Agenda & Overview

Jeff Billinton
Director, Transmission Infrastructure Planning

2020-2021 Transmission Planning Process Stakeholder Meeting
June 3, 2020

2020-2021 Transmission Planning Process Stakeholder Call - Agenda

Topic	Presenter
Overview	Jeff Billinton
Wildfire risk assessment	Binaya Shrestha
Use of past studies	Lindsey Thomas
Project review update – SDG&E area	Charles Cheung
Round Mountain 500 kV reactive device update	Binaya Shrestha
Storage mapping and resource retirement	Sushant Barave
10-year LCR study update and approach	Catlin Micsa
Interregional Transmission Project (ITP) update	Gary DeShazo
Wrap-up	Jeff Billinton

2020-2021 Transmission Planning Process

December 2019

April 2020

March 2021

Phase 1 – Develop detailed study plan

State and federal policy

CEC - Demand forecasts

CPUC - Resource forecasts and common assumptions with procurement processes

Other issues or concerns

Phase 2 - Sequential technical studies

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

Publish comprehensive transmission plan with recommended projects

Phase 3 Procurement

CAISO Board for approval of transmission plan

California ISO

2020-2021 Transmission Plan Milestones

- Draft Study Plan posted on February 21
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 13
- Final Study Plan to be posted on March 31
- Stakeholder call – update June 3
- Comments to be submitted by June 17
- Preliminary reliability study results to be posted on August 14
- Stakeholder meeting on September 23 and 24
- Comments to be submitted by October 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

Stakeholder comments

- Stakeholders requested to submit comments to: regionaltransmission@caiso.com
- Stakeholder comments are to be submitted within two weeks after stakeholder meetings: **by June 17**
- CAISO will post comments and responses on website

California ISO

Wildfire Mitigation Assessment Update

Binaya Shrestha
Manager Regional Transmission Engineer North

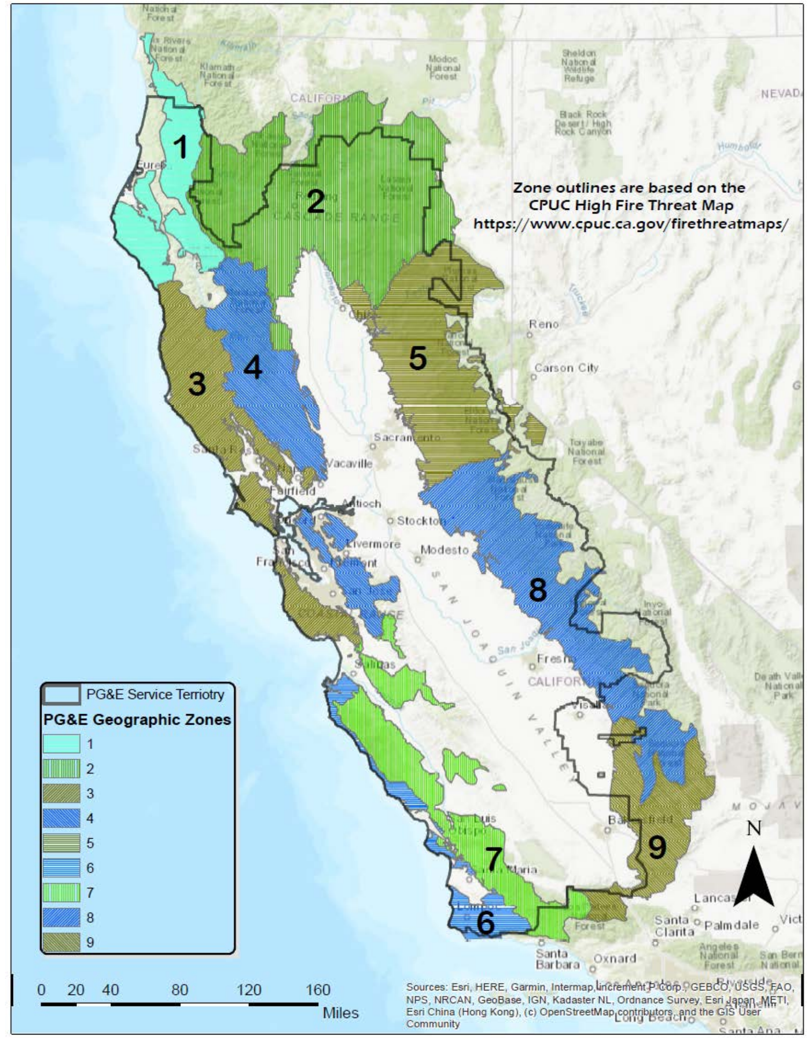
2020-2021 Transmission Planning Process Stakeholder Meeting
June 3, 2020

Discussion Items

- Wildfire & PSPS event information
- Planning approach
- Next Steps

Wildfire related information being collected for transmission planning

- Transmission system overlaid with fire zones
  - Facilities in Tier 2 and 3 fire zones
- Facilities de-energized for PSPS event in 2019
- Hardening program of existing facilities



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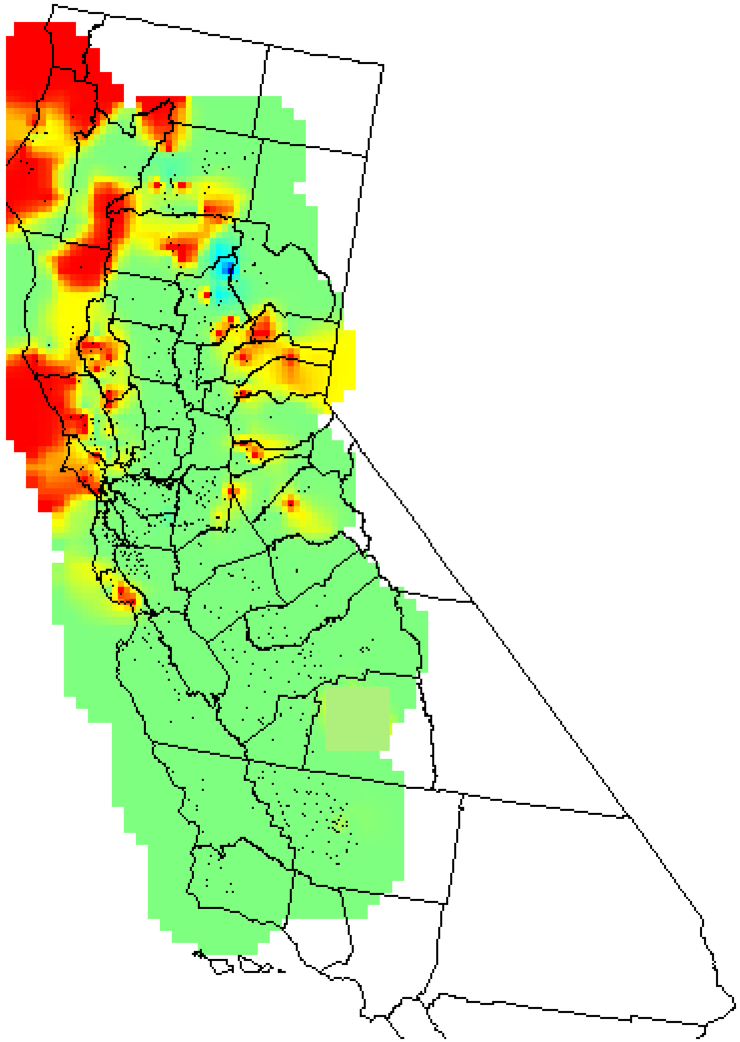
2019 PSPS Event Example: October 29, 2019 Event

