Agenda
Unified Planning Assumptions & Study Plan

Isabella Nicosia
Associate Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020
## 2020-2021 Transmission Planning Process Stakeholder Meeting - Agenda

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Overview
Unified Planning Assumptions & Study Plan

Jeff Billinton
Director, Transmission Infrastructure Planning

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020
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
CAISO Board for approval of transmission plan

December 2019
April 2020
March 2021

Procurement
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
- Preliminary reliability study results to be posted on August 14
- Stakeholder meeting on September 23 and 24
- Comments to be submitted by October 7
- 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 January 31, 2019
- Stakeholder meeting in February
- Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at March Board of Governor meeting
Planning and procurement overview

CEC & CPUC

Create demand forecast & assess resource needs

ISO

Creates transmission plan

CPUC

Creates procurement plan

IOUs

Final plan authorizes procurement

Results of 2-3-4 feed into next biennial cycle
Key Issues in 2020-2021 Transmission Plan Cycle:

- CAISO will incorporate renewable portfolios from the CPUC
  - Baseline portfolio
    - Reliability, Policy and Economic Assessments
  - Sensitivity portfolios
    - Policy Assessment
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.
2020-2021 Transmission Plan Study Plan

- Reliability Assessment to identify reliability-driven needs
- Policy Assessment to identify policy-driven needs
- Economic Planning Study to identify needed economically-driven elements

- Interregional Transmission Planning Process
  - In year one (even year) of 2 year planning cycle

- Other Studies
  - Local Capacity Requirements
    - Near-Term (2021) and Mid-Term (2025)
    - Long-term (2030)
      - Considering additional information related to storage potential
  - Long-term Congestion Revenue Rights
  - Frequency response
  - Flexible deliverable capacity
    - Considering biennial assessment
Interregional Transmission Coordination - Year 1 of 2

- Open window (January 1 through March 31) for proposed interregional transmission projects to be submitted to the CAISO for consideration in the CAISO's 2020-2021 TPP planning cycle

- Interregional Coordination stakeholder meeting held on February 27

http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx
Study Information

• Final Study Plan will be posted on 2020-2021 transmission planning process webpage on March 31st
  

• Base cases will be posted on the Market Participant Portal (MPP)
  – For reliability assessment in Q3

• Market notices will be posted in the Daily Briefings to notify stakeholders of meetings and any relevant information
  
  http://www.caiso.com/dailybriefing/Pages/default.aspx
Stakeholder comments

• Stakeholders requested to submit comments to: regionaltransmission@caiso.com

• Stakeholder comments are to be submitted within two weeks after stakeholder meetings: by March 13

• CAISO will post comments and responses on website
Reliability Assessment
Unified Planning Assumptions & Study Plan

Binaya Shrestha / Nebiyu Yimer
Regional Transmission Engineer Lead

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020
Planning Assumptions

• Reliability Standards and Criteria
  – California ISO Planning Standards
  – NERC Reliability Criteria
    • TPL-001-5
    • NUC-001-3
  – WECC Regional Criteria
    • TPL-001-WECC-CRT-3.2
Planning Assumptions

• Major changes in TPL-001-5
  – Protection system “single point of failure” refers to a non-redundant component of a protection system.
  – Removal of exclusion of known outages of less than six months.
  – Requirements for stability analysis to assess the impact of the possible unavailability of long lead time equipment.
Planning Assumptions (continued)

• Study Horizon
  – 10 years planning horizon
    • near-term: 2021 to 2025
    • longer-term: 2026 to 2030

• Study Years
  • near-term: 2022 and 2025
  • longer-term: 2030
Study Areas

- **Northern Area - Bulk**
  - PG&E Local Areas:
    - Humboldt area
    - North Coast and North Bay area
    - North Valley area
    - Central Valley area
    - Greater Bay area:
      - Greater Fresno area;
      - Kern area;
      - Central Coast and Los Padres areas.
  - Southern Area – Bulk
    - SCE local areas:
      - Tehachapi and Big Creek Corridor
      - North of Lugo area
      - East of Lugo area;
      - Eastern area; and
      - Metro area

- **SDG&E area**
  - Bulk transmission
  - Sub-transmission

- **Valley Electric Association area**
- **ISO combined bulk system**
Use of Past Studies

• Starting this cycle, the CAISO will evaluate areas known to have no major changes compared to assumptions made in prior planning cycles for potential use of past studies.

• Within the current TPL-001-5 Standard, the Requirement R2.6 allows for use of past studies to support the planning assessment.

• At a high level, the process will include three major steps. 1) Data collection, 2) Evaluation of data change and 3) Drawing conclusions using outcome of data change evaluation and engineering judgement.

