Agenda
Unified Planning Assumptions & Study Plan

Yelena Kopylov-Alford
Stakeholder Engagement and Policy Specialist

2024-2025 Transmission Planning Process Stakeholder Meeting
February 28, 2024

Reminders

- Stakeholder calls and meetings related to Transmission Planning are not recorded.
  - Given the expectation that documentation from these calls will be referred to in subsequent regulatory proceedings, we address written questions through written comments, and enable more informal dialogue at the call itself.
  - Minutes are not generated from these calls, however, written responses are provided to all submitted comments.

- Calls are structured to stimulate an honest dialogue and engage different perspectives.

- Please keep comments professional and respectful.

Instructions for raising your hand to ask a question

- If you are connected to audio through your computer or used the “call me” option, select the raise hand icon located on the bottom of your screen.

  Note: #2 only works if you dialed into the meeting.

- Please remember to state your name and affiliation before making your comment

2024-2025 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Yelena Kopylov-Alford
Overview & Key Issues	Andrew Rivera
Reliability Assessment	Preethi Rondla
Policy Assessment	Nebiyu Yimer
Economic Assessment	Yi Zhang
Frequency Response Assessment	Chris Fuchs
Wrap-up & Next Steps	Yelena Kopylov-Alford

Overview
Unified Planning Assumptions & Study Plan

Andrew Rivera
Transmission Planning Specialist

2024-2025 Transmission Planning Process Stakeholder Meeting
February 28, 2024

2024-2025 Transmission Planning Process

January 2024 | April 2024 | May 2024

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

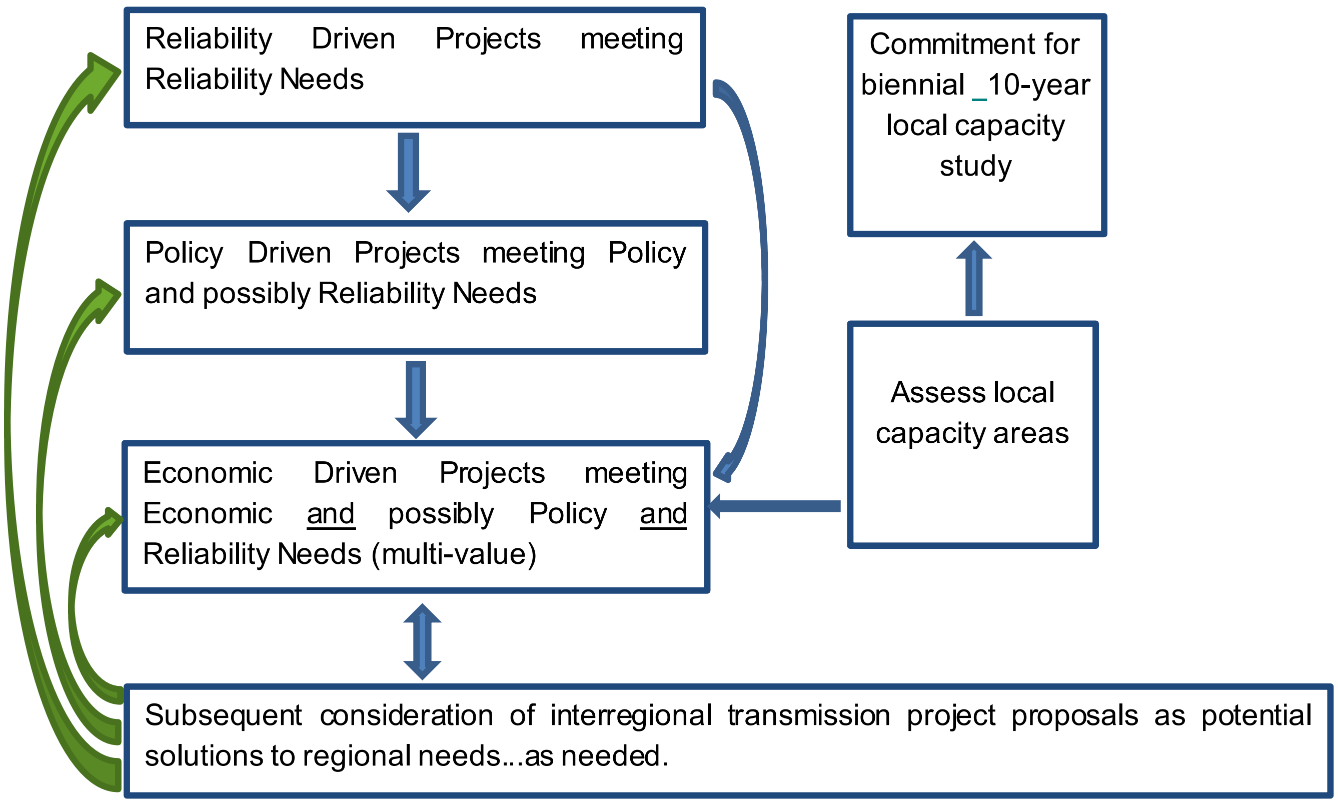
CAISO Board for approval of transmission plan

California ISO

2024-2025 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 in April
- Preliminary reliability study results to be posted on August 15
- Stakeholder meeting on September 26 and 27
  - Comments to be submitted by October 11
- Request window closes October 15
- Preliminary policy and economic study results on November 14
  - Comments to be submitted by November 28
- Draft transmission plan to be posted on March 31, 2025
- Stakeholder meeting in April 2025
  - Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at May 2025 Board of Governor meeting

Studies are coordinated as a part of the transmission planning process



2024-2025 Transmission Plan Study Plan

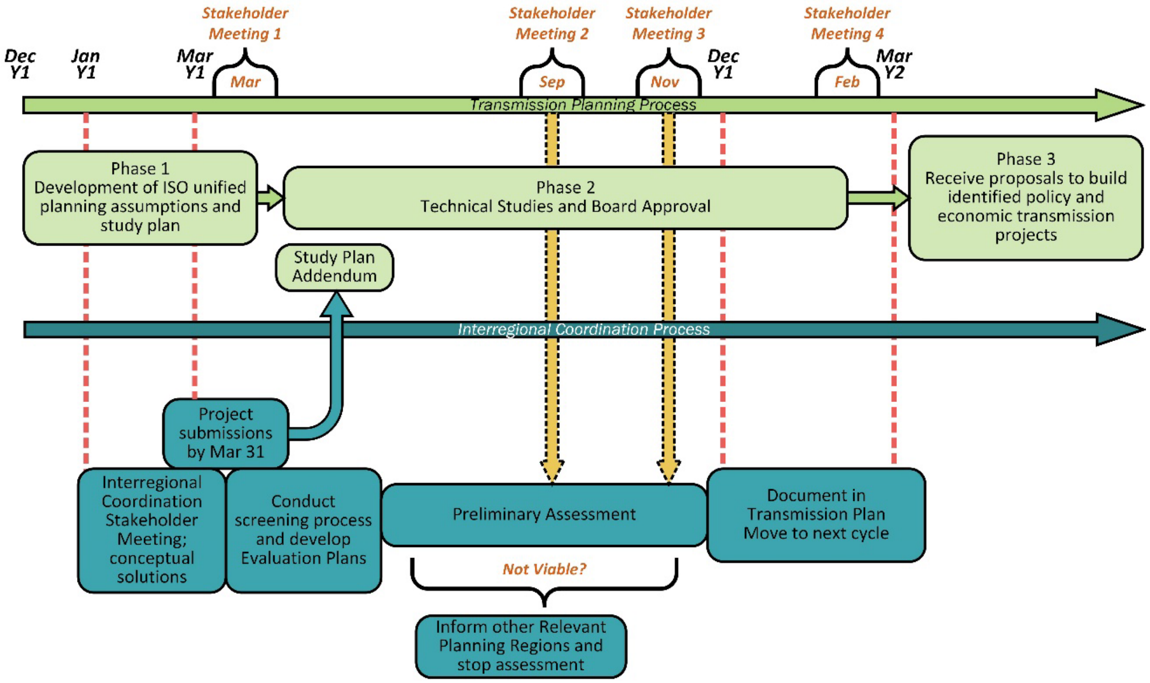
- Reliability Assessment to identify reliability-driven needs
- Policy Assessment to identify policy-driven needs
- Economic Planning Studies to identify needed economically-driven elements
- Other Studies
  - Near-Term / Long-Term Local Capacity Requirement (LCR)
  - Maximum Import Capability expansion requests
  - Long-term Congestion Revenue Rights
  - Frequency response
- No special studies are currently planned for the 2024-2025 TPP

Interregional Transmission Coordination - Year 1 of 2

- Host an open window (January 1 through March 31) for proposed interregional transmission projects to be submitted to the CAISO for consideration in the CAISO's 2024-2025 TPP planning cycle

- Participate in a western planning regions' stakeholder meeting. The Northern Grid is hosting the meeting on March 26, 2024.

