Agenda
Draft 2020-2021 Transmission Plan

Isabella Nicosia
Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
February 9, 2021
<table>
<thead>
<tr>
<th>Topic</th>
<th>Presenter</th>
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</thead>
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<tr>
<td>Introduction</td>
<td>Isabella Nicosia</td>
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<td>Overview</td>
<td>Jeff Billinton</td>
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<td>Reliability Assessment Recommendations</td>
<td>Abhishek Singh</td>
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<td>Wildfire Assessment – PG&amp;E Area</td>
<td>Binaya Shrestha</td>
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<td>Frequency Response Study</td>
<td>Irina Green</td>
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<td>Policy Assessment</td>
<td>Nebiyu Yimer</td>
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<td>Economic Assessment</td>
<td>Yi Zhang</td>
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<td>Isabella Nicosia</td>
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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

**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
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

- Reliability Driven Projects meeting Reliability Needs
- Policy Driven Projects meeting Policy and possibly Reliability Needs
- Economic Driven Projects meeting Economic and possibly Policy and Reliability Needs (multi-value)

Commitment for biennial _10-year local capacity study

Assess local capacity areas

Subsequent consideration of interregional transmission project proposals as potential solutions to regional needs...as needed.
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
  

- 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

CEC & CPUC
1. Create demand forecast & assess resource needs
   - With input from ISO, IOUs & other stakeholders

ISO
2. Creates transmission plan
   - With input from CEC, CPUC, IOUs & other stakeholders

CPUC
3. Creates procurement plan
   - With input from CEC, ISO, IOUs & other stakeholders

IOUs
4. Final plan authorizes procurement

Results of 2-3-4 feed into next biennial cycle

With input from CEC, CPUC, IOUs & other stakeholders
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

<table>
<thead>
<tr>
<th>Projects</th>
<th>Planning Area</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Palermo – Wyandotte 115 kV Line Section Reconductoring</td>
<td>North Valley</td>
<td>Presented in November meeting</td>
</tr>
<tr>
<td>Manteca #1 60 kV Line Section Reconductoring</td>
<td>Central Valley</td>
<td>Presented in November meeting</td>
</tr>
<tr>
<td>Kasson – Kasson Junction 1 115 kV Line Section Reconductoring</td>
<td>Central Valley</td>
<td>Presented in November meeting</td>
</tr>
</tbody>
</table>
Moraga-Sobrante 115 kV Line ReconductoR Project

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

**Original scope:**
- Reconduct 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.
Alternatives considered TPP20-21 (continued)

• 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-$10 Million
  - 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)
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

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

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

<table>
<thead>
<tr>
<th>No.</th>
<th>Project</th>
<th>Reliability Need found?</th>
<th>Can 4-hour battery mitigate the need?</th>
<th>Project to be canceled?</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>TL6983 2nd Pomerado – Poway 69 kV Circuit</td>
<td>No</td>
<td>N/A</td>
<td>Yes</td>
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<tr>
<td>2</td>
<td>TL690E Stuart Tap - Las Pulgas 69kV Reconductor</td>
<td>Yes</td>
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<td>No</td>
<td>No</td>
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<tr>
<td>6</td>
<td>Open Sweetwater Tap (TL603) and Loop into Sweetwater</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>
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)

Governor response
AGC
Operator actions
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.
  
  \[
  \text{Frequency drops to 59.9 Hz, with 5\% droop setting, unit responds with } \frac{[60-59.9]/60}{0.05} = 3.33\% \text{ of rated power}
  \]
  
  \[
  \text{With 4\% droop settings it responds } \frac{[60-59.9]/60}{0.04} = 4.17\%
  \]

- 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-003-2Frequency Response & Frequency Bias Setting Standard
- For WECC, FRO is 858 MW/0.1Hz
- Balancing Authority FRO allocation

\[ FRO_{BA} = FRO_{Int} \frac{P_{gen_{BA}} + P_{load_{BA}}}{P_{gen_{Int}} + P_{load_{Int}}} \]

- 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 increase 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

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

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

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>SC1</th>
<th>SC2</th>
<th>SC3</th>
<th>SC4</th>
</tr>
</thead>
<tbody>
<tr>
<td>PFR from IBR is switched off</td>
<td>✓</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>PFR from IBR is switched off and low overall generation headroom.</td>
<td>-</td>
<td>✓</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>PFR enabled for new BESS only and low overall generation headroom</td>
<td>-</td>
<td>-</td>
<td>✓</td>
<td>-</td>
</tr>
<tr>
<td>PFR enabled for all new IBRs assuming 10% headroom and low overall generation headroom</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>✓</td>
</tr>
</tbody>
</table>
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)
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

