Agenda
Draft 2020-2021 Transmission Plan

Isabella Nicosia
Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

2020-2021 Transmission Planning Process Stakeholder Meeting Agenda

Topic	Presenter
Introduction	Isabella Nicosia
Overview	Jeff Billinton
Reliability Assessment Recommendations	Abhishek Singh Frank Chen
Wildfire Assessment – PG&E Area	Binaya Shrestha
Frequency Response Study	Irina Green
Policy Assessment	Nebiyu Yimer
Economic Assessment	Yi Zhang
Next Steps	Isabella Nicosia

Overview
Draft 2020-2021 Transmission Plan

Jeff Billinton
Director, Transmission Infrastructure Planning

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

2020-2021 Transmission Planning Process

December 2019 | April 2020 | March 2021

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

Draft transmission plan presented for stakeholder comment.

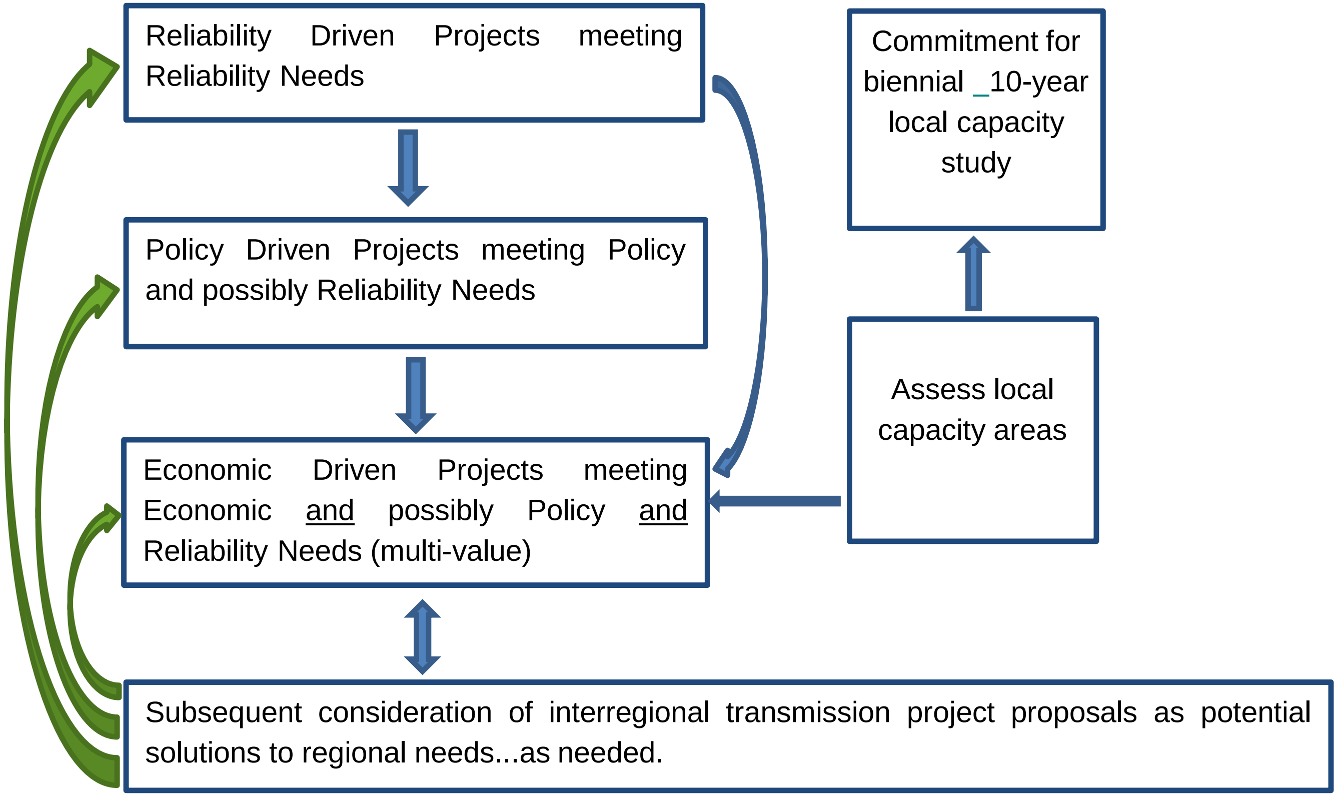
ISO Board for approval of transmission plan

California ISO

2020-2021 Transmission Plan Milestones

- Draft Study Plan posted on February 21
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 13
- Final Study Plan to be posted on March 31
- Stakeholder call – update June 3
- Comments to be submitted by June 17
- Preliminary reliability study results to be posted on August 14
- Stakeholder meeting on September 23 and 24
- Comments to be submitted by October 8
- Request window closes October 15
- Preliminary policy and economic study results on November 17
- Comments to be submitted by December 1
- Draft transmission plan to be posted on February 1, 2021
- Stakeholder meeting in February 9
- Comments to be submitted by February 23
- Revised draft for approval at March Board of Governor meeting

Studies are coordinated as a part of the transmission planning process



Forecast coordination is continuing with CPUC and CEC, with focus on renewable generation:

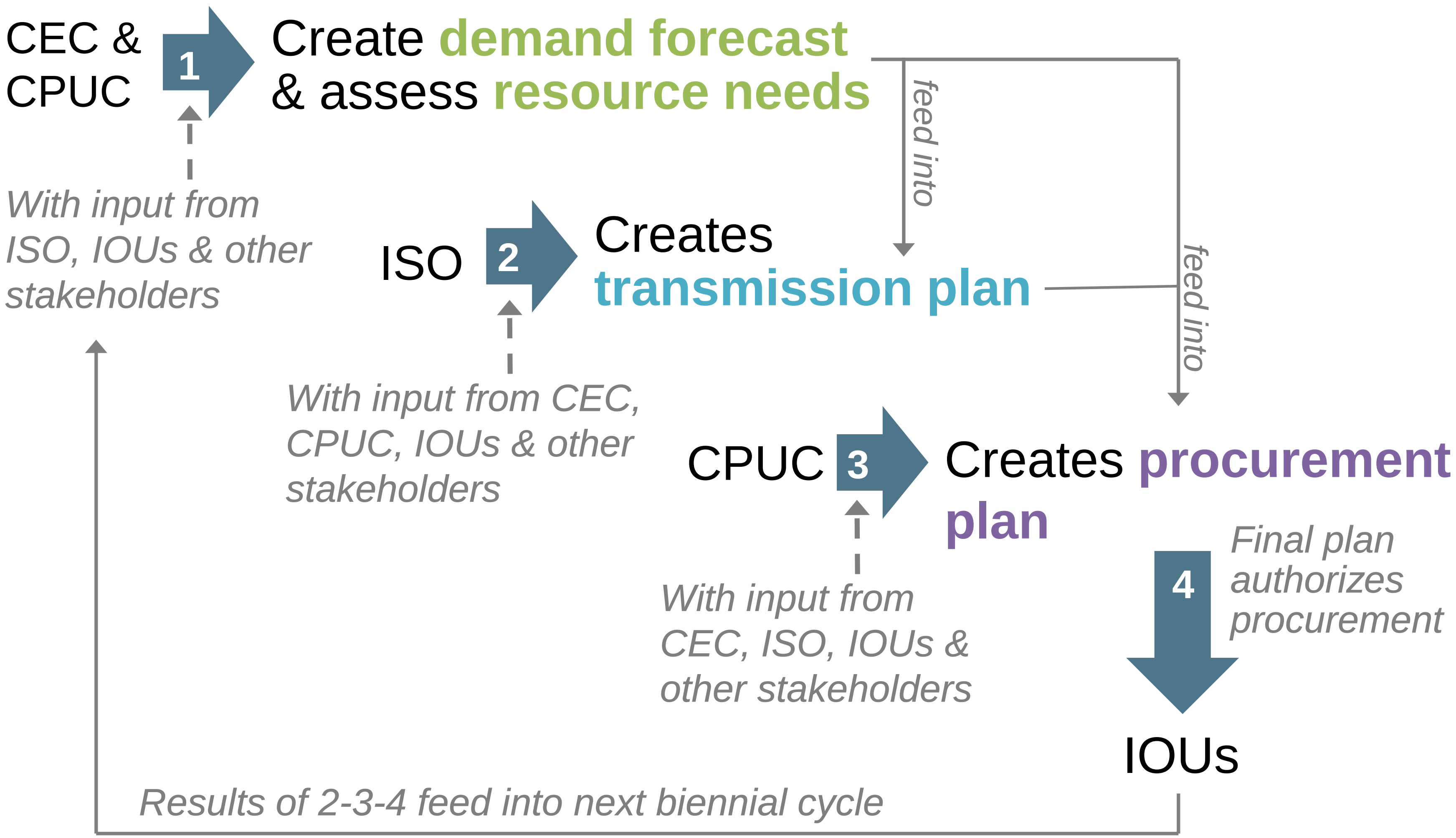
- Load forecast based on California Energy Demand Updated Forecast 2020-2030 (CED 2019) adopted by California Energy Commission (CEC) on January 22, 2020

  https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr

- RPS portfolio direction for 2020-2021 transmission planning process was received from the CPUC and CEC
  - The CPUC IRP Base Case portfolio – is used for the reliability, policy and economic assessment
  - Two sensitivity portfolios to be assessed in the policy assessment

  https://www.cpuc.ca.gov/General.aspx?id=6442464144

Planning and procurement overview



Key Issues in 2020-2021 Transmission Plan Cycle:

- ISO incorporated renewable portfolios from the CPUC
  - Baseline portfolio
    - Reliability, Policy and Economic Assessments
  - Sensitivity portfolios
    - Policy Assessment
- Interregional Transmission Planning Process
  - In year one (even year) of 2 year planning cycle
- A number of studies incorporated in the “other studies” section
  - Frequency Response
  - Flexible Capacity Deliverability
  - Wildfire assessment – PG&E area in this planning cycle
  - 10-year Local Capacity Technical Study (conducted every two years)
    - Continuation of alternatives to gas-fired generation
    - Updated storage capabilities

Reliability Assessment Recommendations – PG&E Area Draft 2020-2021 Transmission Plan

Lindsey Thomas/Abhishek Singh
Regional Transmission - North

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

New Projects Recommended for Approval in 2020-2021 TPP - PG&E Area

Projects	Planning Area	Status
Palermo – Wyandotte 115 kV Line Section Reconductoring	North Valley	Presented in November meeting
Manteca #1 60 kV Line Section Reconductoring	Central Valley	Presented in November meeting
Kasson – Kasson Junction 1 115 kV Line Section Reconductoring	Central Valley	Presented in November meeting

Moraga-Sobrante 115 kV Line Reconductor Project

Approved cycle:
- 2018-2019 TPP
- 2019-2020 (On Hold)

Original scope:
- Reconductor the Moraga - Sobrante 115 kV line with a larger capacity conductor

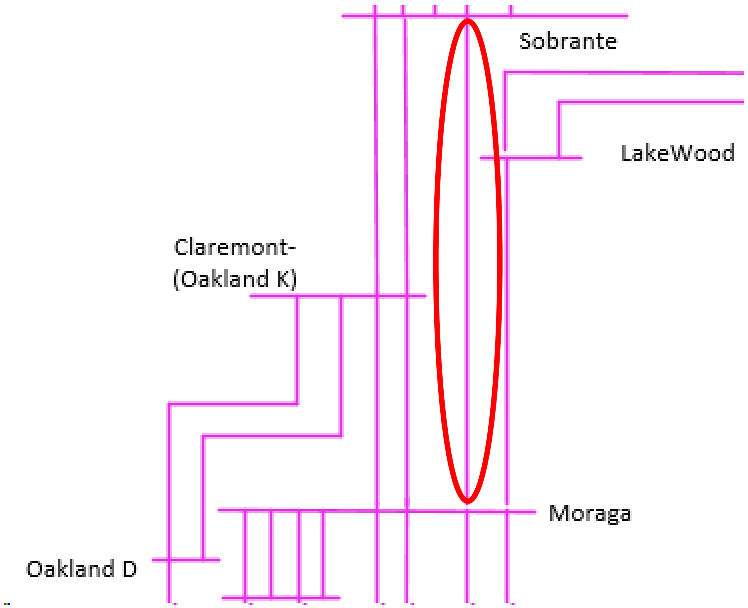
Project cost:
- Original cost: $12-$18M
- 2019-2020 cost estimate: $10-$20M

Current In-service Date:
- On hold

Reliability Assessment Need:
- Multiple P2 overloads at Sobrante substation starting 2030

Alternatives under consideration TPP20-21
- None

Recommendation
- On-hold for this cycle as well due to long term needs associated with the project



Wheeler Ridge Junction Project

Approved cycle:

- 2013-2014 TPP
- 2018-2019 TPP
- 2019-2020 (On Hold)

Original scope:

- Build new substation between Kern PP 230kV and Wheeler Ridge 230kV. Convert Wheeler Ridge Lamont 115kV to 230kV operation and terminate at WRJ.

Project cost:

- Original cost: $90M-$140M
- 2019-2020 cost estimate: $250-$300M

Current In-service Date:

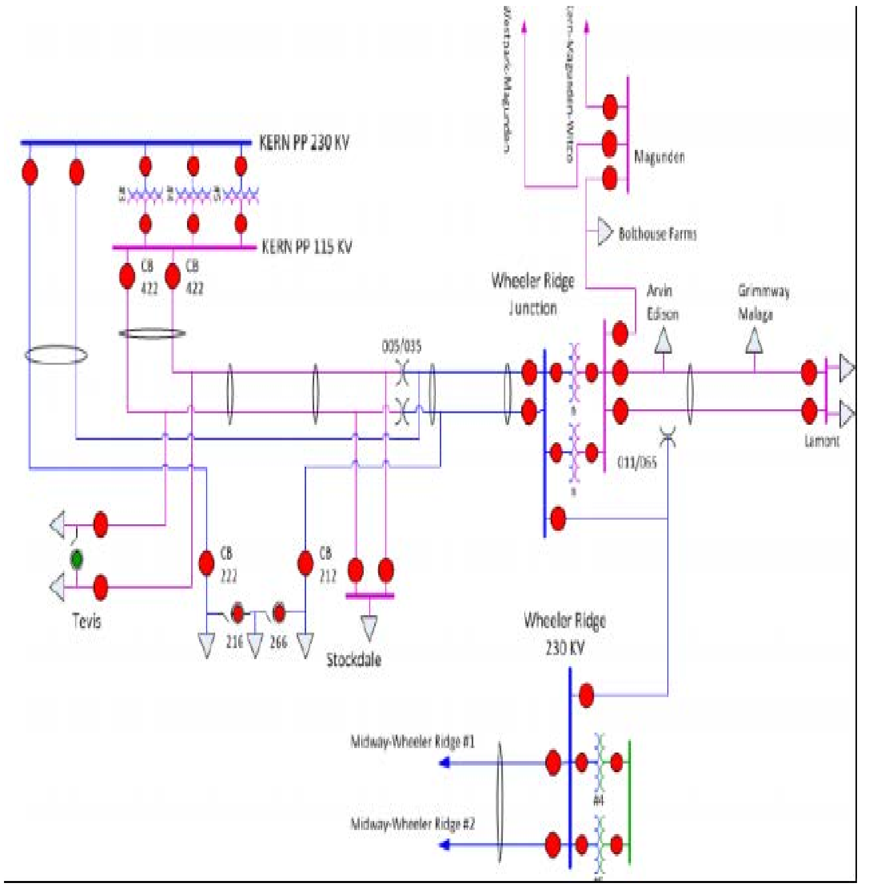
- On hold

Reliability Assessment Need:

- Multiple P1, P2, P3 & P6 overloads in both Kern 115 areas and the 230 kV Midway-Wheeler ridge lines

Alternatives considered TPP20-21

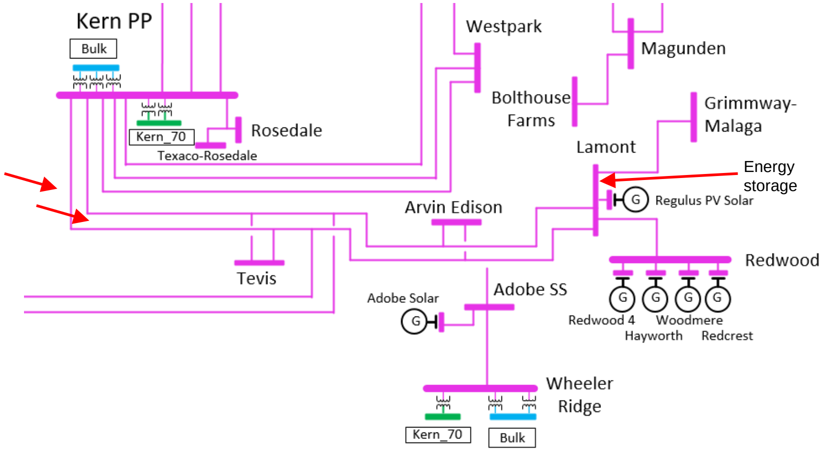
- Option 1: New Wheeler ridge Jn 115 kV SS, Looping of 115 kV lines to this SS, New 115 kV line from SS to Wheeler 115 kV,Reconductoring of Kern-Tevis-Lamont lines and a BESS at Wheeler 230 kV bus.
- Option 2: New Stockdale 230/115 kV T/F, Wheeler ridge Jn SS, Wheeler ridge 230/115 kV T/F, reconductoring Wheeler ridge-Lamont line with higher capacity and a BESS at Wheeler 230 kV bus.