Even year Interregional Coordination Process



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

Maximum Import Capability Expansion Requests

- Maximum import capability expansion requests are to be submitted with the comments on the draft study plan by March 13, 2024
  - Must identify the intertie(s) (branch group(s)) that require expansion
  - For an LSE, the request must include information about existing resource adequacy contracts
  - For new transmission owners or other market participants the request must include information on contractual arrangements or other evidence of financial commitments the requestor has already made in order to serve load or meet resource adequacy requirements within the CAISO balancing authority area
  - The quality of the data must be sufficient for the CAISO to make a determination about the validity of such request
  - The CAISO will maintain confidentiality of data provided except for the requestor name, intertie (branch group), the MW quantity and the technology of the expansion request

Maximum Import Capability Expansion Requests (continued)

- The CAISO will evaluate each maximum import capability expansion request in order to establish if the submitting entity meets the criteria
- The descriptions of valid maximum import capability requests will be included in the final study plan
- The valid MIC expansion requests along with the policy driven MIC expansion will be used to identify all branch groups that do not have sufficient Remaining Import Capability to cover both

Previously Submitted Maximum Import Capability Expansion Requests

- The CAISO is in the process of finalizing the Draft 2023-2024 Transmission Plan to be post April 1, 2024.
- This document will identify which MIC expansion requests will be approved or denied based on:
  - TPP deliverability study; and
  - TPP recommended upgrade(s) in areas creating additional capability to support the MIC expansion requests and/or the constraint has no mitigation required for reliability, economic or policy needs
- For details, please read the expanded section 6.1.2 in the upcoming Draft 2023-2024 Transmission Plan
- If submitter wants request submitted in previous planning cycle to still be considered, in the event that the previously request is denied in 2023-2024 TPP, they will need to resubmit the request in this planning cycle

2024-2025 Transmission Planning Process Key Inputs

- On February 15, 2024 CPUC adopted a base and a sensitivity portfolio for 2034 and 2039 for use in the 2024-2025 TPP
  https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp

- 2023 IEPR California Energy Demand forecast adopted by the CEC on February 14, 2024
  https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report

Non-CPUC Jurisdictional Approved Integrated Resource Plans

- Non-CPUC jurisdictional approved IRP will be incorporated in the analysis with the CPUC busbar mapped IRP base portfolio
- Northern California Power Agency (NCPA) provided the 2023 Inter-Agency Resource Plan (2023 IARP) adopted by the NCPA Commission for use in the 2024-2025 Transmission Plan.
- Non-CPUC jurisdictional approved IRP can be submitted into the comments for inclusion in the 2024-2025 transmission planning process study plan

Study Information

- Final Study Plan will be posted on 2024-2025 transmission planning process webpage in April
  http://www.caiso.com/planning/Pages/TransmissionPlanning/2024-2025TransmissionPlanningProcess.aspx

- 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

Comments
2024-2025 TPP Draft Study Plan

- Comments due by end of day March 13, 2024 including:
  - Economic study requests and
  - Maximum Import Capability (MIC) expansion requests are to be submitted with comments
  - Non-CPUC jurisdictional approved IRP portfolios

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

https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2024-2025-Transmission-planning-process

- Submit confidential comments and data to:

regionaltransmission@caiso.com

Reliability Assessment
Unified Planning Assumptions & Study Plan

Preethi Rondla

2024-2025 Transmission Planning Process Stakeholder Meeting
February 28, 2024

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
(continued)

- Study Horizon
  - 15 years planning horizon
    - near-term: 2026 to 2029
    - longer-term: 2030 to 2039*

- Study Years
    - near-term: 2026 and 2029
    - longer-term: 2034 and 2039*

* *A 15-year planning horizon, 2034 and 2039 are selected as the long-term study year as the CEC's IEPR goes out to 2040. Furthermore, the NERC TPL-001 Planning Standard allows any year beyond year five to be selected for the long-term planning horizon with the rational for selecting the year.*

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
  - Metro area
- **SDG&E area**
- **Valley Electric Association area**
- **ISO combined bulk system**

Use of Past Studies

- CAISO will continue to evaluate areas known to have no major changes compared to assumptions made in prior planning cycles for potential use of past studies. (TPL-R2.6)
- At a high level, the process will include three major steps :
  – Data collection
  – Evaluation of data change
  – Drawing conclusions based on judgment and evaluation collection
- 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
  - Existing and planned reactive power resources will be modeled
- Protection Systems
  - Existing and planned RAS, safety nets, UVLS & UFLS will be modeled
  - Continue to include RAS models and work with PTOs to obtain remaining RAS models.
- Control Devices
  - Existing and Planned control devices will be modeled in the studies

Load Forecast Assumptions
Energy and Demand Forecast

- California Energy Demand Updated Forecast 2023-2040 adopted by California Energy Commission (CEC) on February 14, 2024 will be used:
  - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
  - Additional Achievable Energy Efficiency (AAEE), Additional Achievable Fuel Substitution (AAFS) and Additional Achievable Transportation Electrification (AATE) will be provided by the CEC at the load bus-bar level:
    - Consistent with CEC 2023 IEPR
    - AAEE 3 (Mid), AATE 3 (Mid) and AAFS 3 (Mid)will be used for system-wide studies
    - AAEE 2 (Low), AATE 3 (Mid) and AAFS 4 (High) will be used for local reliability studies
  - CEC forecast information is available on the CEC website at:

    https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report/2023-1

Load Forecast Assumptions
Energy and Demand Forecast (continued)

- Load forecasts to be used for each of the reliability assessment studies.
  - The 1-in-10 weather year, mid demand baseline with AAEE 2, AAFS 4 and AATE 3 forecast will be used in PG&E, SCE, and SDG&E local area studies including the studies for the local capacity requirement (LCR) areas. The VEA area will use 1-in-10 weather year with mid demand baseline forecast.
  - The 1-in-5 weather year, mid demand baseline with AAEE 3, AAFS 3 and AATE 3 forecast will be used for CAISO system study.
  - The 1-in-2 weather year, mid demand baseline with AAEE 3, AAFS 3 and AATE 3 forecast will be used for production cost study.

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. However, the CEC does provide the load modifiers (AAEE, AAFS, AATE) at the bus-bar load level.

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

- Updated descriptions to 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. The CEC also provides the methodology for allocating the load modifiers to the load buses.

Load Forecast Assumptions

BTM-PV, BTM-Storage, AAEE, AAFS and AATE

- Similar to previous cycles, BTM-PV will be modeled explicitly in the 2024-2025 TPP base cases.
  - Amount of the BTM-PV to be modeled will be based on 2023 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 CMPLDWG 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 2024-2025 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. However it will be accounted for by netting to the load.
- AAEE , AATE and AAFS will be modeled using the CEC provided bus-bar allocations and will be modeled as negative load for AAEE (i.e., reducing conforming load) and positive load for AATE and AAFS (adding to conforming load).

