on system frequency response.

Conclusions of FR Impact Assessment in 2019-2020 TPP

- If there is headroom, just enabling the FR of the existing IBRs significantly improved frequency response in this study even with 5% droop and ±0.036 Hz deadband.
- 4% droop and ±0.0167 Hz deadband would slightly increased the ISO generator output.
- The reason changing the settings have minimal impact is that the trip of two Palo Verde units causes a significant drop in frequency that results in IBRs responding to almost the same frequency drop, independent of the dead-band or droop parameters.

ISO Frequency Response Study 2021-2022 TPP Study Background

- Total installed Inverter-Based Resources (IBR) capacity in the ISO is expected to reach 33 GW by 2030.
- The majority of the existing IBRs do not provide frequency response but, consistent with FERC Order 842, all IBRs that sign Large Generation Interconnection Agreements (LGIA) on or after 5/15/2018 will have frequency response capability.
- With high levels of IBRs it is critical to assess the frequency response of the system in future years and identify mitigation measures if there are any issues. In addition to transmission – connected IBRs, as of 4/30/2020, around 9.4 GW Behind the Meter Distributed Energy Resources (BTM DER) is installed in the system and the total installed BTM DER is expected to reach around 21 GW in 2030.

Study Methodology and Objective

- Evaluate primary frequency response with high IBR penetration, including DER and BESS
- Assess the CAISO system frequency response in the year 2026 & 2031 and identify any performance issues related to frequency response.
- The starting base case was the Spring off-Peak case for 2016 & 2031. The cases studied had different assumptions on the generation dispatch and the headroom and on frequency response provided by IBRs and the battery energy storage devices.
- An outage of two Palo Verde nuclear units was studied.
- Dynamic stability simulations were run for 60 seconds.

Study Scenarios

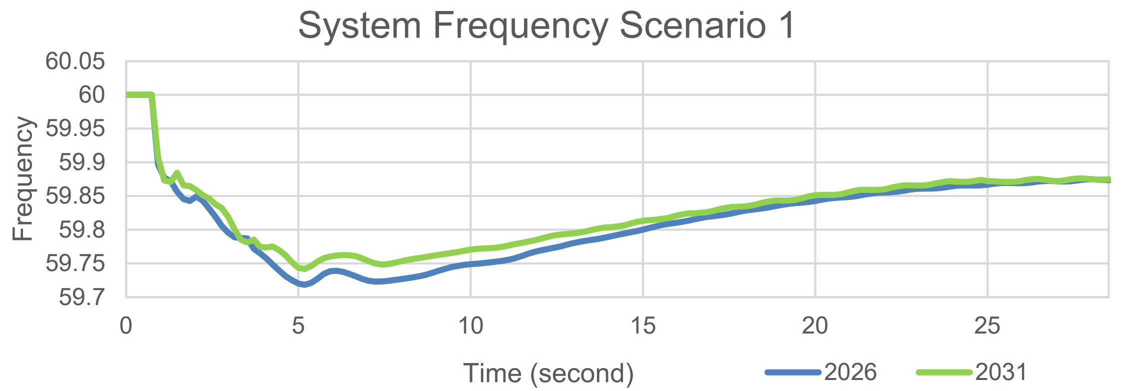
- Cases: Base case 2031 Spring off-Peak and the selected case with reduced headroom.
- BESS are in charging mode

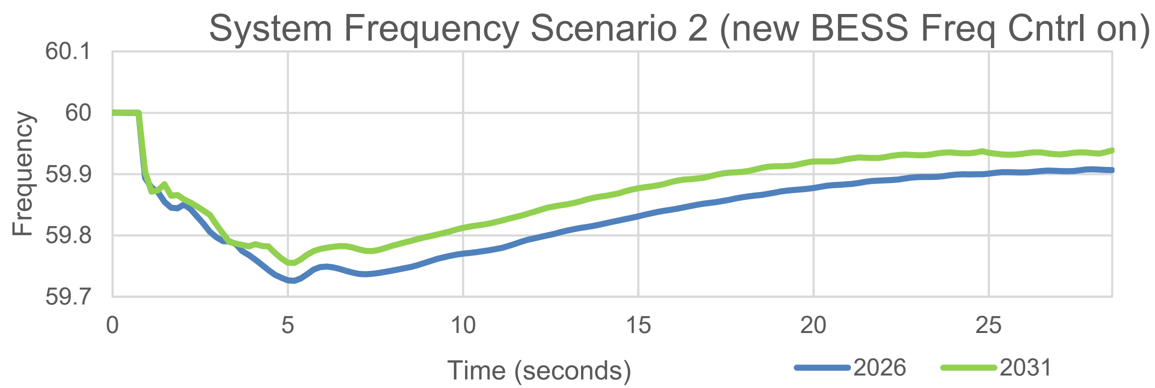
Scenarios	SC1	SC2	SC3	SC4
IBR Frequency Control is switched off	✓	-	-	-
New BESS Frequency Control is switched on	-	✓	-	-
Frequency Control enabled for new IBR/BESS at 10% headroom	-	-	✓	-
PFR enabled for all new IBRs assuming WECC spinning reserve headroom	-	-	-	✓

Monitored Values

- System frequency including frequency nadir and settling frequency after primary frequency response
- The total new IBR output
- The total output of all other CAISO generators
- The major path flows
- Frequency Response Measures of the WECC and CAISO (MW/0.1 Hz)
- Frequency response from each unit in MW and in percent of the maximum output.
- Rate of Change of Frequency (ROCOF)