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

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

<table>
<thead>
<tr>
<th></th>
<th>2030 Spring off-Peak case</th>
<th>2030 Spring off-Peak case with reduced headroom</th>
<th>2030 Spring off-Peak case with reduced headroom and responsive BESS</th>
<th>2030 Spring off-Peak case with reduced headroom and responsive IBR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Settling Frequency, Hz</td>
<td>59.889</td>
<td>59.884</td>
<td>59.897</td>
<td>59.904</td>
</tr>
<tr>
<td>Frequency Nadir, Hz</td>
<td>59.776</td>
<td>59.744</td>
<td>59.767</td>
<td>59.795</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Case</th>
<th>2030 Spring off-Peak case</th>
<th>2030 Spring off-Peak case with reduced headroom</th>
<th>2030 Spring off-Peak case with reduced headroom and responsive BESS</th>
<th>2030 Spring off-Peak case with reduced headroom and responsive IBR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Headroom, MW</td>
<td>ISO, incl. MUNI</td>
<td>2,629</td>
<td>2,293</td>
<td>4,541</td>
</tr>
<tr>
<td></td>
<td>Total WECC</td>
<td>15,021</td>
<td>11,641</td>
<td>13,722</td>
</tr>
<tr>
<td>Responsive units</td>
<td>ISO, incl. MUNI</td>
<td>141</td>
<td>131</td>
<td>161</td>
</tr>
<tr>
<td></td>
<td>Total WECC</td>
<td>875</td>
<td>858</td>
<td>888</td>
</tr>
<tr>
<td>Response, MW</td>
<td>ISO, incl. MUNI</td>
<td>268</td>
<td>269</td>
<td>509</td>
</tr>
<tr>
<td></td>
<td>Total WECC</td>
<td>2,607</td>
<td>2,438</td>
<td>2,535</td>
</tr>
<tr>
<td>Response from Batteries, MW</td>
<td>WECC/ISO</td>
<td>0</td>
<td>0</td>
<td>262</td>
</tr>
<tr>
<td>Response from IBR, MW</td>
<td>WECC/ISO</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Response, MW/0.1Hz</td>
<td>ISO, incl. MUNI</td>
<td>241.5</td>
<td>231.7</td>
<td>494.4</td>
</tr>
<tr>
<td></td>
<td>Total WECC</td>
<td>2,349</td>
<td>2,101</td>
<td>2,461</td>
</tr>
<tr>
<td>FRO, MW/0.1 Hz</td>
<td>ISO, incl. MUNI</td>
<td></td>
<td></td>
<td>257.4</td>
</tr>
<tr>
<td></td>
<td>Total WECC</td>
<td></td>
<td></td>
<td>858</td>
</tr>
</tbody>
</table>
Real Power Output from a Hydro Unit, BESS and IBR with Frequency Control
Output of the BESS when BESS are Under Frequency Control
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
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.
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 Transmission 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.

<table>
<thead>
<tr>
<th>II.19</th>
<th>Upward frequency response droop (increase output for low frequency)</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>II.20</td>
<td>Downward frequency response droop (reduce output for high frequency)</td>
<td>%</td>
</tr>
<tr>
<td>II.21</td>
<td>Frequency response deadband +/-</td>
<td>Hz</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>GBA Division</th>
<th>Scenario 4 PSPS Impact</th>
<th>Critical Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Load Impact (MW)</td>
<td>System Performance Impact</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Contingency analysis shows overloads in Peninsula 60 kV system.</td>
</tr>
<tr>
<td>East Bay</td>
<td>0</td>
<td>N/A</td>
</tr>
<tr>
<td>Diablo</td>
<td>0</td>
<td>N/A</td>
</tr>
<tr>
<td>San Francisco</td>
<td>0</td>
<td>N/A</td>
</tr>
<tr>
<td>Peninsula</td>
<td>58</td>
<td>N/A</td>
</tr>
<tr>
<td>Mission</td>
<td>0</td>
<td>N/A</td>
</tr>
<tr>
<td>South Bay</td>
<td>3</td>
<td>N/A</td>
</tr>
</tbody>
</table>

- 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**

<table>
<thead>
<tr>
<th>Humboldt Division</th>
<th>Scenario 4 PSPS Impact</th>
<th>Critical Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Humboldt</td>
<td>Direct Load Impact (MW)</td>
<td>Humboldt system isolated</td>
</tr>
</tbody>
</table>
|                   | 130                    | • 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.
### Scenario 4 PSPS Impact

<table>
<thead>
<tr>
<th>NCNB Division</th>
<th>Scenario 4 PSPS Impact</th>
<th>Critical Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Load Impact (MW)</td>
<td>System Performance Impact</td>
</tr>
</tbody>
</table>
| 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

<table>
<thead>
<tr>
<th>North Valley Division</th>
<th>Scenario 4 PSPS Impact</th>
<th>Critical Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Load Impact (MW)</td>
<td>System Performance Impact</td>
</tr>
<tr>
<td>North Valley</td>
<td>11</td>
<td>Contingency analysis identified one overload in Cottonwood 60 kV system.</td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th>CVLY Division</th>
<th>Scenario 4 PSPS Impact</th>
<th>Critical Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Load Impact (MW)</td>
<td>System Performance Impact</td>
</tr>
<tr>
<td>Sacramento</td>
<td>3</td>
<td>Contingency analysis identified no reliability concerns</td>
</tr>
<tr>
<td>Sierra</td>
<td>161</td>
<td></td>
</tr>
<tr>
<td>Stockton</td>
<td>43</td>
<td></td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th>GFA Division</th>
<th>Scenario 4 PSPS Impact</th>
<th>Critical Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Load Impact (MW)</td>
<td>System Performance Impact</td>
</tr>
<tr>
<td>Yosemite</td>
<td>6</td>
<td>Contingency analysis identified no reliability concerns.</td>
</tr>
<tr>
<td>Fresno</td>
<td>13</td>
<td></td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th>CCLP Division</th>
<th>Scenario 4 PSPS Impact</th>
<th>Critical Facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct Load Impact (MW)</td>
<td>System Performance Impact</td>
</tr>
<tr>
<td>Central Coast</td>
<td>No impact</td>
<td></td>
</tr>
<tr>
<td>Los Padres</td>
<td>No impact</td>
<td>• N/A</td>
</tr>
</tbody>
</table>

- No new upgrades are required.
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
Senior Advisor, Regional Transmission Engineer

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 remapping on congestion and curtailment*
- PCM assessment of impact of transmission upgrades on Sensitivity 2 congestion and curtailment*
- Conclusions

* Included within the Economic Assessment and Production Cost Simulation presentation.
In this 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*
- Conclusions

* Included within the Economic Assessment and Production Cost Simulation presentation.
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