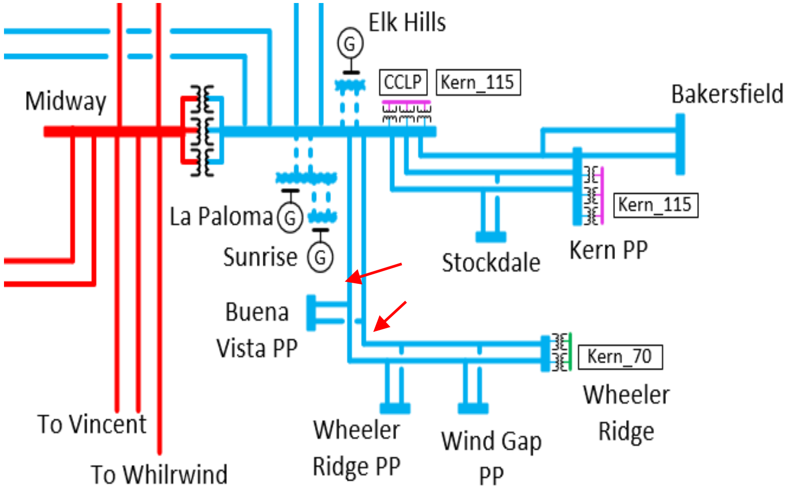


Wheeler Ridge Junction Project

<u>Alternatives considered TPP20-21 (continued)</u>

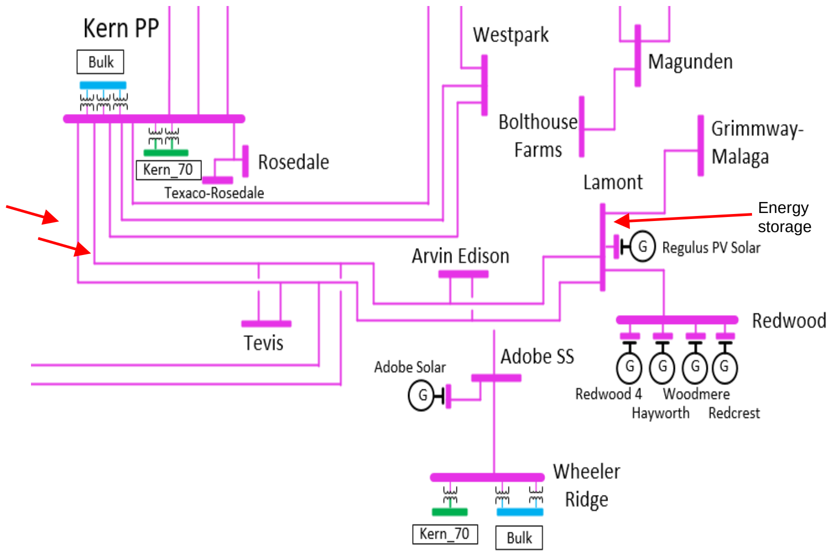
- Option 3
  - Evaluate transmission and/or energy storage solution for the Kern-Tevis-Lamont 115 kV issues seen in both short and long term.
  - Evaluate operating solutions for the Kern-Magunden-Witco 115 kV transmission system
  - Evaluate transmission and/or energy storage solution for the 230 kV issues on the Midway-Wheeler ridge system.





Wheeler Ridge Junction Project-Recommendation

- Reliability Assessment Need
  - NERC Category P1,P2-1 and P6 issues seen in both short and long term
- Project Submitter
  - CAISO
- Project Scope
  - Install a 95 MW/168 MWh battery at Lamont 115 kV substation.
- Project Costs (Preliminary)
  - Interconnection costs only without the capital cost of the Energy storage : $5-$10Million
  - Cost of alternate transmission reconductor : $30 Million
- Alternatives Considered
  - Status quo which is not acceptable due to existing P2-1 and a short term P1 issue
  - Re-rate is not feasible as Kern area peaks after 7pm.
- Recommendation
  - Procurement of a 95 MW/168 MWh battery at Lamont 115 kV substation as mitigation plan.
  - Keep Wheeler Ridge Junction Project on hold pending procurement of the battery in the 115 kV system and until the evaluation of 230 kV options are completed.



North of Mesa Project

Approved cycle:
- 2012-2013 TPP
- 2018-2019 TPP
- 2019-2020 (On Hold)

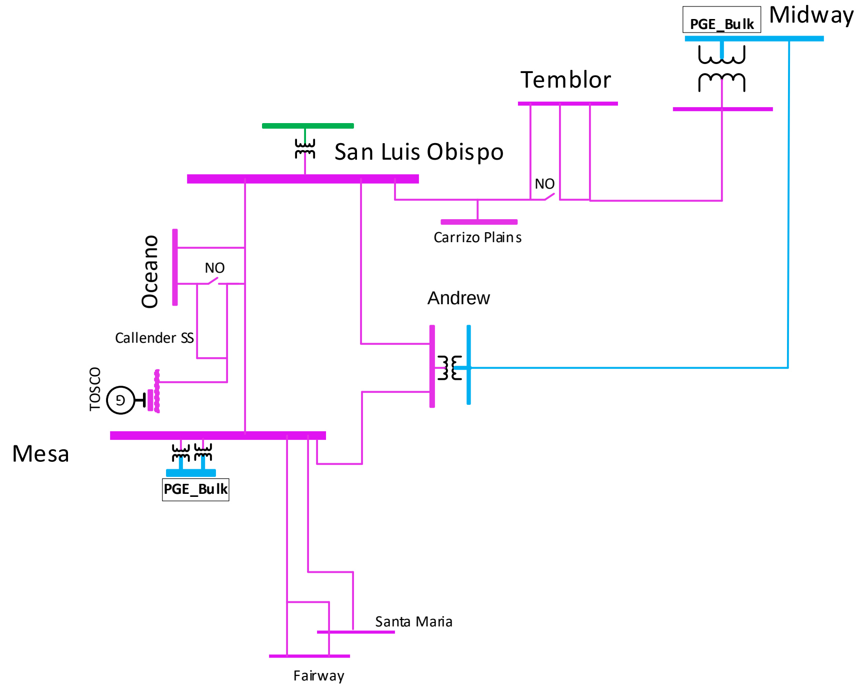
Original scope:
Build Andrew 230/115 kV substation, energize Diablo – Midway 500 kV line at 230 kV and connect to Andrew substation, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.

Project cost:
- Original cost: $120-$150M
- 19-20 cost estimate: $114-$144M

Current In-service Date:
- On hold

Reliability Assessment Need:
- Multiple P2, P6 & P7 overloads in both Mesa 115 kV area. In addition, the load forecast and profile in the area does not provide periods for maintenance to facilities where the next contingency would not result in load loss in the area.

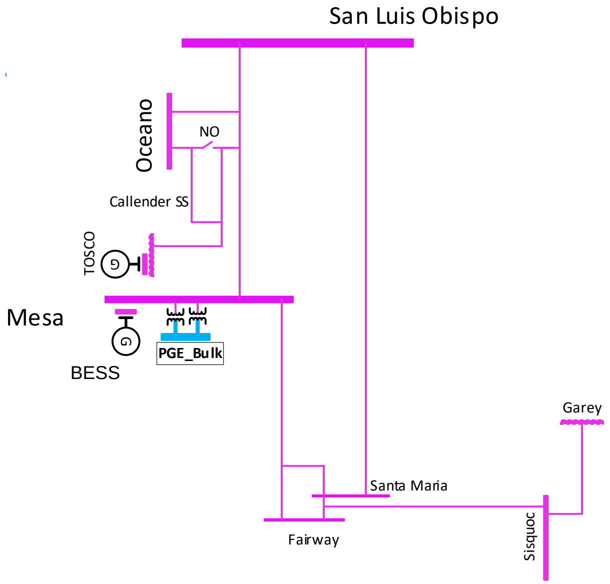
Alternatives under consideration TPP20-21
- Option 1: Install 500/115 kV transformer and loop in to Diablo - Midway 500 kV line, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations. (~$300M)



North of Mesa Project

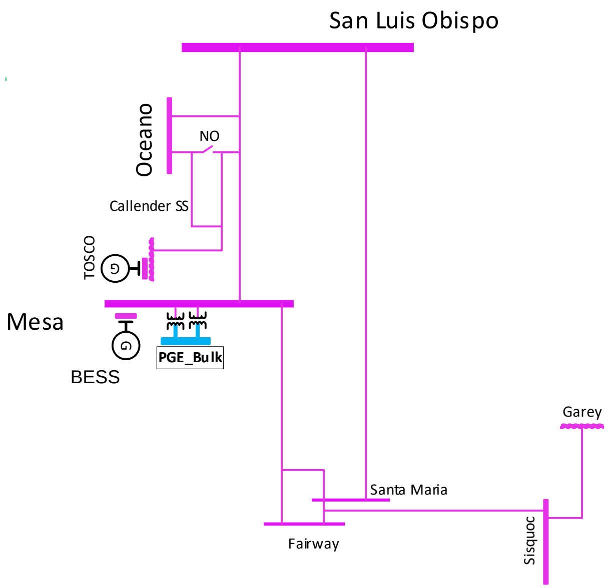
Alternatives considered TPP20-21 (continued)

- Option 2 (Preferred)
  - Install approximately 50 MW/200 MWh BESS at Mesa 115kV substation to address maintenance window. Utilize existing Mesa, Divide and Santa Maria UVLS for peak load conditions.



North of Mesa Project-Recommendation

- Reliability Assessment Need
  - NERC Category P2, P2 and P7 issues seen in both short and long term
- Project Submitter
  - CAISO
- Project Scope
  - Install approximately 50 MW/200 MWh BESS at Mesa 115kV substation to address maintenance window. Utilize existing Mesa, Divide and Santa Maria UVLS for peak load conditions.
- Project Cost (Preliminary)
  - Interconnection costs only without the capital cost of the Energy storage : ~$3-$5Million
- Alternatives Considered
  - Status quo which is not acceptable due to existing maintenance issue
  - Reconductoring of 115 kV lines – not recommended due to higher cost.
- Recommendation
  - Procurement of 50 MW/200 MWh battery at Mesa 115 kV substation as mitigation plan.
  - Keep North of Mesa Project on hold pending procurement of the battery in the Mesa 115 kV system.



Reliability Assessment Recommendation - SDG&E Area
Draft 2020-2021 Transmission Plan

Frank Chen
Regional Transmission Engineer Lead

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

SDG&E Sub-transmission Projects Re-evaluation

No.	Project	In-service Date
1	TL6983 2nd Pomerado – Poway 69 kV Circuit	4/2/2026
2	TL690E Stuart Tap - Las Pulgas 69kV Reconductor	5/1/2026
3	TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa Heights	7/28/2026
4	Loop Granite – Granite Tap, TL632A, into Granite and Cancel Los Coches – El Cajon Reconductor, TL631	10/22/2026
5	TL605 Silvergate – Urban Reconductor	6/25/2027
6	Open Sweetwater Tap (TL603) and Loop into Sweetwater	12/20/2027

SDG&E Sub-transmission Projects Re-evaluation

1. Evaluate the Reliability and Deliverability need
2. If there is reliability need, project the behind-the-meter generation and net load profile for the load pocket on the peak day in 2030
3. Determine the amount of battery storage needed to mitigate the need on the peak day in 2030
4. Determine whether battery storage can be charged without other reliability issues on the peak day
5. Determine whether 4-hour battery storage is sufficient to mitigate the need

SDG&E Sub-transmission Projects Re-evaluation

No.	Overloaded Facility	Battery needed to mitigate	Any Charging Violation?	4-hour battery sufficient?
2	Stuart Tap - Las Pulgas 69kV line	35 MW	Yes	No
4	El Cajon-Los Coches 69 kV line	30 MW	No	No
5	Silvergate – Urban 69 kV line	90 MW	Yes	No
6	Naval Sttion Meter-Sweetwater Tap 69 kV/ Sweetwater-Sweetwater Tap 69 kV	75 MW	Yes	No

Duration of Storage needed to mitigate the El Cajon-Los Coches 69 kV line overload

- A 30 MW/180MWh, six-hour battery storage project could mitigate the El Cajon-Los Coches 69 kV line overload
- However, the storage project alternative requires an additional two hours of storage that would not count for system resource adequacy
- The additional cost of the two-hour storage would be similar or more than the cost of the transmission project
- Therefore, the transmission project is still needed

SDG&E Sub-transmission Projects Re-evaluation Results

No.	Project	Reliability Need found?	Can 4-hour battery mitigate the need?	Project to be canceled?
1	TL6983 2nd Pomerado – Poway 69 kV Circuit	No	N/A	Yes
2	TL690E Stuart Tap - Las Pulgas 69kV Reconductor	Yes	No	No
3	TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa Heights	No	N/A	Yes
4	Loop Granite – Granite Tap, TL632A, into Granite and Cancel Los Coches – El Cajon Reconductor, TL631	Yes	No	No
5	TL605 Silvergate – Urban Reconductor	Yes	No	No
6	Open Sweetwater Tap (TL603) and Loop into Sweetwater	Yes	No	No

Frequency Response Assessment and Data Requirements
Draft 2020-2021 Transmission Plan

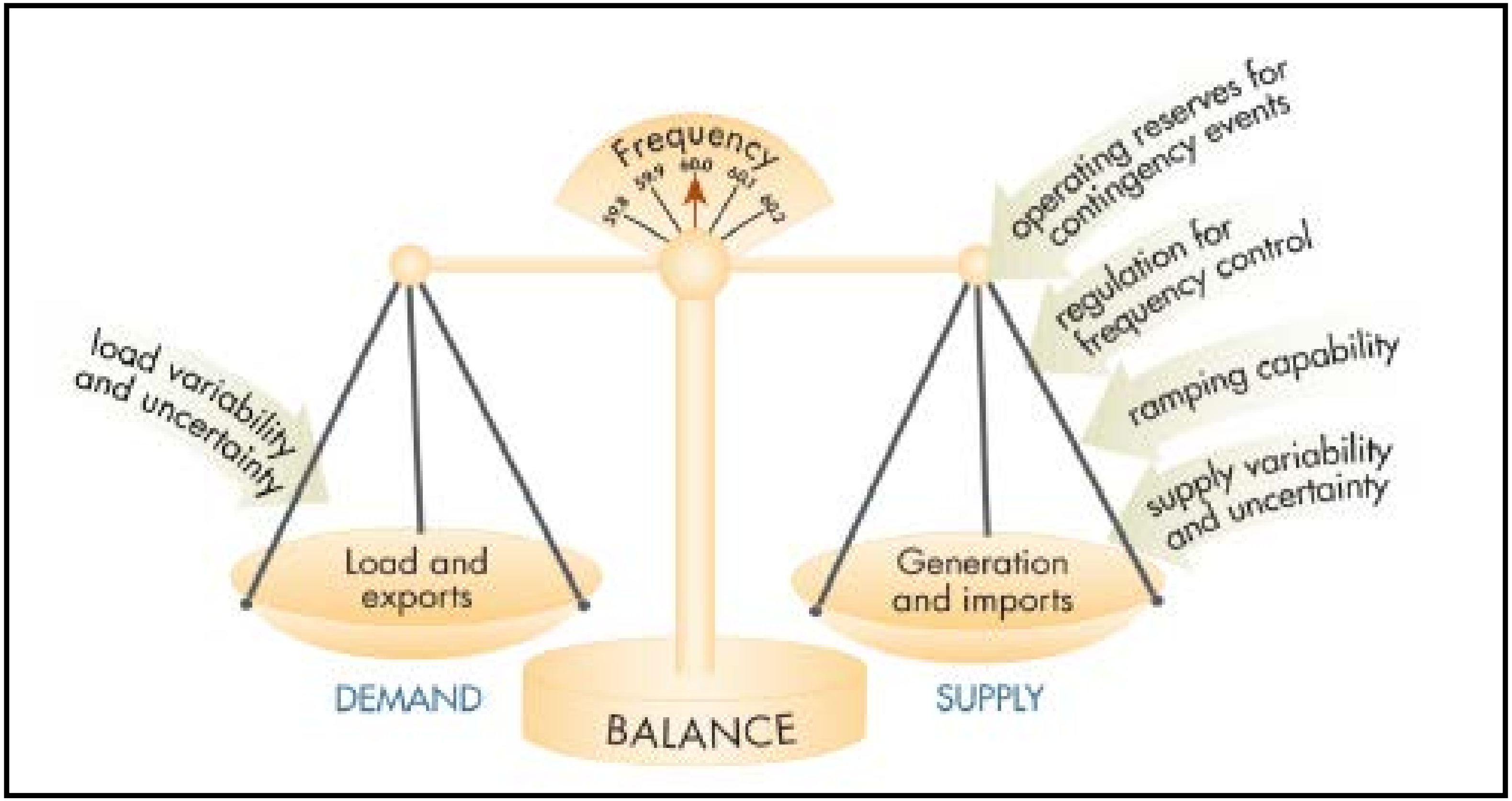
Irina Green, Ebrahim Rahimi
Regional Transmission North

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

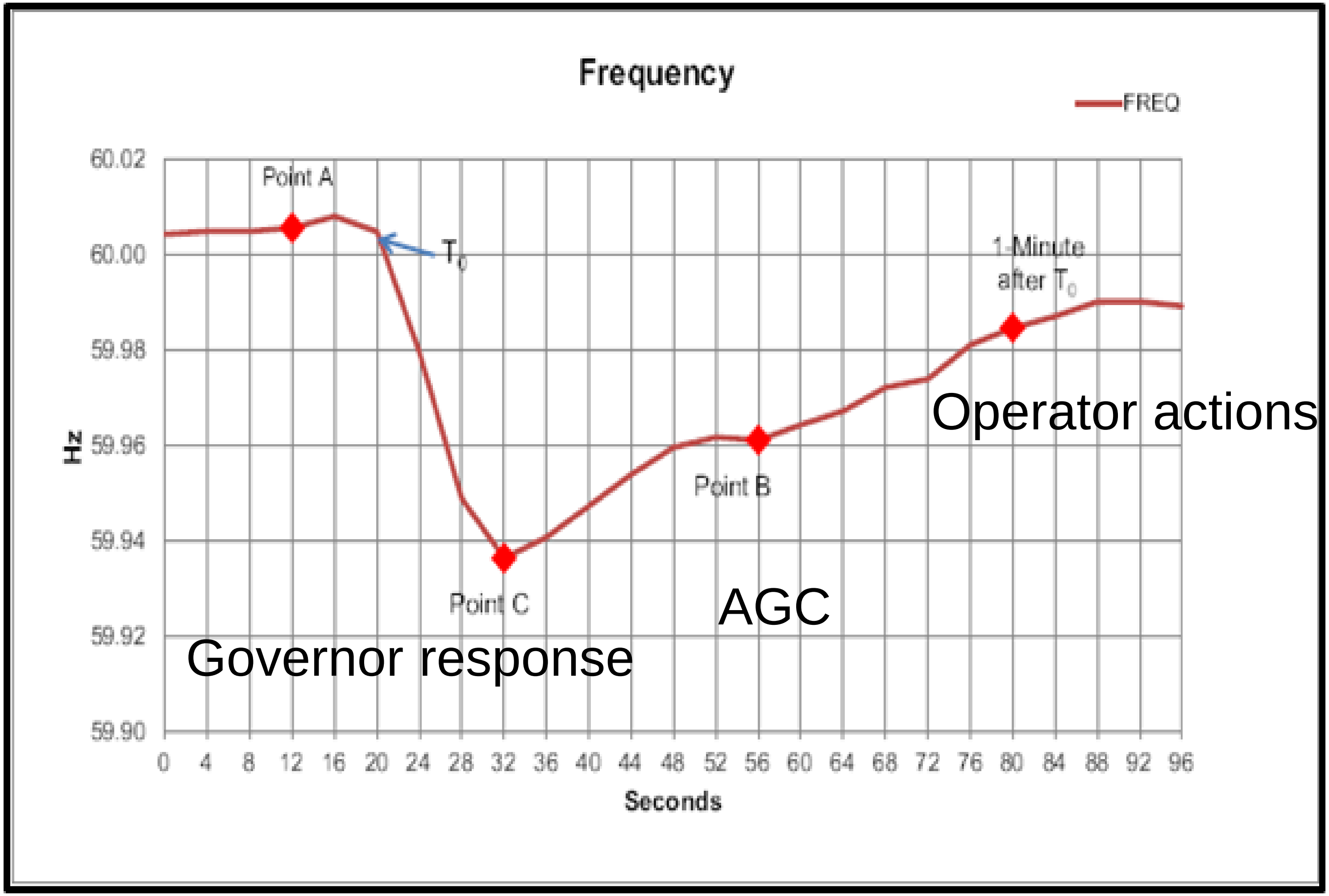
Overview

- Basics of frequency response
- ISO frequency response study results in previous TPPs
- ISO frequency response study results 2020-2021 TPP - impact of frequency response from Inverter Based Resources (IBRs)
- Data collection and model improvement efforts

Continuous Supply and Demand Balance



Frequency Events



Point C – nadir

Point B – settling frequency

Nadir needs to be higher than set-point for UFLS (59.5 Hz)

Generator Response to Frequency Events

- Generating units play a major role in controlling system frequency through their governors
- For studies of off-nominal frequency events, it is essential to properly characterize the response of each generator
- The headroom of the generator and the droop and deadband of the governor determine a generator response to frequency events.
- System inertia 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.