<u>Impacted substation heat map</u>

- Identifies geographic areas that were impacted as a result of the specific PSPS Event
- Local areas identified as being impacted in various parts of the system



Potential scenario development for planning assessments

- Scenarios may be created by taking out transmission facilities in identified fire zones within various planning areas or bulk system assessments
  - Different scenarios may be created by taking out combination of different voltage facilities and/or facilities within various fire zones
  - A reasonable number of boundary case scenarios need to be considered, <u>based on a fact-based framework</u>, as:
    - Taking all facilities may be infeasible
    - Far too many combinations of overlapping outages exist to be practical or manageable for study
    - Facility integrity and/or meteorology data, if available, may also be used in determining facilities to take out within each scenario.
- Additional scenarios may be created based on 2019 PSPS events

Assessment of PSPS Impacts to prioritize areas for potential mitigation

- Assessment of potential impact
  - Direct impact
    - Local or radial system
    - For scenario based on 2019 actual events, may include impact from distribution facility outages based on data availability
  - Indirect impact
    - Area supply or bulk system with security for next N-1 contingency

Potential mitigation development

- Identify critical facilities in each local areas for potential to reduce risk of fire impact
- Coordinate with PTOs on existing infrastructure hardening plans
- Identify active CAISO approved projects that could potentially reduce risk of fire impact
  – Identify opportunities to expedite implementation of active projects that could help alleviate identified issues
  – Identify opportunities for minor scope change of active projects that could help alleviate identified issues
- Identify potential new upgrades that could help reduce risk of fire impact

Planning standards performance requirements

- System performance under contingency events of PSPS beyond minimum requirements of NERC mandatory reliability standards and CAISO planning standards
- System performance of Extreme Events does not require mitigation
  - What criteria should be applied to approve mitigation
  - Critical Infrastructure concerns related to extreme event analysis

Next steps

- CAISO will be conducting assessment in 2020-2021 transmission planning process
- Stakeholder meeting in September will discuss:
  – Preliminary findings

Use of Past Studies Assessment

Lindsey Thomas

Regional Transmission Engineer

2020-2021 Transmission Planning Process Stakeholder Meeting

June 3, 2020

Background

The annual Transmission Planning Process (TPP) Reliability Assessment is performed in accordance with study requirements set forth in NERC TPL-001 Standard. Within the current TPL-001-4 Standard, the Requirement R2.6 allows for use of past studies to support the planning assessment. Below is the excerpt for the Standard:

"R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

> 2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
>
> 2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included."

High Level Process

On a high level, the process includes three major steps.

- Data collection
- Use of excel spreadsheet tool to evaluate change in data and
- Drawing conclusions using tool output and engineering judgement.

Inputs
Transmission
•New approval or re-scope
•Project cancellation
•Implementation delays
•Rating changes (TR ratings or rerates (high wind speed) not applicable)
•Seasonal setups
•Transformer tap settings
•Substation configuration changes
•SPS, RAS, operating procedure updates
•Additional (new) contingency
•Path Flow
•Planned outages
Generation
•New resources coming on-line
•Resource retirement
•Amount of resources in portfolio
•Generation technology change
•IBR reactive support capability modeling
•Capacity update
•Storage operating mode change
•Generator modeling updates
•Schedule voltage
•Planned outages
Demand
•Load forecast compared to previous cycle
•DER forecast compared to previous cycle
•Load power factor
•IBR reactive support capability modeling
•Load distribution change
Other
•Reliability Standards

Use of Past Study Methodology

For a given data parameter and engineer will determine the extent of change for that parameter. The tool will then look at how that particular parameter will affect a specific type of study. It will then combine that information in the form of a heat map. The darker the color the higher the extent of change and the bigger the impact on the study.

Inputs	Extent of Change			Outputs											
				Year-2	Year-5	Year-10	Steady-State			Transient			Short-Circuit		
Transmission	Year-2	Year-5	Year-10				Y2	Y5	Y10	Y2	Y5	Y10	Y2	Y5	Y10
•New approval or re-scope	N	L	L	NH	LH	LH	NH	LH	LH	NL	LL	LL	NM	LM	LM
•Project cancellation	N	N	N	NH	NH	NH	NH	NH	NH	NL	NL	NL	NM	NM	NM
•Implementation delays	N	M	M	NH	MH	MH	NH	MH	MH	NL	ML	ML	NM	MM	MM
•Rating changes (TR ratings or rerates (high wind speed) not applicable)	L	L	L	LH	LH	LH	LH	LH	LH	LL	LL	LL	LL	LL	LL
•Seasonal setups	N	N	N	NH	NH	NH	NH	NH	NH	NL	NL	NL	NL	NL	NL
•Transformer tap settings	N	N	N	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL
•Substation configuration changes	N	N	N	NM	NM	NM	NH	NH	NH	NL	NL	NL	NM	NM	NM
•SPS, RAS, operating procedure updates	N	N	N	NM	NM	NM	NM	NM	NM	NL	NL	NL	NL	NL	NL
•Additional (new) contingency	L	L	L	LL	LL	LL	LL	LL	LL	LL	LL	LL	LL	LL	LL
•Path Flow	N	N	N	NM	NM	NM	NM	NM	NM	NM	NM	NM	NL	NL	NL
•Planned outages	N	N	N	NH	NH	NH	NH	NH	NH	NH	NH	NH	NM	NM	NM
Generation															
•New resources coming on-line	N	N	N	NM	NM	NM	NM	NM	NM	NL	NL	NL	NH	NH	NH
•Resource retirement	N	N	N	NM	NM	NM	NM	NM	NM	NL	NL	NL	NH	NH	NH
•Amount of resources in portfolio	N	N	N	NM	NM	NM	NM	NM	NM	NL	NL	NL	NH	NH	NH
•Generation technology change	N	N	N	NL	NL	NL	NL	NL	NL	NL	NL	NL	NM	NM	NM
•IBR reactive support capability modeling	N	N	N	NM	NM	NM	NH	NH	NH	NL	NL	NL	NM	NM	NM
•Capacity update	N	N	N	NM	NM	NM	NL	NL	NL	NL	NL	NL	NM	NM	NM
•Storage operating mode change	N	N	N	NM	NM	NM	NL	NL	NL	NL	NL	NL	NM	NM	NM
•Generator modeling updates	N	N	N	NM	NM	NM	NL	NL	NL	NH	NH	NH	NM	NM	NM
•Schedule voltage	N	N	N	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL
•Planned outages	N	N	N	NM	NM	NM	NL	NL	NL	NL	NL	NL	NH	NH	NH
Demand															
•Load forecast compared to previous cycle	L	L	M	LH	LH	MH	LH	LH	MH	LL	LL	ML	LH	LH	MH
•DER forecast compared to previous cycle	L	L	L	LM	LM	LM	LM	LM	LM	LM	LM	LM	LL	LL	LL
•Load power factor	N	N	N	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL
•IBR reactive support capability modeling	N	N	N	NM	NM	NM	NH	NH	NH	NL	NL	NL	NM	NM	NM
•Load distribution change	N	N	N	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL	NL
Other															
•Reliability Standards	M	M	M	MH	MH	MH	MH	MH	MH	MH	MH	MH	MH	MH	MH