<table>
<thead>
<tr>
<th>Transmission zones and sub-zones</th>
<th>Estimated Existing System FCDS Capability Adjusted for New Baseline Resources (MW)</th>
<th>FCDS Resources in Portfolios (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Base</td>
</tr>
<tr>
<td>Northern CA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Round mountain</td>
<td>1,821</td>
<td>-</td>
</tr>
<tr>
<td>- Humboldt</td>
<td>500</td>
<td>-</td>
</tr>
<tr>
<td>- Humboldt</td>
<td></td>
<td>-</td>
</tr>
<tr>
<td>- Sacramento River</td>
<td>1,901</td>
<td>-</td>
</tr>
<tr>
<td>- Solano</td>
<td>520</td>
<td>-</td>
</tr>
<tr>
<td>Southern PG&amp;E</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Westlands</td>
<td>394</td>
<td>146</td>
</tr>
<tr>
<td>- Kern and Greater Carrizo</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Carrizo</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Central Valley North &amp; Los Banos</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tehachapi</td>
<td>4,155</td>
<td>725</td>
</tr>
<tr>
<td>Greater Kramer (North of Lugo)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- North of Victor</td>
<td>500</td>
<td>554</td>
</tr>
<tr>
<td>- Inyokern and North of Kramer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Pisgah</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- North of Victor</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Southern CA Desert and Southern NV</td>
<td>2,273</td>
<td></td>
</tr>
<tr>
<td>- Eldorado/Mtn Pass (230 kV)</td>
<td></td>
<td>1,640</td>
</tr>
<tr>
<td>- Southern NV (GLW-VEA)</td>
<td></td>
<td>102</td>
</tr>
<tr>
<td>- Greater Imperial</td>
<td></td>
<td>624</td>
</tr>
<tr>
<td>- Riverside East &amp; Palm Springs</td>
<td></td>
<td>604</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>9,143</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
## Utilization of EODS transmission capability estimates

<table>
<thead>
<tr>
<th>Transmission zones and sub-zones</th>
<th>Estimated Existing System EODS Capability Adjusted for New Baseline Resources, (MW)</th>
<th>FCDS + EODS Resources in Portfolios (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Original</td>
<td>Relaxed</td>
</tr>
<tr>
<td><strong>Northern CA</strong></td>
<td>3,721</td>
<td>3,721</td>
</tr>
<tr>
<td>- Round mountain</td>
<td>2,100</td>
<td>2,100</td>
</tr>
<tr>
<td>- Humboldt</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>- Sacramento River</td>
<td>4,501</td>
<td>4,501</td>
</tr>
<tr>
<td>- Solano</td>
<td>1,220</td>
<td>1,220</td>
</tr>
<tr>
<td><strong>Southern PG&amp;E</strong></td>
<td><strong>TBD</strong></td>
<td><strong>4,474</strong></td>
</tr>
<tr>
<td>- Westlands</td>
<td>TBD</td>
<td>3,200</td>
</tr>
<tr>
<td>- Kern and Greater Carrizo</td>
<td>TBD</td>
<td>3,804</td>
</tr>
<tr>
<td>- Carrizo</td>
<td>400</td>
<td>1,100</td>
</tr>
<tr>
<td>- Central Valley North &amp; Los Banos</td>
<td>TBD</td>
<td>670</td>
</tr>
<tr>
<td><strong>Tehachapi</strong></td>
<td><strong>4,955</strong></td>
<td><strong>5,955</strong></td>
</tr>
<tr>
<td><strong>Greater Kramer (North of Lugo)</strong></td>
<td><strong>500</strong></td>
<td><strong>500</strong></td>
</tr>
<tr>
<td>- North of Victor</td>
<td>300</td>
<td>300</td>
</tr>
<tr>
<td>- Inyokern and North of Kramer</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>- Pisgah</td>
<td>400</td>
<td>400</td>
</tr>
<tr>
<td><strong>Southern CA Desert and Southern NV</strong></td>
<td><strong>8,873</strong></td>
<td><strong>12,533</strong></td>
</tr>
<tr>
<td>- Eldorado/Mtn Pass (230 kV)</td>
<td>2,400</td>
<td>4,040</td>
</tr>
<tr>
<td>- Southern NV (GLW-VEA)</td>
<td>624</td>
<td>2,094</td>
</tr>
<tr>
<td>- Greater Imperial</td>
<td>2,995</td>
<td>2,995</td>
</tr>
<tr>
<td>- Riverside East &amp; Palm Springs</td>
<td>4,954</td>
<td>5,504</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>18,443</strong></td>
<td><strong>27,183</strong></td>
</tr>
</tbody>
</table>
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*
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- Conclusions

* Included within the Economic Assessment and Production Cost Simulation presentation.
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.

<table>
<thead>
<tr>
<th>Area</th>
<th>HSN Solar</th>
<th>HSN Wind</th>
<th>SSN Solar</th>
<th>SSN Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>SDG&amp;E</td>
<td>3.0%</td>
<td>33.7%</td>
<td>40.2%</td>
<td>11.2%</td>
</tr>
<tr>
<td>SCE</td>
<td>10.6%</td>
<td>55.7%</td>
<td>42.7%</td>
<td>20.8%</td>
</tr>
<tr>
<td>PG&amp;E</td>
<td>10.0%</td>
<td>66.5%</td>
<td>55.6%</td>
<td>16.3%</td>
</tr>
</tbody>
</table>