Headroom, Droop and Deadband

- 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.
- Droop is the ratio of the frequency change to generator output change. The smaller is the droop, the higher is response, but generator may become unstable if it is too small. Droop is typically in the 4%-5% range.
  - *Frequency drops to 59.9 Hz, with 5% droop setting, unit responds with ([60-59.9]/60)/0.05 = 3.33% of rated power*
  - *With 4% droop settings it responds ([60-59.9]/60)/0.04 =4.17%*
- Deadband is the minimum frequency deviation from 60 Hz before governor responds. Deadband is typically 0.036 Hz.

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.
- With lower commitment of the frequency-responsive units, frequency response from the ISO could become below the FRO specified by NERC.
- With more inverter-based resources (IBR) online, 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.
- This study was the major cause why the ISO reviewed dynamic stability models

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 deadband or droop parameters.

ISO Frequency Response Study 2020-2021 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 2030 and identify any performance issues related to frequency response.
- The starting base case was the Spring off-Peak case for 2030. 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.
- Latest updated dynamic stability models for the generators and load were used

Interface Flow and Generation Dispatch Assumptions

Parameter	Value (MW)
COI (N-S)	-3,609.6
PDCI (N-S)	-199.9
Path 15 (S-N)	499.5
Path 26 (N-S)	780.1
Path 46 (WOR) (E-W)	-2,052.3
Path 49 (EOR) (E-W)	-4,718.3
IPPDC (E-W)	403
SDG&E (area 22) Export	461.5
SCE (area 24) Export	5,199
PG&E (area 30) Export	4,475
LADWP (area 26) Export	1,360
ISO installed/dispatched solar	21,506 / 14,357
ISO installed/dispatched wind	7,600 / 2,307
ISO installed/dispatched BESS	2,593 / -2,568 (load)
ISO installed/dispatched BTM DER	21,189 / 17,127
ISO Inertia	94.6 GW.S
WECC Inertia	644.1 GW.S

Study Scenarios

- Cases: Base case 2030 Spring off-Peak and the selected case with reduced headroom.
- BESS– charging

Scenarios	SC1	SC2	SC3	SC4
PFR from IBR is switched off	✓	-	-	-
PFR from IBR is switched off and low overall generation headroom.	-	✓	-	-
PFR enabled for new BESS only and low overall generation headroom	-	-	✓	-
PFR enabled for all new IBRs assuming 10% headroom and low overall generation 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)

Load and Generation in the Cases Studied

Case		2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Gross Load, including pumps and motors, MW	ISO, incl. MUNI	31,776	31,776	31,776	31,776
	Total WECC	146,098	146,098	146,098	146,098
Generation total dispatch , incl. DER, not including batteries, MW	ISO, incl. MUNI	45,112	45,078	45,078	45,078
	Total WECC	154,353	154,310	154,310	154,310
BESS total dispatch, MW (Negative sign charging)	ISO, incl. MUNI	-2,568	-2,568	-2,568	-2,568
	Total WECC	-2,699	-2,699	-2,699	-2,699
Conventional Generation with responsive governors, MW	ISO, incl. MUNI, dispatch	6,262	5,928	5,928	5,928
	ISO, incl. MUNI, capacity	9,190	8,329	8,329	8,329
	Total WECC, dispacth	67,689	59,252	59,252	59,252
	Total WECC, capacity	84,814	71,514	71,514	71,514
Wind and solar, non responsive, including x-mission DER, dispatch MW	ISO, incl. MUNI	16,664	16,664	16,664	10,112
	Total WECC	30,276	30,276	30,276	23,724
Wind and solar, responsive, dispatch MW	ISO, incl. MUNI	0	0	0	6,552
	Total WECC	0	0	0	6,552
Batteries, non responsive, MW	ISO, incl. MUNI	-2,568	-2,568	-258	-2,568
	Total WECC	-2,699	-2,699	-389	-2,699
Batteries, responsive, MW	ISO, incl. MUNI	0	0	-2,310	0
	Total WECC	0	0	-2,310	0
Conventional non responsive, MW	ISO, incl. MUNI	5,402	5,065	5,065	5,065
	Total WECC	47,565	47,170	47,170	47,170
Dispatch of responsive generation, % of capacity	ISO, incl. MUNI	68.1%	71.2%	43.4%	59.1%
	Total WECC	79.8%	82.9%	79.6%	78.1%

Solar PV and wind generation dispatch not including battery storage was 36.9% of the total generation dispatch in the ISO and 19.6% of the total dispatch in WECC.

Amount of Frequency Responsive and non-Frequency Responsive Units

Case		2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Total generation units on-line, not including BESS	ISO, incl. MUNI	**875**	**863**	**863**	**863**
	Total WECC	**2,558**	**2,537**	**2,537**	**2,537**
Conventional Generation with responsive governors	ISO, incl. MUNI	**141**	**131**	**131**	**131**
	Total WECC	**875**	**858**	**858**	**858**
Conventional Generation with non- responsive governors	ISO, incl. MUNI	**258**	**256**	**256**	**256**
	Total WECC	**937**	**933**	**933**	**933**
Batteries, responsive	ISO, incl. MUNI	**0**	**0**	**30**	**0**
	Total WECC	**0**	**0**	**30**	**0**
Batteries, non- responsive	ISO, incl. MUNI	**37**	**37**	**7**	**37**
	Total WECC	**39**	**39**	**9**	**39**
Wind and solar responsive	**ISO, incl. MUNI**	**0**	**0**	**0**	**70**
	Total WECC	**0**	**0**	**0**	**70**
Wind and solar non-responsive	**ISO, incl. MUNI**	**476**	**476**	**476**	**406**
	Total WECC	**746**	**746**	**746**	**676**
Kt – ratio of number of responsive generation to number of total generation, %	**ISO, incl. MUNI**	**16.1%**	**15.2%**	**18.5%**	**21.5%**
	Total WECC	**34.2%**	**33.8%**	**34.9%**	**35.6%**

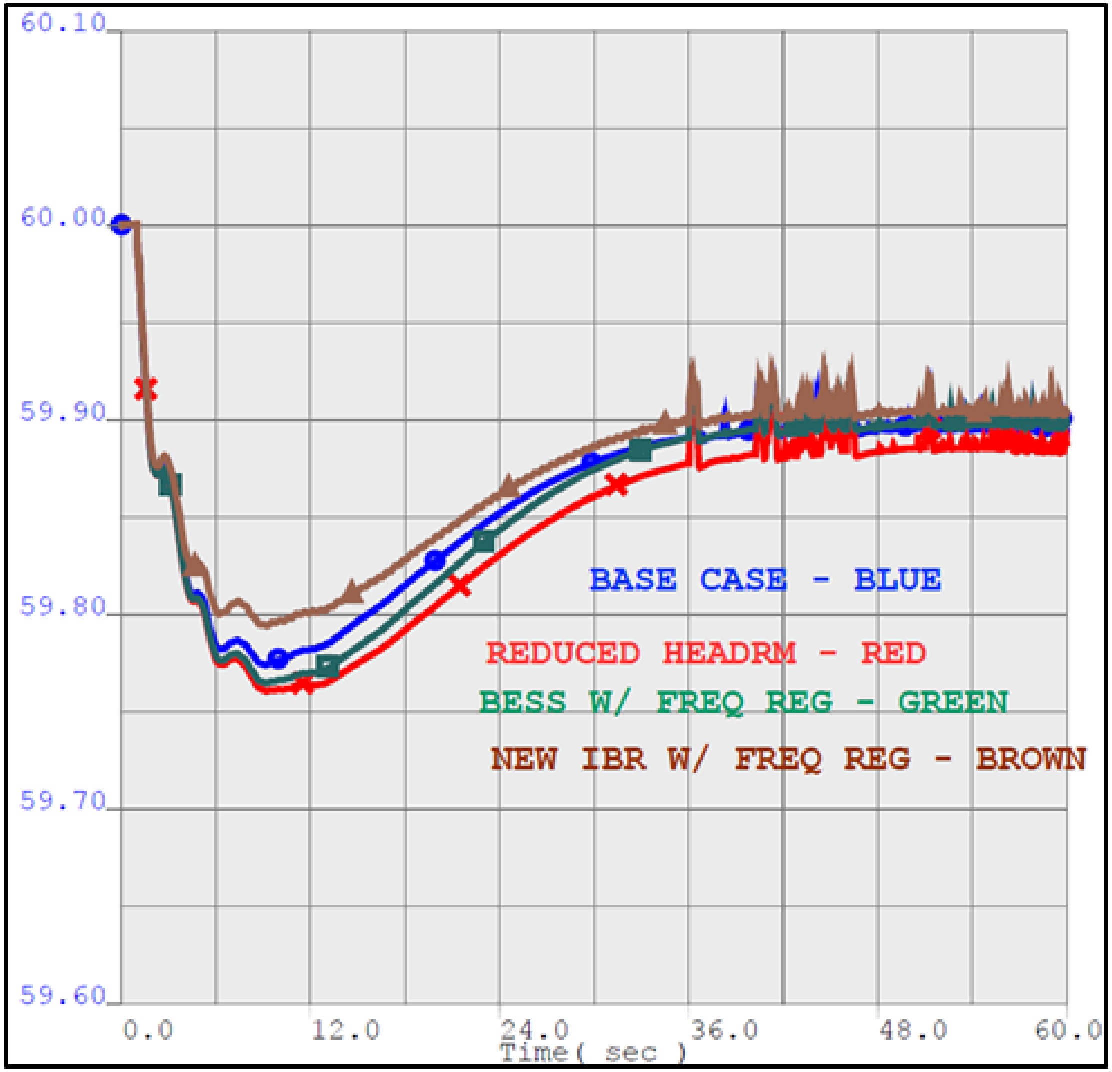
Study Results

- Outage of two Palo Verde units, simulation run for 60 seconds
- Frequency nadir and settling frequency

	2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Settling Frequency, Hz	59.889	59.884	59.897	59.904
Frequency Nadir, Hz	59.776	59.744	59.767	59.795

- It appeared that the frequency response is connected with the measure Kt - ratio of number of responsive generation to number of total generation. The higher is this ratio, the better is the system frequency response.

Frequency on the Midway 500 kV Bus

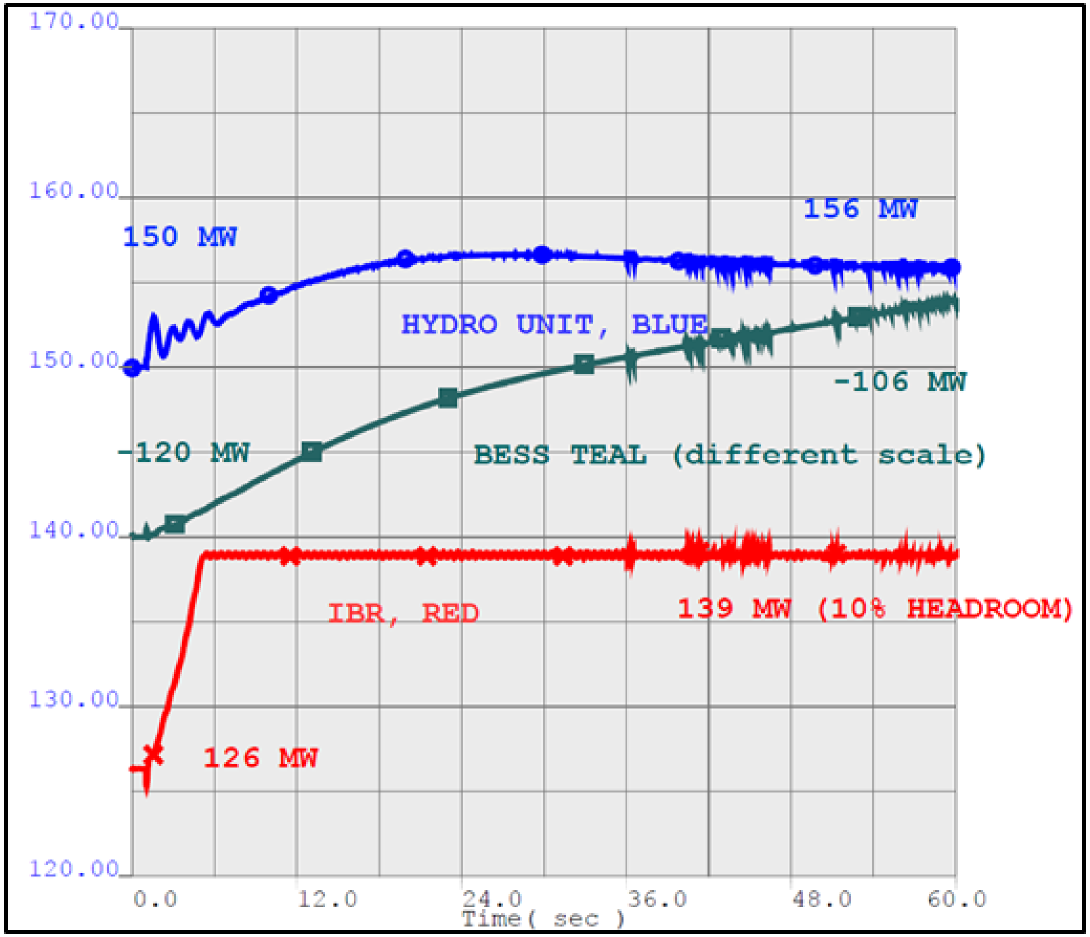


- The curves slope which depends on the system inertia appeared to be the same for all three cases.
- Having frequency response from the BESS and IBR improved frequency performance, and the improvement from the IBR response was more than the improvement from the BESS response.
- The frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz for all four cases

Headroom and Frequency Response in the Cases Studied

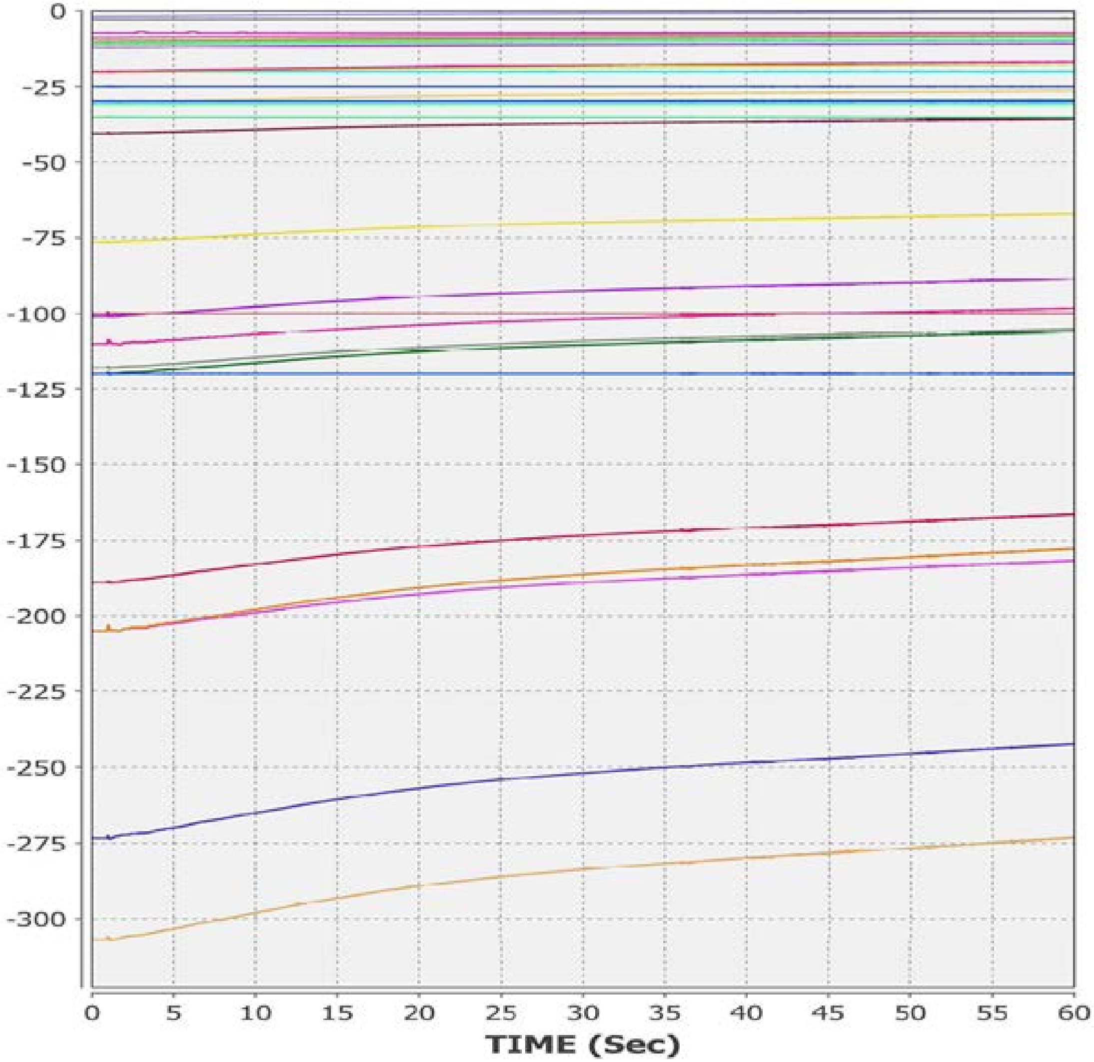
Case		2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Headroom, MW	ISO, incl. MUNI	**2,629**	**2,293**	**4,541**	**2,927**
	Total WECC	**15,021**	**11,641**	**13,722**	**12,351**
Responsive units	ISO, incl. MUNI	**141**	**131**	**161**	**201**
	Total WECC	**875**	**858**	**888**	**928**
Response, MW	ISO, incl. MUNI	**268**	**269**	**509**	**659**
	Total WECC	**2,607**	**2,438**	**2,535**	**2,533**
Response from Batteries, MW	WECC/ISO	**0**	**0**	**262**	**0**
Response from IBR, MW	WECC/ISO	**0**	**0**	**0**	**440**
Response, MW/0.1Hz	ISO, incl. MUNI	**241.5**	**231.7**	**494.4**	**686.0**
	Total WECC	**2,349**	**2,101**	**2,461**	**2,639**
FRO, MW/0.1 Hz	ISO, incl. MUNI	**257.4**			
	Total WECC	**858**			