• Data collection and evaluation of extent of change will include following major categories:
  – Transmission data
  – Generation data
  – Load data
  – Applicable standards
Transmission Assumptions

• Transmission Projects
  – Transmission projects that the CAISO has approved will be modeled in the study base case
  – Canceled and on-hold projects will not be modeled

• Reactive Resources
  – The study models the existing and new reactive power resources in the base cases to ensure that realistic reactive support capability will be included in the study

• Protection Systems
  – The major new and existing SPS, safety nets, and UVLS that will be included in the study
  – Continue to include RAS models and work with PTOs to obtain remaining RAS models.

• Control Devices
  – Several control devices were modeled in the studies
Load Forecast Assumptions

Energy and Demand Forecast

- California Energy Demand Updated Forecast 2020-2030 adopted by California Energy Commission (CEC) on January 22, 2020 will be used:
  - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
  - Additional Achievable Energy Efficiency (AAEE)
    - Consistent with CEC 2019 IEPR
    - Mid AAEE will be used for system-wide studies
    - Low AAEE will be used for local studies
  - CEC forecast information is available on the CEC website at: 
    http://www.energy.ca.gov/2019_energypolicy/documents/
Load Forecast Assumptions

Energy and Demand Forecast (continued)

• Load forecasts to be used for each of the reliability assessment studies.
  – 1-in-10 weather year, mid demand baseline case with low AAEE load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the local capacity requirement (LCR) areas
  – 1-in-5 weather year, mid demand baseline case with mid AAEE load forecast will be used for bulk system studies
Load Forecast Assumptions
Methodologies to Derive Bus Level Forecast

• The CEC load forecast is generally provided for the larger areas and does not provide the granularity down to the bus-level which is necessary in the base cases for the reliability assessment.

• The local area load forecast are developed at the bus-level by the participating transmission owners (PTOs).

• Descriptions of the methodologies used by each of the PTOs to derive bus-level load forecasts using CEC data as a starting point are included in the draft Study Plan.
Load Forecast Assumptions

**BTM-PV, BTM-Storage and AAEE**

- Similar to previous cycles, BTM-PV will be modeled explicitly in the 2020-2021 TPP base cases.
  - Amount of the BTM-PV to be modeled will be based on 2019 IEPR data.
  - Location to model BTM-PV will be identified based on location of existing BTM-PV, information from PTO on future growth and BTM-PV capacity by forecast climate zone information from CEC.
  - Output of the BTM-PV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.
  - Composite load model CMPLDWWG will be used to model the BTM-PV. DER_A model will be used for dynamic representation of BTM-PV.

- BTM-storage will not be modeled explicitly in 2020-2021 TPP base cases due to limitation within the GE PSLF tool to model more than one distributed resources behind each load and lack of locational information.

- AAEE will be modeled using the CEC provided bus-bar allocations and will be modeled as negative load.
Supply Side Assumptions - Continued coordination with CPUC Integrated Resource Planning (IRP)

• CPUC Proposed Decision:  
  http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF  
  – Base portfolio (for Reliability, Policy and Economic Assessment)

• **Base portfolio** modeling assumptions to be used in 2020-2021 TPP:  
  – CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP  
    (Release 1 covering base portfolio details)  
Generation Assumptions

- One-year operating cases
- 2-5-year planning cases
  - Generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study;
  - Conventional generation in pre-construction phase with executed LGIA and progressing forward will be modeled off-line but will be available as a non-wire mitigation option.
  - OTC repowering projects will be modeled in lieu of existing resources as long as they have power purchase approval from the CPUC or other Local Regulatory Agency (LRA) and are projected to be in service within the timeframe of the study.
  - The contracted resources considered to be baseline assumptions for selecting the CPUC’s Base Portfolio will be utilized for modeling specific generation.
- 6-10-year planning cases
  - The CPUC’s Portfolio
  - Retired generation is modeled offline and disconnected in appropriate study years
  - Generation greater than 40 years old modeled offline; however may be dispatched for identified reliability needs
Generation Assumptions

*Distribution connected resources modeling*

- Behind-the-meter generators: Model explicitly as component of load
- In-front-of-the-meter with resource ID: Model as individual generator
- In-front-of-the-meter without resource ID: Model as individual generator if >10 MW, aggregate <10 MW same technology
Generation Assumptions

Generation Retirements

• **Nuclear Retirements**
  – Diablo Canyon will be modeled off-line based on the OTC compliance date

• **Once Through Cooled Retirements**
  – Separate slide below for OTC assumptions

• **Renewable and Hydro Retirements**
  – Assumes these resource types stay online unless there is an announced retirement date.