Color Grade	
NL	darker shade means higher material change
LN	
NM	
MN	
NH	
HN	
LL	
LM	
LM	
LH	
HL	
MM	
MH	
HM	
HH	

Assessment Conclusions – North

Area	Steady-State			Transient			Steady state analysis comments	Stability analysis comments
	Y2	Y5	Y10	Y2	Y5	Y10		
Greater Bay Area	√	√	√	San Jose and new P5	San Jose and new P5	San Jose and new P5	Recommend performing study for all three years, excluding Peninsula division due to new projects, project on-hold, project cancellation, new load interconnection and continued monitor of various facility loadings from previous cycle.	Recommend performing study for all three years with focus in south Bay area due to new energy storage projects (E-4949), significant amount of BTM-PV and interaction with SVP system.
North Valley	√	√	√	x	x	x	Recommend performing study for all three years due to changes to contingencies, SPS models.	Since these areas don't have new major generation addition or retirement, it is recommended to use last year study results, unless new P5 contingencies are identified in the area.
Central Valley	√	√	√	x	x	x	Recommend performing study for all three years due to changes to contingencies, SPS models.	
Humboldt	X	X	X	√	√	√	Recommend relying on last years studies for steady state. There was almost no BES facility results last cycle and there has been very minimal changes.	Recommend performing study for all three years due to the fact that there were some anomaly's seen in the results last cycle.
Central Coast/ Los Padres	X	√	√	x	x	x	Recommend performing study for all three years due to one new approved project that will be modeled also there is the existing on-hold project "North of Mesa" that will need to be evaluated this cycle.	Since this area doesn't have new major generation addition or retirement compared to last year's assumptions, the recommendation is to use past studies for dynamic stability analysis for all three study years, unless new P5 contingencies are included for this division.

Assessment Conclusions – North (continued)

Area	Steady-State			Transient			Steady state analysis comments	Stability analysis comments
	Y2	Y5	Y10	Y2	Y5	Y10		
North Coast North Bay	X	X	X	X	X	X	Recommend relying on last years studies for steady state. There was almost no BES facility results last cycle and there has been very minimal changes.	Since these areas don't have new major generation addition or retirement, it is recommended to use last year study results, unless new P5 contingencies are identified in the area.
Kern	√	√	√	x	√	√	Recommend performing study for all three years due to load changes, contingencies(P2-1) and evaluation of the on-hold Wheeler ridge Junction project.	Recommend performing study for the longer time frame e.g. Y5 and Y10 to evaluate the impact of rescoped Wheeler ridge Junction project. Evaluate the impact of P5 contingencies only for the short term Y2
Fresno	√	√	√	√	√	√	Recommend performing study for all three years due to new generation, line ratings and new projects in the area	Recommend performing study for all three years due to new generation

Assessment Conclusions – South

Area	Steady-State			Transient			Recommendation on the need for steady state analysis comments	Recommendation on the need for stability analysis comments
	Y2	Y5	Y10	Y2	Y5	Y10		
Big Creek/Tehachapi	√	√	√	√	√	√	There are changes in the load and DER forecast, as well as a planned RAS modification in the area. The recommendation is to run the studies for steady state analysis for all three study years.	Due to a planned Big Creek RAS modification to account for new generation in the area, the recommendation is to run the studies for dynamic stability analysis for all three study years.

SDG&E Area
Sub-transmission Project Re-evaluation

Charles Cheung
Senior Regional Transmission Engineer

2020-2021 Transmission Planning Process Stakeholder Meeting
June 3, 2020

SDG&E Sub-transmission Projects Re-evaluation

- Recent changes to the CAISO Planning Standards require that only P0, P1, and P3 contingencies are studied for non-BES equipment
- The in-serviced dates of 6 previously-approved projects on the non-BES system have been delayed beyond 2025
- The need for these projects will be reevaluated, so they will not be modeled in the TPP power flow cases

SDG&E Sub-transmission Projects Re-evaluation

No.	Project	In-service Date	Category	Year Approved
1	TL6983 2nd Pomerado – Poway 69 kV Circuit	4/2/2026	P3	2014-2015
2	TL690E Stuart Tap - Las Pulgas 69kV Reconductor	5/1/2026	P1/P7	2013-2014
3	TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa Heights	7/28/2026	P6	2015-2016
4	Loop Granite – Granite Tap, TL632A, into Granite and Cancel Los Coches – El Cajon Reconductor, TL631	10/22/2026	P0	2014-2015
5	TL605 Silvergate – Urban Reconductor	6/25/2027	P6	2015-2016
6	Open Sweetwater Tap (TL603) and Loop into Sweetwater	12/20/2027	P3	2012-2013

Round Mountain 500 kV Area Dynamic Reactive Support Project Update

Binaya Shrestha

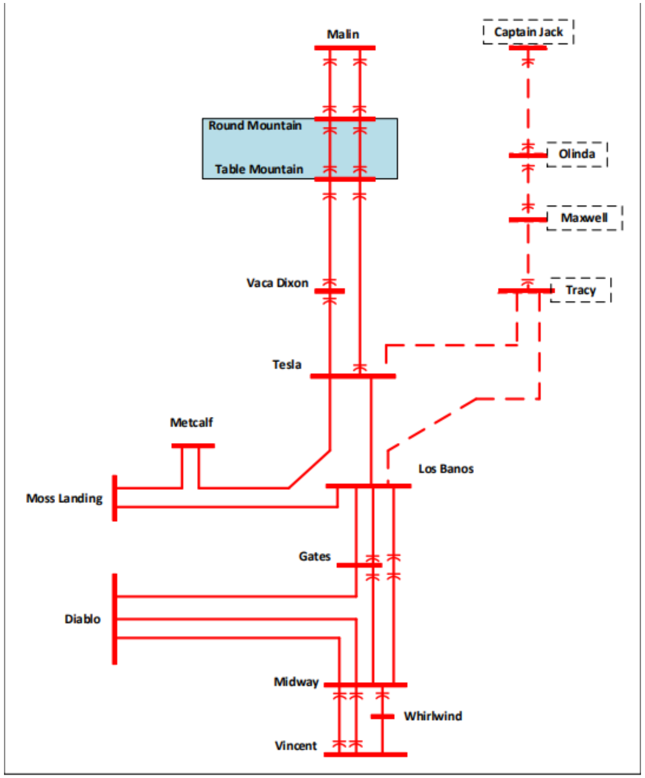
2020-2021 Transmission Planning Process Stakeholder Meeting
June 3, 2020

Round Mountain 500 kV Area Dynamic Reactive Support Project Description

In the 2018-2019 Transmission Plan, the CAISO identified a reliability-driven need for a +/- 500 Mvar dynamic reactive support in the vicinity of the Round Mountain 500 kV substation.

- Latest in-service date: June 1, 2024
- Can be a SVC (Static VAR Compensator), STATCOM (Static Synchronous Compensator), Synchronous Condenser, or Inverter with Battery Storage
- Must be in 2 equal sized blocks independently connected

The CAISO identified two interconnection alternatives – a 500 kV alternative and a 230 kV alternative. The substation costs associated with the 230 kV alternative rendered further consideration unnecessary.