Real Power Output from a Hydro Unit, BESS and IBR with Frequency Control



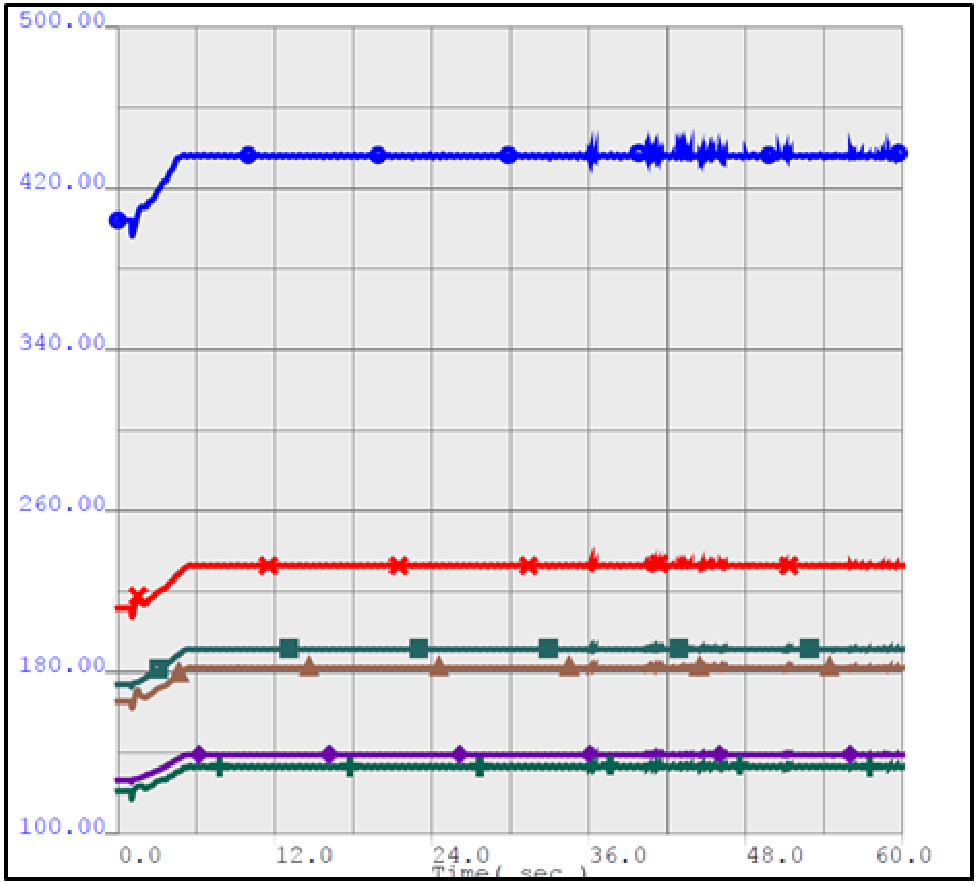
California ISO

Output of the BESS when BESS are Under Frequency Control

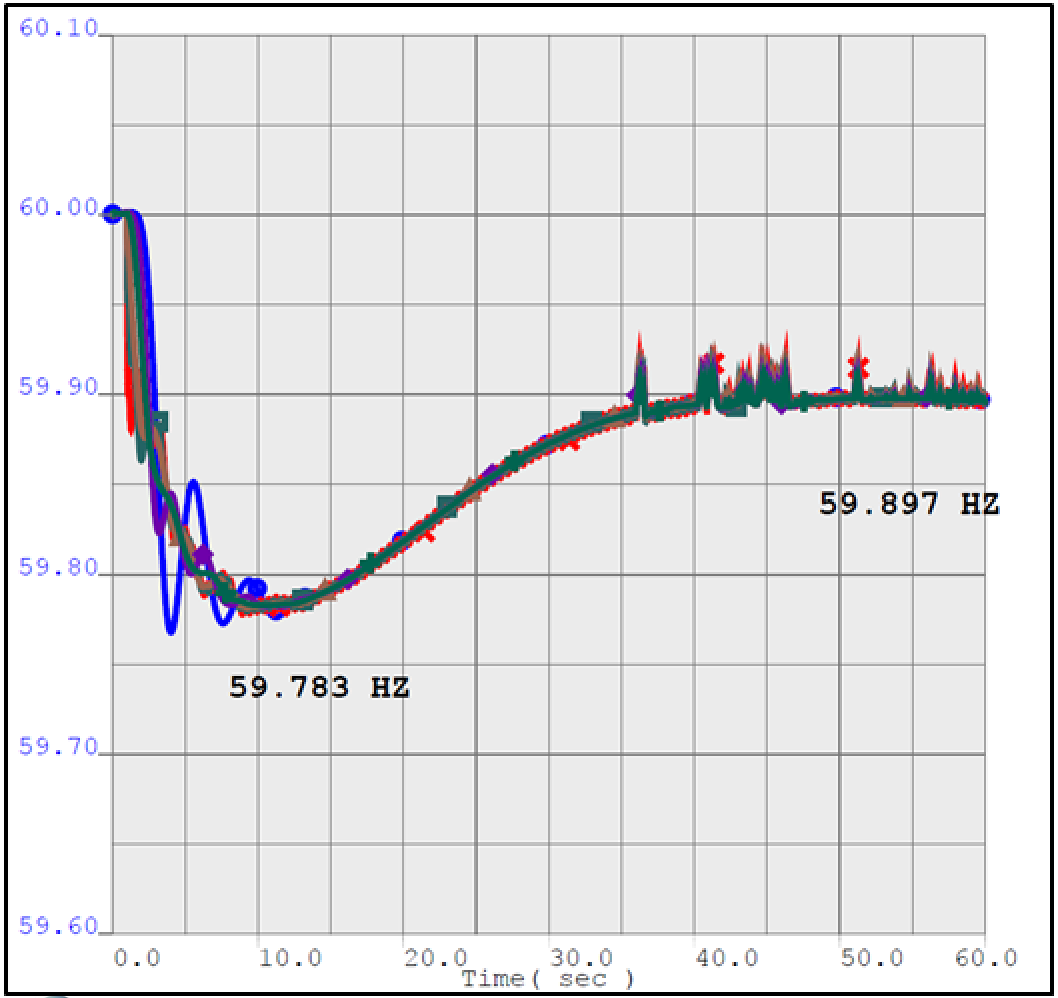


California ISO

Output of the Large IBR Units when they are under Frequency Control. 10% Headroom



Sensitivity Study. In the ISO, only IBR have frequency response. Frequency on 500 kV buses



- Study goal – to check if ISO can have 100% IBR and still meet the BAL-003 criteria
- The FRM for WECC was 2,507 MW/0.1 Hz and the for the ISO was 497 MW/0.1 Hz which is above the FRO
- For comparison, if other ISO units have frequency response, the FRM for WECC was 2,639 MW/0.1 Hz and for the ISO 686 MW/0.1 Hz

2020-2021 TPP Study Conclusions

- Acceptable frequency performance within WECC but not acceptable within the ISO for the base case (Spring Off-Peak of 2030). WECC FRM was above the FRO and the ISO FRM was slightly below the ISO FRO. The case with the reduced headroom had even lower ISO FRM, but WECC FRM was still well above its obligation.
- 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 available, especially in Canada and Northwest.

2020-2021 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, but the response from IBR appears to be more effective than the response from the BESS. The reason may be different parameters of the IBR and batteries, but this needs to be explored further.
- 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 at least 10% headroom and other generation in WECC has sufficient frequency response

Updating Generators Models

Generator Model Update

- The ISO added a section to the Tranmission Planning Process BPM regarding data collection (Section 10)
- Five categories of participating generators were developed based on size and interconnection voltage
- The ISO developed data templates for the generator owners to provide the data
- 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 by 2022.

Generator Data Template

- Generator data templates have been posted on the CAISO website. [1]

- 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.caiso.com/Pages/documentsbygroup.aspx?GroupID=95422303-C0DD-43DF-9470-5492167A5EC5

Next Steps

- The current efforts on the collecting and improving modeling data will continue. The WECC dynamic modeling database is being updated and it will continue to be updated as the responses from the generation owners are received.
- 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.
- More work on the BESS models is needed

2020-2021 TPP Wildfire Impact Assessment Results Update and Conclusion

Binaya Shrestha
Manager, Regional Transmission – North

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

Outline

- Study scope and objective
- Wildfire related information
- Study scenario development
- Study approach
- Additional scenarios assessed
- Scenario scope comparison
- Scenario results comparison
- Identification of critical facilities
- Conclusion

Identification of critical facilities

- The critical facilities are such that if excluded from the scope of PSPS scenario, the exclusion will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss
  - Scenario 4, Lines de-energized based upon October 26 2019 PSPS event conditions with PG&E's wildfire mitigations (10-26 PSPS-WFM), is used to determine critical facilities for each area.
  - Starting from the scenario 4 PSPS scope, each de-energized lines are energized one at a time and reduction in direct load loss is recorded.
  - The lines with the most amount of direct load loss reduction are reported as critical facilities.

Greater Bay Area – Scenario 4 result, critical facilities and conclusion

GBA Division	Scenario 4 PSPS Impact		Critical Facilities
	Direct Load Impact (MW)	System Performance Impact	
East Bay	0	Contingency analysis shows overloads in Peninsula 60 kV system.	N/A
Diablo	0		N/A
San Francisco	0		N/A
Peninsula	58		• Monta Vista-Jefferson #1 230 kV line and • Monta Vista-Jefferson #2 230 kV line
Mission	0		N/A
South Bay	3		• Monta Vista-Burns 60 kV line

- Exclusion of critical facilities from future PSPS scope would address 100% of direct load impact in Peninsula and South Bay divisions.
- TPP approved project is expected to alleviate the system performance issue in Peninsula 60 kV system.
- No new upgrades are required.

Humboldt –
Scenario 4 result, critical facilities and conclusion

Humboldt Division	Scenario 4 PSPS Impact		Critical Facilities
	Direct Load Impact (MW)	System Performance Impact	
Humboldt	130	Humboldt system isolated	• Bridgeville-Cottonwood 115 kV line and • Humboldt-Trinity 115 kV line

- Exclusion of critical facilities from future PSPS scope would address about 80% of direct load impact in Humboldt division.
- No new upgrades are required.

North Coast / North Bay – Scenario 4 result, critical facilities and conclusion

NCNB Division	Scenario 4 PSPS Impact		Critical Facilities
	Direct Load Impact (MW)	System Performance Impact	
North Coast	106	Contingency analysis identified one overload in Hopland and Mendocino 60 kV system and Hopland, Eagle Rock and Mendocino 115 kV system .	• Fulton-Pueblo 115 kV line • Eagle Rock-Fulton-Silverado 115 kV line • Sonoma-Pueblo 115 kV line • Windsor-Fitch Mountain 60 kV line and • Mendocino-Willits-Fort Bragg 60 kV line
North Bay	164		

- Exclusion of critical facilities from future PSPS scope would address about 81% direct load impact in North Coast and North Bay divisions.
- System performance issues will need to be re-evaluated after critical facilities are able to be excluded. Further work is also needed to determine load loss due to distribution line de-energization only.
- No new upgrades are recommended at this time.

North Valley – Scenario 4 result, critical facilities and conclusion

North Valley Division	Scenario 4 PSPS Impact		Critical Facilities
	Direct Load Impact (MW)	System Performance Impact	
North Valley	11	Contingency analysis identified one overload in Cottonwood 60 kV system.	• Centerville-Table Mtn-Oroville 60 kV line

- Exclusion of critical facilities from future PSPS scope would address about 25% of direct load impact in North Valley division.
- TPP approved project is expected to alleviate the system performance issue in Cottonwood 60 kV system.
- No new upgrades are required.

Central Valley –
Scenario 4 result, critical facilities and conclusion

CVLY Division	Scenario 4 PSPS Impact		Critical Facilities
	Direct Load Impact (MW)	System Performance Impact	
Sacramento	3	Contingency analysis identified no reliability concerns	• El Dorado-Missouri Flat #1 115 kV line • El Dorado-Missouri Flat #2 115 kV line • West Point-Valley Springs 60 kV line • Drum-Rio Oso #1 115 kV line and • Drum-Rio Oso #2 115 kV line
Sierra	161		
Stockton	43		

- Exclusion of critical facilities from future PSPS scope would address about 67% direct load impact in the Central Valley area.
- No new upgrades are required.

Greater Fresno Area– Scenario 4 result, critical facilities and conclusion

GFA Division	Scenario 4 PSPS Impact		Critical Facilities
	Direct Load Impact (MW)	System Performance Impact	
Yosemite	6	Contingency analysis identified no reliability concerns.	• Wishon-Coppermine 70 kV line
Fresno	13		

- Exclusion of critical facilities from future PSPS scope would address about 70% direct load impact in the Greater Fresno Area.
- No new upgrades are required.

Central Coast and Los Padres – Scenario 4 result, critical facilities and conclusion

CCLP Division	Scenario 4 PSPS Impact		Critical Facilities
	Direct Load Impact (MW)	System Performance Impact	
Central Coast	No impact		• N/A
Los Padres			

- No new upgrades are required.

California ISO

Conclusion

- The transmission issues are confined to direct load impact and no performance deficiencies identified in most areas for the plausible scenarios.
- Critical facilities in each areas have been identified.
- The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS events.
- With this no new upgrades were developed.

Policy-driven Assessment
Draft 2020-2021 Transmission Plan

Nebiyu Yimer
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2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

In the November presentation on the policy-driven assessment we presented

- Objectives of the policy-driven assessment
- Description of the base and two sensitivity portfolios studied
- Battery storage and resource retirement mapping steps and results for the sensitivity portfolios
- Deliverability assessment methodology and results
- Production cost simulation results (presented separately with the Economic Planning Study presentation)

In today's presentation we provide some updates that are included in the draft transmission plan including

- Transmission capability estimates and utilization by the three portfolios
- Transmission Plan Deliverability (TPD) values for use in updating transmission capability estimates
- Production cost simulation results for portfolios*
- PCM assessment of impact of Sensitivity 2 battery re-mapping on congestion and curtailment*
- PCM assessment of impact of transmission upgrades on Sensitivity 2 congestion and curtailment*
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Tx. capability estimates and utilization by portfolios

- For the Base Portfolio, resource totals are within the corresponding total FCDS and EODS limits with the exception of Greater Kramer Zone and Southern Nevada (GLW-VEA) Sub-zone
- For the sensitivity portfolios, resource totals exceed the corresponding total FCDS and applicable EODS limits in most zones and several sub zones
- The FCDS transmission capability estimates used by the CPUC in RESOLVE to develop the portfolios are based on the CAISO's previous deliverability methodology.
- As a result values tend to underestimate available FCDS transmission capability in particular for solar resources compared to the methodology implemented in 2020.
- As indicated in the Nov. presentation, the on-peak deliverability assessment showed almost all constraints can be addressed by re-locating battery storage or RAS, some of which are still under review.