• **Other Retirements**
  – Unless otherwise noted, assumes retirement based resource age of 40 years or more. List included in Appendix A of the draft study plan.
Generation Assumptions

OTC Generation

Modeling of the once-through cooled (OTC) generating units follows the State Water Resources Control Board (SWRCB)’s Policy on OTC plants with the following exception:

- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table A2-1 in the draft study plan; and
- All other OTC generating units will be modeled off-line beyond their compliance dates, as illustrated in Table A2-1, or per proposed retirements by the generation owners to proceed on repowering projects that have been approved by the state regulatory agencies.
### Generation Assumptions

**CEC permitted resources or CPUC-approved long-term procurement resources (Thermal and Solar Thermal)**

<table>
<thead>
<tr>
<th>PTO Area</th>
<th>Project</th>
<th>Capacity (MW)</th>
<th>Expected In-service Date</th>
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<tr>
<td>SCE</td>
<td>Huntington Beach Energy Project Unit 6 (CCGT) *</td>
<td>644</td>
<td>2020</td>
</tr>
<tr>
<td>SCE</td>
<td>Alamitos Energy Center Unit 8 (CCGT) *</td>
<td>640</td>
<td>2020</td>
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**Notes:**

*These projects have received PPTA approvals from the CPUC as part of Long Term Procurement Plan (LTPP) process.*
Preferred Resources

• Demand Response
  – Long-term transmission expansion studies may utilize fast-response DR and slow-response PDR if it can be dispatched pre-contingency.
  – DR that can be relied upon participates, and is dispatched from, the ISO market in sufficiently less than 30 minutes (implies that programs may need 20 minutes response time to allow for other transmission operator activities) from when it is called upon.
  – DR capacity will be allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs.
  – The DR capacity amounts will be modeled offline in the initial reliability study cases and will be used as potential mitigation in those planning areas where reliability concerns are identified.
Preferred Resources

- **Energy Storage**
  - CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the CAISO planning area.
  - Existing and proposed energy storage that will be procured by IOUs including approved by CPUC.
  - Behind-the-meter energy storage is netted to load due to tool limitation and lack of locational information.
  - The CPUC staff has indicated that while considering portfolio-selected storage as a mitigation option for reliability issues, the ISO should not include the full capital cost of storage in the assessment of alternatives.
### Major Path Flows and Interchange

#### Northern area (PG&E system) assessment

<table>
<thead>
<tr>
<th>Path</th>
<th>Transfer Capability/SOL (MW)</th>
<th>Scenario in which Path will be stressed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Path 26 (N-S)</td>
<td>4,000</td>
<td>Summer Peak</td>
</tr>
<tr>
<td>PDCI (N-S)</td>
<td>3,220</td>
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</tr>
<tr>
<td>Path 66 (N-S)</td>
<td>4,800</td>
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<tr>
<td>Path 15 (N-S)</td>
<td>-5,400</td>
<td>Spring Off Peak</td>
</tr>
<tr>
<td>Path 26 (N-S)</td>
<td>-3,000</td>
<td></td>
</tr>
<tr>
<td>Path 66 (N-S)</td>
<td>-3,675</td>
<td>Winter Peak</td>
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</table>

#### Southern area (SCE & SDG&E system) assessment

<table>
<thead>
<tr>
<th>Path</th>
<th>Transfer Capability/SOL (MW)</th>
<th>Near-Term Target Flows (MW)</th>
<th>Scenario in which Path will be stressed, if applicable</th>
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<tr>
<td>Path 26 (N-S)</td>
<td>4,000</td>
<td>4,000</td>
<td>Summer Peak</td>
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<tr>
<td>Path 26 (N-S)</td>
<td>3,000</td>
<td>0 to 3,000</td>
<td>Spring Off Peak</td>
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<tr>
<td>PDCI (N-S)</td>
<td>3220</td>
<td>3220</td>
<td>Summer Peak</td>
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<tr>
<td>West of River (WOR)</td>
<td>11,200</td>
<td>5,000 to 11,200</td>
<td>Summer Peak</td>
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<tr>
<td>East of River (EOR)</td>
<td>10,100</td>
<td>4,000 to 10,100</td>
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<tr>
<td>San Diego Import</td>
<td>2765~3565</td>
<td>2,400 to 3,500</td>
<td>Summer Peak</td>
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<tr>
<td>SCIT</td>
<td>17,870</td>
<td>15,000 to 17,870</td>
<td>Summer Peak</td>
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<td>Path 45 (N-S)</td>
<td>600</td>
<td>0 to 408</td>
<td>Summer Peak</td>
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<tr>
<td>Path 45 (S-N)</td>
<td>800</td>
<td>0 to 300</td>
<td>Spring Off Peak</td>
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<td>Study Area</td>
<td>Near-term Planning Horizon</td>
<td>Long-term Planning Horizon</td>
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<td></td>
<td>2022</td>
<td>2025</td>
<td>2030</td>
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<td>Northern California (PG&amp;E) Bulk System</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak, Spring Off-Peak, Winter Off-Peak</td>
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<td>Summer Peak, Winter Peak, Spring Off-Peak</td>
<td>Summer Peak, Winter Peak, Spring Off-Peak</td>
<td>Summer Peak, Winter Peak</td>
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<td>North Coast and North Bay</td>
<td>Summer Peak, Winter Peak, Spring Off-Peak</td>
<td>Summer Peak, Winter Peak, Spring Off-Peak</td>
<td>Summer Peak, Winter Peak</td>
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<td>North Valley</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak</td>
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<tr>
<td>Central Valley</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak</td>
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<td>Greater Bay Area</td>
<td>Summer Peak, Winter peak - (SF &amp; Peninsula), Spring Off-Peak</td>
<td>Summer Peak, Winter peak - (SF &amp; Peninsula), Spring Off-Peak</td>
<td>Summer Peak, Winter peak - (SF Only)</td>
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<td>Greater Fresno</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak, Spring Off-Peak</td>
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<td>Kern</td>
<td>Summer Peak, Spring Off-Peak</td>
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<td>Central Coast &amp; Los Padres</td>
<td>Summer Peak, Winter Peak, Spring Off-Peak</td>
<td>Summer Peak, Winter Peak, Spring Off-Peak</td>
<td>Summer Peak, Winter Peak</td>
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<td>Southern California Bulk Transmission System</td>
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<td>Summer Peak, Spring Off-Peak</td>
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<td>Summer Peak, Spring Off-Peak</td>
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<td>Valley Electric Association</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak, Spring Off-Peak</td>
<td>Summer Peak</td>
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## Study Scenarios - Baseline Scenarios Definition and Renewable Dispatch for System-wide Cases