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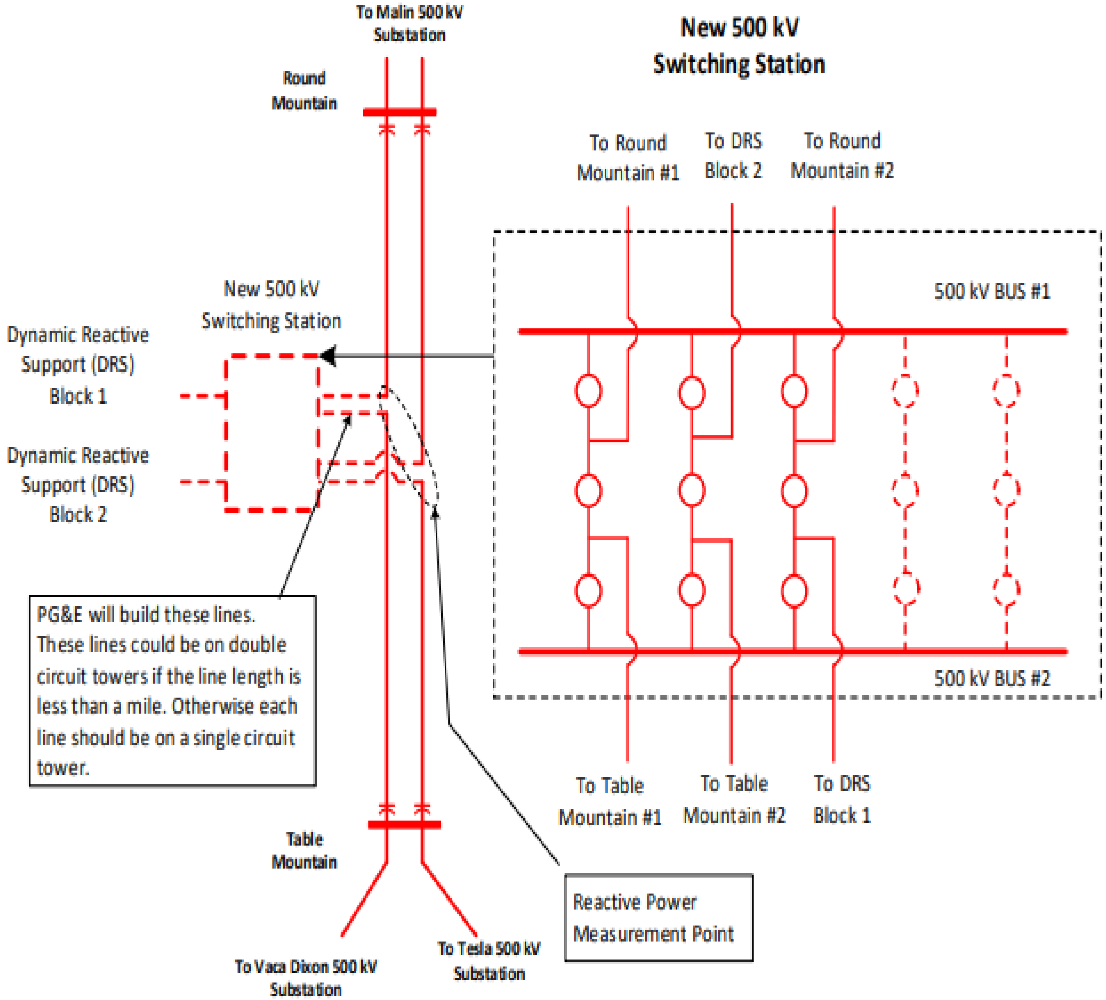
Alternative 1: Connection to 500 kV lines.

- Connection via new 500 kV substation looping in both Round Mountain–Table Mountain 500 kV lines
- Must be located between Round Mountain and 60% of the line to Table Mountain
- 500 kV tie lines will be constructed, owned, and operated by PG&E

Figure 2: High level schematic diagram for Alternative 1



Project solicitation

- The CAISO received 13 submissions from 6 different project sponsors for the Round Mountain 500 kV Dynamic Reactive Support project

- LS Power Grid California (LSPGC) was awarded the project. Their proposal includes two blocks of STATCOM with a total of ±529 Mvar rating. The new switching station is proposed to be located approximately 11 miles south of Round Mountain substation.

Project update

- In the detailed analysis after the project was awarded, PG&E identified to the CAISO that the series capacitors at Round Mountain and Table Mountain would need to be adjusted to meet PG&E's protection design criteria and to maintain the overall compensation between Round Mountain and Table Mountain the same as current values.
- The project will go through the detail design and permitting process. The location of the new switching station will be finalized in the permitting process.
- The level of series capacitor adjustments at Round Mountain and Table mountain will be determined after the CPUC permitting process is complete with regards to the location of the new switching station.