Utilization of FCDS transmission capability estimates

Transmission zones and sub-zones	Estimated Existing System FCDS Capability Adjusted for New Baseline Resources (MW)	FCDS Resources in Portfolios (MW)		
		Base	Sensitivity-1	Sensitivity-2
Northern CA	**1,821**	**-**	**2,240**	**3,064**
- Round mountain	500	-	-	530
- Humboldt	-	-	-	-
- Sacramento River	1,901	-	866	866
- Solano	520	-	700	862
Southern PG&E	**394**	**146**	**2,742**	**2,388**
- Westlands	1,100	-	1,968	1,655
- Kern and Greater Carrizo	624	-	157	181
- Carrizo	400	-	287	187
- Central Valley North & Los Banos	670	146	330	365
Tehachapi	**4,155**	**725**	**3,934**	**3,972**
Greater Kramer (North of Lugo)	**500**	**554**	**1,524**	**1,738**
- North of Victor	300	-	1,326	1,537
- Inyokern and North of Kramer	-	554	959	1,109
- Pisgah	400	-	100	104
Southern CA Desert and Southern NV	**2,273**	**1,640**	**6,618**	**9,111**
- Eldorado/Mtn Pass (230 kV)	250	102	120	164
- Southern NV (GLW-VEA)	624	700	740	739
- Greater Imperial	1,095	604	600	919
- Riverside East & Palm Springs	2,404	234	5,050	4,791
Total	**9,143**	**3,065**	**17,058**	**20,273**

Utilization of EODS transmission capability estimates

Transmission zones and sub-zones	Estimated Existing System EODS Capability Adjusted for New Baseline Resources , (MW)		FCDS + EODS Resources in Portfolios (MW)		
	Original	Relaxed	Base	Sensitivity-1	Sensitivity-2
Northern CA	**3,721**	**3,721**	**643**	**2,274**	**4,146**
- Round mountain	2,100	2,100	-	-	1,500
- Humboldt	100	100	-	34	34
- Sacramento River	4,501	4,501	-	866	866
- Solano	1,220	1,220	643	700	940
Southern PG&E	**TBD**	**4,474**	**306**	**2,945**	**6,468**
- Westlands	TBD	3,200	-	2,026	2,155
- Kern and Greater Carrizo	TBD	3,804	-	302	3,061
- Carrizo	400	1,100	160	287	887
- Central Valley North & Los Banos	TBD	670	146	330	365
Tehachapi	**4,955**	**5,955**	**1,153**	**4,734**	**5,371**
Greater Kramer (North of Lugo)	**500**	**500**	**554**	**1,524**	**1,738**
- North of Victor	300	300	-	1,326	1,537
- Inyokern and North of Kramer	-	-	554	959	1,109
- Pisgah	400	400	-	100	104
Southern CA Desert and Southern NV	**8,873**	**12,533**	**6,354**	**8,900**	**17,654**
- Eldorado/Mtn Pass (230 kV)	2,400	4,040	425	203	164
- Southern NV (GLW-VEA)	624	2,094	700	740	2,500
- Greater Imperial	2,995	2,995	1,256	1,148	1,672
- Riverside East & Palm Springs	4,954	5,504	2,092	6,206	7,641
Total	**18,443**	**27,183**	**9,010**	**20,377**	**35,377**

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Transmission Plan Deliverability (TPD)

- The TPD values (next slides) provide an estimate of the on-peak generation deliverability supported by the existing system and approved upgrades beyond existing and contracted resources
- The values are based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. Queue clusters up to and including queue cluster 13 were considered.
- Two values are provided: deliverable interconnection service capacity amount, which is dependent on the specific resource mix studied, as well as deliverable study amount, which is independent of the resource mix studied
- The relationship between the generation interconnection service capacity and the study amount is shown in the table below

Area	HSN		SSN	
	Solar	Wind	Solar	Wind
SDG&E	3.0%	33.7%	40.2%	11.2%
SCE	10.6%	55.7%	42.7%	20.8%
PG&E	10.0%	66.5%	55.6%	16.3%
For non-intermittent generation – 100% of NQC, Energy storage – 4-hour capacity				

TPD values - Southern CA

Area Deliverability Constraint	Renewable Zones	Deliverable Study Amount (MW)	Deliverable Interconnection Service Capacity (MW)
GLW-VEA Area Constraint	Southern_Nevada	500	790
Eldorado transformer constraint	Southern_Nevada Eldorado/Mountain Pass (230kV)	3,360	3700
Colorado River transformer constraint	Riverside_Palm_Springs	2,110	1,628
Devers – Red Bluff constraint	Riverside_Palm_Springs, Arizona	5,400	7,808
Serrano – Alberhill – Valley constraint	Riverside_Palm_Springs, Arizona, Imperial	7,110	10,342
Lugo transformer constraint	Inyokern_North_Kramer	950	1,250
Kramer- Victor/Roadway -Victor South of Kramer flow limit	Inyokern_North_Kramer	200	325
Victor-Lugo South of Kramer flow limit	Inyokern_North_Kramer	530	980
Windhub transformer constraint	Tehachapi	3,080	3,970
Antelope – Vincent flow limit	Tehachapi, Non-CREZ – Big Creek	4,040	4,950
Laguna Bell – Mesa flow limit	Non-CREZ – Ventura	1,208	1208
South of Magunden flow limit	Non-CREZ – Big Creek	670	710
East of Miguel constraint	Arizona, Imperial, Baja, Riverside	1,335	1,969
Encina-San Luis Rey constraint	Arizona, Imperial, Baja, Non-CREZ	2,901	3,479
Imperial Valley transformer constraint	Imperial	1,959	2,106
San Luis Rey-San Onofre constraint	Arizona, Imperial, Baja, Non-CREZ	1,748	1,886
SDGE – Internal Area constraint	Imperial, Non-CREZ	968	968
Silvergate-Bay Boulevard constraint	Imperial, Baja, Non-CREZ	1,202	1,438
Oceanside constraint	Non-CREZ	280	280

TPD values - Northern CA

Area Deliverability Constraint	Renewable Zones	Deliverable Study Amount (MW)	Deliverable Interconnection Service Capacity (MW)
Gates Bank 500/230kV #13	Carrizo	3,151	4,220
Wilson-Storey-Borden #1 & #2 Lines 230kV lines	Westlands	113	200
Tesla-Westley 230kV line	Westlands and Carrizo	1,098	1,381
GWF Hanford Sw Sta-Contadina-Jackson Sw Sta 115kV lines	Westlands	146	153
New Diablo-Midway #4 500 kV Line	Westlands and Carrizo	13,888	19,258
Gates-Panoche #1 and #2 230kV lines	Westlands	8,851	11,011
Vierra-Tracy-Kasson 230kV line	Northern California	149	151
Melones-Tulloch 230kV line	Non-CREZ	126	129
Rio Oso-SPI-Lincoln 230V line	Non-CREZ	42	46
Q653F-Davis 230kV lines	Northern California	64	64
Los Banos 500/230kV TB	Westlands	2,356	3,103
Gates-Midway 500kV Line	Westlands and Carrizo	TBD	TBD
Contra Costa-Delta Switchyard 230kV line	Non-CREZ	TBD	TBD
Morro Bay-Templeton 230kV Line	Carrizo	TBD	TBD
Delevan-Cortina 230kV line	Northern California	TBD	TBD

Use of TPD values for updating FC Tx. capacity estimates used in RESOLVE

- CAISO intends to use the TPD information as an input for updating the FC Tx. capacity estimates used in RESOLVE (https://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf)
- Our current thinking is to use the TPD study amounts, which are independent of the resource mix, as linear equations of the form

$$TxCapFCDS = \textbf{Deliverable study amount for a zone} = \sum \boldsymbol{f_i} * R_i$$

Where: - TxCapFCDS is the FCDS Transmission capability estimate for the zone

- R_i is the MW amount of FC resource i selected in the zone and

- f_i is the corresponding study amount factor for the resource type and location per the current deliverability methodology

- Resources counted in the TPD calculation will be similarly subtracted when they achieve commercial operation
- CAISO will consult the CPUC to confirm the approach can be implemented in RESOLVE

In this presentation we provide some updates that are included in the draft transmission plan including

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Policy-driven assessment overall conclusions

- No policy-driven upgrades were identified. The conclusion assumes all previously approved projects modeled in the studies proceed as planned
- 1,464 MW of battery storage in Sensitivity 1 and 3,287 MW in Sensitivity 2 was found to be undeliverable without tx upgrades. Almost all other FCDS resources in the portfolios were found to be deliverable with RAS, where needed.
- Off-peak deliverability constraints resulted in 830 MW and 378 MW of curtailment in Gridliance/VEA and Greater Carizzo Zone, respectively. Transmission upgrades may be needed unless resources are re-mapped. No other major issues were identified.
- PCM results indicate 15%, 11% and 17% total curtailment for the Base, Sensitivity 1 and Sensitivity 2 portfolios, respectively. Battery re-mapping and transmission upgrades studied for Sensitivity-2 show some reduction in congestion and curtailment.

Economic Assessment and Production Cost Simulation
Draft 2020-2021 Transmission Plan

Yi Zhang
Senior Advisor, Transmission Infrastructure Planning

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

Summary of key steps since November stakeholder session database development

- Continued to update the Planning PCMs
  - SPS associated with SDG&E Silvergate-Bay Blvd constraint
  - Additional PG&E contingencies
  - Additional VEA contingencies and SPS
  - ADS PCM hydro model update
- Finished study request evaluation
- Posted PCM cases on the CAISO's MPP
- Simulation software version
  - Hitachi ABB GridView 10.3.1

Base Portfolio - summary of congestions

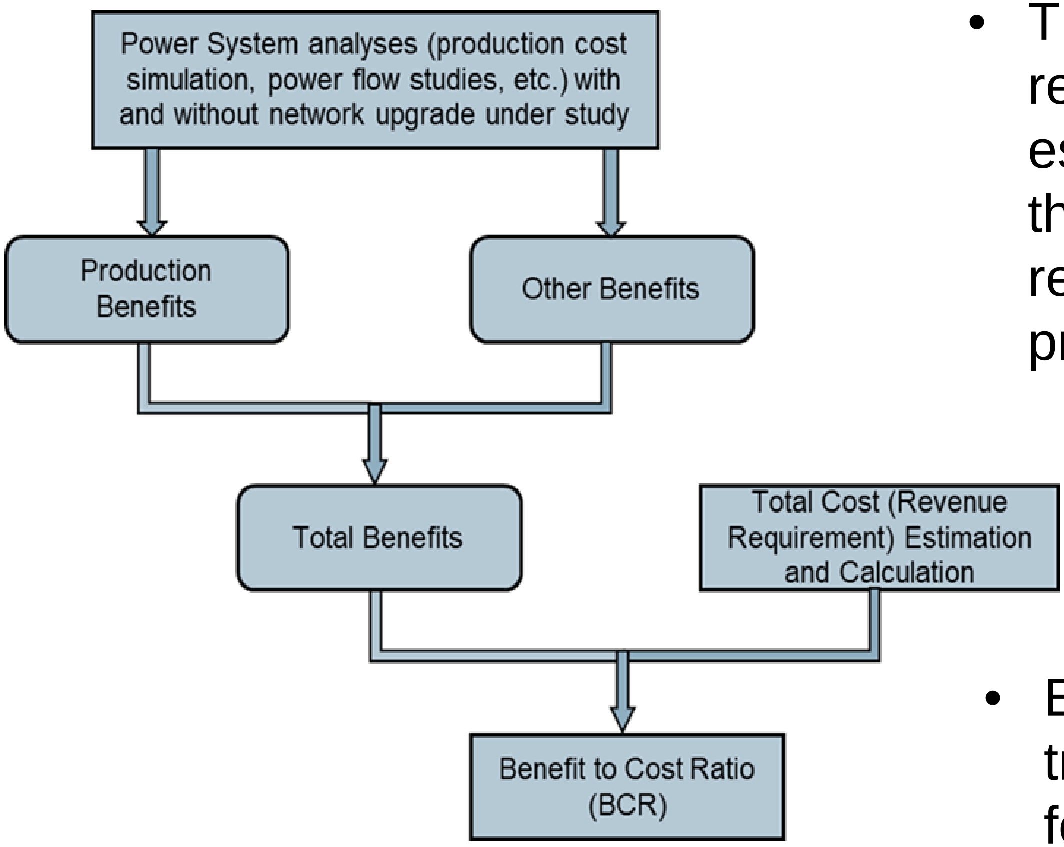
No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	SDGE DOUBLTTP-FRIARS 138 kV	52.74	2,749
2	SCE Whirlwind Transformer	22.91	295
3	COI Corridor	12.96	329
4	PDCI	8.95	562
5	PG&E Fresno	8.64	4,520
6	Path 45	7.80	1,453
7	Path 26 Corridor	6.74	237
8	PG&E Sierra	6.30	439
9	SCE LCIENEGA-LA FRESA 230 kV line	3.59	84
10	SCE RedBluff-Devers 500 kV	3.42	33
11	Path 60 Inyo-Control 115 kV	3.35	1,666
12	SCE NOL-Kramer-Inyokern-Control	3.23	266
13	Path 25 PACW-PG&E 115 kV	2.81	486
14	SCE Antelope 66 kV system	2.77	1,008
15	Path 42 IID-SCE	2.26	71
16	SDGE IV-San Diego Corridor	0.95	45
17	SCE J.HINDS-MIRAGE 230 kV line	0.65	80
18	SCE LagunaBell-Mesa Cal	0.64	21
19	SDGE-CFE OTAYMESA-TJI 230 kV line	0.45	107
20	Path 61/Lugo - Victorville	0.38	41
21	San Diego	0.35	155
22	San Diego Silver Gate-Bay Boulervard	0.28	20
23	SCE Lugo 500 kV Transformer	0.18	5
24	SCE Devers 500/230 kV transformer	0.13	2
25	Path 15/CC	0.10	8
26	PG&E Mosslanding -Lasguilass 230 kV	0.10	7

- Only listed congestions with congestion cost greater than $0.1 million per year. 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 Silver Gate – Bay Blvd congestion.

Constrained areas selected for detailed investigation and economic assessment

Constraints	Cost (M$)	Duration (Hours)	Overview of congestion investigation
SDG&E DOUBLTTP-FRIARS 138 kV line	52.74	2,749	SDG&E Doublet Tap – Friars 138 kV line congestion has the largest congestion cost among congestions identified in this planning cycle.
SCE Whirlwind 500/230 kV Transformers	22.91	295	About 4000 MW of renewable generators were modeled behind the Whirlwind 500/230 kV transformers constraint in the base portfolio PCM
COI Corridor	12.96	329	COI congestion slightly increased in this planning cycle The changes in transmission and renewable assumptions in the Northern Grid territory contributed to the COI congestion.
PG&E Fresno area constraints	8.64	4,520	Congestions were observed on multiple lines in the PG&E Fresno area, with relatively high congestion cost and duration. Some are recurring congestions.
Path 26 corridor south to north congestion	6.74	273	Path 26 congestion was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio

Technical approach of economic study



- The CC-to-RR multiplier for revenue requirement (total cost) estimation is used for estimating the present value of the revenue requirement of transmission project
  - Revenue requirements =1.3*Capital Cost
  - This multiplier is used for screening purposes
- Economic life: 50 years for new transmission facilities; 40 years for upgraded transmission facilities

SDG&E Doublet Tap – Friars 138 kV congestion

- Congestion was observed under contingency condition.
  - The critical contingency is the N-2 contingency of the SDG&E Sycamore – Penasquitos and Penasquitos – Old Town 230 kV lines
  - Flow was from Friars to Doublet Tap
- SPS of tripping generators in the Otay Mesa area was modeled associated with the N-2 contingency.
  - This SPS was proposed in the generation interconnection study
- The congestion cost is $52.74 million per year, total congestion hours are 2,749

Occurrences of Doublet Tap – Friars congestion

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

Otay Mesa area generation average hourly output

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0	0	0	0	0	0	0	10	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	-3	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	4	0	0	0	0	0
7	0	0	13	0	0	0	18	31	0	0	0	0
8	0	24	16	0	0	0	16	28	0	0	0	7
9	0	25	0	0	0	0	16	7	0	0	0	8
10	0	0	0	-4	-1	0	5	0	-5	-3	-3	0
11	-19	-18	-46	-97	-149	-71	-60	-54	-113	-96	-154	-23
12	-154	-172	-250	-250	-257	-214	-138	-173	-193	-225	-230	-139
13	-218	-194	-261	-269	-265	-229	-143	-211	-182	-236	-226	-195
14	-209	-199	-256	-269	-254	-215	-125	-181	-141	-214	-226	-177
15	-179	-164	-259	-261	-215	-183	-97	-139	-87	-157	-192	-134
16	-100	-105	-152	-129	-62	-104	-41	-42	-18	-56	-13	-21
17	21	-3	-2	-5	0	-10	-8	33	80	62	103	99
18	188	98	85	28	111	46	37	151	240	190	199	171
19	227	192	237	247	225	181	192	366	622	376	193	254
20	224	214	254	303	256	251	492	666	702	421	237	209
21	158	215	206	268	241	403	575	695	626	359	202	157
22	95	132	174	267	164	333	503	567	495	277	95	119
23	25	84	83	92	44	179	383	508	182	56	10	91
24	5	17	2	23	23	92	38	65	21	16	0	34

San Diego import east to west average hourly flow

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	88,807	79,808	81,406	79,290	75,394	78,009	86,922	88,994	83,335	81,409	84,433	89,085
2	85,273	76,841	75,936	76,615	68,754	70,208	82,333	86,072	78,263	76,004	79,799	86,462
3	81,103	73,429	70,769	73,523	61,369	63,637	78,523	82,944	74,679	71,055	73,864	82,336
4	78,039	71,135	68,595	72,108	59,658	60,400	75,433	81,279	72,742	69,391	69,908	80,026
5	76,354	69,911	68,418	71,909	61,110	61,578	75,565	81,007	72,631	70,650	68,514	78,603
6	76,201	70,701	73,572	75,898	66,523	68,187	78,266	83,555	76,183	76,050	70,062	78,145
7	78,907	73,315	78,729	78,543	72,392	73,088	80,324	85,387	81,062	82,084	74,346	80,328
8	83,570	76,058	82,363	76,212	71,770	76,979	81,196	86,947	82,426	86,121	78,222	83,839
9	88,171	76,835	75,649	64,415	66,044	75,020	78,246	84,208	76,433	81,595	70,979	85,905
10	74,075	66,160	64,393	54,684	57,925	72,170	70,095	74,787	67,291	70,772	60,663	76,515
11	62,208	55,493	54,390	48,033	52,133	67,773	67,025	65,996	61,477	62,827	52,815	62,449
12	55,369	54,046	52,419	44,021	47,710	65,346	66,871	63,058	60,149	60,142	50,322	56,735
13	51,322	49,124	45,519	39,018	44,518	62,123	67,323	62,441	60,320	55,426	46,605	54,496
14	48,368	47,830	42,255	36,643	44,778	61,027	66,903	63,976	63,532	54,580	44,965	52,669
15	48,335	45,101	42,545	37,174	45,665	61,679	67,757	65,442	67,486	55,526	45,634	52,783
16	50,225	46,774	40,416	36,062	45,169	60,311	66,849	66,730	71,473	59,048	44,392	52,408
17	53,767	49,625	41,860	39,655	51,944	61,592	69,981	70,241	76,434	66,324	55,251	62,747
18	65,976	61,459	52,426	50,819	61,221	66,816	76,055	75,612	78,830	76,022	73,111	78,418
19	87,692	76,018	72,689	61,416	73,110	72,931	78,681	76,334	76,341	86,849	88,934	90,182
20	90,517	80,903	87,671	76,032	82,425	78,326	77,841	75,655	81,679	91,121	88,188	92,680
21	90,793	81,124	89,041	79,652	87,439	87,503	83,039	83,114	86,297	92,391	87,849	92,827
22	90,806	81,438	87,712	77,819	84,644	87,441	85,151	85,810	85,559	89,905	88,396	92,445
23	91,133	80,763	86,169	79,646	84,537	84,389	86,182	85,698	87,895	89,164	87,819	91,361
24	90,536	80,855	84,023	78,288	77,239	78,377	89,517	91,274	86,170	86,270	86,190	90,875

- Congestion as flow is from Friars to Doublet Tap is more in phase with the San Diego import flow
- The Otay Mesa area generation contribute to the Friars to Doublet Tap flow mainly in the evening

Doublet Tap – Friars congestion - three mitigation alternatives

- Alternative 1 - Expand the previously proposed SPS to trip generators in the ECO and Imperial Valley areas
  - The total tripped generation is less than the 1400 MW limit for N-2 contingency as required by the CAISO's Planning Standard.
- Alternative 2 - Reconductoring the Doublet Tap – Friars 138 kV line with increased rating of 320 MVA, which was proposed in the CAISO's generation interconnection study
- Alternative 3 - Rearrange the Penasquitios – Old Town 230 kV line to eliminate the N-2 contingency

Doublet Tap – Friars congestion - congestion and curtailment results with mitigation

	Base case		Alternative 1 – Expended SPS		Alternative 2 - Reconductoring		Alternative 3 – Rearrangement	
Congestion	$M	Hours	$M	Hours	$M	Hours	$M	Hours
Doublet Tap - Friars 138 kV	52.74	2,749	5.47	378	0	0	0	0
Wind and Solar	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)
CAISO Total	75,051	13,595	75,072	13,575	75,072	13,575	75,066	13,581

Doublet Tap – Friars congestion – production cost benefit

	Base case	Alternative 1 – Expanded SPS		Alternative 2 - Reconductoring		Alternative 3 – Rearrangement	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
CAISO load payment	7,954	7,961	-6	7,949	6	7,944	10
CAISO generator net revenue benefiting ratepayers	3,554	3,583	29	3,579	26	3,579	25
CAISO transmission revenue benefiting ratepayers	268	230	-39	226	-42	227	-42
CAISO Net payment	4,132	4,148	-16	4,143	-11	4,139	-7
WECC Production cost	13,213	13,169	44	13,157	56	13,153	60

Doublet Tap – Friars congestion – summary and conclusion

- None of the three alternatives showed economic benefit to the CAISO's ratepayers
- The CAISO does not recommend these alternatives for approval as economic-drive projects in this planning cycle
- Further evaluation may be conducted in future planning cycles with additional clarity of renewable development and SPS implementation in the SDG&E system

SCE Whirlwind transformer congestion

- Wind and solar generators connected to the Whirlwind 230 kV bus are the main driver of the Whirlwind transformer congestion

Generator Type	Capacity (MW)
Battery Storage	10
Wind	333
Solar	3,715
Total	4,058

- There are three 500/230 kV transformers at the Whirlwind substation, each with a 1120 MVA normal rating

Whirlwind transformer congestion – mitigation alternatives

- Alternative 1 - Add 1170 MW of battery storage at Whirlwind 230 kV bus
  - The 1170 MW is the maximum available deliverability at Whirlwind 230 kV, considering the generators that were already modeled in the base portfolio case
- Alternative 2 - Add the fourth transformer in the Whirlwind substation

Whirlwind transformer congestion – congestion and curtailment results with mitigation

	Base case		Alternative 1 – 1170 MW battery at Whirlwind 230 kV		Alternative 2 – The Fourth Whirlwind transformer	
Congestion	$M	Hours	$M	Hours	$M	Hours
Whirlwind transformer	22.91	295	9.35	165	0	0
Wind and Solar	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)
CAISO Total	75,051	13,595	76,633	12,014	75,108	13,538

- Adding the fourth Whirlwind transformer is sufficient to mitigate the congestion
- Adding battery is more effective in reducing renewable curtailment than adding a new transformer.