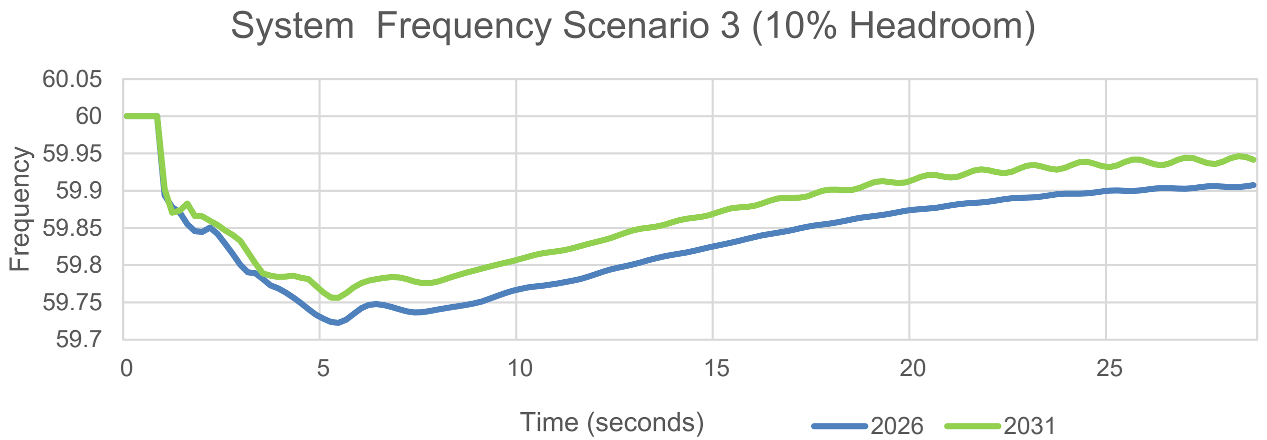
Scenario #1&2: Comparative Base 2026 & 2031

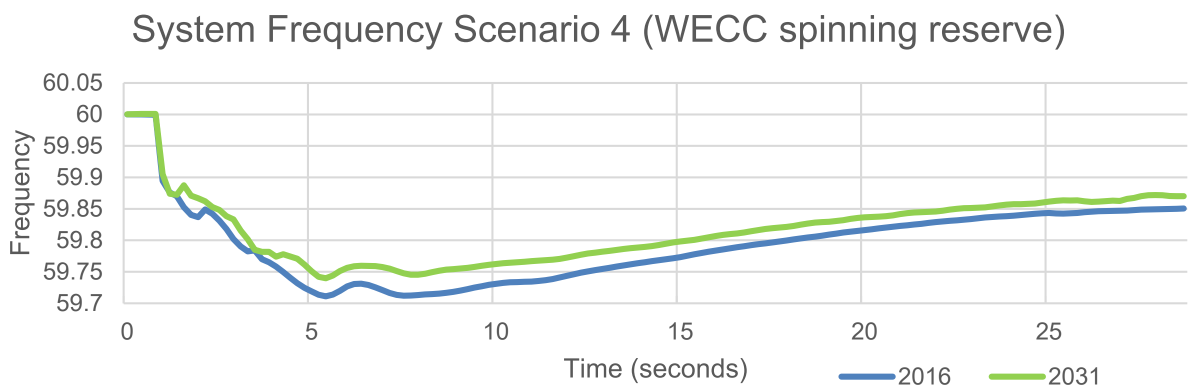




California ISO

Scenario #3&4: Comparative Base 2026 & 2031





System Frequency Response Results

Scenario	Description	Year	(i) Nadir		(i) Settling Freq		(v) Freq Resp			(vi) Rate Of Chng Of Frq				
			Hertz	Time	Hertz	Time	WECC	> 858?	CAISO (30% of WECC)	init frq	tinit	init+0.5 frq	tinit+~0.5	ROCOF
1	All IBR Freq Cntrl Off	2026	59.733	5.678	59.872	25.894	806	NO	241.8	59.876	1.479	59.847	1.954	-0.061
		2031	59.741	5.655	59.872	25.910	793	NO	237.9	59.864	2.200	59.848	2.700	-0.031
2	New BESS Freq Cntrl on only	2026	59.726	5.680	59.912	35.745	796	NO	238.8	59.854	2.417	59.822	2.917	-0.064
		2031	59.755	5.622	59.913	20.493	968	YES	290.4	59.866	2.179	59.851	2.679	-0.030
3	New BESS on; 10% headroom	2026	59.772	5.685	59.913	35.494	802	NO	240.6	59.853	2.429	59.818	2.930	-0.070
		2031	59.754	5.630	59.934	27.982	958	YES	287.4	59.862	2.300	59.837	3.100	-0.031
4	Scenario 1 + WECC at spinning reserve	2026	59.711	5.750	59.843	26.745	802	NO	240.6	59.844	2.510	59.813	3.000	-0.062
		2031	59.740	5.742	59.860	27.207	840	NO	252	59.867	2.267	59.848	2.754	-0.039

System Frequency Observations

- The ROCOF for 2031 half that of 2026.
- Having frequency response from the BESS improves frequency performance
- The frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz for all four cases

2021-2022 TPP Study Conclusions

- With lower commitment of the frequency-responsive units, and no frequency response from the IBR and BESS, the ISO FRM may be even lower and the deficiency in frequency response may be higher.
- In the assumptions studied, not meeting the standard is not likely for WECC as a whole, considering large amount of frequency responsive units that are availables, especially in Canada and Northwest.

2021-2022 TPP Study Conclusions (continued)

- BESS and IBR having frequency response will significantly improve the system frequency performance and will allow the ISO to fulfill its FRO, even if not all IBR and BESS provide frequency response.
- Both BESS and IBR are effective in enhancing frequency stability and providing compliance with the BAL-003-2 Standard, if they have frequency response.
- Being in compliance with the BAL-003-2 Standard while having 100% of energy provided by renewable resources in the ISO is possible if the new IBR resources have frequency response and have and adequate headroom.

Generator Model Data Update

- ISO is requesting validated modeling data from all generators
- The process started in May 2019 and the plan is to have updated models for all generators in coming years.
- Generator owners will provide governor data (droop and deadband) as part of their submission.

II.19	Upward frequency response droop (increase output for low frequency)		%
II.20	Downward frequency response droop (reduce output for high frequency)		%
II.21	Frequency response deadband	+/-	Hz

1 http://www.