BTM-PV installed capacity for mid demand scenario by PTO and forecasting climate zones

PTO	Forecast Climate Zone	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PGE	Central Coast	625	682	742	803	865	928	990	1051	1112	1172	1231	1289	1347
	Central Valley	1813	1958	2108	2263	2422	2582	2742	2902	3059	3213	3359	3499	3630
	Greater Bay Area	2114	2286	2471	2666	2872	3082	3296	3514	3731	3946	4157	4362	4561
	North Coast	598	646	696	746	798	848	898	948	996	1043	1089	1133	1176
	North Valley	373	400	429	459	491	523	554	586	617	647	676	703	729
	Southern Valley	2258	2414	2575	2739	2904	3068	3229	3389	3544	3693	3836	3973	4105
	PG&E Total	7781	8387	9020	9677	10352	11030	11710	12388	13058	13713	14348	14959	15548
SCE	Big Creek East	536	571	607	644	681	717	754	791	829	868	907	947	986
	Big Creek West	304	328	353	380	408	437	467	498	529	562	595	628	661
	Eastern	1163	1229	1297	1364	1432	1501	1572	1645	1718	1792	1865	1937	2006
	LA Metro	1842	1984	2138	2302	2477	2658	2849	3047	3255	3470	3691	3918	4148
	Northeast	908	980	1059	1144	1233	1328	1428	1532	1641	1753	1868	1985	2105
	SCE Total	4753	5092	5455	5834	6231	6642	7069	7513	7973	8445	8926	9414	9906
SDGE	SDGE	1876	1999	2129	2265	2404	2544	2685	2826	2967	3107	3245	3380	3514
CAISO Total		14409	15477	16604	17776	18987	20216	21464	22728	23998	25265	26518	27754	28968

Draft note: Above table is from TPP 2023-24 study plan. Still awaiting information from CEC to update this

Behind-the-meter storage installed capacity for mid demand scenario by PTO and forecasting climate zones

PTO	Forecast Climate Zone	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PGE	Central Coast	95	122	149	177	206	236	266	298	330	362	396	430	464
	Central Valley	192	251	313	377	444	513	585	659	735	814	895	978	1063
	Greater Bay Area	60	78	96	115	135	156	178	200	223	246	270	295	320
	North Coast	13	17	21	25	30	34	39	44	49	54	59	64	70
	North Valley	69	87	105	123	142	161	181	200	221	241	261	282	303
	Southern Valley	487	630	777	930	1088	1251	1420	1593	1772	1955	2142	2334	2529
	PG&E Total	95	122	149	177	206	236	266	298	330	362	396	430	464
SCE	Big Creek East	26	31	36	41	46	51	56	61	66	71	76	81	87
	Big Creek West	28	35	43	52	60	69	77	87	96	106	116	126	136
	Eastern	53	66	79	93	107	121	135	150	165	181	197	214	231
	LA Metro	224	273	323	375	427	480	535	590	647	705	764	824	885
	Northeast	73	88	103	119	135	151	168	185	202	219	237	255	274
	SCE Total	404	494	585	679	774	872	971	1072	1176	1282	1390	1500	1613
SDGE	SDGE	149	183	218	253	289	326	364	402	441	481	521	562	604
CAISO Total		1040	1306	1580	1862	2152	2449	2754	3067	3389	3717	4053	4396	4746

Draft note: Above table is from TPP 2023-24 study plan. Still awaiting information from CEC to update this

Supply Side Assumptions - Continued coordination with CPUC Integrated Resource Planning (IRP)

- On February 15, 2024 CPUC adopted a base and a sensitivity portfolio for 2034 and 2039 for use in the 2024-2025 TPP
- The ISO will also be incorporating approved IRP portfolios of non-CPUC jurisdictional entities
- 2023 IEPR California Energy Demand forecast adopted by the CEC on February 14, 2024

  https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report/2023-1

Generation Assumptions

- New Generation Modeling
  - Level 1: Resource projects that have become operational
  - Level 2:
    - Resource projects on the CPUC's in-development resource list;
    - Resource projects, if any, that are not on the CPUC in-development resource list but are known to have commenced construction or have a power purchase agreement (PPA) with a load serving entity (LSE). For clarity, simply having executed generation interconnection agreement (GIA) is not sufficient to meet the resource inclusion criteria
  - Level 3: Generic resources that are included in the CPUC base portfolio
- Retired generation is modeled offline and disconnected in appropriate study years

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,
  - Model as aggregate if <10 MW for same technology

Generation Assumptions
Generation Retirements

- Nuclear Retirements
  - Diablo Canyon will be modeled online in near and mid-term scenarios and offline in the long-term scenarios based on the expansion.

- 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.
- Thermal Generation Retirement Assumptions in the Portfolios
  - Other thermal generators will be assumed to be retired in the long term base cases based on the Gas capacity Not Retained Assumption List for the Base Case and Sensitivity Portfolios provided by CPUC. The list identifies the specific units to be assumed retired for each category of thermal generation (CCGT and Peakers, CHPs) based on the selection criteria described in the workbook.

Generation Assumptions

OTC Generation

- Modeling based on the SWRCB's compliance schedule with the following exceptions:
  - Generating units that are repowered, replaced or have firm plans to connect to acceptable cooling technology.
  - Generating units with approved Track 2 mitigation plan.
  - The extension of the compliance date for Alamitos Units 3, 4, and 5, Huntington Beach Unit 2, and Ormond Beach Units 1 and 2 from December 31, 2023, to December 31, 2026, is contingent on these generating stations participating in the Electricity Supply Strategic Reliability Reserve Program established through Assembly Bill 205, which was approved by Governor Gavin Newsom on June 30, 2022.
  - On September 2, 2022, Governor Gavin Newsom approved Senate Bill 846, which added Section 13193.5 to the California Water Code and extended the OTC Policy compliance date for Diablo Canyon Units 1 and 2 to October 31, 2030.

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
  - Existing, under construction and/or approved procurement status energy storage projects.
  - Behind-the-meter energy storage will be netted to load due to tool limitation

Major Path Flows and Interchange

Northern area (PG&E system) assessment

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4,000	Summer Peak
PDCI (N-S)	3,100	
Path 66 (N-S)	4,800	
Path 15 (N-S)	-5,400	Spring Off Peak
Path 26 (N-S)	-3,000	
PDCI (N-S)	-975	
Path 66 (N-S)	-3,675	Winter Peak

Southern area (SCE & SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (S-N)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3,210	3,100	Summer Peak
PDCI (S-N)	975	975	Spring Off Peak
West of River (WOR) (E-W)	12,150	0 to 11,200	Summer Peak
East of River (EOR) (E-W)	10,100	1,400 to 10,100	Summer Peak
East of River (EOR) (W-E)		2,000 to 7,500	Summer Peak/Spring Off peak
San Diego Import	2,765~3,565	2,400 to 3,500	Summer Peak
Path 45 (N-S)	600	0 to 600	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring Off Peak
Harry Allen-Eldorado (Path 84) (N-S)	3496	1000-3000	Spring Off Peak/Summer Peak
Harry Allen-Eldorado (Path 84) (S-N)	1390	500-1000	Summer Peak/Spring Off-Peak

Study Scenarios - *Base Scenarios*

Study Area	Near-term Planning Horizon		Long-term Planning Horizon	
	2026	2029	2034	2039
California ISO Bulk System			Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Winter Off-Peak	
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak	
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak	
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak	
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak <u>Summer Off-Peak</u> Spring Off-Peak	Summer Peak	
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)	
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak <u>Summer Off-Peak</u> Spring Off-Peak	Summer Peak	
Kern	Summer Peak Spring Off-Peak	Summer Peak <u>Summer Off-Peak</u> Spring Off-Peak	Summer Peak	
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak	

Study Scenarios - *Base Scenarios (Cont.)*

Study Area	Near-term Planning Horizon		Long-term Planning Horizon	
	2026	2029	2034	2039
California ISO Bulk transmission system			Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak		
SCE Main Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak Winter Peak	
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SDG&E Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak Winter Peak	
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Winter Peak	