Whirlwind transformer congestion – production cost benefit

	Base case	Alternative 1 – 1170 MW battery at Whirlwind 230 kV		Alternative 2 – The Fourth Whirlwind transformer	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
CAISO load payment	7,954	8,049	-94	7,962	-8
CAISO generator net revenue benefiting ratepayers	3,554	3,611	57	3,571	17
CAISO transmission revenue benefiting ratepayers	268	261	-7	253	-15
CAISO Net payment	4,132	4,177	-45	4,138	-6
WECC Production cost	13,213	13,223	-10	13,220	-7

Whirlwind transformer congestion – Compare Alternative 1 to a Reference case with battery at Lugo

- The Alternative 1 case was also assessed against a reference case that has the additional 1170 MW of battery capacity modeled at the Lugo 500 kV bus
- Essentially, the potential benefits of remapping battery storage from other unconstrained locations to the Whirlwind 230 kV bus were assessed
  - The Lugo 500 kV bus is not in any congested areas

Whirlwind transformer congestion – Compare Alternative 1 to a Reference case (cont.) - curtailment

- Compared these two cases, battery storage can help to reduce renewable curtailment regardless the location of the battery storage
- The Alternative 1 case has less renewable curtailment than the reference case because battery at the Whirlwind 230 kV bus is effective to reduce the curtailment in the local area

	Base case		Reference Case - 1170 MW battery at Lugo 500 kV		Alternative 1 – 1170 MW battery at Whirlwind 230 kV	
Wind and Solar	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)
CAISO Total	75,051	13,595	76,563	12,084	76,633	12,014

Whirlwind transformer congestion – Compare Alternative 1 to a Reference case (cont.) - benefit

	Reference Case	Alternative 1	Alternative 1 Savings compared with Reference Case 1
	$M	$M	$M
CAISO load payment	8,066	8,049	18
CAISO generator net revenue benefiting ratepayers	3,612	3,611	-1
CAISO transmission revenue benefiting ratepayers	280	261	-19
CAISO Net payment	4,174	4,177	-3
WECC Production cost	13,225	13,223	3

- Remapping battery storage to a highly congested area with high renewable curtailment can help to reduce congestion and renewable curtailment
- There were still no production benefits for CAISO ratepayers found with the batteries remapped to the Whirlwind 230 kV bus

Whirlwind transformer congestion - conclusion

- Both alternatives, adding 1170 MW of battery and adding a transformer, can mitigate the congestion on the Whirlwind transformers,
- However they don’t have economic benefit to the CAISO’s ratepayers based on the TEAM perspective.
- Therefore, the CAISO does not recommend either of these alternatives for approval as economic-driven projects in this planning cycle
- Further evaluation will be conducted in a future planning cycle once there is more clarity in the battery storage development picture in the CAISO controlled grid from the CPUC’s IRP.

COI corridor congestion

- COI corridor congestion includes congestions on Path 66 (COI) and its downstream lines
- Most COI corridor congestion was from the Path 66 flow binding at the path rating or the derated path rating due to scheduled maintenance

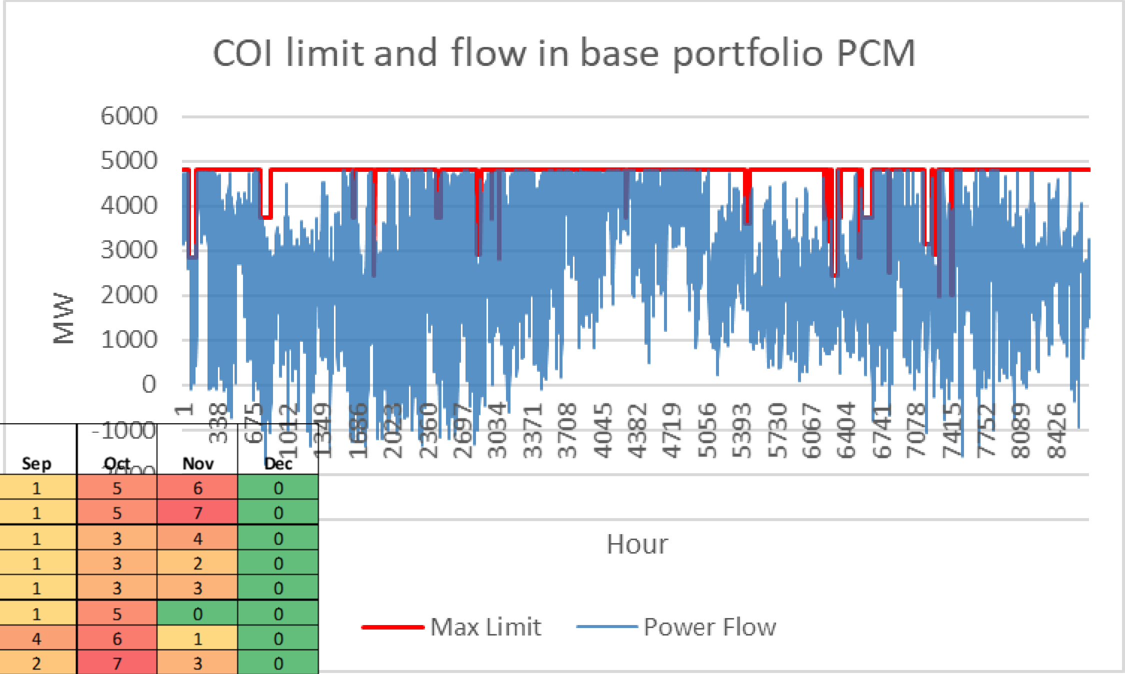
Constraints	Costs ($M)	Duration (Hrs)
P66 WECC COI	8.85	259
Table Mountain – Tesla 500 kV line	2.56	27
Table Mountain – Vaca Dixon 500 kV line	0.59	7
Round Mountain – Table Mountain 500 kV line	0.97	38

COI corridor congestion – reasons for doing detailed study

- The COI corridor congestion observed in this planning cycle did not significantly increase compared with the congestion in the previous planning cycles
- The COI corridor congestion and the potential mitigation was reinvestigated, due to the transmission and resource modeling changes in the ADS PCM 2030
  - Resource assumption changes in the Northern Grid areas and in the NVE areas
  - Transmission model changes in the Northern Grid areas – the B2H Project and the additional 500 kV segments of the Gateway West Project

Path 66 congestion

Path 66 derate due to scheduled maintenances based on the data provided by COI facility owners



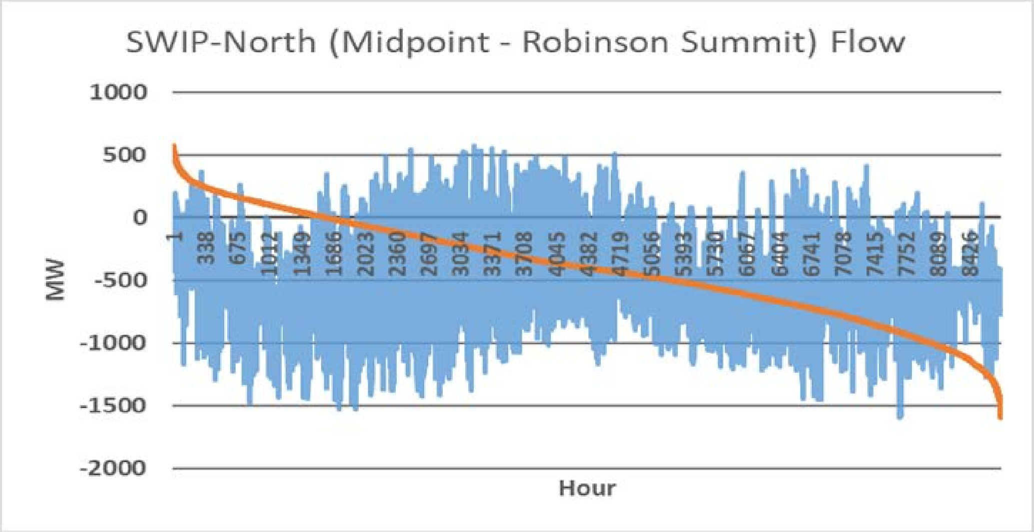
Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2	1	2	1	0	0	1	0	1	5	6	0
2	3	1	2	2	0	0	1	1	1	5	7	0
3	3	0	1	0	0	0	2	2	1	3	4	0
4	1	0	1	1	0	0	1	0	1	3	2	0
5	1	0	1	0	0	0	1	1	1	3	3	0
6	1	0	2	0	0	0	1	1	1	5	0	0
7	1	0	2	1	2	0	3	0	4	6	1	0
8	2	0	1	0	1	2	4	0	2	7	3	0
9	1	0	0	0	1	2	0	0	1	5	1	0
10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

There are total 118 hours in October and November when COI congestion was observed, which is partially attributed to the PDCI scheduled maintenance

COI corridor congestion – mitigation alternative

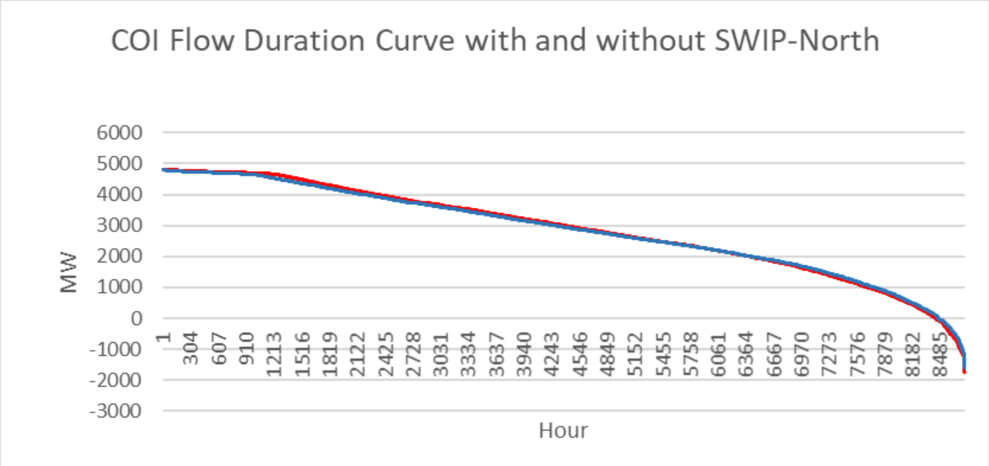
- SWIP-North project was studied as a mitigation alternative for the COI corridor congestion.
  - Was proposed to build a new 500 kV line between the Idaho Power's Midpoint 500 kV bus and the Nevada Energy's Robinson Submit 500 kV bus.
  - Was submitted as an economic study request and an Interregional Transmission Process (ITP) project as well in this planning cycle.

COI corridor congestion – SWIP North flow and its impact on COI flow

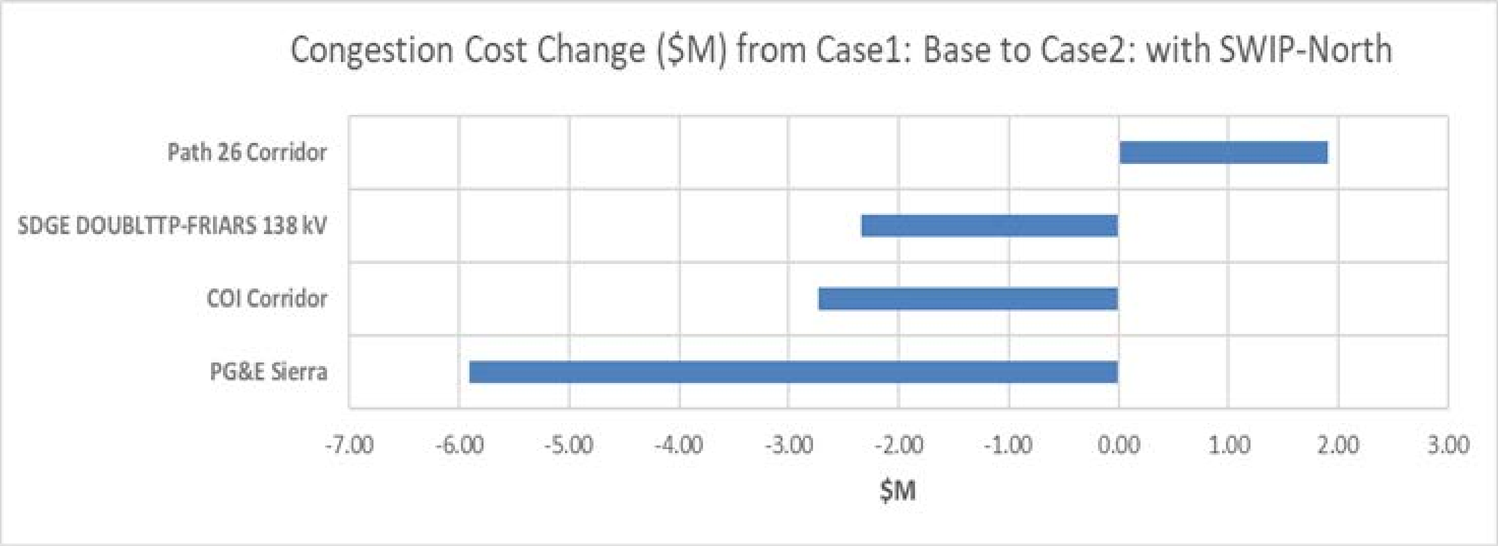


- SWIP North flow from south to north was observed in more hours than the flow from north to south.
- Flow magnitude from south to north can be as high as 1500 MW, which is also higher than the flow magnitude from north to south, which is less than 600 MW.

- Not expected that the SWIP-North project would impact COI flow too much - COI flow duration curves with and without SWIP-North project are very close to each other
- the SWIP-North flow from north to south can help to mitigate COI corridor congestion

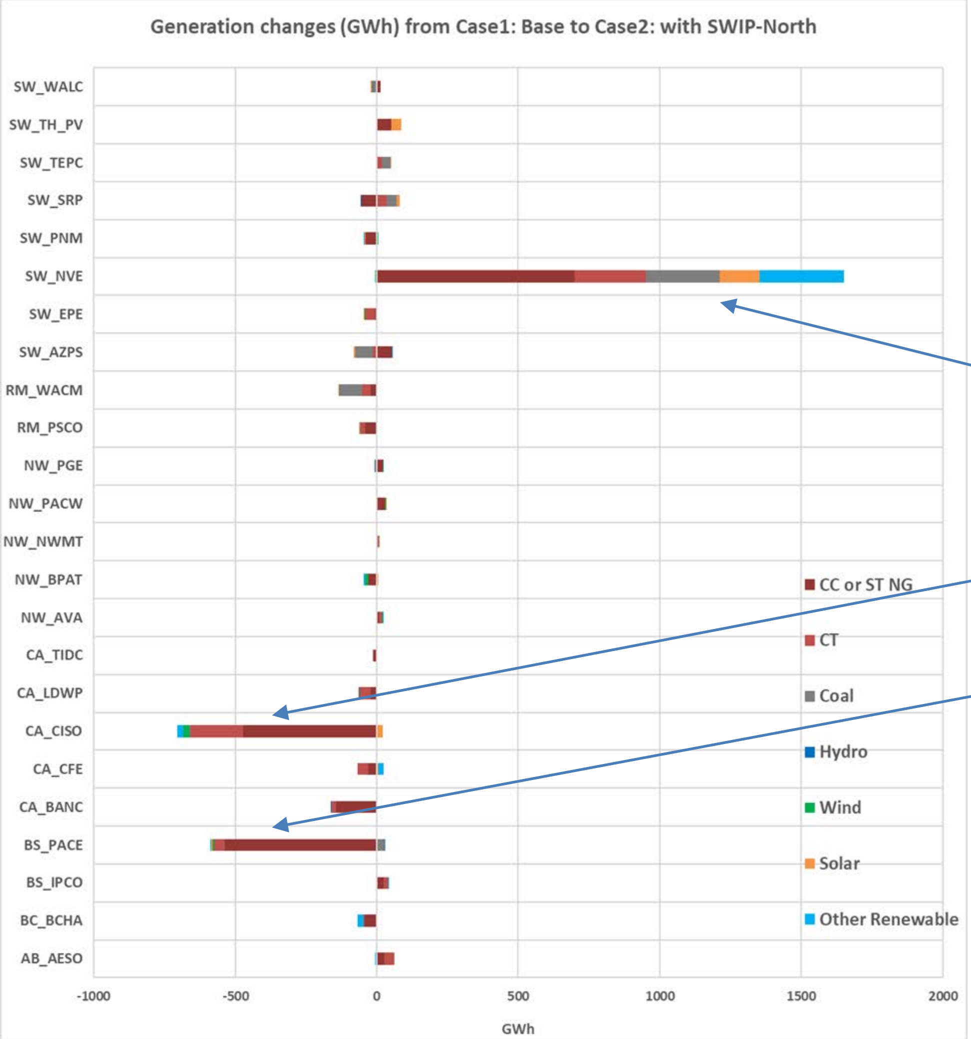


COI corridor congestion – congestion and curtailment with SWIP–North



- PG&E Sierra area congestion reduced because the loop flow through the NVE Sierra area to the PG&E Valley area was mitigated
- The Path 26 congestion increased because the Path 26 flow from south to north was aggravated when the SWIP-North flow was from Midpoint to Robinson Summit
- The increased flow injection into southern California by the SWIP-North project can provide counter flow to mitigate the congestion on the SDG&E's Doublet Tap – Friars 138 kV line