Future Initiatives (1)

- A whitepaper released in September 2021 entitled 'Dynamic Model Review Guideline for Inverter based Interconnection Requests' outlines the selection of inverter parameters to ensure interconnection requirements
- 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

Future Initiatives (2)

- Future work will include validation of models based on real-time contingencies and studies with modeling of behind the meter generation.
- Further work will also investigate measures to improve the ISO frequency response post contingency. Other contingencies may also need to be studied, as well as other cases that may be critical for frequency response.

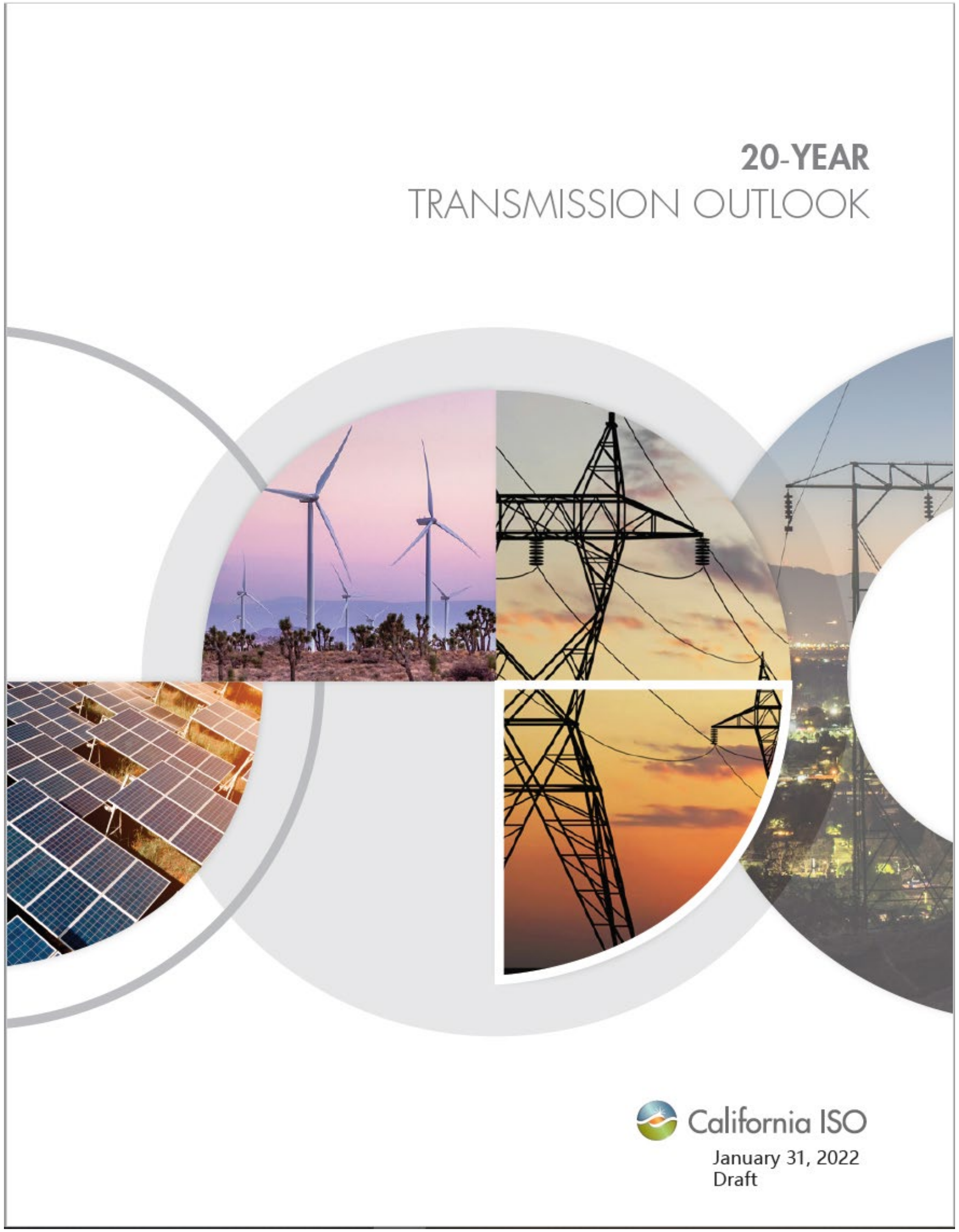
Draft 20-Year Transmission Outlook

Jeff Billinton
Director, Transmission Infrastructure Planning

2021-2022 Transmission Planning Process Stakeholder Meeting
February 7, 2022

Draft 20-Year Transmission Outlook

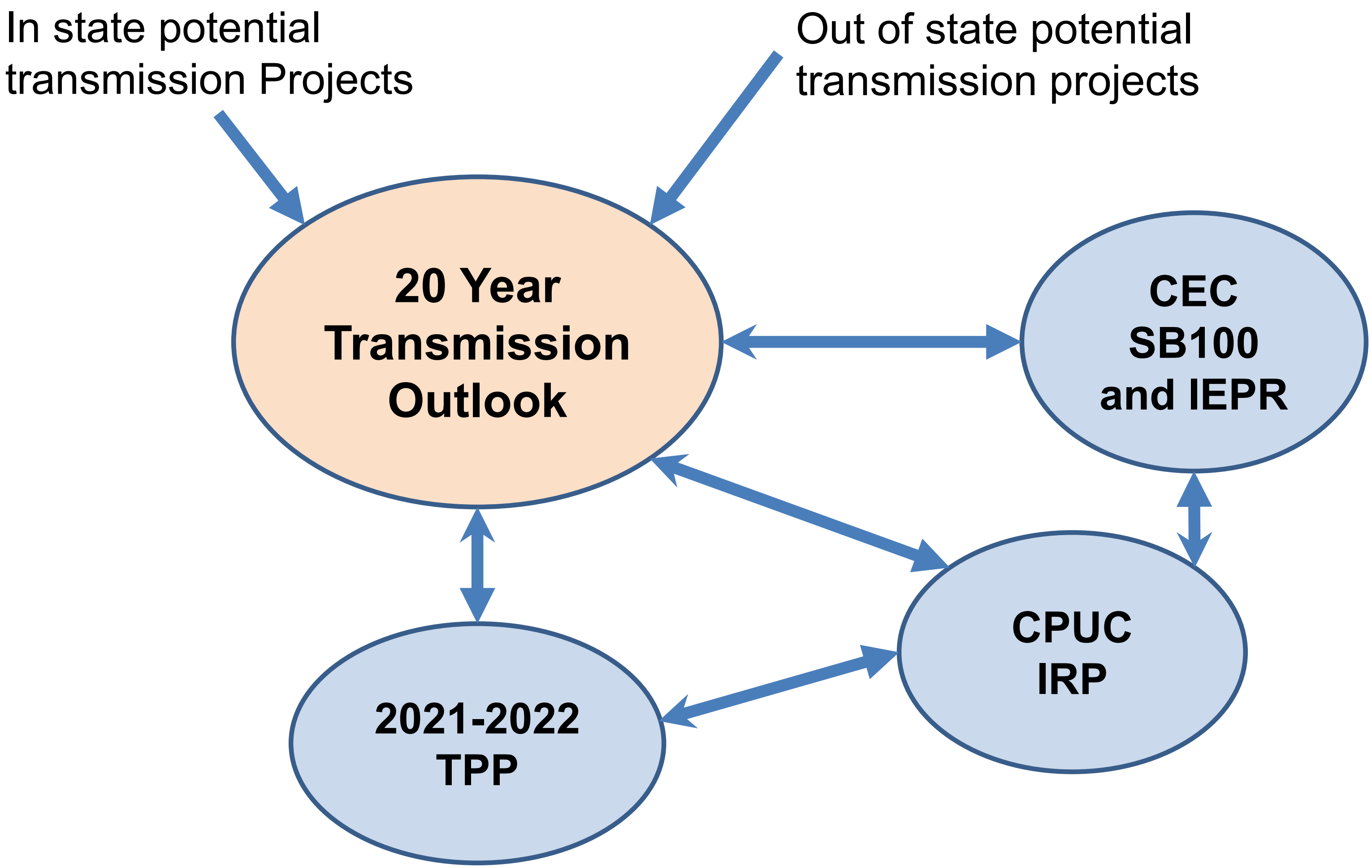
- The CAISO has produced its first ever 2-Year Transmission Outlook focused on providing a longer term view of transmission needed to reliably meet state clean energy goals
- Posted on CAISO website on January 31, 2022
  http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf
- Is a draft and not as a final document – will be finalized in March in parallel with the 2022-2023 Transmission Plan



The 20-year transmission outlook provides a "baseline" architecture for future planning activities:

- Includes high level technical studies to test feasibility of alternatives, focusing on the bulk transmission system
- Used a "Starting Point" scenario docketed that:
  – has diverse resources known to require transmission development such as offshore wind energy, out-of-state resources, and geothermal
  – gas power plant retirements that may require transmission development to reduce local area constraints.
- Is intended to help:
  – scope the challenges we face,
  – help the state to further refine resource planning,
  – and provide longer term context for decisions made in the 10 year transmission plan process.

Primary Paths for Coordination with Other Initiatives



20 Year Outlook – SB100 Starting Point Scenario

	Portfolios for 2020-2021 Plan (2030)	Portfolios for 2021-2022 Plan (2031)	*Authorized near and mid term (2025) procurement*	*Proposed Decision Preferred System Plan (2025)*	Proposed Decision Preferred System Plan (2032)	SB 100 Starting Point Scenario (2040)