Storage mapping and resource retirement in policy assessment

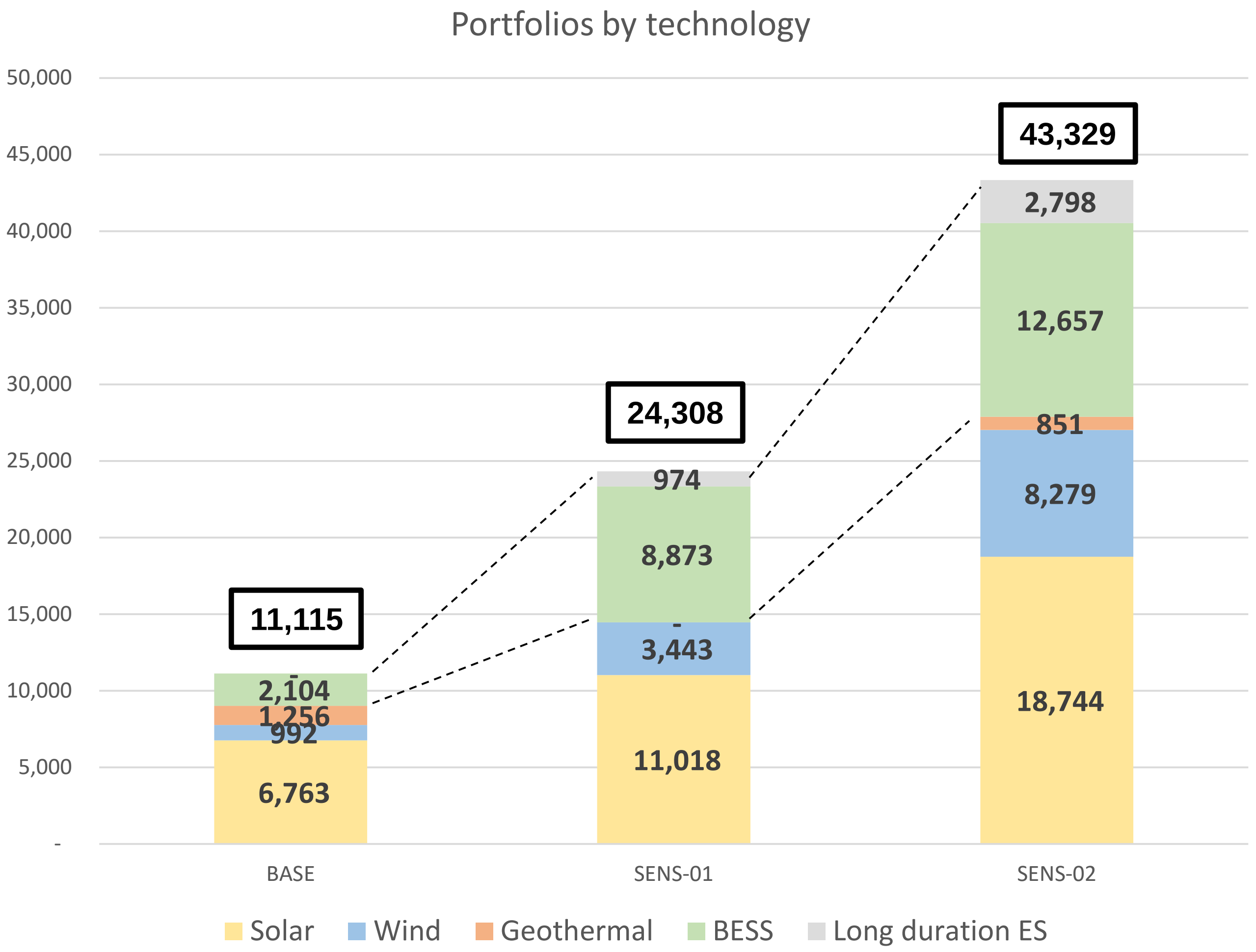
Sushant Barave
Senior Advisor

June 03, 2020

Discussion agenda

- The need to map generic storage in 2020-2021 TPP
- CPUC staff recommendation for busbar level storage mapping
- CAISO's plan to utilize the CPUC's recommended storage mapping to model generic storage in the base cases
  - Reliance on gas retirement assumptions
  - Reliance on storage charging analysis performed in 2021 LCT studies
- Storage-centric analysis of the sensitivity portfolio/s

The need to map generic storage to specific locations is driven by the increasing role of storage in meeting portfolio GHG objectives



Storage component as % of total portfolio

BASE = 19%

SENS-01 = 41%

SENS-02 = 36%

At these levels locational impacts of energy storage become critical to transmission assessment of portfolios.

Storage mapping in the base portfolio is handled differently from storage mapping in sensitivity portfolios

Base portfolio storage mapping

- Existing battery storage units and contracted battery storage projects shall be mapped to busbars to the extent possible during TPP by CAISO staff and the participating transmission owners (PTOs).
- CPUC staff did not map generic battery storage to specific locations.
- CAISO to retain the flexibility necessary to apply the storage where it provides value that can be clearly identified through TPP.

Sensitivity portfolios storage mapping

- CPUC provided the recommended storage mapping at busbar level for SENS-02 portfolio
- CAISO will utilize CPUC's mapping as a starting point and refine the mapped locations for SENS-01 and SENS-02

Storage mapping recommended by the CPUC is driven by *commercial interest, project status* and *location*

CAISO interconnection queue information

Storage in CAISO interconnection queue (Dec 2019) + **One time deliverability transfer requests to add storage (Dec 2019)**

CPUC staff assigned confidence levels based on generator status, interconnection agreement status and LCR area information

High confidence (~3,192 MW) — *Bucket A*

Moderate confidence (~5,428 MW) — *Bucket B*

Storage in LCR areas (~5,830 MW) — *Bucket C*

High-confidence category: Fully utilized
The remaining two utilized in proportion to locational distribution.

Category	Substation	Busbar allocation (MW)
High Confidence (MMA)	Calcite	-
High Confidence (MMA)	Colorado River	230
High C[illegible]dence ([illegible]MA)	C[illegible]Water	-

CPUC's busbar level storage mapping

Two considerations drive the need to refine CPUC's recommended storage mapping

Category	Substation	Busbar allocation (MW)
High Confidence (MMA)	Calcite	-
High Confidence (MMA)	Colorado River	230
High C[illegible]dence ([illegible]MA)	C[illegible]Water	[illegible]

CPUC's busbar level storage mapping

1. *Gas retirement*

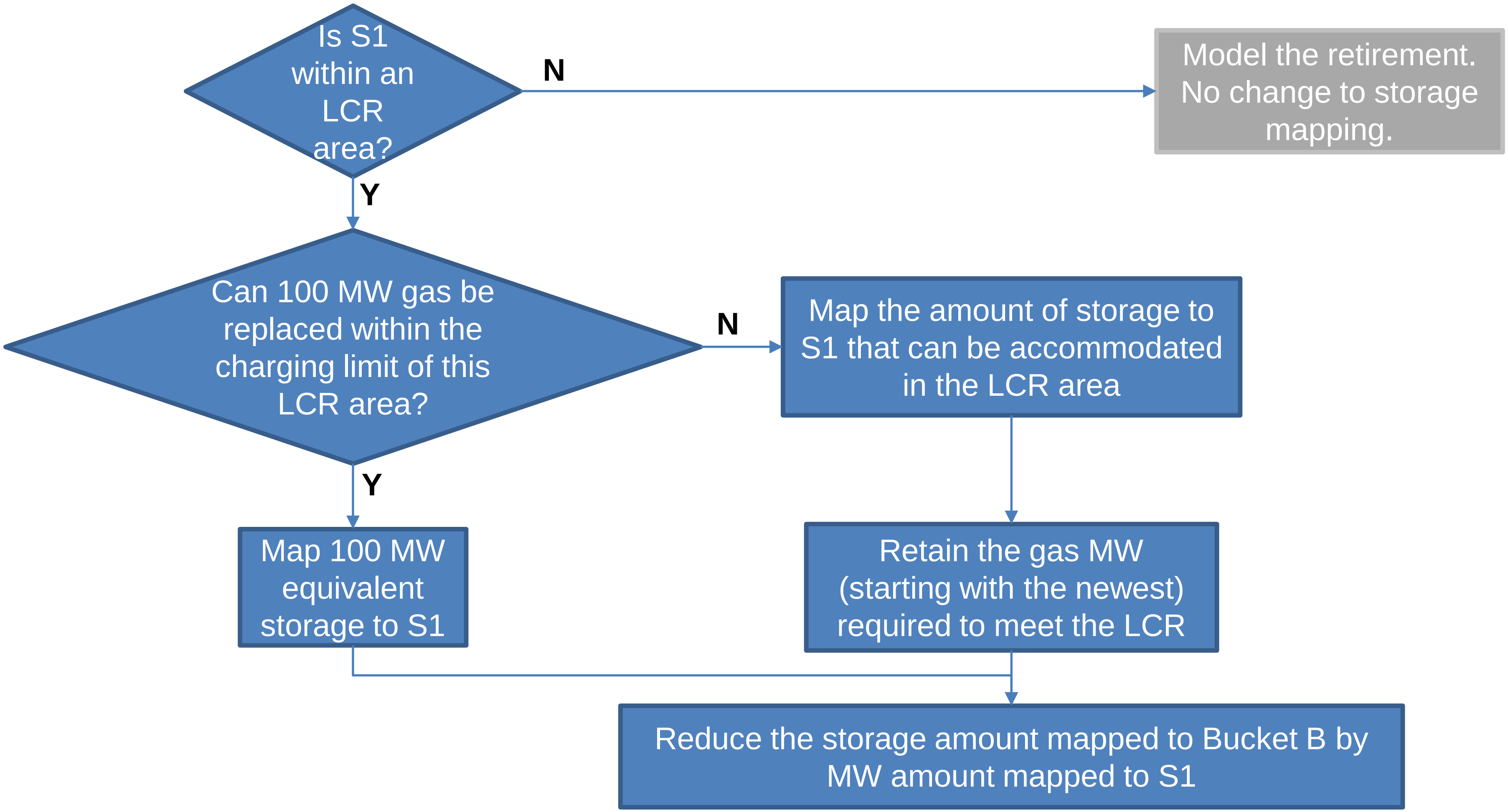
(Re-map MW from Bucket B to replace retired gen)

2. *Storage mapping to LCR areas*

(Re-map MW from Bucket B to LCR areas up to the charging limitations based on 2021 LCT studies)

Example of mapping refinement driven by retirement assumptions and charging limitations in LCR areas

Consider a 100 MW gas resource retirement identified at substation S1



CPUC's recommendations for resource retirement modeling for sensitivity portfolios

1. Rank all existing generation units by age in the categories of: combined cycle (CCGT), combustion turbine (Peaker), and reciprocating engine. Combined heat and power units are excluded from this list since RESOLVE assumes they remain online through 2030.
2. Model offline the oldest units up to but not exceeding the amounts in each category
3. <u>If known local area requirements are not met then add battery storage to meet the local area requirement up to known battery storage charging limits.</u>
4. If known local area requirements are still not met then local gas generation will be restored in reverse order in steps 1 and 2.
5. If specific local units are turned back on in step 4 then an equal amount of additional system generation capacity will be modeled off-line following steps 1 and 2.