For non-intermittent generation – 100% of NQC, Energy storage – 4-hour capacity
<table>
<thead>
<tr>
<th>Area Deliverability Constraint</th>
<th>Renewable Zones</th>
<th>Deliverable Study Amount (MW)</th>
<th>Deliverable Interconnection Service Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GLW-VEA Area Constraint</td>
<td>Southern_Nevada</td>
<td>500</td>
<td>790</td>
</tr>
<tr>
<td>Eldorado transformer constraint</td>
<td>Southern_Nevada</td>
<td>3,360</td>
<td>3700</td>
</tr>
<tr>
<td>Colorado River transformer constraint</td>
<td>Riverside_Palm_Springs</td>
<td>2,110</td>
<td>1,628</td>
</tr>
<tr>
<td>Devers – Red Bluff constraint</td>
<td>Riverside_Palm_Springs, Arizona</td>
<td>5,400</td>
<td>7,808</td>
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<tr>
<td>Serrano – Alberhill – Valley constraint</td>
<td>Riverside_Palm_Springs, Arizona, Imperial</td>
<td>7,110</td>
<td>10,342</td>
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<td>Lugo transformer constraint</td>
<td>Inyokern_North_Kramer</td>
<td>950</td>
<td>1,250</td>
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<td>Kramer- Victor/Roadway -Victor South of Kramer flow limit</td>
<td>Inyokern_North_Kramer</td>
<td>200</td>
<td>325</td>
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<tr>
<td>Victor-Lugo South of Kramer flow limit</td>
<td>Inyokern_North_Kramer</td>
<td>530</td>
<td>980</td>
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<td>Windhub transformer constraint</td>
<td>Tehachapi</td>
<td>3,080</td>
<td>3,970</td>
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<tr>
<td>Antelope – Vincent flow limit</td>
<td>Tehachapi, Non-CREZ – Big Creek</td>
<td>4,040</td>
<td>4,950</td>
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<td>Laguna Bell – Mesa flow limit</td>
<td>Non-CREZ – Ventura</td>
<td>1,208</td>
<td>1208</td>
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<tr>
<td>South of Magunden flow limit</td>
<td>Non-CREZ – Big Creek</td>
<td>670</td>
<td>710</td>
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<tr>
<td>East of Miguel constraint</td>
<td>Arizona, Imperial, Baja, Riverside</td>
<td>1,335</td>
<td>1,969</td>
</tr>
<tr>
<td>Encina-San Luis Rey constraint</td>
<td>Arizona, Imperial, Baja, Non-CREZ</td>
<td>2,901</td>
<td>3,479</td>
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<tr>
<td>Imperial Valley transformer constraint</td>
<td>Imperial</td>
<td>1,959</td>
<td>2,106</td>
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<tr>
<td>San Luis Rey-San Onofre constraint</td>
<td>Arizona, Imperial, Baja, Non-CREZ</td>
<td>1,748</td>
<td>1,886</td>
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<td>SDGE – Internal Area constraint</td>
<td>Imperial, Non-CREZ</td>
<td>968</td>
<td>968</td>
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<tr>
<td>Silvergate-Bay Boulevard constraint</td>
<td>Imperial, Baja, Non-CREZ</td>
<td>1,202</td>
<td>1,438</td>
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<tr>
<td>Oceanside constraint</td>
<td>Non-CREZ</td>
<td>280</td>
<td>280</td>
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</table>
## TPD values - Northern CA

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


- Our current thinking is to use the TPD study amounts, which are independent of the resource mix, as linear equations of the form

  \[ TxCapFCDS = \text{Deliverable study amount for a zone} = \sum f_i \times R_i \]

  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

- 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 remapping on congestion and curtailment*
- PCM assessment of impact of transmission upgrades on Sensitivity 2 congestion and curtailment*
- Conclusion

* Included within the Economic Assessment and Production Cost Simulation presentation.
In this 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*

- Conclusion

* Included within the Economic Assessment and Production Cost Simulation presentation.
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

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

- 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

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

- 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.

San Diego import east to west average hourly flow

<table>
<thead>
<tr>
<th>Hour</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
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<th>Nov</th>
<th>Dec</th>
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<tbody>
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<td>22</td>
<td>20</td>
<td>9</td>
<td>7</td>
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<td>1</td>
<td>6</td>
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<td>19</td>
<td>9</td>
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<td>5</td>
<td>2</td>
<td>3</td>
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<td>16</td>
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<tr>
<td>22</td>
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<td>9</td>
<td>10</td>
<td>23</td>
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</tr>
<tr>
<td>23</td>
<td>16</td>
<td>16</td>
<td>14</td>
<td>8</td>
<td>2</td>
<td>2</td>
<td>17</td>
<td>27</td>
<td>35</td>
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<td>57</td>
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<td>13</td>
<td>16</td>
<td>17</td>
<td>19</td>
<td>17</td>
<td>23</td>
<td></td>
</tr>
</tbody>
</table>

Otay Mesa area generation average hourly output

- 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 Penasquitos – Old Town 230 kV line to eliminate the N-2 contingency
# Doublet Tap – Friars congestion - congestion and curtailment results with mitigation

<table>
<thead>
<tr>
<th>Congestion</th>
<th>Base case</th>
<th>Alternative 1 – Expended SPS</th>
<th>Alternative 2 - Reconductoring</th>
<th>Alternative 3 – Rearrangement</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Doublet Tap - Friars 138 kV</strong></td>
<td>$52.74</td>
<td>$5.47</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Wind and Solar</strong></td>
<td>Output (GWh)</td>
<td>Curtail (GWh)</td>
<td>Output (GWh)</td>
<td>Curtail (GWh)</td>
</tr>
<tr>
<td><strong>CAISO Total</strong></td>
<td>75,051</td>
<td>75,072</td>
<td>75,072</td>
<td>75,072</td>
</tr>
</tbody>
</table>
### Doublet Tap – Friars congestion – production cost benefit