Solar	6,763	13,044	*12,800 **	*11,000*	17,506	53,212
Wind	992	4,005		*3,531 in state 0 OOS 0 offshore*	3,531 in state 1,500 OOS 1,708 offshore	2,237 in state 12,000 OOS 10,000 offshore
Battery storage	1,376	9,368		*11,317*	13,571	37,000
Gas-fired						
Biomass				*107*	134	
Geothermal	0	651	*1,000 likely beyond 2026*	*114*	1,160	2,332
Pumped Hydro / Long Duration	1,256	627	*1,000 likely beyond 2026*		1,000	4,000
Total	**10,387**	**27,695**	***14,800***	***26,069***	**40,110**	**120,781**
Gas retirements	0	0			~1,000	-15,000

* NQC value as opposed to installed capacity

Table does not include behind-the-meter resources and supply-side demand response

Integration of the resources in SB100 Starting Point

California ISO

Study cases

- Three base cases were developed for the contingency analysis to identify the potential transmission enhancement requirements.
  - Peak consumption (SSN)
    - based on the SSN in deliverability studies and reflects the system in early afternoon summer conditions
  - Net Peak (HSN)
    - based on the HSN in deliverability studies and reflects the system in early evening summer conditions
  - Off Peak
    - reflects the system in the middle of the day in spring when electricity consumption is low and at the same time the solar and BTM PV generation is high

High electrification load scenario development

- SB 100 Core statewide high electrification load projection of 82,364 MW in 2040
- CEC 2020 IEPR Mid-Mid (1-in-2 weather) scenario for 2031 statewide load is 64,076 MW.
- 18,288 MW (28.5 percent) increase from the IEPR 2020 load forecast in 2031 to the high electrification forecast base of the SB 100 Core scenario in 2040
- SB 100 Core scenario statewide behind-the-meter PV (BTM-PV) in the state of California to reach 33,807 MW in year 2040

Load and Installed BTM-PV	State	CAISO
CEC peak consumption forecast in 2031	64,076	57,498
SB-100 peak consumption in 2040	82,364	73,909
BTM-PV installed capacity in CEC 2031 forecast	25,092	22,655
BTM-PV in SB-100 in 2040	33,807	30,336

Dispatch and high level technical studies

- Hourly CEC load profile in year 2030 are used to estimate the load and behind-the-meter PV generation for the three study cases