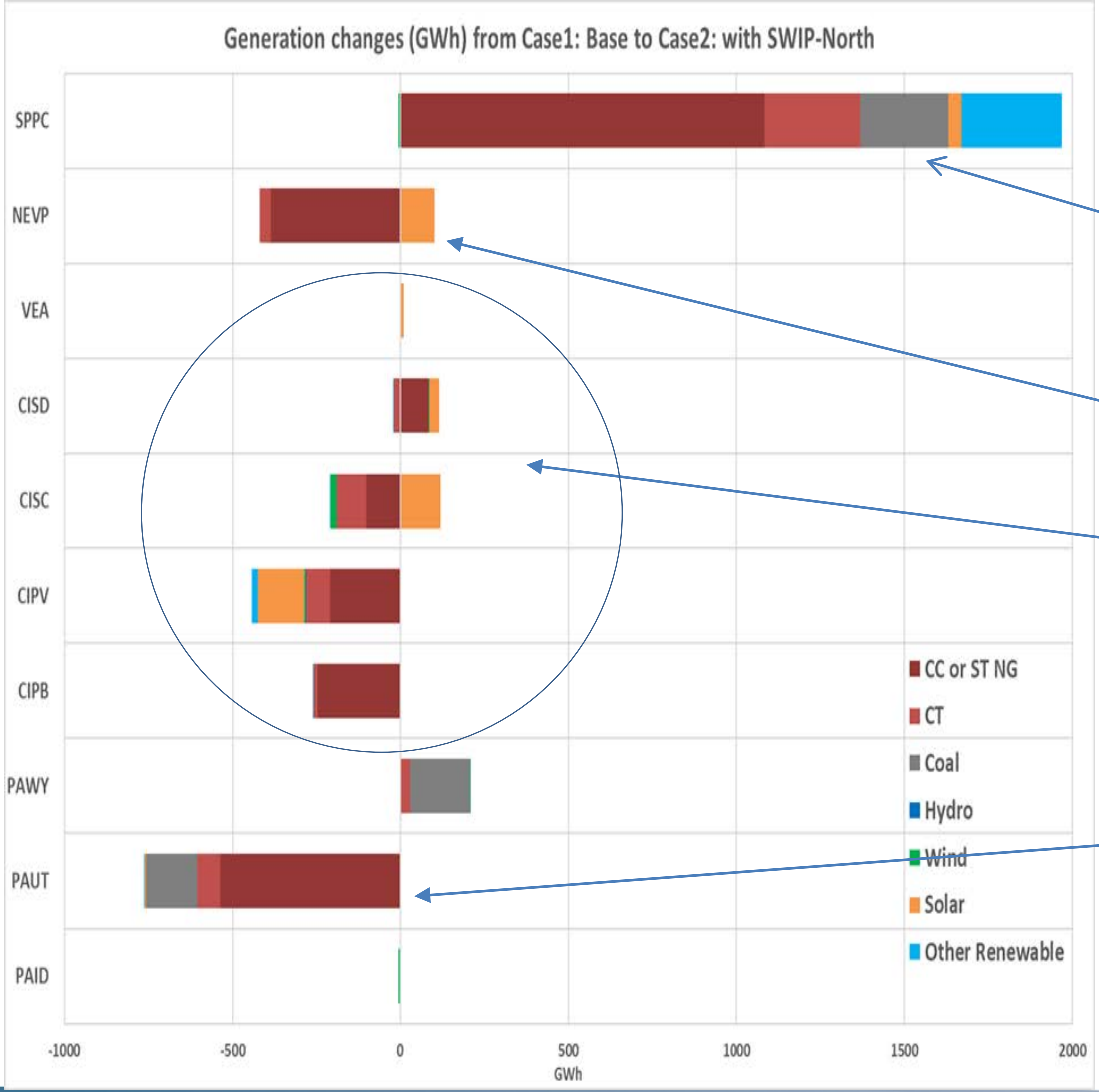
COI corridor congestion – generation dispatch change with SWIP-North



- The SWIP-North project impacts generation dispatch in all three planning regions
- The largest generation increase was in the SW_NVE region, which is the Nevada Energy BAA (NVE).
- The generation outputs in the CAISO region (CA_CISO) and the PacifiCorp East region (BS_PACE) had the largest decrease.
- Majority of generation changes in these regions were from thermal generators.

California ISO

COI corridor congestion – generation dispatch change with SWIP-North (cont.)



- The largest generation increase happened in the NVE's Sierra area (SPPC), but the total generation in the southern NV area (NEVP) decreased
- The CAISO overall renewable generation increased slightly
- The largest generation decrease happened in the PacifiCorp Utah area

COI corridor congestion – production cost benefit of SWIP-North project

	Pre project ($M)	Post project ($M)	Savings ($M)
CAISO load payment	7,954	7,904	51
CAISO generator net revenue benefiting ratepayers	3,554	3,520	-34
CAISO transmission revenue benefiting ratepayers	268	262	-6
CAISO Net payment	4,132	4,122	10
WECC Production cost	13,213	13,178	35

- Capacity benefit was not assessed in this planning cycle. It requires
    - Clarity of the CPUC's assumption for out of state resources
    - Coordination with planning regions to identify potential impacts on the CAISO's import capability

SWIP-North project	
Production cost savings ($million/year)	10.10
Capacity saving ($million/year)	0
Capital cost ($million)	543
Discount Rate	7%
PV of Production cost savings ($million)	149
PV of Capacity saving ($million)	0
Total benefit ($million)	149
Total cost (Revenue requirement) ($million)	706
Benefit to cost ratio (BCR)	0.21

- $10 million production benefit to CAISO ratepayers per year

COI corridor congestion and SWIP-North - summary

- COI congestion can be reduced by the SWIP-North Project
- The SWIP-North Project impacts the generation dispatch across the Western Interconnection
- The SWIP-North Project has BCR at 0.21, not sufficient to be an economic-driven project
- Also under assessment in the ITP by the CAISO and other planning regions

PG&E Fresno area congestion

Constraints Name	Costs _F (K$)	Duration _F (Hrs)	Costs_ B (K$)	Duration _B (Hrs)	Costs T (K$)	Duration _T (Hrs)
LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	4,831	1,365	4,831	1,365
Q526TP-PLSNTVLY 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	1,469	634	0	0	1,469	634
KETLMN T-GATES 70.0 kV line #1	1,056	1,354	0	0	1,056	1,354
FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	842	863	34	1	876	864
HELM 70.0/230 kV transformer #1	339	294	0	0	339	294

PG&E Fresno area congestion - observations

- Most of the congestions in the PG&E's Fresno area were observed during the daytime, especially within the solar hours
  - Indicates that the solar generation in the Fresno area were the main driver of these congestion.
- In addition, congestions were observed more frequently in the summer months than in the winter months, because
  - Local load is higher in summer
  - Summer rating is lower
    - Except for the Helms transformer, which has the same winter and summer ratings

PG&E Fresno congestion – mitigations

Constraints Name	Mitigation
LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	SPS
Q526TP-PLSNTVLY 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	SPS
KETLMN T-GATES 70.0 kV line #1	Reconductoring
FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	SPS
HELM 70.0/230 kV transformer #1	Transformer upgrade

- Reconductoring the Kettleman Hills Tap – Gates 70 kV line and upgrading the Helm transformer can completely mitigate the congestion on the line and the transformer, respectively
- The SPS alternatives can only partially mitigate the respective congestions.
  - Only trip the generators most effective to the congestions
  - Tripping generators in adjacent areas may further reduce the congestions, but requires to evaluate the feasibility and the potential impact on the reliability of the study area

PG&E Fresno area congestion – production cost benefit

- Only calculated the production cost benefit of the reconductoring and transformer upgrade

	Base case	Reconductoring Kettleman Hills Tap to Gates		Upgrading Helm transformer	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
CAISO load payment	7,954	7,957	-2	7,953	1
CAISO generator net revenue benefiting ratepayers	3,554	3,555	1	3,554	0
CAISO transmission revenue benefiting ratepayers	268	268	0	268	0
CAISO Net payment	4,132	4,133	-1.04	4,131	0.82
WECC Production cost	13,213	13,214	-1	13,217	-4

PG&E Fresno area congestion – economic assessment

- Only calculated the BCR of the Helm transformer upgrade
  - Capital cost was estimated at $10 M, which was translated to the total cost at $13 M by multiplying the 1.3 CC-to-RR ratio
- BCR is 0.9
- Not sufficient for approval as an economic-driven project

PG&E Fresno Helm 70/230 kV transformer Upgrade	
Production cost savings ($million/year)	0.82
Capacity saving ($million/year)	0
Capital cost ($million)	10
Discount Rate	7%
PV of Production cost savings ($million)	12
PV of Capacity saving ($million)	0
Total benefit ($million)	12
Total cost (Revenue requirement) ($million)	13
Benefit to cost ratio (BCR)	0.90

Path 26 corridor congestion

- Congestion on Path 26 corridor was observed mainly when the flow was from south to north, except for the congestion on the Midway – Vincent 500 kV line
- Renewable generators 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 its congestion

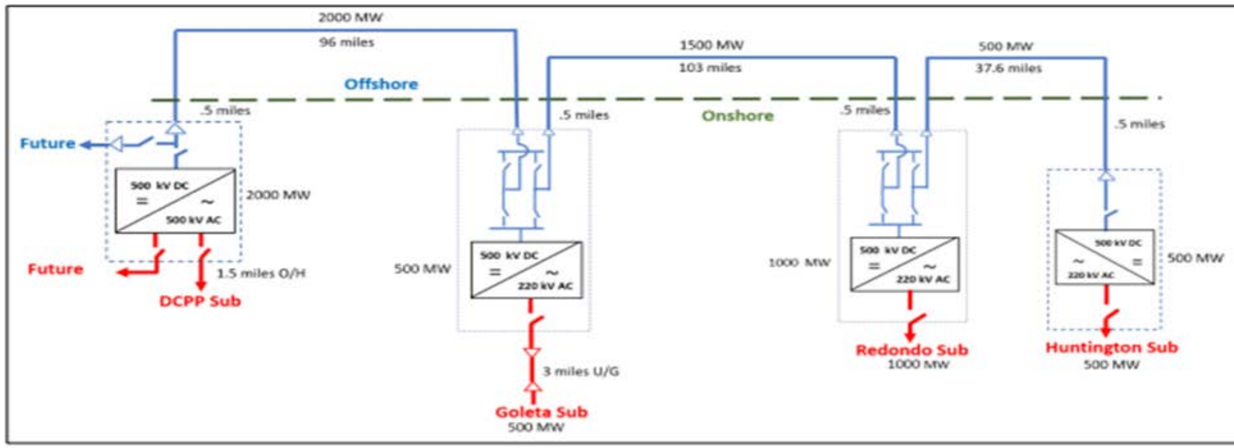
Constraints Name	Congestion Costs ($M)	Congestion Duration (Hrs)
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	3.81	77
P26 WECC Northern-Southern California	2.87	154
MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	0.055	6

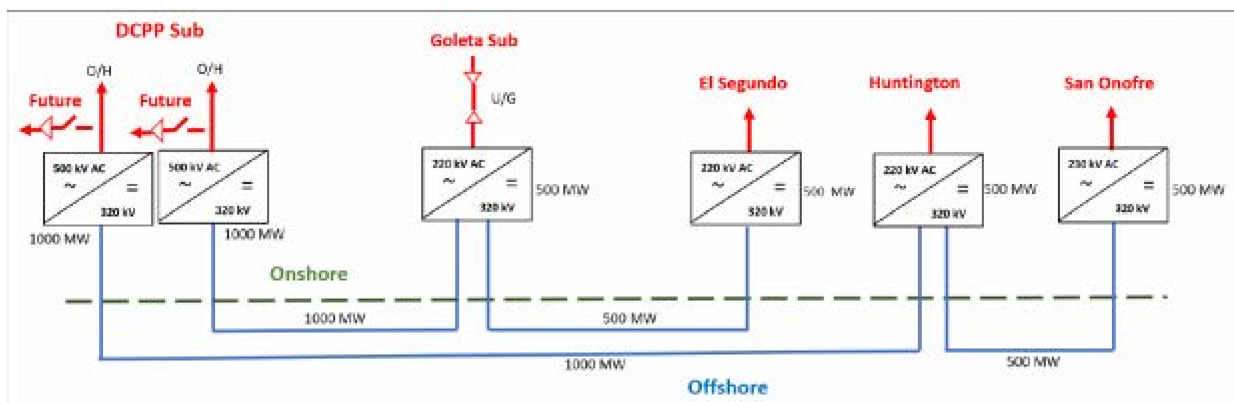
Path 26 corridor congestion – mitigation with the PTE HVDC project

- Two options were proposed for the PTE project

- The HVDC lines provide parallel path to Path 26

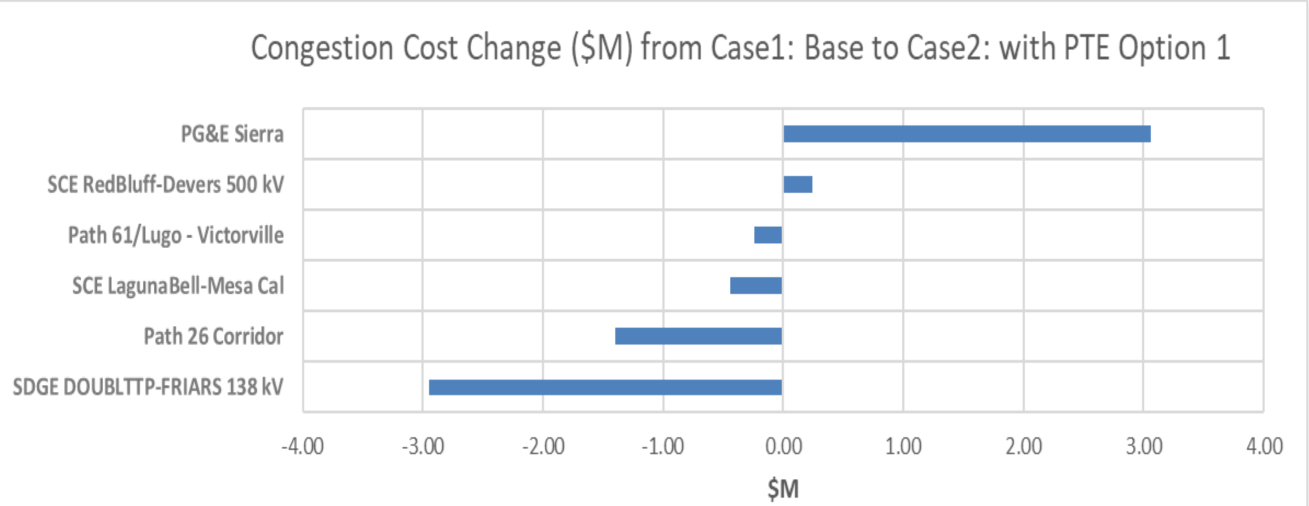
- This project was also studied in local capacity reduction assessment for the Big Creek/Ventura area and Western LA Basin area



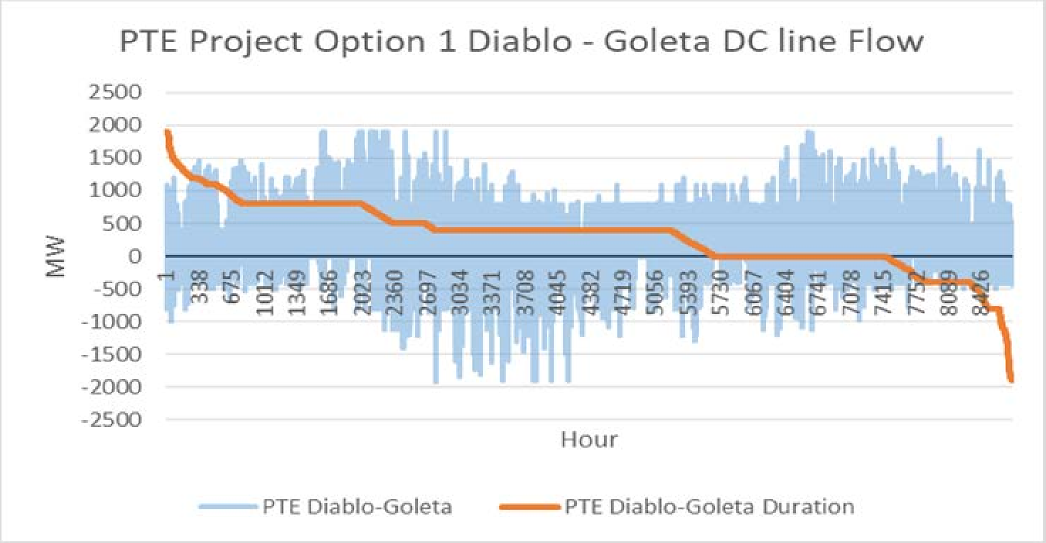


Path 26 corridor congestion – PTE Option 1 results

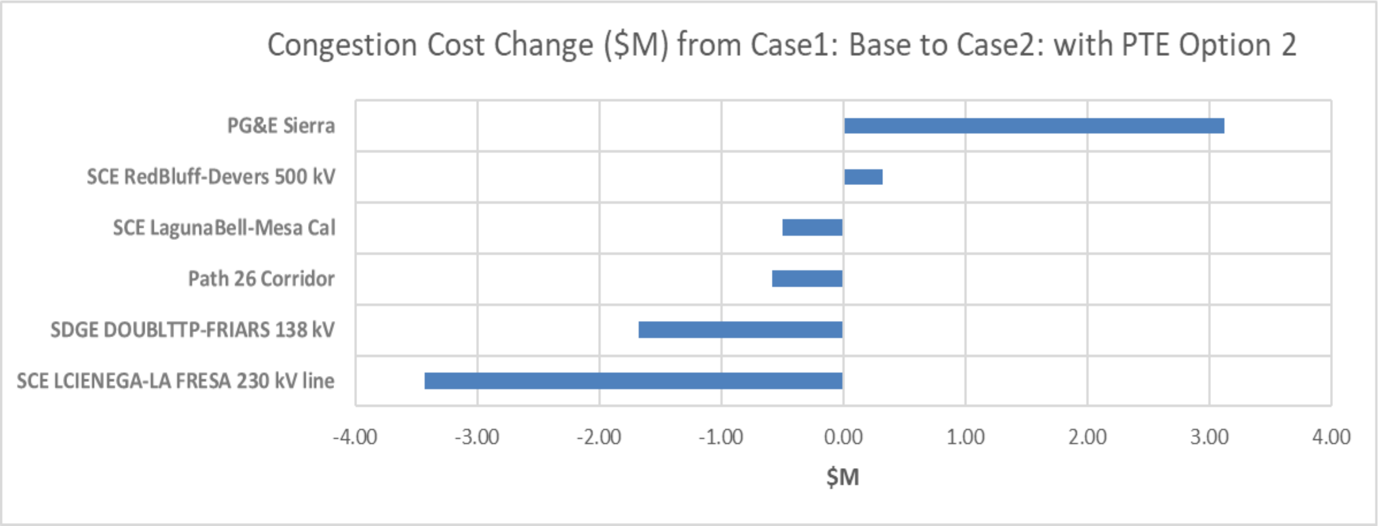
- Path 26 corridor congestion did not reduce significantly compared with the study results for the PTE project in the last planning cycle