### PTO Scenario Day/Time BTM-PV Transmission Connected PV Transmission Connected Wind % of managed peak load

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<tbody>
<tr>
<td>PGE</td>
<td>Summer Peak</td>
<td>7/28 HE 18</td>
<td>See CAISO</td>
<td>17%</td>
<td>See CAISO</td>
<td>See CAISO</td>
<td>10%</td>
<td>See CAISO</td>
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<td>62%</td>
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<td>100%</td>
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<td>4/2 HE 13</td>
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<td>80%</td>
<td>See CAISO</td>
<td>See CAISO</td>
<td>92%</td>
<td>See CAISO</td>
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<td>20%</td>
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<tr>
<td>PGE</td>
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<td>11/9 HE 4</td>
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<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>13%</td>
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<td>SCE</td>
<td>Summer Peak</td>
<td>9/2 HE 17</td>
<td>See CAISO</td>
<td>44%</td>
<td>23%</td>
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<td>51%</td>
<td>21%</td>
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<td>40%</td>
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<td>SCE</td>
<td>Spring Off Peak</td>
<td>4/3 HE 12</td>
<td>See CAISO</td>
<td>80%</td>
<td>See CAISO</td>
<td>See CAISO</td>
<td>96%</td>
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<td>34%</td>
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<td>31%</td>
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<td>SDG&amp;E</td>
<td>Summer Peak</td>
<td>9/3 HE 19</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>33%</td>
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<td>SDG&amp;E</td>
<td>Spring Off Peak</td>
<td>4/9 HE 13</td>
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<td>78%</td>
<td>See CAISO</td>
<td>95%</td>
<td>See CAISO</td>
<td>30%</td>
<td>See CAISO</td>
<td>23%</td>
<td>See CAISO</td>
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</tr>
<tr>
<td>VEA</td>
<td>Summer Peak</td>
<td>6/24 HE 16</td>
<td>36%</td>
<td>36%</td>
<td>36%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
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</tr>
<tr>
<td>VEA</td>
<td>Spring Off Peak</td>
<td>4/15 HE 3</td>
<td>0%</td>
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<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>33%</td>
<td>33%</td>
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</table>

### CAISO Scenarios Day/Time BTM-PV Transmission Connected PV Transmission Connected Wind % of non-coincident PTO managed peak load

<table>
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</tr>
</thead>
<tbody>
<tr>
<td>CAISO</td>
<td>Summer Peak</td>
<td>9/3 HE 19</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>42%</td>
<td>40%</td>
<td>33%</td>
<td>95%</td>
<td>100%</td>
<td>98%</td>
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<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>CAISO</td>
<td>Spring Off Peak</td>
<td>4/7 HE 13</td>
<td>80%</td>
<td>81%</td>
<td>80%</td>
<td>92%</td>
<td>94%</td>
<td>95%</td>
<td>20%</td>
<td>34%</td>
<td>30%</td>
<td>16%</td>
<td>23%</td>
<td>14%</td>
<td>16%</td>
<td>23%</td>
<td>14%</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>CAISO</td>
<td>Summer Peak</td>
<td>9/2 HE 18</td>
<td>8%</td>
<td>5%</td>
<td>4%</td>
<td>4%</td>
<td>2%</td>
<td>1%</td>
<td>32%</td>
<td>32%</td>
<td>27%</td>
<td>94%</td>
<td>99%</td>
<td>95%</td>
<td>94%</td>
<td>99%</td>
<td>95%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CAISO</td>
<td>Spring Off Peak</td>
<td>5/3 HE 20</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>60%</td>
<td>59%</td>
<td>68%</td>
<td>64%</td>
<td>57%</td>
<td>66%</td>
<td>64%</td>
<td>57%</td>
<td>66%</td>
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</table>
## Study Scenarios - Sensitivity Studies