<table>
<thead>
<tr>
<th></th>
<th>Base case</th>
<th>Alternative 1 – Expanded SPS</th>
<th>Alternative 2 - Reconductoring</th>
<th>Alternative 3 – Rearrangement</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>($M)</td>
<td>Post project ($M)</td>
<td>Post project ($M)</td>
<td>Post project ($M)</td>
</tr>
<tr>
<td>CAISO load payment</td>
<td>7,954</td>
<td>7,961</td>
<td>7,949</td>
<td>7,944</td>
</tr>
<tr>
<td>CAISO generator net revenue benefiting ratepayers</td>
<td>3,554</td>
<td>3,583</td>
<td>3,579</td>
<td>3,579</td>
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<tr>
<td>CAISO transmission revenue benefiting ratepayers</td>
<td>268</td>
<td>230</td>
<td>226</td>
<td>227</td>
</tr>
<tr>
<td>CAISO Net payment</td>
<td>4,132</td>
<td>4,148</td>
<td>4,143</td>
<td>4,139</td>
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<tr>
<td>WECC Production cost</td>
<td>13,213</td>
<td>13,169</td>
<td>13,157</td>
<td>13,153</td>
</tr>
</tbody>
</table>

Post project savings ($M): CAISO load payment -6; CAISO generator net revenue benefiting ratepayers 29; CAISO transmission revenue benefiting ratepayers -39; CAISO Net payment -16; WECC Production cost 44; Alternative 1 – Expanded SPS 44; Alternative 2 - Reconductoring 56; Alternative 3 – Rearrangement 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

<table>
<thead>
<tr>
<th>Generator Type</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery Storage</td>
<td>10</td>
</tr>
<tr>
<td>Wind</td>
<td>333</td>
</tr>
<tr>
<td>Solar</td>
<td>3,715</td>
</tr>
<tr>
<td>Total</td>
<td>4,058</td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th></th>
<th>Base case</th>
<th>Alternative 1 – 1170 MW battery at Whirlwind 230 kV</th>
<th>Alternative 2 – The Fourth Whirlwind transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Congestion</strong></td>
<td>$M</td>
<td>Hours</td>
<td>$M</td>
</tr>
<tr>
<td>Whirlwind transformer</td>
<td>22.91</td>
<td>295</td>
<td>9.35</td>
</tr>
<tr>
<td>Wind and Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind and Solar (GWh)</td>
<td>Output</td>
<td>Curtail (GWh)</td>
<td>Output (GWh)</td>
</tr>
<tr>
<td>Curtail (GWh)</td>
<td></td>
<td></td>
<td>Curtail (GWh)</td>
</tr>
<tr>
<td>CAISO Total</td>
<td>75,051</td>
<td>13,595</td>
<td>76,633</td>
</tr>
<tr>
<td>Curtail (GWh)</td>
<td></td>
<td></td>
<td>12,014</td>
</tr>
<tr>
<td>CAISO Total</td>
<td>75,108</td>
<td>13,538</td>
<td>75,108</td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th>Model</th>
<th>Base case</th>
<th>Alternative 1 – 1170 MW battery at Whirlwind 230 kV</th>
<th>Alternative 2 – The Fourth Whirlwind transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>($M)</td>
<td>Post project ($M)</td>
<td>Savings ($M)</td>
</tr>
<tr>
<td>CAISO load payment</td>
<td>7,954</td>
<td>8,049</td>
<td>-94</td>
</tr>
<tr>
<td>CAISO generator net revenue benefiting ratepayers</td>
<td>3,554</td>
<td>3,611</td>
<td>57</td>
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<tr>
<td>CAISO transmission revenue benefiting ratepayers</td>
<td>268</td>
<td>261</td>
<td>-7</td>
</tr>
<tr>
<td>CAISO Net payment</td>
<td>4,132</td>
<td>4,177</td>
<td>-45</td>
</tr>
<tr>
<td>WECC Production cost</td>
<td>13,213</td>
<td>13,223</td>
<td>-10</td>
</tr>
</tbody>
</table>
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.

<table>
<thead>
<tr>
<th>Wind and Solar</th>
<th>Wind and Solar</th>
<th>Reference Case - 1170 MW battery at Lugo 500 kV</th>
<th>Alternative 1 – 1170 MW battery at Whirlwind 230 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Output (GWh)</td>
<td>Output (GWh)</td>
<td>Curtail (GWh)</td>
<td>Curtail (GWh)</td>
</tr>
<tr>
<td>Curtail (GWh)</td>
<td>Curtail (GWh)</td>
<td>Output (GWh)</td>
<td>Output (GWh)</td>
</tr>
<tr>
<td>CAISO Total</td>
<td>CAISO Total</td>
<td>CAISO Total</td>
<td>CAISO Total</td>
</tr>
<tr>
<td>75,051</td>
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<td>76,563</td>
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<td>76,633</td>
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Whirlwind transformer congestion – Compare Alternative 1 to a Reference case (cont.) - benefit

<table>
<thead>
<tr>
<th></th>
<th>Reference Case</th>
<th>Alternative 1</th>
<th>Alternative 1 Savings compared with Reference Case 1</th>
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<tbody>
<tr>
<td>CAISO load payment</td>
<td>$M 8,066</td>
<td>$M 8,049</td>
<td>$M 18</td>
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<tr>
<td>CAISO generator net revenue benefiting ratepayers</td>
<td>3,612</td>
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<tr>
<td>CAISO transmission revenue benefiting ratepayers</td>
<td>280</td>
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<td>-19</td>
</tr>
<tr>
<td>CAISO Net payment</td>
<td>4,174</td>
<td>4,177</td>
<td>-3</td>
</tr>
<tr>
<td>WECC Production cost</td>
<td>13,225</td>
<td>13,223</td>
<td>3</td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th>Constraints</th>
<th>Costs ($M)</th>
<th>Duration (Hrs)</th>
</tr>
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<tbody>
<tr>
<td>P66 WECC COI</td>
<td>8.85</td>
<td>259</td>
</tr>
<tr>
<td>Table Mountain – Tesla 500 kV line</td>
<td>2.56</td>
<td>27</td>
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<tr>
<td>Table Mountain – Vaca Dixon 500 kV line</td>
<td>0.59</td>
<td>7</td>
</tr>
<tr>
<td>Round Mountain – Table Mountain 500 kV line</td>
<td>0.97</td>
<td>38</td>
</tr>
</tbody>
</table>
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.