Resource Category	MW
CCGT	2,260
Peaker	4,125
Reciprocating Engine	71

Analysis of energy storage modeled in SENS-01 and SENS-02

1. Test charging feasibility and deliverability of the refined storage mapping in 2020-20221 TPP.
   (*prior to TPP Stakeholder Meeting #3 – Nov 2020)*

2. Create storage mapping sensitivities for specific renewable zones of interest in the sensitivity portfolio #2 to evaluate curtailment reduction options.

3. Study the selected renewable zones to evaluate the effectiveness of transmission solutions and any re-mapping of storage.
   (*prior to draft TP release – Jan 2021)*

2030 Long-Term Local Capacity Technical Study

Catalin Micsa
Senior Advisor Regional Transmission Engineer

2020-2021 Transmission Planning Process Stakeholder Call
June 3, 2020

Long-Term Local Capacity Technical Study

Based on the alignment of the CAISO Transmission Planning Process (TPP) with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Integrated Resource Plan (IRP), the Long-Term LCR assessment is to be evaluated ***every two years.***

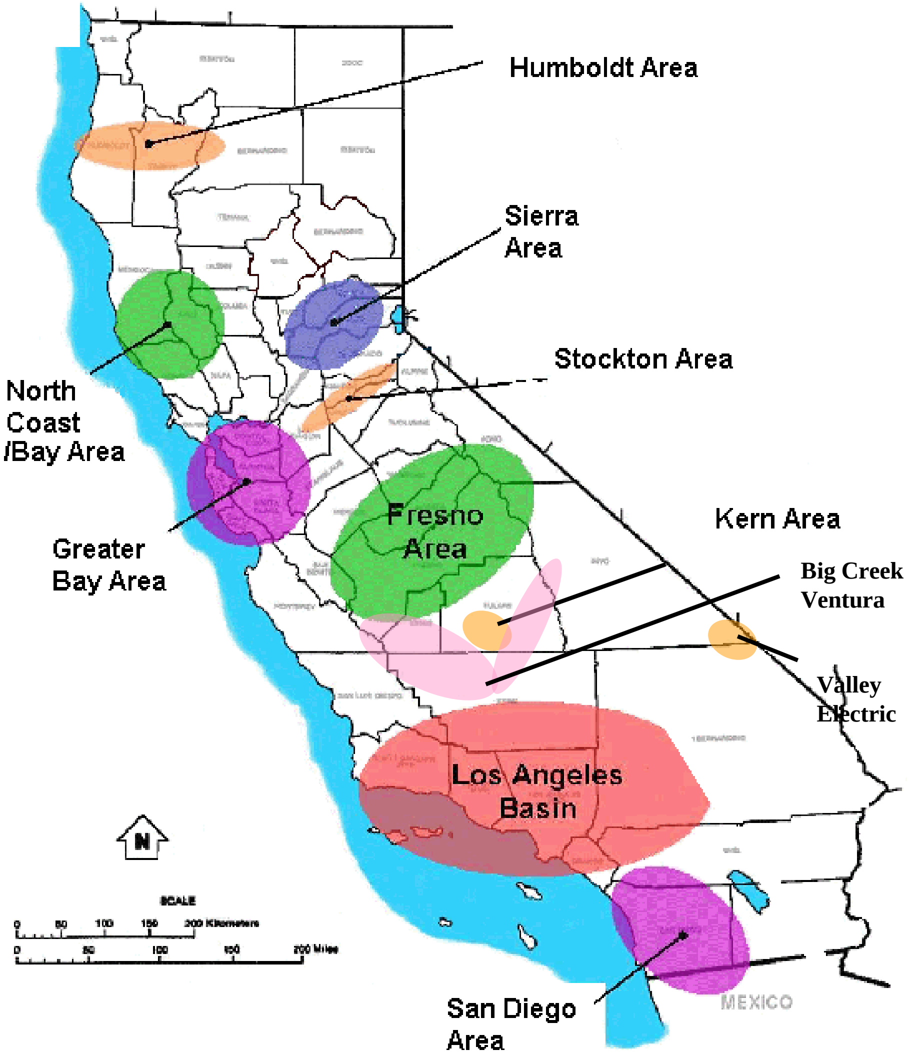
In the 2020-2021 transmission planning process all LCR areas within the CAISO BAA will be evaluated for long-term assessment.

Scope plus Input Assumptions, Methodology and Criteria

The scope of the LCR studies is to reflect the minimum resource capacity needed in transmission constrained areas in order to meet NERC, WECC and CAISO mandatory standards.

For latest study assumptions, methodology and criteria see the October 31, 2019 stakeholder meeting. This information along with the 2021 LCR Manual can be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

LCR Areas within CAISO



California ISO

Study will identify

- Local capacity requirements.

- Required characteristics for batteries in order to displace part of the required local resource adequacy resources such that the transmission capability under the most limiting contingency and the other remaining local capacity resources (required to meet the need) must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day’s peak load period.

CAISO performed an economic study as part of the 2018-2019 & 2019-2020 transmission planning cycles

- Identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas.

- Explore and assess alternatives – conventional transmission and preferred resources - to reduce or eliminate need for gas-fired generation in all existing areas and sub-areas.

As part of the 2020-2021 transmission planning cycle

- Clarify the impact batteries with correct characteristics may have in reducing the need for local gas fired generation requirements
- Prioritize areas and sub-areas having a higher risk of gas-fired generation retirement by examining parameters like:
  - Technical parameters of the resource
  - Age of the resource
  - Location in disadvantaged community
- Identify transmission options that combined with batteries could eliminate or materially reduce gas-fired generation in targeted areas and sub-areas.

Alternative submittals

- Potential alternatives may be submitted to reduce or eliminate the gas-fired generation for targeted LCR areas and sub-areas
- The potential alternatives need to be included as part of your comments to the September transmission planning process stakeholder meeting
- The potential alternatives should not be submitted in the CAISO open window.