<table>
<thead>
<tr>
<th>Sensitivity Study</th>
<th>Near-term Planning Horizon</th>
<th>Long-Term Planning Horizon</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2022</td>
<td>2025</td>
</tr>
<tr>
<td>Summer Peak with high CEC forecasted load</td>
<td>-</td>
<td>PG&amp;E Bulk</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PG&amp;E Local Areas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Southern California Bulk</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCE Local Areas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SDG&amp;E Main</td>
</tr>
<tr>
<td>Off peak with heavy renewable output and minimum gas generation commitment</td>
<td>-</td>
<td>PG&amp;E Bulk</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PG&amp;E Local Areas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Southern California Bulk</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCE Local Areas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SDG&amp;E Main</td>
</tr>
<tr>
<td>Summer Peak with heavy renewable output and minimum gas generation commitment</td>
<td>PG&amp;E Bulk</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>PG&amp;E Local Areas</td>
<td></td>
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<tr>
<td></td>
<td>Southern California Bulk</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SCE Local Areas</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SDG&amp;E Main</td>
<td></td>
</tr>
<tr>
<td>Summer Peak with high SVP forecasted load</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Summer Peak with forecasted load addition</td>
<td>VEA Area</td>
<td>VEA Area</td>
</tr>
<tr>
<td>Summer Off peak with heavy renewable output</td>
<td>VEA Area</td>
<td></td>
</tr>
<tr>
<td>Summer Peak with Retirement of QF Generations</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Summer Peak without Facility Rerates</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PG&amp;E Local Areas</td>
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</table>
## Study Scenarios - Sensitivity Scenario Definitions and Renewable Generation Dispatch

<table>
<thead>
<tr>
<th>PTO</th>
<th>Scenario</th>
<th>Starting Baseline Case</th>
<th>BTM-PV Baseline</th>
<th>BTM-PV Sensitivity</th>
<th>Transmission Connected PV Baseline</th>
<th>Transmission Connected PV Sensitivity</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E</td>
<td>Summer Peak with high CEC forecasted load</td>
<td>2025 Summer Peak</td>
<td>3%</td>
<td>3%</td>
<td>2%</td>
<td>2%</td>
<td>Load increased by turning off AAEE</td>
</tr>
<tr>
<td></td>
<td>Off peak with heavy renewable output and minimum gas generation commitment</td>
<td>2025 Spring Off-peak</td>
<td>0%</td>
<td>99%</td>
<td>0%</td>
<td>99%</td>
<td>Solar and wind dispatch increased to average of 20% exceedance values</td>
</tr>
<tr>
<td></td>
<td>Summer Peak with heavy renewable output and minimum gas generation commitment</td>
<td>2022 Summer Peak</td>
<td>17%</td>
<td>99%</td>
<td>10%</td>
<td>99%</td>
<td>Solar and wind dispatch increased to 20% exceedance values</td>
</tr>
<tr>
<td></td>
<td>Summer Peak with Retirement of QF Generations</td>
<td>2030 Summer Peak</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>All QF facilities in Kern area turned off</td>
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<td></td>
<td>Summer Peak with high SVP forecasted load</td>
<td>2030 Summer Peak</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>Use SPV’s forecast for 2030</td>
</tr>
<tr>
<td></td>
<td>Summer Peak without Facility Rerates</td>
<td>2030 Summer Peak</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>Study to be performed using regular (non-rerated) facility ratings</td>
</tr>
<tr>
<td>SCE</td>
<td>Summer Peak with high CEC forecasted load</td>
<td>2025 Summer Peak</td>
<td>23%</td>
<td>23%</td>
<td>21%</td>
<td>21%</td>
<td>Load increased per CEC high load scenario</td>
</tr>
<tr>
<td></td>
<td>Off peak with heavy renewable output and minimum gas generation commitment</td>
<td>2025 Spring Off-peak</td>
<td>0%</td>
<td>91%</td>
<td>0%</td>
<td>99%</td>
<td>Solar and wind dispatch increased to 20% exceedance values</td>
</tr>
<tr>
<td></td>
<td>Summer Peak with heavy renewable output and minimum gas generation commitment</td>
<td>2022 Summer Peak</td>
<td>44%</td>
<td>91%</td>
<td>51%</td>
<td>99%</td>
<td>Solar and wind dispatch decreased with net load unchanged</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>Summer Peak with high CEC forecasted load</td>
<td>2025 Summer Peak</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>Load increased per CEC high load scenario</td>
</tr>
<tr>
<td></td>
<td>Off peak with heavy renewable output and minimum gas generation commitment</td>
<td>2025 Spring Off-peak</td>
<td>0%</td>
<td>96%</td>
<td>0%</td>
<td>96%</td>
<td>Solar and wind dispatches increased to 20% exceedance values</td>
</tr>
<tr>
<td></td>
<td>Summer Peak with heavy renewable output and minimum gas generation commitment</td>
<td>2022 Summer Peak</td>
<td>0%</td>
<td>96%</td>
<td>0%</td>
<td>96%</td>
<td>Solar and wind dispatches increased to 20% exceedance values</td>
</tr>
<tr>
<td>VEA</td>
<td>Summer Peak with forecasted load addition</td>
<td>2022 Summer Peak</td>
<td>44%</td>
<td>44%</td>
<td>36%</td>
<td>36%</td>
<td>Load increase reflect future load service request</td>
</tr>
<tr>
<td></td>
<td>Summer Peak with forecasted load addition</td>
<td>2025 Summer Peak</td>
<td>44%</td>
<td>44%</td>
<td>36%</td>
<td>36%</td>
<td>Load increase reflect future load service request</td>
</tr>
<tr>
<td></td>
<td>Off-peak with heavy renewable output</td>
<td>2025 Spring Off-peak</td>
<td>0%</td>
<td>0%</td>
<td>-</td>
<td>-</td>
<td>Modeled active GIDAP projects in the queue</td>
</tr>
</tbody>
</table>
Study Base Cases