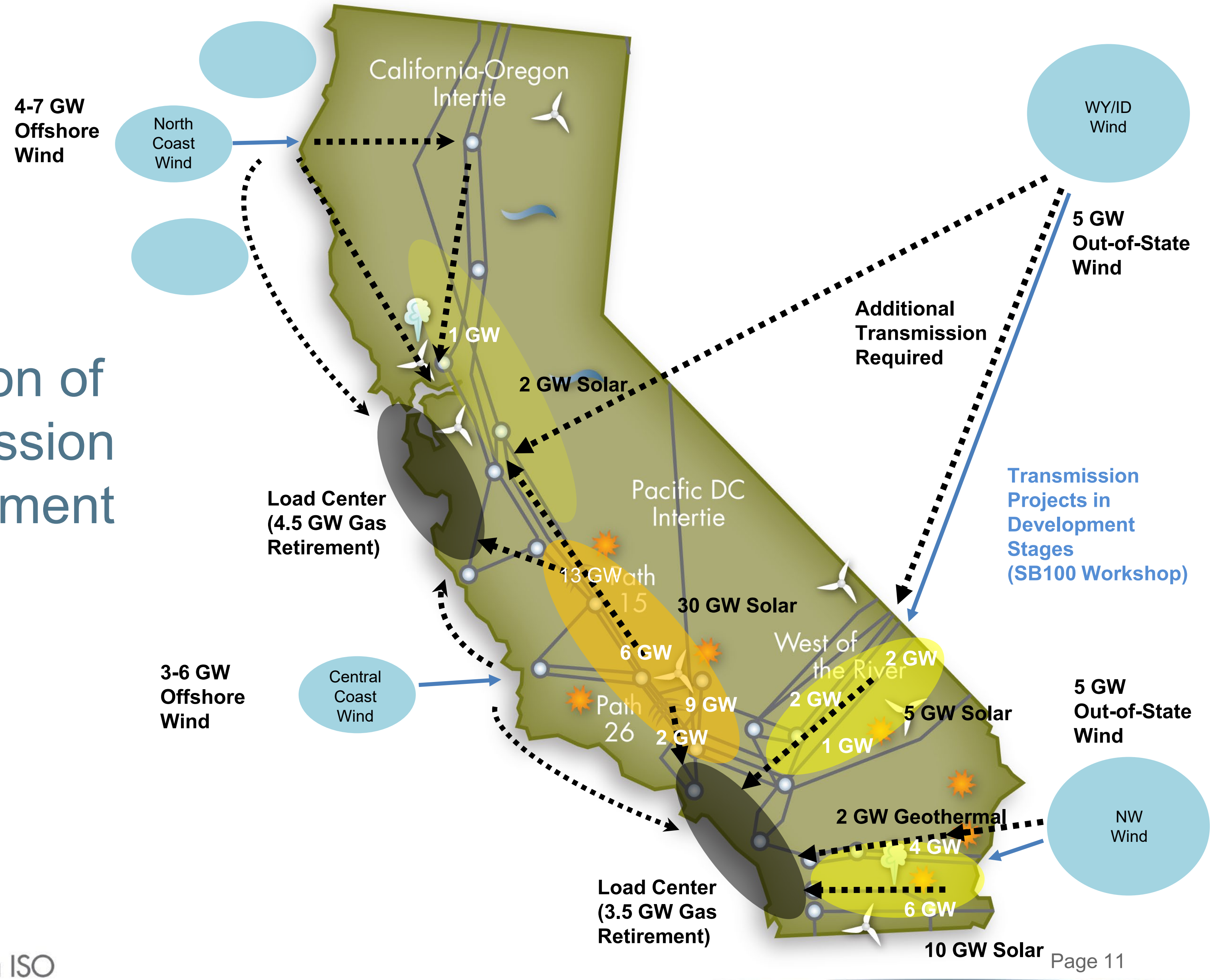
- Resource dispatch based upon dispatch in policy studies in 2021-2022 transmission planning process for different study cases

- Contingency analysis
  - N-0 base case with no contingency
  - Only 230 kV and 500 kV contingencies were evaluated for N-1 analysis
  - Only 500 kV contingencies were evaluated for N-1-1 analysis
  - No RAS action was modelled in this study
  - Generators were not re-dispatched before or after the contingencies
  - Only power flow analysis was performed focusing on thermal overloads.
  - It is assumed that local area overloads are addressed with local transmission upgrades

Transmission assumptions

- Previously approved projects transmission planning process
- Projects Recommended in draft 2021-2022 Transmission Plan
  – Manning 500/230 kV Project
  – Collinsville 500/230 kV Project
  – Newark – Los Esteros – NRS HVDC
  – Metcalf – San Jose B HVDC
  – Mesa – Laguna Bell Reconductor
  – GLW Proposed Upgrades
- System Upgrades Required for Starting Point Generation Interconnection
  – Wheeler Ridge – Kern 230 kV DCTL Project
  – Kramer – Victor – Lugo Path Upgrade Project