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		
		2026	2029	2034	2039	2026	2029	2034	2026	2029	2034	2026	2029	2034	2026	2029	2034
PG&E	Summer Off Peak	N/A	7/25 HE15	N/A	N/A	N/A	82%	N/A	N/A	77%	N/A	N/A	36%	N/A	N/A	85%	N/A
PG&E	Summer Peak	7/22 HE 19	7/25 HE 19	See CAISO	See CAISO	4%	5%	See CAISO	2%	2%	See CAISO	91%	91%	See CAISO	100%	100%	See CAISO
PG&E	Spring Off Peak	4/29 HE 20	4/22 HE 13	See CAISO	N/A	0%	96%	See CAISO	0%	97%	See CAISO	82%	51%	See CAISO	67%	15%	See CAISO
PG&E	Winter Off peak	N/A	N/A	1/29 HE 6	N/A	N/A	N/A	0%	N/A	N/A	0%	N/A	N/A	33%	N/A	N/A	41%
PG&E	Winter peak	12/16 HE 19	12/19 HE 8	1/5 HE 9	N/A	0%	2%	10%	0%	30%	59%	50%	31%	57%	65%	67%	77%
SCE	Summer Off Peak	N/A	8/29 HE 15	N/A	N/A	N/A	74%	N/A	N/A	82%	N/A	N/A	56%	N/A	N/A	98%	N/A
SCE	Summer Peak	8/31 HE 16	8/31 HE17	See CAISO	See CAISO	54%	30%	See CAISO	60%	30%	See CAISO	63%	68%	See CAISO	100%	100%	See CAISO
SCE	Spring Off Peak	4/29 HE 19	3/25 HE 13	See CAISO	N/A	1%	95%	See CAISO	1%	96%	See CAISO	77%	51%	See CAISO	62%	14%	See CAISO
SCE	Winter Peak	N/A	N/A	11/1 HE 18	N/A	N/A	N/A	7%	N/A	N/A	0%	N/A	N/A	66%	N/A	N/A	71%

California ISO

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		
		2026	2029	2034	2039	2026	2029	2034	2026	2029	2034	2026	2029	2034	2026	2029	2034
SDG&E	Summer Off Peak	N/A	9/4 HE 14	N/A	N/A	N/A	83%	N/A	N/A	82%	N/A	N/A	1%	N/A	N/A	86%	N/A
SDG&E	Summer Peak	9/1 HE 17	9/4 HE 17	9/5 HE 17	See CAISO	24%	24%	24%	20%	20%	20%	9%	9%	9%	100%	100%	100%
SDG&E	Spring Off Peak	5/6 HE 19	4/15 HE 13	See CAISO	N/A	1%	100%	See CAISO	0%	95%	See CAISO	63%	30%	See CAISO	69%	8%	See CAISO
SDG&E	Winter Peak	N/A	N/A	12/12 HE 18	N/A	N/A	N/A	1%	N/A	N/A	0%	N/A	N/A	13%	N/A	N/A	76%
VEA	Summer Peak	8/31 HE 16	8/31 HE17	See CAISO	See CAISO	N/A	N/A	N/A	60%	30%	See CAISO	N/A	N/A	See CAISO	100%	100%	See CAISO
VEA	Spring Off Peak	4/29 HE 19	3/25 HE 13	See CAISO	N/A	N/A	N/A	N/A	1%	96%	See CAISO	N/A	N/A	See CAISO	62%	14%	See CAISO
VEA	Winter Peak	N/A	N/A	11/1 HE 18	N/A	N/A	N/A	7%	N/A	N/A	0%	N/A	N/A	66%	N/A	N/A	71%

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 non-coincident PTO managed peak load		
			PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2034 Summer Peak	9/6 HE 18	9%	6%	6%	4%	2%	8%	32%	30%	32%	97%	100%	95%
	2034 Spring Off Peak	3/26 HE 13	88%	100%	95%	96%	95%	97%	51%	51%	42%	14%	14%	7%
	2039 Summer peak	9/5 HE 19	0%	0%	0%	0%	0%	0%	42%	41%	40%	100%	88%	96%
	2039 Spring Off peak	4/15 HE 13	88%	98%	100%	98%	98%	99%	47%	56%	57%	15%	27%	21%

Study Scenarios - *Sensitivity Studies*

Sensitivity Study	Near-term Planning Horizon		Long-term Planning Horizon	
	2026	2029	2034	2039
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area		
Spring shoulder-peak with heavy renewable output or different import level or storage charging	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area VEA Area	-		
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area	-		
Summer Peak with forecasted load addition	VEA Area	VEA Area		
South Bay high load sensitivity			PG&E Greater Bay area	
Summer Peak with retirements identified in 2034 portfolio			Area impacted by retirements	
Summer Peak with retirements identified in 2039 portfolio				Area impacted by retirements PG&E Greater Bay area LA Basin

Study Scenarios - *Sensitivity Scenario Definitions and Renewable Generation Dispatch*

PTO	Scenario	Starting Baseline Case	BTM-PV		Transmission Connected PV		Transmission Connected Wind		Comment
			Baseline	Sensitivity	Baseline	Sensitivity	Baseline	Sensitivity	
PG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2026 Summer Peak	4%	99%	2%	99%	91%	62%	Solar and wind dispatch increased to 20% exceedance values
PG&E	Spring shoulder-peak with heavy renewable output or different import level	2026 Spring Off-Peak	0%	0%	0%	0%	82%	47%	Different import levels on COI and P26.
PG&E	Summer Peak with high CEC forecasted load	2029 Summer Peak	5%	5%	2%	11%	91%	54%	Load increased by turning off AAEE
PG&E	Summer Peak with high gas retirement	2034 Summer Peak	9%	9%	4%	4%	32%	32%	CPUC high gas retirement scenario for 2034
PG&E	Summer Peak with high gas retirement	2039 Summer Peak	0%	0%	0%	0%	42%	42%	CPUC high gas retirement scenario for 2039
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2026 Summer Peak	54%	99%	60%	99%	63%	67%	Solar and wind dispatch increased to 20% exceedance values
SCE	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2026 Spring Off-Peak	1%	1%	1%	1%	77%	77%	Storage Charging in load pockets.
SCE	Summer Peak with high CEC forecasted load	2029 Summer Peak	30%	30%	30%	30%	68%	68%	Load increased per CEC high load scenario
SCE	Summer Peak with high gas retirement	2034 Summer Peak	6%	6%	2%	2%	30%	30%	CPUC high gas retirement scenario for 2034
SCE	Summer Peak with high gas retirement	2039 Summer Peak	0%	0%	0%	0%	41%	41%	CPUC high gas retirement scenario for 2039

Study Scenarios - *Sensitivity Scenario Definitions and Renewable Generation Dispatch*

PTO	Scenario	Starting Baseline Case	BTM-PV		Transmission Connected PV		Transmission Connected Wind		Comment
			Baseline	Sensitivity	Baseline	Sensitivity	Baseline	Sensitivity	
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2026 Summer Peak	24%	96%	20%	96%	9%	51%	Solar and wind dispatches increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2026 Spring Off-Peak	1%	1%	0%	0%	50%	50%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2029 Summer Peak	24%	24%	45%	45%	11%	11%	Load increased per CEC high load scenario
	Summer Peak with high gas retirement	2034 Summer Peak	6%	6%	8%	8%	32%	32%	CPUC high gas retirement scenario for 2034
	Summer Peak with high gas retirement	2039 Summer Peak	0%	0%	0%	0%	40	40	CPUC high gas retirement scenario for 2039
VEA	Summer Peak with forecasted load addition	2026 Summer Peak	N/A	N/A	96%	96%	N/A	N/A	Load increase reflect future load service request
	Summer Peak with forecasted load addition	2029 Summer Peak	N/A	N/A	88%	88%	N/A	N/A	Load increase reflect future load service request
	Spring Off-peak with storage charging	2026 Spring Off-Peak	N/A	N/A	0%	0%	N/A	N/A	Storage charging

Study Base Cases

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

Study Year	Season	WECC Base Case	Year Published
2026	Summer Peak	2025 Heavy Summer 3	10/29/2021
	Winter Peak	2023-24 Heavy Winter 3 2024-25 Heavy Winter 3	3/21/2023 Under review
	Spring Off-Peak	2024 Heavy Spring 2	12/18/2023
2029	Summer Peak	2029 Heavy Summer 2	5/8/2023
	Summer Off-Peak	2029 Heavy Summer 2	5/8/2023
	Winter Peak	2028-29 Heavy winter 2	07/05/2023
	Spring Off-Peak	2024 Light Spring 2 2025 Light Spring 1	01/27/2023 Under review
2034	Summer Peak	2034 Heavy Summer 1	10/25/2023
	Spring Off-Peak	2033 Light Spring 1	01/28/2022
	Winter Peak	2033-34 Heavy Winter 1	09/08/2023
2039	Summer Peak	2034 Heavy Summer 1	10/25/2023
	Spring off-peak	2033 Light Spring 1	01/28/2022

Under review* - if the basecase is approved by end of march, will be used

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 structure14 (P7.1)
    - Loss of a bipolar DC lines (P7.2)

Contingency Analysis *(continued)*

- **Extreme contingencies (TPL-001-5)**
  - As a part of the planning assessment the ISO assesses Extreme Event contingencies;
    - Analysis will be included in TPP if requirements drive the need for mitigation plan.