- WECC base cases will be used as the starting point to represent the rest of WECC

<table>
<thead>
<tr>
<th>Study Year</th>
<th>Season</th>
<th>WECC Base Case</th>
<th>Year Published</th>
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<tbody>
<tr>
<td>2022</td>
<td>Summer Peak</td>
<td>20HS3a1</td>
<td>2019</td>
</tr>
<tr>
<td></td>
<td>Winter Peak</td>
<td>20HW3a1</td>
<td>2019</td>
</tr>
<tr>
<td></td>
<td>Spring Off-Peak</td>
<td>20LSP1sa1</td>
<td>2019</td>
</tr>
<tr>
<td>2025</td>
<td>Summer Peak</td>
<td>25HS2a1</td>
<td>2019</td>
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<tr>
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<td>Winter Peak</td>
<td>25HW2a1</td>
<td>2019</td>
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<tr>
<td></td>
<td>Spring Off-Peak</td>
<td>20LSP1sa1</td>
<td>2019</td>
</tr>
<tr>
<td>2030</td>
<td>Summer Peak</td>
<td>30HS1a1</td>
<td>2019</td>
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<td>Winter Peak</td>
<td>30HW1a1</td>
<td>2019</td>
</tr>
<tr>
<td></td>
<td>Spring Off-Peak</td>
<td>30LSP1Sa1</td>
<td>2019</td>
</tr>
<tr>
<td></td>
<td>Winter Off-Peak</td>
<td>30LSP1Sa1</td>
<td>2019</td>
</tr>
</tbody>
</table>
Contingencies

• Normal conditions (P0)

• Single contingency (Category P1)
  – The assessment will consider all possible Category P1 contingencies based upon the following:
    • Loss of one generator (P1.1)
    • Loss of one transmission circuit (P1.2)
    • Loss of one transformer (P1.3)
    • Loss of one shunt device (P1.4)
    • Loss of a single pole of DC lines (P1.5)

• Single contingency (Category P2)
  – The assessment will consider all possible Category P2 contingencies based upon the following:
    • Loss of one transmission circuit without a fault (P2.1)
    • Loss of one bus section (P2.2)
    • Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
    • Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)
Contingencies (continued)

• **Multiple contingency (Category P3)**
  - The assessment will consider the Category P3 contingencies with the loss of a generator unit followed by system adjustments and the loss of the following:
    - Loss of one generator (P3.1)
    - Loss of one transmission circuit (P3.2)
    - Loss of one transformer (P3.3)
    - Loss of one shunt device (P3.4)
    - Loss of a single pole of DC lines (P3.5)

• **Multiple contingency (Category P4)**
  - The assessment will consider the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:
    - Loss of one generator (P4.1)
    - Loss of one transmission circuit (P4.2)
    - Loss of one transformer (P4.3)
    - Loss of one shunt device (P4.4)
    - Loss of one bus section (P4.5)
    - Loss of a bus-tie-breaker (P4.6)
Contingencies (continued)

- **Multiple contingency (Category P5)**
  - The assessment will consider the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant component of protection system protecting the faulted element to operate as designed, for one of the following:
    - Loss of one generator (P5.1)
    - Loss of one transmission circuit (P5.2)
    - Loss of one transformer (P5.3)
    - Loss of one shunt device (P5.4)
    - Loss of one bus section (P5.5)

- **Multiple contingency (Category P6)**
  - The assessment will consider the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.