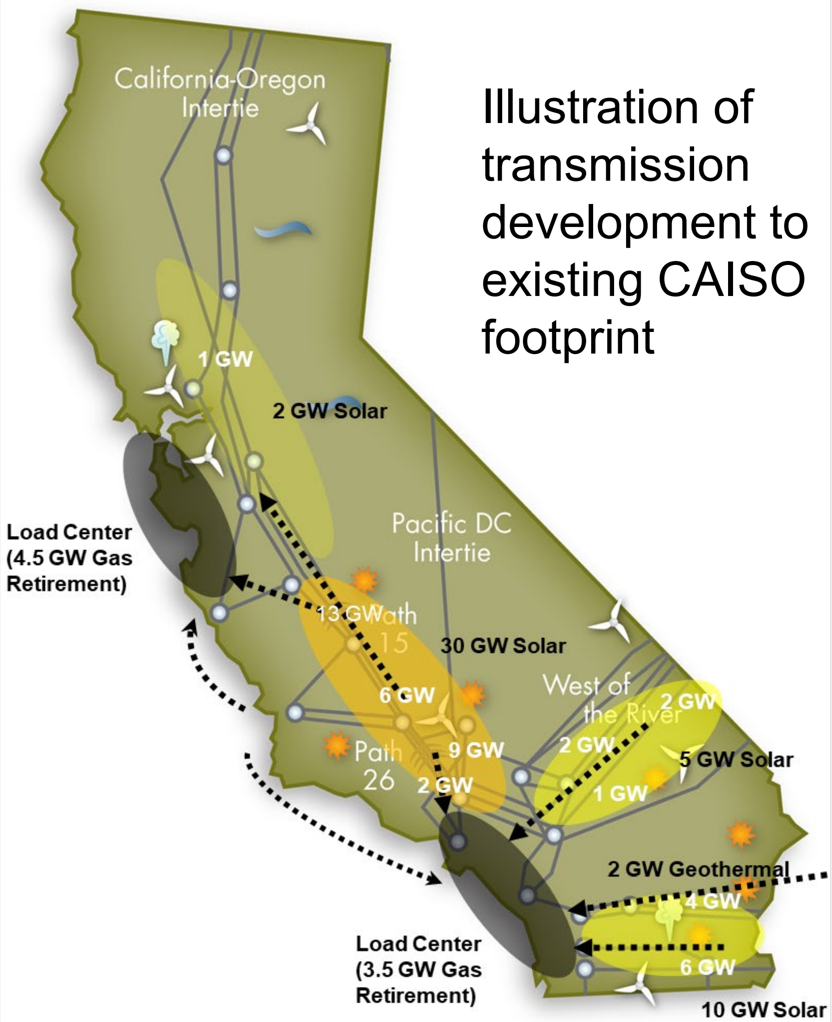
Illustration of Transmission Development



California ISO

Transmission upgrades to existing CAISO footprint

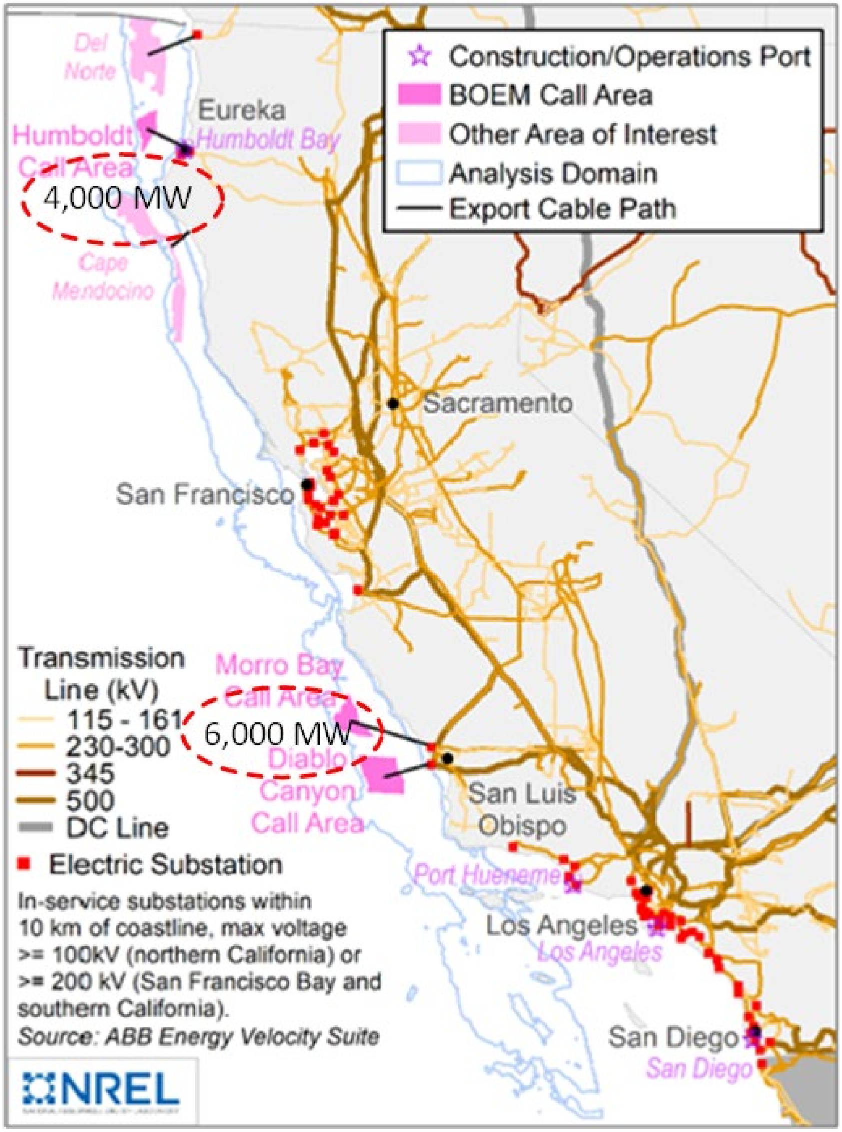
Illustration of transmission development to existing CAISO footprint