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

- ISO will identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards.
  - ISO in coordination with PTO 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

Nebiyu Yimer
Senior Advisor, Regional Transmission South

2024-2025 Transmission Planning Process Stakeholder Meeting
February 28, 2024

Agenda

- Policy-driven assessment objectives and scope
- Description of portfolios transmitted by the CPUC
- Deliverability assessment methodology and assumptions

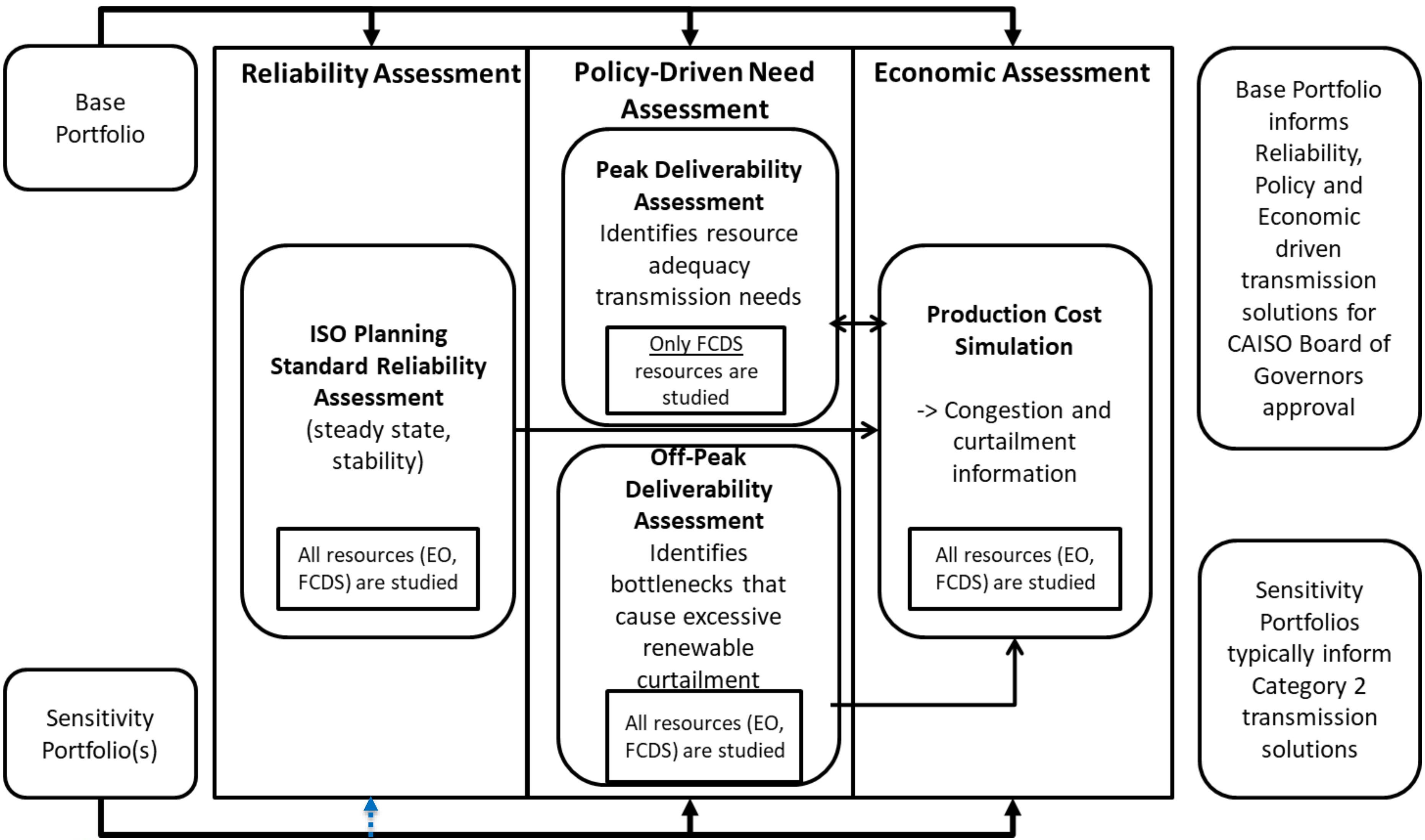
Agenda

- Policy-driven assessment objectives and scope
- Description of portfolios transmitted by the CPUC
- Deliverability assessment methodology and assumptions

Objectives and scope

- Overarching objective is to ensure alignment between resource planning (CPUC) and transmission planning (CAISO)
- Deliverability assessment (on-peak) supports deliverability of FCDS resources selected to meet resource adequacy needs
- Production cost simulation supports the economic delivery of renewable energy over the course of all hours of the year
- Reliability assessment and off-peak deliverability assessment are used to identify constraints for further evaluation using production cost simulation
- Assessment is used to identify transmission needs and inform future portfolio development
- Policy-driven deliverability assessment is the focus of this presentation