- **Multiple contingency (Category P7)**
  - The assessment will consider the Category P7 contingencies for the loss of a common structure as follows:
    - Any two adjacent circuits on common structure (P7.1)
    - Loss of a bipolar DC lines (P7.2)
Contingency Analysis (continued)

- **Extreme contingencies (TPL-001-4)**
  - As a part of the planning assessment the ISO assesses Extreme Event contingencies per the requirements of TPL-001-4;
  - however the analysis of Extreme Events will not be included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.
Technical Studies

• The planning assessment will consist of:
  – Power Flow Contingency Analysis
  – Post Transient Analysis
    • Post Transient Thermal Analysis
    • Post Transient Voltage Stability Analysis
      – Post Transient Voltage Deviation Analysis
      – Voltage Stability and Reactive Power Margin Analysis
  – Transient Stability Analysis
Corrective Action Plans

• The technical studies mentioned in this section will be used for identifying mitigation plans for addressing reliability concerns.

• As per ISO tariff, identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards.
  
  – In making this determination, the ISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as:
    • acceleration or expansion of existing projects,
    • demand-side management,
    • special protection systems,
    • generation curtailment,
    • interruptible loads,
    • storage facilities; or
    • reactive support
Policy-driven Assessment
Unified Planning Assumptions & Study Plan

Sushant Barave
Senior Advisor, Regional Transmission South

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2019
Agenda

• Policy-driven assessment objectives and methodology

• Description of portfolios transmitted (and to be transmitted) by the CPUC

• Modeling data transmitted by the CPUC for 2020-2021 TPP
Agenda

• Policy-driven assessment objectives and methodology

• Description of portfolios transmitted (and to be transmitted) by the CPUC

• Modeling data transmitted by the CPUC for 2020-2021 TPP
Evaluation of transmission solutions needed to meet state, municipal, county or federal policy requirements:

- **Reliability Analysis**
  - NERC Compliance, Local Capacity Needs

- **Policy-driven Analysis**
  - RPS Portfolio Analysis

- **Economic Analysis**
  - Congestion studies
  - Identify economic transmission needs

Interregional Transmission Projects considered at each stage.

Results
Key objectives of the policy-driven assessment in 2020-2021 TPP:

1. Study the transmission impacts of the base and sensitivity portfolios transmitted to the CAISO by CPUC
   a. Capture powerflow and stability impacts
   b. Test the deliverability of resources selected to be full capacity deliverability status (FCDS)
   c. Analyze renewable curtailment data

2. Evaluate transmission solutions (Category 1 and Category 2) needed to meet state, municipal, county or federal policy requirements or directives

3. Test the CAISO-provided transmission capability estimates used in CPUC’s integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation

4. Support and test the framework based on CPUC-provided objectives for siting generic storage selected in CPUC IRP process
The policy assessment framework relies on three study components to identify transmission impacts and solutions:

**CPUC and CEC**
- Portfolio MW amounts and locations provided by the state agencies
- Portfolio modeling
- Technical analysis

**CAISO**
- Transmission impacts identification
- Transmission solution identification

---

**Renewable Portfolios**
- Input into the next cycle of renewable portfolio creation

**Resource Mapping**
- Power flow base cases (deliverability)
- Production cost simulation base case

**Portfolio modeling**
- Deliverability Assessment
- Power flow base cases (reliability)

**Technical analysis**
- Production Cost Simulation
- Generation dispatch and path flow modeling for severe snapshots

**Transmission impacts identification**
- Deliverability constraints
- Renewable curtailment and congestion information

**Transmission solution identification**
- Identification of Category 1 and Category 2 policy-driven transmission solutions

---

**Reliability Studies**
- Reliability constraints
Agenda

• Policy-driven assessment objectives and methodology

• Description of portfolios transmitted (and to be transmitted) by the CPUC

• Modeling data transmitted by the CPUC for 2020-2021 TPP
The CPUC Proposed Decision released on February 21, 2020 recommended portfolios for use in TPP

- Proposed Decision: [http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF](http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF)
  - Base portfolio (for Reliability, Policy and Economic Assessment)
  - Sensitivity portfolio #1 (for Policy Assessment)
  - Sensitivity portfolio #2 (for Policy Assessment)

- The CPUC staff developed the base and sensitivity portfolios using RESOLVE capacity expansion model
Policy-driven base portfolio: Adjusted Preferred System Plan (2017-2018 IRP)

• The base portfolio for reliability, policy and economic assessment is based on the 2018 Preferred System Portfolio (PSP) adopted in D.19-04-040, with certain updates.

• GHG target for the electric sector used in this portfolio is 46 million metric tons (MMT) by 2030.
Policy-driven sensitivity portfolio #1: Reference System Portfolio (2019-2020 IRP)

- GHG target for the electric sector used in this portfolio is 46 million metric tons (MMT) by 2030.

- This portfolio significantly varies from the previous portfolios analyzed for TPP purposes and warrants analysis as a sensitivity prior to moving to investment stage.