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
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.
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

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

- $10 million production benefit to CAISO ratepayers per year

- 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

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production cost savings</strong> ($million/year)</td>
<td>10.10</td>
</tr>
<tr>
<td><strong>Capacity saving</strong> ($million/year)</td>
<td>0</td>
</tr>
<tr>
<td><strong>Capital cost ($million)</strong></td>
<td>543</td>
</tr>
<tr>
<td><strong>Discount Rate</strong></td>
<td>7%</td>
</tr>
<tr>
<td><strong>PV of Production cost savings ($million)</strong></td>
<td>149</td>
</tr>
<tr>
<td><strong>PV of Capacity saving ($million)</strong></td>
<td>0</td>
</tr>
<tr>
<td><strong>Total benefit ($million)</strong></td>
<td>149</td>
</tr>
<tr>
<td><strong>Total cost (Revenue requirement) ($million)</strong></td>
<td>706</td>
</tr>
<tr>
<td><strong>Benefit to cost ratio (BCR)</strong></td>
<td>0.21</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Constraints Name</th>
<th>Costs _F (K$)</th>
<th>Duration _F (Hrs)</th>
<th>Costs _B (K$)</th>
<th>Duration _B (Hrs)</th>
<th>Costs _T (K$)</th>
<th>Duration _T (Hrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LE GRAND-CHWCHLASSLRJT 115 kV line, subject to PG&amp;E N-1 Panoche-Mendota 115 kV</td>
<td>0</td>
<td>0</td>
<td>4,831</td>
<td>1,365</td>
<td>4,831</td>
<td>1,365</td>
</tr>
<tr>
<td>Q526TP-PLSNTVLY 70 kV line, subject to PG&amp;E N-2 Panoche-Schindler and Panoche-Excelsiorss 115 kV</td>
<td>1,469</td>
<td>634</td>
<td>0</td>
<td>0</td>
<td>1,469</td>
<td>634</td>
</tr>
<tr>
<td>KETLMN T-GATES 70.0 kV line #1</td>
<td>1,056</td>
<td>1,354</td>
<td>0</td>
<td>0</td>
<td>1,056</td>
<td>1,354</td>
</tr>
<tr>
<td>FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&amp;E N-2 Panoche-Schindler and Panoche-Excelsiorss 115 kV</td>
<td>842</td>
<td>863</td>
<td>34</td>
<td>1</td>
<td>876</td>
<td>864</td>
</tr>
<tr>
<td>HELM 70.0/230 kV transformer #1</td>
<td>339</td>
<td>294</td>
<td>0</td>
<td>0</td>
<td>339</td>
<td>294</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Constraints Name</th>
<th>Mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&amp;E N-1 Panoche-Mendota 115 kV</td>
<td>SPS</td>
</tr>
<tr>
<td>Q526TP-PLSNTVLY 70 kV line, subject to PG&amp;E N-2 Panoche-Schindler and</td>
<td>SPS</td>
</tr>
<tr>
<td>Panoche-Excelsiorss 115 kV</td>
<td></td>
</tr>
<tr>
<td>KETLMN T-GATES 70.0 kV line #1</td>
<td>Reconductoring</td>
</tr>
<tr>
<td>FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&amp;E N-2 Panoche-Schindler and</td>
<td>SPS</td>
</tr>
<tr>
<td>Panoche-Excelsiorss 115 kV</td>
<td></td>
</tr>
<tr>
<td>HELM 70.0/230 kV transformer #1</td>
<td>Transformer upgrade</td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th></th>
<th>Base case ($M)</th>
<th>Reconductoring Kettleman Hills Tap to Gates</th>
<th>Upgrading Helm transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAISO load payment</td>
<td>7,954</td>
<td>7,957</td>
<td>7,953</td>
</tr>
<tr>
<td>CAISO generator net revenue benefiting ratepayers</td>
<td>3,554</td>
<td>3,555</td>
<td>3,554</td>
</tr>
<tr>
<td>CAISO transmission revenue benefiting ratepayers</td>
<td>268</td>
<td>268</td>
<td>268</td>
</tr>
<tr>
<td>CAISO Net payment</td>
<td>4,132</td>
<td>4,133</td>
<td>4,131</td>
</tr>
<tr>
<td>WECC Production cost</td>
<td>13,213</td>
<td>13,214</td>
<td>13,217</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>PG&amp;E Fresno Helm 70/230 kV transformer Upgrade</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production cost savings ($million/year)</td>
</tr>
<tr>
<td>Capacity saving ($million/year)</td>
</tr>
<tr>
<td>Capital cost ($million)</td>
</tr>
<tr>
<td>Discount Rate</td>
</tr>
<tr>
<td>PV of Production cost savings ($million)</td>
</tr>
<tr>
<td>PV of Capacity saving ($million)</td>
</tr>
<tr>
<td>Total benefit ($million)</td>
</tr>
<tr>
<td>Total cost (Revenue requirement) ($million)</td>
</tr>
<tr>
<td>Benefit to cost ratio (BCR)</td>
</tr>
</tbody>
</table>
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

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

<table>
<thead>
<tr>
<th></th>
<th>Base case</th>
<th>Option 1</th>
<th>Option 2</th>
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<tbody>
<tr>
<td></td>
<td>($M)</td>
<td>Post project ($M)</td>
<td>Savings ($M)</td>
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<tr>
<td>CAISO load payment</td>
<td>7,954</td>
<td>7,986</td>
<td>-32</td>
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<tr>
<td>CAISO generator net revenue benefiting ratepayers</td>
<td>3,554</td>
<td>3,572</td>
<td>18</td>
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<tr>
<td>CAISO transmission revenue benefiting ratepayers</td>
<td>268</td>
<td>267</td>
<td>-1</td>
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<tr>
<td>CAISO Net payment</td>
<td>4,132</td>
<td>4,147</td>
<td>-15</td>
</tr>
<tr>
<td>WECC Production cost</td>
<td>13,213</td>
<td>13,219</td>
<td>-6</td>
</tr>
</tbody>
</table>