CPUC resource portfolio use cases in the ISO TPP



Agenda

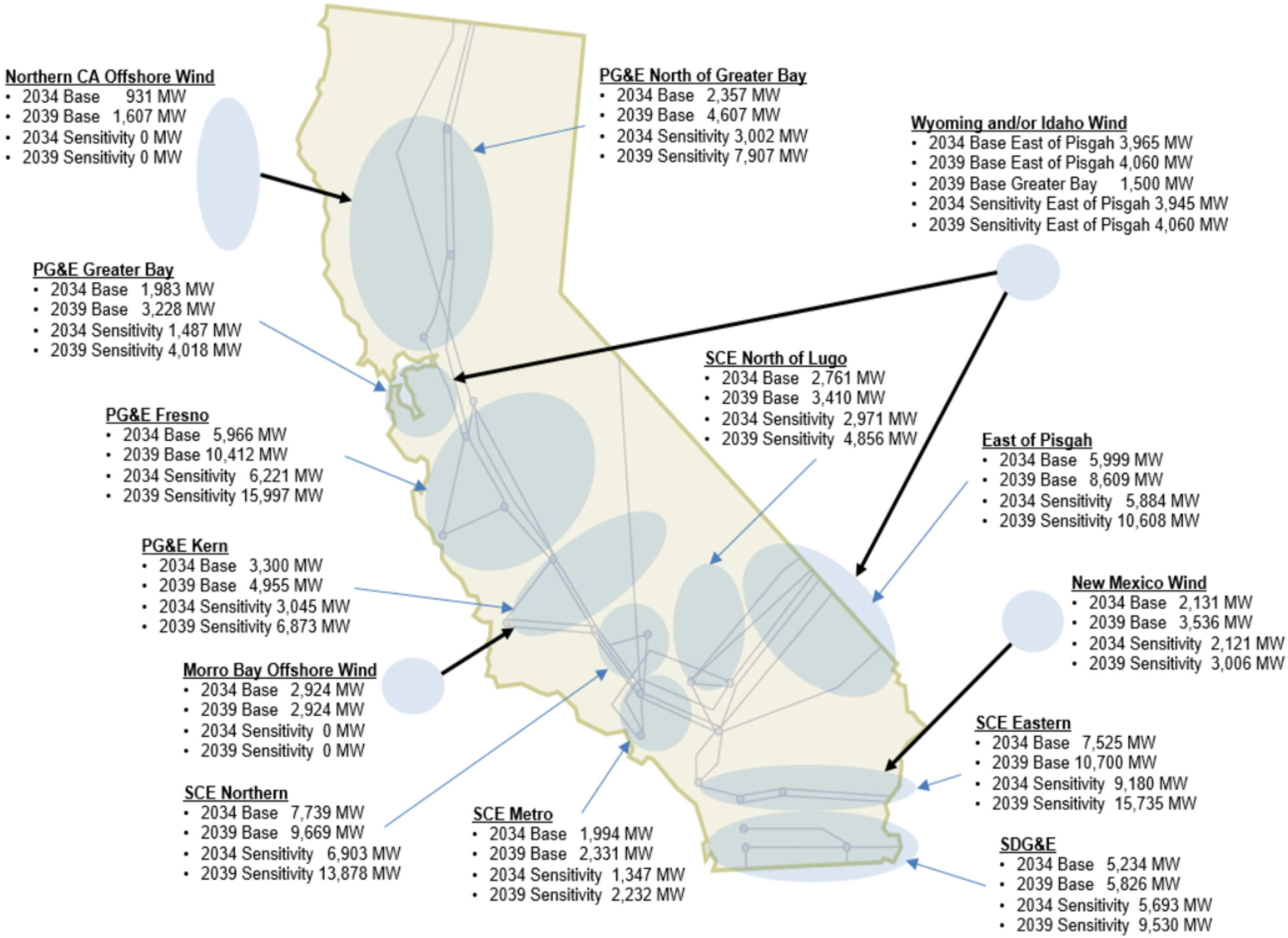
- Policy-driven assessment objectives and scope
- Description of portfolios transmitted by the CPUC
- Deliverability assessment methodology and assumptions

2024-2025 TPP resources portfolios

- On February 15, 2024 the CPUC adopted a Preferred System Plan (PSP) portfolio as the base portfolio and a sensitivity portfolio with high gas retirement assumptions for use in the 2024-2025 TPP
- The portfolios are designed to reduce statewide yearly GHG emissions from the electric sector to 25 MMT by 2035 and were developed with updated assumptions from 2022 CEC demand forecast.
- The portfolio data and modeling assumptions are available on the CPUC website[1] and include
  - Modeling Assumptions for the 2024-2025 Transmission Planning Process (Yet to be released)
  - Resource to substation bus mapping workbook for both portfolios for years 2034 and 2039 (study years) complete with transmission capability exceedance estimates
  - Gas generation retirement list for the base and sensitivity portfolios

1 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp

2034 and 2039 portfolio resources by area



Composition of 2034 base and sensitivity portfolios

	Base Portfolio			Sensitivity Portfolio		
Resource Type	**FCDS (MW)**	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**
Biomass	171	0	171	22	0	22
Distributed_Solar	260	0	260	329	0	329
Geothermal	1,969	0	1,969	3,961	0	3,961
LDES	1,030	0	1,030	3,280	0	3,280
Li_Battery (4-hour)	14,958	0	14,958	9,305	0	9,305
Li_Battery (8-hour)	1,618	0	1,618	2,867	0	2,867
Offshore Wind	3,855	0	3,855	0	0	0
OOS Wind	6,096	0	6,096	6,066	0	6,066
Solar	8,481	10,248	18,729	10,751	9,479	20,230
Wind, Onshore	5,203	921	6,123	4,885	855	5,739
TOTAL	**43,640**	**11,168**	**54,808**	**41,465**	**10,333**	**51,799**

Composition of 2039 base and sensitivity portfolios

	Base Portfolio			Sensitivity Portfolio		
Resource Type	**FCDS (MW)**	**EO (MW)**	**Total (MW)**	**FCDS (MW)**	**EO (MW)**	**Total (MW)**
Biomass	171	0	171	22	0	22
Distributed_Solar	283	0	283	335	0	335
Geothermal	1,969	0	1,969	5,089	0	5,089
LDES	1,080	0	1,080	3,680	0	3,680
Li_Battery (4-hour)	15,707	0	15,707	9,305	0	9,305
Li_Battery (8-hour)	7,115	0	7,115	15,612	0	15,612
Offshore Wind	4,531	0	4,531	0	0	0
OOS Wind	9,096	0	9,096	7,066	0	7,066
Solar	10,858	19,541	30,399	21,304	30,547	51,851
Wind, Onshore	6,103	921	7,023	4,885	855	5,739
TOTAL	**56,912**	**20,462**	**77,374**	**67,298**	**31,401**	**98,699**

Gas generation retirement assumptions in the portfolios

Portfolio	Assumed gas retirements (MW)	
	2034	2039
Base	7,140	8,110
Sensitivity (High gas retirement scenario)	9,130	15,966

- The amounts include about 3,700 MW of scheduled OTC retirements

Gas generation retirement by local capacity area

Base Portfolio - Gas-fired Generation Retirement by Local Capacity Area (exluding OTC)						
	2034			2039		
LCR Area	CHP	CCGT_and_Peakers	Base-Total	CHP	CCGT_and_Peakers	Base-Total
Sierra			0	8		8
Stockton		25	25		25	25
Bay Area	7		7	273		273
Fresno	17	99	115	25	99	124
Kern	103	304	407	103	304	407
BC/Ventura	366	300	666	413	300	713
LA Basin	125	666	791	430	666	1096
Not_in_LCR	148	1289	1437	483	1289	1773
Total	765	2683	3448	1735	2683	4418

Sensitivity Portfolio - Gas-fired Generation Retirement by Local Capacity Area (exluding OTC)						
	2034			2039		
LCR Area	CHP	CCGT_and_Peakers	Sensitivity -Total	CHP	CCGT_and_Peakers	Sensitivity -Total
Sierra			0	8	146	153
Stockton		25	25		25	25
Bay Area	7	231	238	273	1819	2092
Fresno	17	503	520	25	526	551
Kern	103	304	407	103	304	407
BC/Ventura	366	300	666	413	1153	1567
LA Basin	125	803	928	430	2361	2791
Not_in_LCR	148	2506	2654	483	4205	4688
Total	765	4673	5438	1735	10539	12274

Comparison of current and 2023-2024 TPP base portfolios

	Total Resources (GW)			
	23-24 TPP (2035)		Current 24-25 TPP	
	(Original)	(Adjusted)*	(2034)	(2039)
Biomass	0.1	0.1	0.2	0.2
Geothermal	2.0	1.7	2.0	2.0
In-State Wind	3.9	2.3	6.1	7.0
LDES	2.0	2.0	1.0	1.1
LI Battery	28.4	19.9	16.6**	22.8***
Offshore Wind	4.7	4.7	3.9	4.5
OOS Wind	4.8	4.8	6.1	9.1
Solar	39.1	32.9	19.0	30.7
Gas retirements	(4.5)	(4.5)	(7.1)	(8.1)
Total	**81.7**	**64.0**	**47.7**	**69.3**

* Subtracting resources now in updated IRP baseline

** 1. 6 GW of the current TPP 2034 LI Battery has 8-hour duration

*** 7. 1 GW of the current TPP 2039 LI Battery has 8-hour duration

- The 23-24 TPP base portfolio (2035) is updated to remove resources now included the new 2023 IRP baseline.