Schedule

- June 3 TPP stakeholder call
  - Update on scope and approach
- September 23-24 TPP stakeholder Meeting
  - 10-year LCR assessment results
    - Include update on storage capability
  - Proposed prioritization
  - Stakeholder comments and alternatives
- November 17 TPP stakeholder meeting
  - Preliminary alternative assessment
  - Stakeholder comments
- January 31, 2021 Draft Transmission Plan
  - Final analysis and recommendations (if any)

Interregional Transmission Project (ITP)
Mid-year update

Gary DeShazo

2020-2021 Transmission Planning Process Stakeholder Meeting
June 3, 2020

The 2020-2021 biennial interregional coordination cycle began on January 1, 2020

- The WPRs coordinate implementation of each IC cycle
  - Interregional Coordination and ITP Evaluation Schedule *(Posted)*
  - ITP Project Submittal Information *(Posted)*
- Conduct a biennial “open window” for ITP submittals that closes on March 31 or every even numbered year *(Completed)*
- Relevant Planning Regions coordinate the development of ITP Coordination Plans *(In process – finalize June 14)*
- Host an annual IC stakeholder meeting in February to share regional transmission plans and seek stakeholder input *(Complete - held on February 27, 2020)*

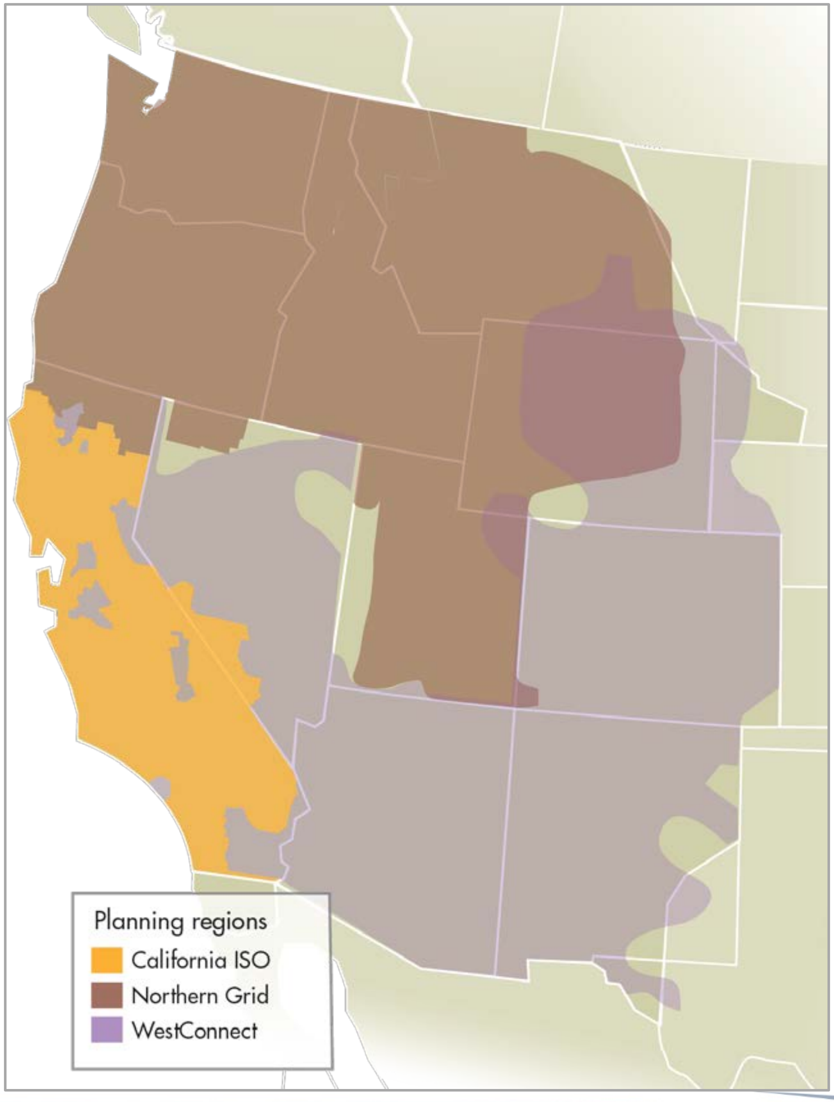
Changes in the FERC Order 1000 regional landscape occurred in early 2020

- FERC accepted tariff modifications filed by the FERC-jurisdictional members of NorthernGrid
- NTTG and ColumbiaGrid no longer considered planning regions

FERC Jurisdictional Members[1]	
Avista Corporation	Idaho Power Company
MATL	NorthWestern Energy
PacifiCorp	Portland General Electric Company
Puget Sound Energy	
Non-FERC Jurisdictional Members[1]	
BHE Canada	Bonneville Power Administration
Chelan County PUD	Enbridge
Grant PUD	Seattle City Light
Snohomish County PUD	Tacoma Power

[1] From the NorthernGrid Website: www.northerngrid.net

FERC accepted NorthernGrid member transmission planning filings on April 1, 2020



All WPRs are consistent in how they address ITPs within their Order 1000 regional processes

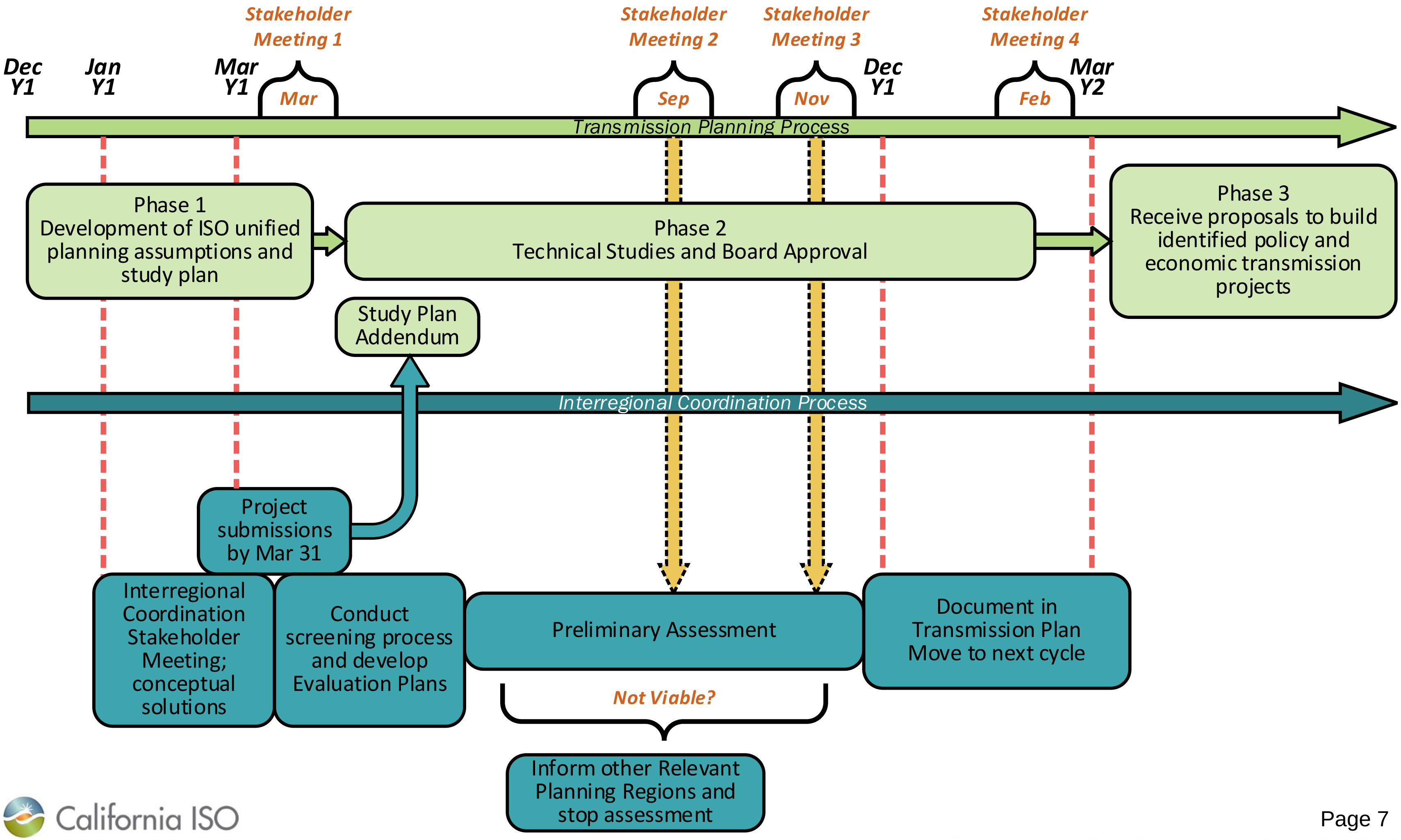
- The ITP must electrically interconnect at least two Order 1000 planning regions
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the CAISO's transmission planning process
- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region
- Without regard to a request for cost allocation, when a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess the ITP