- 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

<table>
<thead>
<tr>
<th>No.</th>
<th>Aggregated congestion</th>
<th>Base</th>
<th>Sensitivity 1</th>
<th>Sensitivity 2</th>
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<tr>
<td></td>
<td></td>
<td>Cost ($M)</td>
<td>Duration (Hr)</td>
<td>Cost ($M)</td>
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<tr>
<td>1</td>
<td>SDGE DOUBLTTP-FRIARS 138 kV</td>
<td>52.74</td>
<td>2,749</td>
<td>72.73</td>
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<tr>
<td>2</td>
<td>SCE Whirlwind Transformer</td>
<td>22.91</td>
<td>295</td>
<td>74.74</td>
</tr>
<tr>
<td>3</td>
<td>COI Corridor</td>
<td>12.96</td>
<td>329</td>
<td>25.00</td>
</tr>
<tr>
<td>4</td>
<td>PDCI</td>
<td>8.95</td>
<td>562</td>
<td>5.52</td>
</tr>
<tr>
<td>5</td>
<td>PG&amp;E Fresno</td>
<td>8.64</td>
<td>4,520</td>
<td>11.59</td>
</tr>
<tr>
<td>6</td>
<td>Path 45</td>
<td>7.8</td>
<td>1,453</td>
<td>12.25</td>
</tr>
<tr>
<td>7</td>
<td>Path 26 Corridor</td>
<td>6.74</td>
<td>237</td>
<td>4.67</td>
</tr>
<tr>
<td>8</td>
<td>PG&amp;E Sierra</td>
<td>6.3</td>
<td>439</td>
<td>2.83</td>
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<tr>
<td>9</td>
<td>SCE LCIENEGA-LA FRESA 230 kV line</td>
<td>3.59</td>
<td>84</td>
<td>4.54</td>
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<tr>
<td>10</td>
<td>SCE RedBluff-Devers 500 kV</td>
<td>3.42</td>
<td>33</td>
<td>1.55</td>
</tr>
<tr>
<td>11</td>
<td>Path 60 Inyo-Control 115 kV</td>
<td>3.35</td>
<td>1,666</td>
<td>4.24</td>
</tr>
<tr>
<td>12</td>
<td>SCE NOL-Kramer-Inyokern-Control</td>
<td>3.23</td>
<td>266</td>
<td>2.52</td>
</tr>
<tr>
<td>13</td>
<td>Path 25 PACW-PG&amp;E 115 kV</td>
<td>2.81</td>
<td>486</td>
<td>2.59</td>
</tr>
<tr>
<td>14</td>
<td>SCE Antelope 66 kV system</td>
<td>2.77</td>
<td>1,008</td>
<td>5.19</td>
</tr>
<tr>
<td>15</td>
<td>Path 42 HD-SCE</td>
<td>2.26</td>
<td>71</td>
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<tr>
<td>16</td>
<td>SDGE IV-San Diego Corridor</td>
<td>0.95</td>
<td>45</td>
<td>1.57</td>
</tr>
<tr>
<td>17</td>
<td>SCE J.HINDS-MIRAGE 230 kV line</td>
<td>0.65</td>
<td>80</td>
<td>3.12</td>
</tr>
<tr>
<td>18</td>
<td>SCE LagunaBell-Mesa Cal</td>
<td>0.64</td>
<td>21</td>
<td>10.95</td>
</tr>
<tr>
<td>19</td>
<td>SDGE-CFE OTAYMESA-TJ 230 kV line</td>
<td>0.45</td>
<td>107</td>
<td>1.21</td>
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<tr>
<td>20</td>
<td>Path 61/Lugo - Victorville</td>
<td>0.38</td>
<td>41</td>
<td>1.11</td>
</tr>
<tr>
<td>21</td>
<td>San Diego</td>
<td>0.35</td>
<td>155</td>
<td>0.37</td>
</tr>
<tr>
<td>22</td>
<td>San Diego Silver Gate-Bay Boulevard</td>
<td>0.28</td>
<td>20</td>
<td>0.17</td>
</tr>
<tr>
<td>23</td>
<td>SCE Lugo 500 kV Transformer</td>
<td>0.18</td>
<td>5</td>
<td>0.00</td>
</tr>
<tr>
<td>24</td>
<td>SCE Devers 500/230 kV transformer</td>
<td>0.13</td>
<td>2</td>
<td>1.23</td>
</tr>
<tr>
<td>25</td>
<td>Path 15/CC</td>
<td>0.1</td>
<td>8</td>
<td>0.00</td>
</tr>
<tr>
<td>26</td>
<td>PG&amp;E Mosslanding-Lasgaullass 230 kV</td>
<td>0.1</td>
<td>7</td>
<td>0.85</td>
</tr>
<tr>
<td>27</td>
<td>PG&amp;E Cottle - Melones 230 kV</td>
<td>0.06</td>
<td>9</td>
<td>0.00</td>
</tr>
<tr>
<td>28</td>
<td>PG&amp;E Gates-CAFLATSSS 230 kV</td>
<td>0.05</td>
<td>3</td>
<td>0.00</td>
</tr>
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</table>
## Policy assessment curtailment results