2034 base portfolio tx. capability exceedances (CPUC) – PG&E Northern

Base Case (2034) Tx Constraint Exceedances		Constraint's White Paper		Calculated Largest On-peak Exceedance**	Calculated Off-peak Exceedance	White Paper Upgrade Info		Comparison to 23-24 TPP Base Case (2035) Calculated w/ New 2023				CPUC staff estimated likelihood of being triggered	CPUC staff discussion notes
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)			Capability Increase (MW)	Estimated Cost (millions)	Previous On-peak Exceedance	24-25 TPP Exceedance is	Previous Off-peak Exceedance	24-25 TPP Exceedance is		
PG&E North of Greater Bay	Vaca Dixon-Tesla 500kV Line	1,044	1,415	**(837)**	**None**	8,645	$ 2,852	**(456)**	**Larger**	**None**	**Similar**	Medium	**Upgrade potentially triggered in 2034, but likely triggered in 2039. Upgrade viewed as effective solution but CPUC staff encourage CAISO to assess potentially less costly alternatives or optimizing with potential upgrades needed for North Coast offshore wind resources mapped.**
	Carberry-Round Mountain 230kV Line	14	183	**(119)**	**None**	26	$ 180	**(35)**	**Similar**	**None**	**Similar**	High	Likely triggered per CAISO staff feedback; identified upgrade is effective solution if TPP determines necessary
	Rocklin-Pleaseant grove 115kV line	92	226	**(27)**	**None**	707	$ 125	**(20)**	**Similar**	**None**	**Similar**	Medium	Potential upgrade is effective solution if identified as necessary, given amount mapped 2039 further increases exceedance
PG&E Greater Bay	Windmaster-Delta pumps 230 kV Line	710	710	**(133)**	**None**	6,034	$ 417	**(364)**	**Smaller**	**None**	**Similar**	Low	Per CAISO staff feedback, mapped resources unlikely to trigger exceedance and similar exceedance in 23-24 TPP.
	Morganhill-Metcalf 115kV Line	314	314	**(299)**	**None**	712	$ 380	**(185)**	**Similar**	**None**	**Similar**	Low	
	Birds Landing-Contra Costa 230kV Line	836	836	**(326)**	**None**	1,766	$ 700	**None**	**Larger**	**None**	**Similar**	Low	Per CAISO staff feedback, upgrade may not be triggered given resource amounts mapped to Glenn, Eagle Rock, and Lakeville are not likely to impact the limit ADC behind constraint per CAISO staff feedback. But TPP analysis is necessary to confirm. However, if it is necessary, CPUC staff identify the White Paper upgrade as an effective solution to this exceedance, particularly given 2039 mapping increases the exceedance, over alternatives such as remapping the resources to other locations.

*Includes capability increase from TPP approved upgrade

** Includes calculations from IRP baseline resources not in mapped portfolio numbers

2034 base portfolio tx. capability exceedances (CPUC) – PG&E Southern

Base Case (2034) Tx Constraint Exceedances		Constraint's White Paper		Calculated Largest On-peak Exceedance**	Calculated Off-peak Exceedance	White Paper Upgrade Info		Comparison to 23-24 TPP Base Case (2035) Calculated w/ New 2023				CPUC staff estimated likelihood of being triggered	CPUC staff discussion notes
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)			Capability Increase (MW)	Estimated Cost (millions)	Previous On-peak Exceedance	24-25 TPP Exceedance is	Previous Off-peak Exceedance	24-25 TPP Exceedance is		
PG&E Kern	**Oceano-Calendar 115kV Line**	937	174	**(375)**	**(296)**	1,418	$ 1,008	**(478)**	**Similar**	**(740)**	**Smaller**	Medium	Potential upgrade is effective solution if identified as necessary, given amount mapped 2039 further increases exceedance
	Midway-Q2005 230kV Line	1,396	278	**(1,260)**	**(927)**	16,891	$ 940	**(2,368)**	**Smaller**	**(1,763)**	**Smaller**	High	Potential upgrade is effective solution for amount mapped, particular given increase in exceedance in 2039 mapping
PG&E Fresno	**Gates 500/230kV TB #12**	3,213	3,148	**(157)**	**None**	14,825	$ 35	**(988)**	**Smaller**	**None**	**Similar**	Medium	Potential upgrade is effective solution if identified as needed, given amount mapped 2039 further increases exceedance
	Chowchilla-Le grand 115kV Line	699	908	**(320)**	**None**	1,211	$ 550	**(316)**	**Similar**	**None**	**Similar**	Low	Potential upgrade is effective solution if identified as needed, given amount mapped 2039 further increases exceedance
	Schindler 115/70kV TB #1	399	491	**(304)**	**None**	3,160	$ 370	**(309)**	**Similar**	**None**	**Similar**	Low	Potential upgrade is same for both constraints and is effective solution if identified as needed, given amount mapped 2039 further increases exceedance
	Panoche-Mendota 115 kV Line	1,798	7	**None**	**(53)**	2,019	Same as Schindler 115/70kV	**None**	**Similar**	**(189)**	**Similar**	Low	
	Moss Landing-Las Aguillas 230 kV Line Off-Peak	2,276	-	**(59)**	**(593)**	1,760 (off-peak)	$ 40	**(59)**	**Similar**	**(1,905)**	**Smaller**	Medium	Potential upgrade is effective solution for amount mapped

*Includes capability increase from TPP approved upgrade

** Includes calculations from IRP baseline resources not in mapped portfolio numbers

2034 base portfolio tx. capability exceedances (CPUC) – South

Base Case (2034) Tx Constraint Exceedances		Constraint's White Paper		Calculated Largest On-peak Exceedance**	Calculated Off-peak Exceedance	White Paper Upgrade Info		Comparison to 23-24 TPP Base Case (2035) Calculated w/ New 2023				CPUC staff estimated likelihood of being triggered	CPUC staff discussion notes
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)			Capability Increase (MW)	Estimated Cost (millions)	Previous On-peak Exceedance	24-25 TPP Exceedance is	Previous Off-peak Exceedance	24-25 TPP Exceedance is		
SCE Northern	South of Magunden	740	500	**(596)**	**None**	2,000	$ 4,358	**(336)**	**Larger**	**None**	**Similar**	Low	**CPUC staff view these upgrades as not cost-effective for the resources mapped. CPUC staff ask the CAISO to consider other potentially less costly upgrades; and if CAISO's TPP analysis does show that either upgrade is likely needed and alternative benefits do not warrant the costs, CPUC staff request that the CAISO consult with CPUC staff about the potential of remapping generic resources as an alternative to triggering the upgrade. Per CAISO staff feedback upgrade is not likely to be triggered given locations mapped and existing TPD allocated. CAISO staff feedback to the working group noted the White Paper upgrade and the 2021 White Paper upgrade (new 500 kV Magunden substation with an estimated cost of $1.5 billion and capability increase of 870 MW) as an alternative less costly solution and that both upgrades could have secondary benefits including reducing Path 26 congestion.**
SCE Eastern	Devers-Red Bluff	9,050*	6,158*	**(2,124)**	**None**	3,000^	$ 1,022^	**(2,260)**	**Similar**	**None**	**Similar**	Medium	The constraint includes capacity from an approved 22-23 TPP upgrade so the constraint capability limit is a default constraint so the exceedance may not trigger an additional transmission upgrade. In feedback to the working group CAISO staff noted the previously identified 2021White Paper upgrade that could provide an estimated 3,000 MW of additional capacity and cost $1.02 billion would be a potential solution to any exceedance. CPUC staff note that the exceedance is comparable to the amount seen for the 23-24 TPP base case for which the preliminary results indicated a transmission upgrade is not likely needed for the 2034 portfolio. If needed, the identified upgrade would be an effective solution to remapping resources.
East of Pisgah	Lugo-Victorville Area	#####	9,600	**(1,716)**	**None**	6,800	$ 2,165	**(1,144)**	**Larger**	**None**	**Similar**	Medium	Upgrade is potentially triggered by the mapping results as the 2034 portfolio's exceedance is slightly larger than the calculated exceedance for the 23-24 TPP base case. Given increases in exceedance in 2039, this is a effective solution for the resources mapped.
SDG&E	Chicarita 138 kV	301	301	**(437)**	**None**	700	$ 100	**(600)**	**Smaller**	**None**	**Similar**	High	the White Paper upgrade as an effective solution to this exceedance over alternatives such as remapping the resources to other locations.
	Silvergate - Bay Blvd 230 kV	796	929	**(627)**	**None**	4,754	$ 30	**(51)**	**Larger**	**None**	**Similar**	High	Upgrade is likely needed to alleviate exceedance. CPUC staff identify the White Paper upgrade as an effective solution to this exceedance over alternatives such as remapping the resources to other locations.
	Silvergate-Old Town 230 kV	1,221	1,221	**(284)**	**None**	2,522	$ 283	**None**	**Larger**	**None**	**Similar**	High	Upgrade is likely needed to alleviate exceedance. CPUC staff identify the White Paper upgrade as an effective solution to this exceedance over alternatives such as remapping the resources to other locations.
	Talega 230 kV	1,205	1,205	**(291)**	**None**	2,201	$ 211	**(480)**	**Smaller**	**None**	**Similar**	High	Upgrade is likely needed to alleviate exceedance. CPUC staff identify the White Paper upgrade as an effective solution to this exceedance over alternatives such as remapping the resources to other locations.