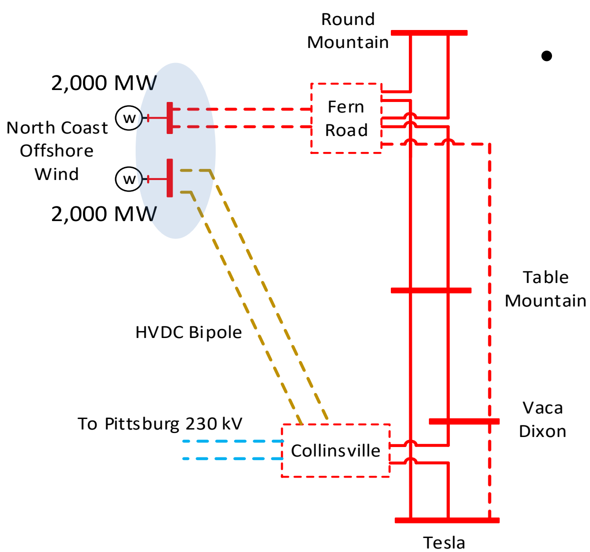
Transmission Development	Description	Cost Estimate
Upgrades to existing CAISO footprint		**10.74**
Eldorado – Lugo 500 kV line	- 180 mi of 500 kV line - Series compensation in number of locations	$1 B
Colorado River – Devers 500 kV line	- Devers – Red Bluff 500 kV line - Ref Bluff – Colorado River 500 kV line	$1.2 B
North Gila – Imperial Valley 500 kV line	- 85 mi of 500 kV line - Series compensation	0.5 B
Westland 500/230 kV station	- 50 mi of 500 kV line - New 500/230 kV substation with two transformers ($200M)	0.5 B
Second Los Banos – Tracy 500 kV line	- 67 mi of 500 kV line	$0.33 B
Third Collinsville – Pittsburg 230 kV cable	- 230 kV cable	$0.14 B
Manning – Moss Landing 500 kV line	- 78 mi of 500 kV line - New 500/230 kV substation with two transformers ($100M)	$0.50 B
Devers – La Fresa HVDC	- 100 mi of DC cables - Two VSC HVDC converter	$1.2 B
Lugo – LA Basin HVDC	- 80 mi of DC cables - Two VSC HVDC converter	$1.0 B
Sycamore – Alberthill HVDC	- 82 mi of DC cables - Two VSC HVDC converter	$1.0 B
Diablo – South HVDC	- Four VSC converter stations - 250 miles HVDC cables	$1.85 B
Diablo – North HVDC	- Four VSC converter stations - 200 miles HVDC cables	$1.60 B
Round Mountain 500/230 kV Transformer	- Add one 500/230 kV transformer	$0.1 B
Lugo 500/230 kV Transformers	- Add one 500/230 kV transformer	$0.1 B

Offshore Wind

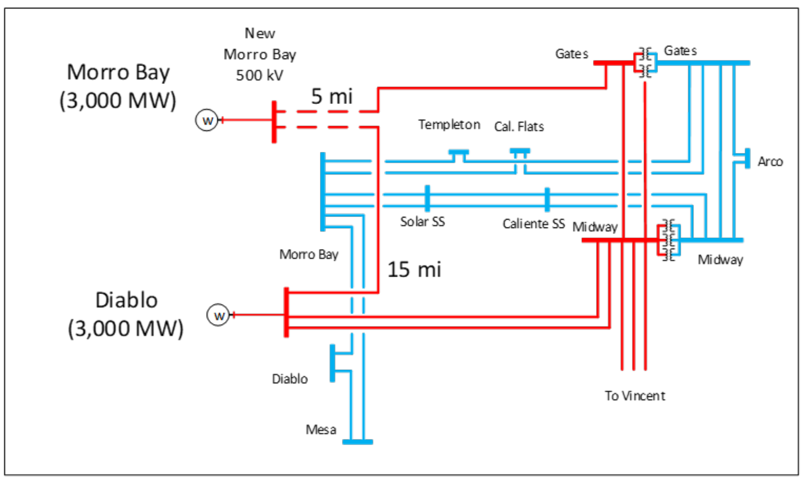
- 10 GW of offshore wind
  - 6 GW in central coast
  - 4 GW in north coast
- Current areas of environmental and leasing development at Bureau Ocean Energy Management (BOEM)
  - Humboldt call area
  - Morro Bay call area



Offshore transmission development



- Central coast offshore wind interconnecting to existing 500 kV in Diablo/Morro Bay area
- North coast offshore wind requires transmission development to interconnect to existing system
  - 500 kV AC interconnection to Fern Road
  - HVDC line to Collinsville
  - interconnect 500 kV AC and HVDC systems together and the offshore wind farms in two wind development areas
  - Potential for offshore grid development and strengthening of interconnection to Pacific Northwest



Transmission Development	Description	Cost Estimate
Offshore Wind		**$8.11 B**
Humboldt Bay Offshore wind area	Total of 4,000 MW offshore wind connected through two of the following options: - Option 1 (Fern Road): $2.3 B - Option 2 (Bay Hub): $4.0 B - Option 3 (Collinsville): $3.0 B Facilities required to interconnect the transmission options connecting to the different offshore wind areas: $0.5B-$1.0 B.	$5.8 B–$8.0 B
Diablo – Morro Bay Offshore wind area	- Total of 6,000 MW offshore wind. Connected to Diablo 500 kV and the new Morro Bay 500 kV substation. - The cost estimate is only for a 500 kV switching station and looping in the existing Diablo – Gates 500 kV line into it.	0.11 B