<table>
<thead>
<tr>
<th>Zone</th>
<th>Base</th>
<th>Sensitivity 1</th>
<th>Sensitivity 2</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base</td>
<td>Generation (GWh)</td>
<td>Curtailment (GWh)</td>
</tr>
<tr>
<td>SCE Tehachapi</td>
<td>20,451</td>
<td>4,378</td>
<td>18%</td>
</tr>
<tr>
<td>PG&amp;E Carrizo</td>
<td>1,871</td>
<td>645</td>
<td>26%</td>
</tr>
<tr>
<td>PG&amp;E Fresno-Kern</td>
<td>7,420</td>
<td>1,565</td>
<td>17%</td>
</tr>
<tr>
<td>SCE EOL</td>
<td>7,349</td>
<td>1,190</td>
<td>14%</td>
</tr>
<tr>
<td>VEA</td>
<td>1,779</td>
<td>107</td>
<td>6%</td>
</tr>
<tr>
<td>NM</td>
<td>832</td>
<td>166</td>
<td>17%</td>
</tr>
<tr>
<td>AZ</td>
<td>2,223</td>
<td>1,174</td>
<td>35%</td>
</tr>
<tr>
<td>NW</td>
<td>5,915</td>
<td>457</td>
<td>7%</td>
</tr>
<tr>
<td>SCE NOL</td>
<td>2,792</td>
<td>511</td>
<td>15%</td>
</tr>
<tr>
<td>SCE Eastern</td>
<td>10,403</td>
<td>2,264</td>
<td>18%</td>
</tr>
<tr>
<td>SDGE IV</td>
<td>5,041</td>
<td>607</td>
<td>11%</td>
</tr>
<tr>
<td>SCE Vestal</td>
<td>672</td>
<td>154</td>
<td>19%</td>
</tr>
<tr>
<td>ID</td>
<td>346</td>
<td>52</td>
<td>13%</td>
</tr>
<tr>
<td>PG&amp;E Solano</td>
<td>5,016</td>
<td>94</td>
<td>2%</td>
</tr>
<tr>
<td>PG&amp;E N. CA</td>
<td>1,032</td>
<td>25</td>
<td>2%</td>
</tr>
<tr>
<td>CO</td>
<td>186</td>
<td>33</td>
<td>15%</td>
</tr>
<tr>
<td>IID</td>
<td>707</td>
<td>75</td>
<td>10%</td>
</tr>
<tr>
<td>SCE Others</td>
<td>271</td>
<td>48</td>
<td>15%</td>
</tr>
<tr>
<td>SDGE San Diego</td>
<td>246</td>
<td>34</td>
<td>12%</td>
</tr>
<tr>
<td>AB</td>
<td>473</td>
<td>11</td>
<td>2%</td>
</tr>
<tr>
<td>SCE Ventura</td>
<td>27</td>
<td>5</td>
<td>17%</td>
</tr>
<tr>
<td>Total</td>
<td>75,051</td>
<td>13,595</td>
<td>15%</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Zone</th>
<th>Bus Name</th>
<th>Bus kV</th>
<th>Bus ID</th>
<th>Change (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tehachapi</td>
<td>Whirlwind</td>
<td>230</td>
<td>29408</td>
<td>1,170</td>
</tr>
<tr>
<td></td>
<td>Vincent</td>
<td>500</td>
<td>24156</td>
<td>944</td>
</tr>
<tr>
<td>East of Lugo</td>
<td>Eldorado</td>
<td>500</td>
<td>24042</td>
<td>374</td>
</tr>
<tr>
<td>GridLiance/VEA</td>
<td>Trout Canyon</td>
<td>230</td>
<td>189160</td>
<td>60</td>
</tr>
<tr>
<td>Arizona</td>
<td>Hassayampa</td>
<td>500</td>
<td>15090</td>
<td>218</td>
</tr>
<tr>
<td>Carrizo</td>
<td>Renfro</td>
<td>115</td>
<td>34762</td>
<td>120</td>
</tr>
<tr>
<td></td>
<td>Arco</td>
<td>230</td>
<td>30935</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>Stckdlea</td>
<td>230</td>
<td>30940</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>Templeton</td>
<td>230</td>
<td>30905</td>
<td>80</td>
</tr>
<tr>
<td></td>
<td>Wheeler</td>
<td>230</td>
<td>30994</td>
<td>80</td>
</tr>
<tr>
<td>Fresno-Kern</td>
<td>Gates D</td>
<td>230</td>
<td>30900</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>Avnlpark</td>
<td>70</td>
<td>34249</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>Northstar</td>
<td>115</td>
<td>34195</td>
<td>50</td>
</tr>
<tr>
<td></td>
<td>Helm</td>
<td>230</td>
<td>30873</td>
<td>50</td>
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<tr>
<td></td>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>3,287</strong></td>
</tr>
</tbody>
</table>
Congestion changes with battery re-mapped

![Chart showing congestion cost change ($M) from Case 1: Sensitivity 2 to Case 2: Sensitivity 2-Battery Remapping]

- SDGE IV-San Diego Corridor
- SCE Laguna-Bell-Mesa Cal
- PG&E USWP JRW-Cayetano 230 kV
- Path 61/Lugo - Victorville
- SCE-LADWP Eldorado - McCullough 500 kV
- SCE LCIENEGA-LA FRESA 230 kV line
- SCE RedBluff-Devers 500 kV
- PG&E Kern
- PG&E Sierra
- PG&E Mosslanding - Lasguilass 230 kV
- PG&E Carrizo
- PG&E Fresno
- SDGE-CFE OTAYMESA-TJI 230 kV line
- COI Corridor
- SCE Devers 500/230 kV transformer
- SCE NOL-Kramer-Inyokern-Control
- Path 26 Corridor
- SCE Vincent 500 kV Transformer
- SDGE DOUBITTP-FRIARS 138 kV
- SCE Whirlwind Transformer
# Renewable curtailment changes with battery re-mapped

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