Cost allocation is not necessary for one or more planning regions to consider an ITP within it regional process

- The assessment of an ITP in a WPR’s regional process continues until a conclusion on regional need is reached
- If a regional need is not found, no further assessment of the ITP by that Relevant Planning Region is required
- Consideration by at least two Relevant Planning Regions is required for an ITP to be considered for interregional cost allocation purposes
- Otherwise, the ITP will no longer be considered within the context of interregional cost allocation
- One or more planning regions may consider an ITP within its regional process even though it is not on the path of cost allocation
  - Planning region(s) will continue some level of continued cooperation with other planning regions and with WECC
  - Applicable WECC processes will be followed to ensure all regional impacts are considered

Interregional coordination will be achieved through each planning region’s Order 1000 regional process

(Even year - CAISO’s initial assessment on ITP viability)

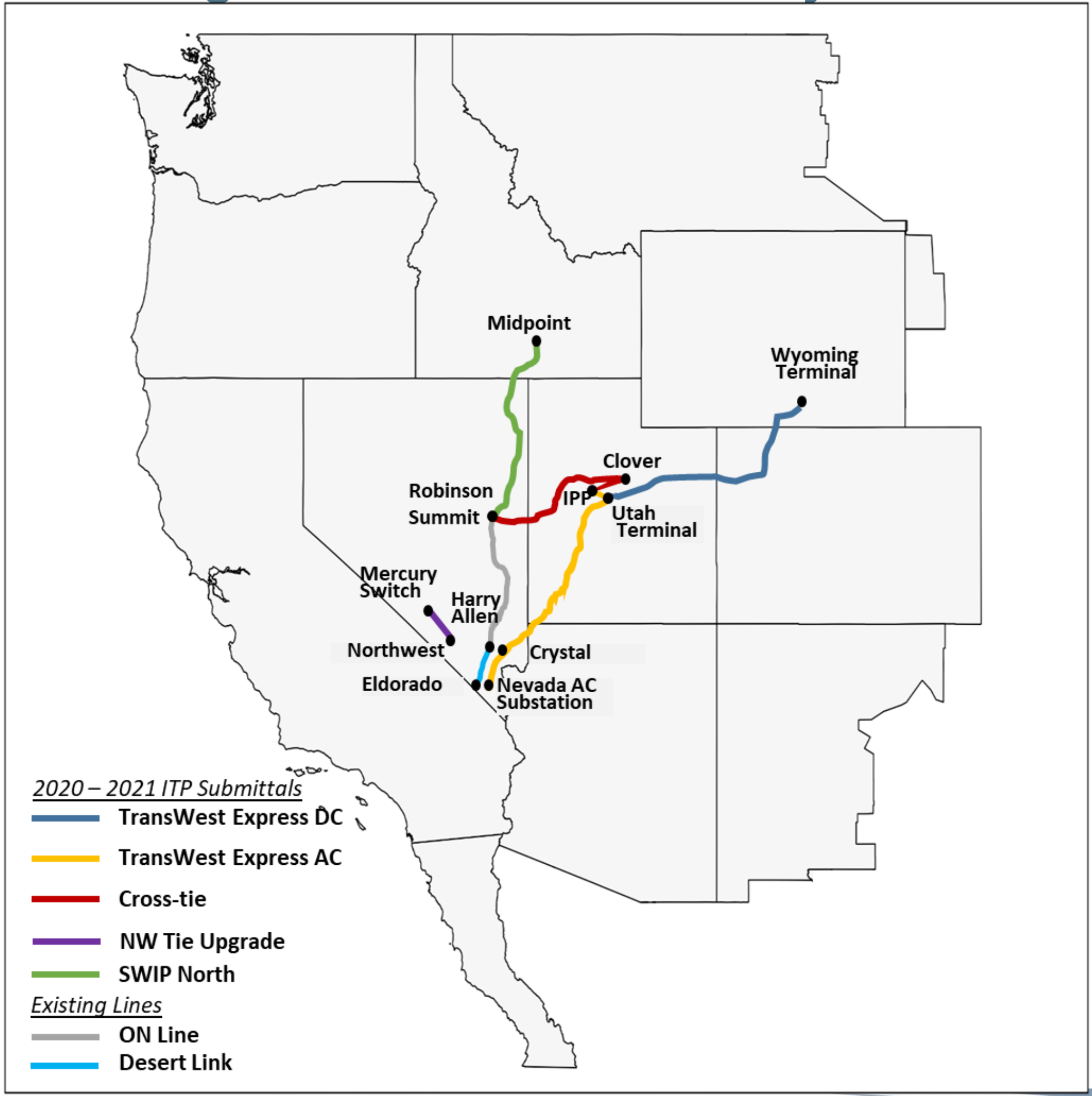


Summary of Q1 2020 ITP submittals

Project Name	Company	Project Submitted to	Relevant Planning Regions	Cost Allocation Requested From	Termination From	Termination to	In Service Date
Cross-Tie Transmission Project	TransCanyon, LLC	CAISO, NG, WC	NG, WC	CAISO, NTTG, WC	Clover, UT (PacifiCorp)	Robinson Summit, NV (NV Energy)	2024
Northwest Tie Upgrade	GridLiance West	CAISO, WC	CAISO, WC	CAISO, WC	Innovation (VEA, GLW, CAISO)	Northwest, NV (NVE)	2024
SWIP-North	Great Basin Transmission LLC	CAISO, NG, WC	CAISO, NG, WC	CAISO, NTTG, WC	Midpoint. ID (IPCO, PAC)	Robinson Summit, NV (NV Energy)	2023
TWE WY-IPP DC Project	TransWest Express, LLC	CAISO, NG	Not an ITP	CAISO	Sinclair, WY (PAC)	IPP, UT (LADWP)	2025
TWE IPP-Crystal 500 kV AC Project	TransWest Express, LLC	CAISO, NG	NG, WC	CAISO	IPP, UT (LADWP)	Crystal, NV (LADWP, NVE, CAISO)	2025
TWE Crystal-Eldorado 500 kV AC Project	TransWest Express, LLC	CAISO, NG	ISO, WC	CAISO	Crystal, NV	Eldorado, NV (CAISO)	2025

California ISO

Proposed Interregional Transmission Projects
2020-2021 Interregional Coordination Cycle



California ISO

Wrap-up

2020-2021 Transmission Planning Process Stakeholder Meeting
June 3, 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 June 17**
- CAISO will post comments and responses on website