- 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 1228 hours with the PTE Option 1 modeled, from the 237 congestion hours in the base PCM



Path 26 corridor congestion – PTE Option 2



- The Option 2 has less impact on the Path 26 corridor congestion than the Option 1 because the Option 2 has a 1000 MW HVDC line between the PG&E's Diablo and the SCE's Goleta substations, but the Option 1 has a 2000 MW HVDC line
- Both options can mitigate congestions in the San Diego and the Western LA Basin areas

Path 26 corridor congestion – PTE project production cost benefit

	Base case	Option 1		Option 2	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
CAISO load payment	7,954	7,986	-32	7,988	-33
CAISO generator net revenue benefiting ratepayers	3,554	3,572	18	3,574	20
CAISO transmission revenue benefiting ratepayers	268	267	-1	267	-1
CAISO Net payment	4,132	4,147	-15	4,147	-15
WECC Production cost	13,213	13,219	-6	13,210	3

- Neither option showed benefit to the CAISO's ratepayers
- The PTE project was also studied in the LCR reduction study

Summary of economic studies

- Economic assessments were conducted for five congested areas in 2020-2021 planning cycle
  - Nine congested lines or transmission corridors/paths
  - 12 mitigation alternatives
- No transmission upgrade was recommended for approval as economically driven upgrade in this planning cycle

Production cost simulation results for Policy Assessment

Production cost simulation in policy assessments

- The base portfolio PCM and the two sensitivity portfolio PCMs were simulated to evaluate the congestion and renewable curtailment in the CAISO controlled grid
- Compared with the Base portfolio PCM case, the congestion changes in the sensitivity portfolio cases were mainly attributed to the resource capacity and location changes

Policy assessment congestion results – all three portfolios

No.	Aggregated congestion	Base		Sensitivity 1		Sensitivity 2	
		Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)
1	SDGE DOUBLTTP-FRIARS 138 kV	52.74	2,749	72.73	3,417	53.87	2,461
2	SCE Whirlwind Transformer	22.91	295	74.74	892	38.72	730
3	COI Corridor	12.96	329	25.00	484	47.26	748
4	PDCI	8.95	562	5.52	494	8.43	773
5	PG&E Fresno	8.64	4,520	11.59	5,526	9.55	5,134
6	Path 45	7.8	1,453	12.25	1,572	10.31	1,233
7	Path 26 Corridor	6.74	237	4.67	170	12.1	428
8	PG&E Sierra	6.3	439	2.83	251	3.5	247
9	SCE LCIENEGA-LA FRESA 230 kV line	3.59	84	4.54	294	12.15	293
10	SCE RedBluff-Devers 500 kV	3.42	33	1.55	33	0.51	29
11	Path 60 Inyo-Control 115 kV	3.35	1,666	4.24	2,059	4.05	2,275
12	SCE NOL-Kramer-Inyokern-Control	3.23	266	2.52	1,666	5.93	2,864
13	Path 25 PACW-PG&E 115 kV	2.81	486	2.59	473	7.13	875
14	SCE Antelope 66 kV system	2.77	1,008	5.19	1,730	3.03	1,472
15	Path 42 IID-SCE	2.26	71	0.00	0	0.34	12
16	SDGE IV-San Diego Corridor	0.95	45	1.57	84	1.83	85
17	SCE J.HINDS-MIRAGE 230 kV line	0.65	80	3.12	318	0.45	36
18	SCE LagunaBell-Mesa Cal	0.64	21	10.95	111	17.05	343
19	SDGE-CFE OTAYMESA-TJI 230 kV line	0.45	107	1.21	221	3.12	528
20	Path 61/Lugo - Victorville	0.38	41	1.11	92	1.96	96
21	San Diego	0.35	155	0.37	576	0.26	814
22	San Diego Silver Gate-Bay Boulervard	0.28	20	0.17	6	0.03	2
23	SCE Lugo 500 kV Transformer	0.18	5	0.00	6	0	1
24	SCE Devers 500/230 kV transformer	0.13	2	1.23	109	7.3	369
25	Path 15/CC	0.1	8	0.00	0	0	0
26	PG&E Mosslanding -Lasguilass 230 kV	0.1	7	0.85	149	1.57	495
27	PG&E Cottle - Melones 230 kV	0.06	9	0.00	0	0	0
28	PG&E Gates-CAIFLATSSS 230 kV	0.05	3	0.00	0	0	0
29	**PG&E USWP JRW-Cayetano 230 kV**	**0.05**	**4**	**0.03**	**5**	**0**	**3**
30	PG&E/Sierra MARBLE transformer	0.04	6	0.03	5	0	5
31	PG&E POE-RIO OSO	0.03	17	0.11	14	0.08	12
32	SCE Serrano-Villa PK 230 kV	0.03	1	0.00	0	0	0
33	VEA	0.03	66	0.07	94	13.67	2,480
34	PG&E North Valley	0.01	1	0.02	2	0	0
35	PG&E Solano	0.01	2	0.02	1	0	0
36	SDGE N.Gila-Imperial Valley 500 kV	0.01	1	0.63	18	0.88	33
37	SDGE-CFE IV-ROA 230 kV line and IV PFC	0.01	2	0.22	52	0.05	26
38	SCE Sylmar - Pardee 230 kV	0	1	0.00	0	0	1
39	PG&E Delevn-Cortina 230 kV	0	1	0.04	2	0.01	1
40	Path 15 Corridor	0	0	0.07	16	0.05	17
41	Path 24 PG&E-NVE Sierra	0	0	0.00	0	0.01	1
42	Path 41 Sylmar transformer	0	0	0.11	7	0.25	13
43	Path 46 WOR	0	0	0.00	0	0.08	2
44	Path 52 Silver Peak-Control 55 kV	0	0	0.00	3	0	0
45	PG&E Carrizo	0	0	0.00	0	27.59	4,519
46	PG&E CC Sub 230 kV transformer	0	0	0.01	119	0.38	1,124
47	PG&E Kelso - Ralph 230 kV	0	0	0.00	0	0	7
48	PG&E Kern	0	0	0.00	0	8.74	1,783
49	PG&E Marshlanding-C.Costa	0	0	0.00	0	0.01	14
50	PG&E Tesla 500 kV Transformer	0	0	0.17	14	0.03	36
51	PG&E VacaDixon - TESLA 500 kV	0	0	0.01	3	0.44	22
52	SCE Pardee-Vincent 230 kV	0	0	0.00	0	0.05	2
53	SCE Antelope - Pardee 230 kV	0	0	0.04	2	0.11	15
54	SCE Ivanpah-MtnPass	0	0	0.00	0	0	1
55	SCE Vincent 500 kV Transformer	0	0	0.09	4	8.34	115
56	SCE Windhub 500 kV transformer	0	0	0.51	28	0.27	20
57	SCE-LADWP Eldorado - McCullough 500 kV	0	0	0.00	0	0.4	7
58	SDGE Sanlusry-S.Onofre 230 kV	0	0	0.00	3	0.03	11

Policy assessment curtailment results

	Base			Sensitivity 1			Sensitivity 2		
Zone	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio
SCE Tehachapi	20,451	4,378	18%	27,641	5,192	16%	26,838	7,447	22%
PG&E Carrizo	1,871	645	26%	2,821	631	18%	7,206	3,971	36%
PG&E Fresno-Kern	7,420	1,565	17%	11,508	1,891	14%	11,294	2,692	19%
SCE EOL	7,349	1,190	14%	4,492	269	6%	16,052	2,527	14%
VEA	1,779	107	6%	1,836	49	3%	4,319	1,884	30%
NM	832	166	17%	2,458	488	17%	5,877	1,551	21%
AZ	2,223	1,174	35%	6,535	1,580	19%	4,311	1,342	24%
NW	5,915	457	7%	5,999	374	6%	10,593	834	7%
SCE NOL	2,792	511	15%	3,203	207	6%	2,579	383	13%
SCE Eastern	10,403	2,264	18%	8,172	379	4%	8,182	369	4%
SDGE IV	5,041	607	11%	8,248	316	4%	7,818	249	3%
SCE Vestal	672	154	19%	735	90	11%	683	142	17%
ID	346	52	13%	350	48	12%	336	62	16%
PG&E Solano	5,016	94	2%	4,912	45	1%	4,903	54	1%
PG&E N. CA	1,032	25	2%	3,363	46	1%	3,163	43	1%
CO	186	33	15%	189	30	14%	180	39	18%
IID	707	75	10%	766	16	2%	747	34	4%
SCE Others	271	48	15%	299	20	6%	289	29	9%
SDGE San Diego	246	34	12%	264	16	6%	263	17	6%
AB	473	11	2%	479	6	1%	473	11	2%
SCE Ventura	27	5	17%	30	3	9%	28	5	15%
Total	75,051	13,595	15%	94,298	11,695	11%	116,133	23,686	17%

Policy assessment curtailment results (cont.)

- Changes in the assumptions for renewable resources and battery storages are the key factors for the curtailment changes
- Additional renewable capacity in some zones resulted in incremental renewable curtailment in sensitivity portfolios cases
- However, renewable curtailment may reduce in some zones as the battery storages also increased
  – For example, SCE Eastern area and SDG&E IV area

Sensitivity 2 battery re-mapping

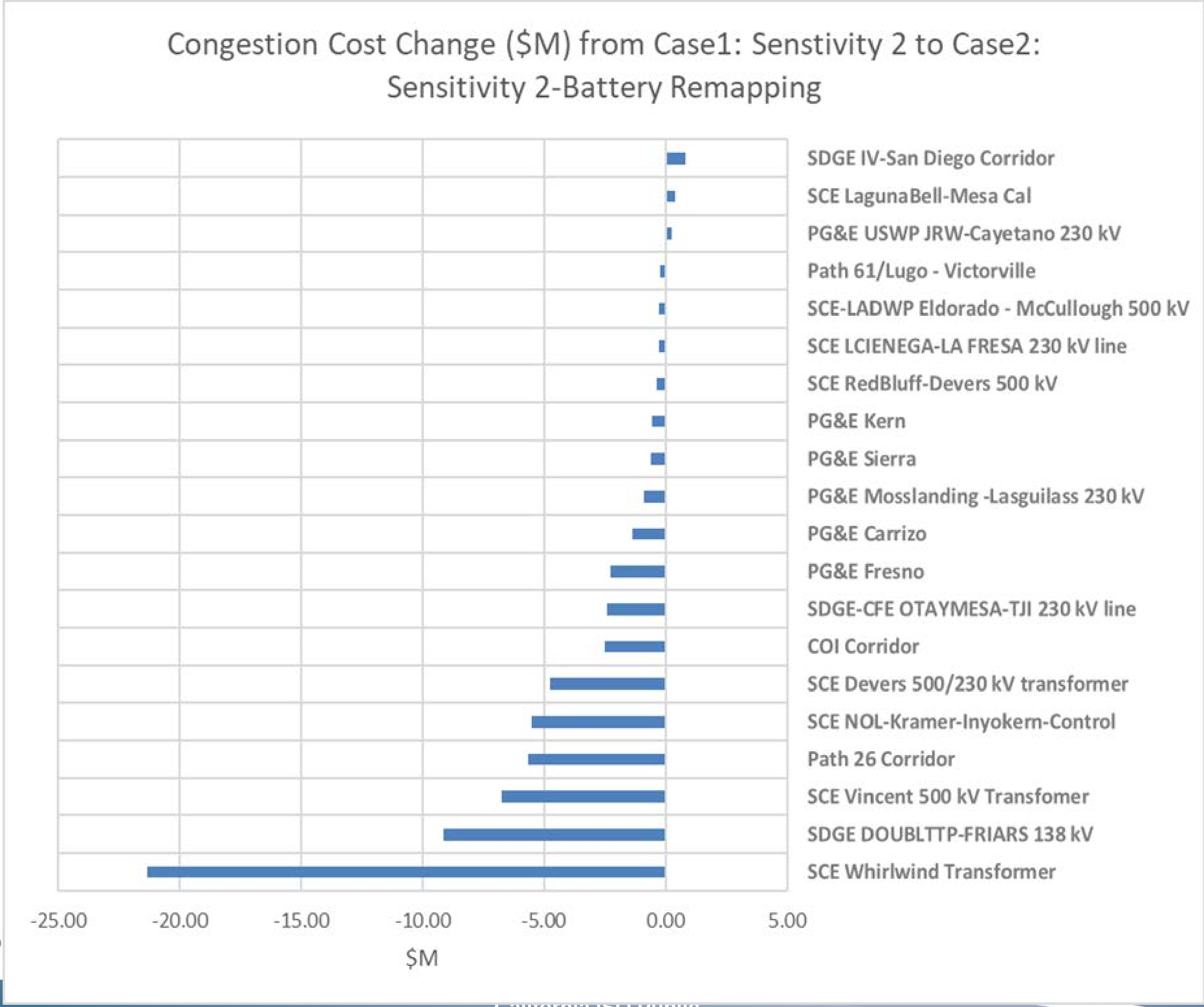
Battery re-mapping study objective and approach

- The objective was to assess the impact of relocating a portion of Sensitivity 2 battery storage to locations with high renewable curtailment
- About 3,287 MW of battery storage that was found to be undeliverable was relocated
- The undeliverable storage was allocated to six of the zones with the highest curtailment in proportion to the curtailment ratio
- The amount of storage allocated to buses located in Carrizo, Fresno-Kern, and GridLiance/VEA areas was capped due to on-peak deliverability considerations
- The resulting busbar mapping is shown on the next slide

Re-mapped Sensitivity 2 portfolio battery storage to reduce curtailment

Zone	Bus Name	Bus kV	Bus ID	Change (MW)
Tehachapi	Whirlwind	230	29408	1,170
	Vincent	500	24156	944
East of Lugo	Eldorado	500	24042	374
GridLiance /VEA	Trout Canyon	230	189160	60
Arizona	Hassayamp a	500	15090	218
Carrizo	Renfro	115	34762	120
	Arco	230	30935	60
	Stckdlea	230	30940	60
	Templeton	230	30905	80
	Wheeler	230	30994	80
Fresno-Kern	Gates D	230	30900	10
	Avnlpark	70	34249	10
	Northstar	115	34195	50
	Helm	230	30873	50
			Total	3,287

Congestion changes with battery re-mapped



Renewable curtailment changes with battery re-mapped

	Sensitivity 2			Sensitivity 2-Re-mapping batteries		
Zone	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio
SCE Tehachapi	26,838	7,447	22%	27,994	6,290	18%
PG&E Carrizo	7,206	3,971	36%	7,808	3,368	30%
PG&E Fresno-Kern	11,294	2,692	19%	11,406	2,580	18%
SCE EOL	16,052	2,527	14%	16,370	2,209	12%
VEA	4,319	1,884	30%	4,397	1,806	29%
NM	5,877	1,551	21%	5,874	1,554	21%
AZ	4,311	1,342	24%	4,304	1,349	24%
NW	10,593	834	7%	10,465	962	8%
SCE Vestal	683	142	17%	705	121	15%
SCE NOL	2,579	383	13%	2,607	355	12%
SCE Eastern	8,182	369	4%	8,171	379	4%
SDGE IV	7,818	249	3%	7,824	244	3%
ID	336	62	16%	333	65	16%
PG&E Solano	4,903	54	1%	4,888	69	1%
PG&E N. CA	3,163	43	1%	3,151	55	2%
CO	180	39	18%	179	39	18%
IID	747	34	4%	753	29	4%
SCE Others	289	29	9%	292	26	8%
SDGE San Diego	263	17	6%	264	16	6%
AB	473	11	2%	470	14	3%
SCE Ventura	28	5	15%	29	4	13%
Total	116,133	23,686	17%	118,286	21,534	15%

Sensitivity 2 battery re-mapping - summary

- Transmission congestion and renewable curtailment can be further reduced by allocating battery storages to constrained areas
- The renewable curtailment reduction with the battery remapped is not as significant as the transmission congestion reduction
  - Since system constraints that impact generation dispatch can also cause renewable curtailment

Transmission alternatives to battery re-mapping

- Some areas, however, may not be able to accommodate additional battery storage due to the limit of on-peak deliverability, for example
  - GridLiance West and VEA area – can only accommodates additional 60 MW of battery storage
  - Whirlwind 230 kV system - the maximum capacity of additional battery storage is limited since the renewable capacity is high in the Whirlwind 230 kV system
- Two transmission alternatives were assessed
  - GridLiance West Conversion Project
  - Fourth transformer at the Whirlwind substation

Transmission alternatives to battery re-mapping

- The two transmission alternatives are effective to mitigate the local renewable curtailment, the GridLiance West/VEA area and the Whirlwind 230 kV system, respectively
- Local congestions can be mitigated effectively as well
- Both transmission alternatives can reduce the CAISO overall renewable curtailment, but not as effective as the battery remapping
- The changes in congestions in other areas varied depending on the locations, because of the change in generation dispatch

Wrap-up
Draft 2020-2021 Transmission Plan

Isabella Nicosia
Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021

Stakeholder Comments

- Stakeholder comments to be submitted by February 23
  - Stakeholders requested to submit comments to: regionaltransmission@caiso.com
  - Stakeholder comments are to be submitted within two weeks after stakeholder meetings
  - ISO will post comments and responses on website