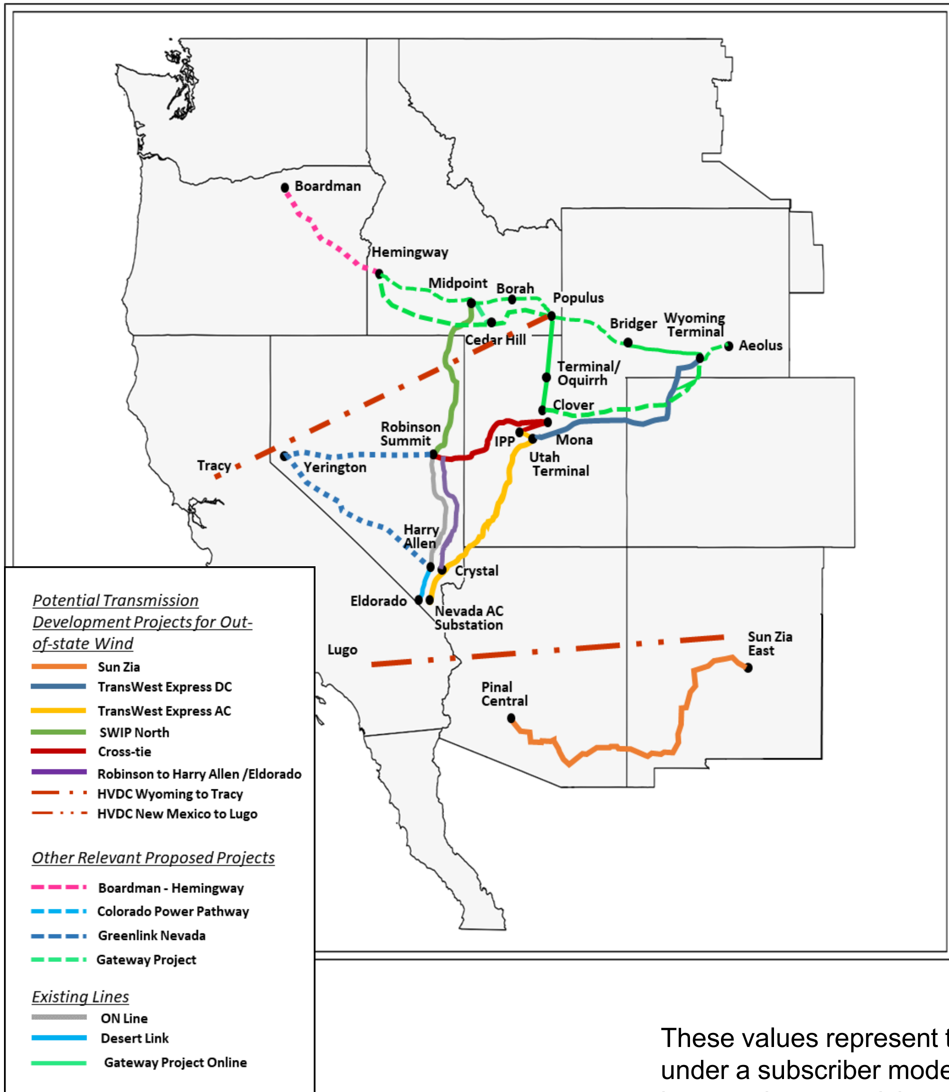
Out-of-state wind

- 12,000 MW of out-of-wind identified in SB 100 Starting Point scenario
  - On new transmission
    - Wyoming 4,685 MW
    - New Mexico 5,215 MW
  - On existing transmission
    - Northwest 1,500 MW
    - Baja California 600 MW

- Transmission projects presented at SB100 workshop by developers can accommodate approximately 6,000 MW of out-of-state wind

Transmission Development Project	Wind Area	Capacity (MW)
SunZia Project • Plus scheduling rights on existing lines from Pinal Central to Palo Verde connecting to the CAISO system	New Mexico	2,000 – 3,000
TransWest Express • Also provides potential for 1,500 MW to LADWP	Wyoming	1,500
SWIP-North • With upgrades and scheduling rights On Line from Robinson to Harry Allen	Idaho	1,000
Cross-tie • Would require additional 500 kV line between Robinson to Eldorado	Wyoming	1,000

Transmission development for out-of-state wind



Transmission Development	Description	Cost Estimate
Out-of-State Wind		**$11.65 B**
SWIP-North	275 mile 500 kV line from Midpoint to Robinson substation with upgrades to On Line from Robinson to Harry Allen to access Idaho wind resources	$0.64 B
Cross-Tie	214 mile 500 kV line from Robinson to Mona/Clover to access Wyoming wind resources	$0.67 B
Robinson-Eldorado	500 kV transmission line from Robinson to Harry Allen/Eldorado	$0.64 B
TransWest Express	732 Mile transmission system consisting of HVDC and 500 kV facilities to access Wyoming wind. Project is designed to potentially provide 1500 MW to LADWP at the IPP facilities in Utah and 1500 MW to the CAISO at Harry Allen/Eldorado	$2.1 B
SunZia	530 mile HVDC line and 35 mile 500 kV AC line plus scheduling rights on existing lines from Pinal Central to Palo Verde connecting to the CAISO system to access New Mexico wind resources	$2.6 B
Additional transmission for additional wind resources from Wyoming/Idaho area	HVDC transmission line from the wind resource area to northern California (Tesla area)	$2.5 B
Additional transmission for additional wind resources from New Mexico area	HVDC transmission line from the wind resource area to southern California (Lugo area)	$2.5 B

These values represent the capital cost of the identified projects; several are currently being developed under a subscriber model – with the transmission costs incorporated into the energy costs – and not rate-base projects receiving cost-of-service cost recovery that would be added to CAISO transmission access charges.

Transmission Development Estimated Cost

Transmission Development	Estimated Cost ($ billions)
Upgrades to existing CAISO footprint consisting of: • 230 kV and 500 kV AC lines • HVDC lines • Substation upgrades	$ 10.74 B
Offshore wind integration consisting of: • 500 kV AC lines • HVDC lines	$ 8.11 B
Out-of-state wind integration consisting of: • 500 kV AC lines • HVDC lines	$ 11.65 B
Total estimated cost of transmission development	**$ 30.5 B**

These values represent the capital cost of the identified projects; several are currently being developed under a subscriber model – with the transmission costs incorporated into the energy costs – and not rate-base projects receiving cost-of-service cost recovery that would be added to CAISO transmission access charges.

Conclusions and next steps

- The 20-Year Transmission Outlook provides a long-term conceptual plan of the transmission grid in 20 years, meeting the resource and electric load needs aligned with state agency input on integrated load forecasting and resource planning, as the basis for further dialogue.
- After finalizing this draft in March, the CAISO intends to:
  - Look for discussion of the findings in ongoing SB 100 processes and perhaps additional stakeholder sessions
  - Collect input on issues and parameters that could be considered and refined in a future outlook development cycle – thinking about 2023
  - Provide industry an update on the 20-Year Outlook activities and communicate intentions going forward, by year end.

Comments
Draft 20-Year Transmission Outlook

- Comments due by end of day February 22, 2022

- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:

  https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook

Wrap-up
Draft 2021-2022 Transmission Plan and Draft 20-Year Transmission Outlook

2021-2022 Transmission Planning Process Stakeholder Meeting

February 7, 2022

Comments
Draft 2021-2022 Transmission Plan

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Comments will be submitted to the ISO using the online stakeholder commenting tool

- Ability to view all comments with a single click.
- Ability to filter comments by question or by entity.
- Login, add your comments directly to the template and submit.
  - You can save and return to your entry anytime during the open comment period.

NOTE

Submitting comments in the tool will require a one-time registration.

Find a video on how to use the commenting tool on the Recurring Stakeholder Processes landing page.