- Consists of new buildout of ~11,000 MW in-state solar, ~2,800 MW in-state wind, ~600 MW out-of-state wind and ~9,800 MW energy storage.
Policy-driven sensitivity portfolio #2: High energy-only buildout (2019-2020 IRP)

- A portfolio to test areas in which the benefits of inexpensive transmission solutions could help reduce curtailment of renewables.

- Relaxed the energy-only transmission capability estimates in zones that are expected to offer relatively low-cost upgrade options to mitigate renewable curtailment.

- GHG target for the electric sector used in this portfolio is 30 million metric tons (MMT) by 2030.
Agenda

• Policy-driven assessment objectives and methodology

• Description of portfolios transmitted (and to be transmitted) by the CPUC

• Modeling data transmitted by the CPUC for 2020-2021 TPP
Base portfolio modeling assumptions to be used in 2020-2021 TPP

• CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP (Release 1 covering base portfolio details)

• CEC’s busbar mapping results (base portfolio)
  https://caenergy.databasin.org/galleries/eab0ce3a5be447ce928a310e80c65c8d#expand=208848
**Sensitivity portfolios** modeling assumptions to be used in 2020-2021 TPP

- CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP
  (Release 2 expected in March 2020)

- CEC’s busbar mapping results
  (expected in March 2020)
In addition to these resources, 1,157 MW of 1.3-hour storage and up to 1,000 MW of 4-hour storage in included in the base portfolio.
Generic energy storage mapping and modeling - base portfolio

• CPUC staff has not mapped the generic storage resources to specific locations.

• The CAISO will consider these generic storage resources as potential mitigation options for reliability needs identified in TPP.

• The CPUC staff has indicated that while considering portfolio-selected storage as a mitigation option for reliability issues, the CAISO should not include the full capital cost of storage in the assessment of alternatives.
Generic energy storage mapping and modeling - sensitivity portfolio #1 and #2

• CPUC staff is in the process of mapping generic storage to specific locations for the sensitivity portfolios.

• The approach and the findings are expected to be included in “Modeling Assumptions for the 2020-2021 TPP (Release 2)”
Economic Assessment
Unified Planning Assumptions & Study Plan

Yi Zhang

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020
Economic planning study

- The CAISO economic planning study follows the CAISO tariff and Transmission Economic Assessment Methodology (TEAM) to do the following studies
  - Congestion analysis
  - Study request evaluations
  - Economic assessments
Production cost model (PCM)

• 2030 ADS PCM will be used as a starting point
  – The first release of the 2030 ADS PCM is projected to be available at the end of June, 2020
• The unified planning assumptions will be used to update the CAISO system model in the PCM, consistent with the CAISO’s TPP reliability study
  – Transmission topology
  – Generator assumptions for existing generators, renewable portfolio (CPUC Base Portfolio), energy storage, and retirement
  – Load forecast for 2030 will use the same CEC forecast, but use 1-in-2 peak demand to adjust load profiles
• Other model updates would be also needed through the PCM development and validation process
  – Will be discussed in future stakeholder meetings
Production cost simulation and congestion analysis

• Production cost simulations will be conducted using ABB GridView software on the CAISO’s planning PCM

• Congestion analysis and renewable curtailment analysis will use the production cost simulation results
  – The analysis results will be considered in finalizing the selection of high priority areas, and in the policy study as well
Economic planning study requests

• Economic Planning Study Requests are to be submitted to the CAISO during the comment period of the draft Study Plan

• The CAISO will evaluate and consider the Economic Planning Study Requests as set out in section 24.3.4.1 of the CAISO Tariff
Selection of high priority areas for detailed study

• In the Study Plan phase of a planning cycle, the CAISO has carried all study requests forward as potential high priority study requests, which are mainly based on the previous cycle’s congestion analysis.

• The congestion results in the current cycle will be considered in finalizing the high priority areas, since changing circumstances may lead to more favorable results.

• This approach gives more opportunity for the study requests to be considered, and can take into account the latest and most relevant information available.
Economic assessment

• The CAISO will conduct economic assessments for the selected high priority areas

• Economic benefit assessment is based on TEAM
  – Production cost benefit is assessed using production cost simulation results
  – Other benefits, such as capacity benefit, are assessed on a case by case basis

• Cost estimates are based on either per unit cost or study request submittal if available

• Total benefit and total cost (revenue requirement) are used in benefit-to-cost ratio calculation
Next Steps
Unified Planning Assumptions & Study Plan

Isabella Nicosia
Associate Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
February 28, 2020
2020-2021 Transmission Planning Process
Next Steps

• Stakeholders requested to submit comments to: regionaltransmission@caiso.com

• Stakeholder comments are to be submitted within two weeks after stakeholder meetings: by March 13

• CAISO will post comments and responses on website

• Final Study Plan will be posted on March 31