*Includes capability increase from TPP approved upgrade

** Includes calculations from IRP baseline resources not in mapped portfolio numbers

2039 base portfolio tx. capability exceedances (CPUC) – PG&E Northern

Base Case (2034) Tx		Constraint's White		Calculated Largest On-peak Exceedance**	Calculated Off-peak Exceedance	White Paper		Comparison to 23-24 TPP Base Case				CPUC staff estimated likelihood of being triggered	CPUC staff discussion notes
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)			Capability Increase (MW)	Estimated Cost (millions)	Previous On-peak Exceedance	24-25 TPP Exceedance is	Previous Off-peak Exceedance	24-25 TPP Exceedance is		
PG&E North of Greater Bay	Vaca Dixon-Tesla 500kV Line	1,044	1,415	**(2,351)**	**None**	8,645	$ 2,852	**(456)**	**Larger**	**None**	**Similar**	High	**effective solution, but CPUC staff encourage CAISO to assess potentially less costly alternatives or co-optimizing with potential upgrades needed for North Coast offshore wind resources mapped.**
	Woodland- Davis 115kV Line	76	76	**(67)**	**(43)**	109	$ 9	**None**	**Larger**	**None**	**Larger**	High	Potential upgrade is effective solution if identified as necessary
	Carberry-Round Mountain 230kV Line	14	183	**(119)**	**None**	26	$ 180	**(35)**	**Larger**	**None**	**Similar**	High	Likely triggered per CAISO staff feedback; identified upgrade is effective solution if TPP determines necessary
	Rocklin-Pleaseant grove 115kV line	92	226	**(170)**	**None**	707	$ 125	**(20)**	**Larger**	**None**	**Similar**	High	Potential upgrade is effective solution if identified as necessary
	Bellota-Weber 230kV Line	2,382	2,382	**(545)**	**None**	460	$ 400	**None**	**Larger**	**None**	**Similar**	High	
PG&E Greater Bay	Windmaster-Delta pumps 230	710	710	**(278)**	**None**	6,034	$ 417	**(364)**	**Similar**	**None**	**Similar**	Low	Per CAISO staff feedback, mapped resources unlikely to trigger exceedance and similar exceedance in 23-24 TPP.
	Morganhill-Metcalf 115kV	314	314	**(349)**	**None**	712	$ 380	**(185)**	**Larger**	**None**	**Similar**	Low	
	Birds Landing-Contra Costa 230kV Line	836	836	**(599)**	**None**	1,766	$ 700	**None**	**Larger**	**None**	**Similar**	Medium	Upgrade may not be triggered given resource amounts mapped to Glenn, Eagle Rock, and Lakeville are not likely to impact the limit ADC behind constraint per CAISO staff feedback. But TPP analysis is necessary

*Includes capability increase from TPP approved upgrade

** Includes calculations from IRP baseline resources not in mapped portfolio numbers

2039 base portfolio tx. capability exceedances (CPUC) – PG&E Southern

Base Case (2034) Tx		Constraint's White		Calculated Largest On-peak Exceedance**	Calculated Off-peak Exceedance	White Paper		Comparison to 23-24 TPP Base Case				CPUC staff estimated likelihood of being triggered	CPUC staff discussion notes
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)			Capability Increase (MW)	Estimated Cost (millions)	Previous On-peak Exceedance	24-25 TPP Exceedance is	Previous Off-peak Exceedance	24-25 TPP Exceedance is		
PG&E Kern	Oceano-Calendar 115kV Line	937	174	(1,130)	(677)	1,418	$ 1,008	(478)	Larger	(740)	Similar	High	Potential upgrade is effective solution if identified as necessary given level of exceedance and resources mapped
PG&E Kern	Midway-Q2005 230kV Line	1,396	278	(3,596)	(1,460)	16,891	$ 940	(2,368)	Larger	(1,763)	Similar	High	Potential upgrade is effective solution if identified as necessary given level of exceedance and resources mapped
PG&E Fresno	Gates 500/230kV TB #12	3,213	3,148	(1,882)	None	14,825	$ 35	(988)	Larger	None	Similar	High	Potential upgrade is same for both constraints, and it is effective solution if identified as necessary given level of exceedance and resources mapped
PG&E Fresno	Gates 500/230kV TB #11	3,684	3,856	(1,863)	None	10,038	High (same upgrade as TB#12)	(423)	Larger	None	Similar	High	
PG&E Fresno	Tranquility-Helm 230kV Line	2,229	1,170	(438)	None	2,274	$ 1,500	None	Larger	(352)	Smaller	Medium	Potential upgrade is same for both constraints and is effective solution if identified as needed,
PG&E Fresno	Chowchilla-Le grand 115kV Line	699	908	(607)	None	1,211	$ 550	(316)	Larger	None	Similar	Medium	
PG&E Fresno	Los Banos 500/230 kV Bank	8,861*	608*	None	(177)	-	$ -	None	Similar	(630)	Smaller	Low	Small exceedance is off-peak default capacity of already approved upgrade is unlikely to trigger additional upgrades, but full TPP analysis is necessary
PG&E Fresno	Schindler 115/70kV TB #1	399	491	(521)	None	3,160	$ 370	(309)	Larger	None	Similar	Medium	Potential upgrade may be needed for the Panoche-Mendota 115 kV exceedance, but unlikely for small off-peak exceedance. The upgrade is same for both constraints and is effective solution if identified as needed.
PG&E Fresno	Panoche-Mendota 115 kV Line	1,798	7	None	(210)	2,019	Same as Schindler 115/70kV	None	Similar	(189)	Similar	Low	
PG&E Fresno	Moss Landing-Las Aguillas 230 kV Line Off-Peak	2,276	-	(919)	(1,096)	1,760 (off-peak)	$ 40	(59)	Larger	(1,905)	Smaller	High	Potential upgrade is effective solution for the off-peak exceedance given amount mapped. It is unknown if the large exceedance in the default on-peak capability limit will trigger additional transmission needs.

*Includes capability increase from TPP approved upgrade

** Includes calculations from IRP baseline resources not in mapped portfolio numbers

2039 base portfolio tx capability exceedances (CPUC) – South

Base Case (2034) Tx		Constraint's White		Calculated Largest On-peak Exceedance**	Calculated Off-peak Exceedance	White Paper		Comparison to 23-24 TPP Base Case				CPUC staff estimated likelihood of being triggered	
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)			Capability Increase (MW)	Estimated Cost (millions)	Previous On-peak Exceedance	24-25 TPP Exceedance is	Previous Off-peak Exceedance	24-25 TPP Exceedance is		CPUC staff discussion notes
SCE Northern	South of Magunden	740	500	(596)	None	2,000	$ 4,358	(336)	Larger	None	Similar	Low	resources mapped. CPUC staff ask the CAISO to consider other potentially less costly upgrades; and if CAISO's TPP analysis does show that either upgrade is likely needed and alternative benefits do not warrant the costs, CPUC staff request that the CAISO consult with CPUC staff about the potential of remapping generic resources as an alternative to triggering the upgrade. Per CAISO staff feedback upgrade is not likely to be triggered given locations mapped and existing TPD allocated. CAISO staff feedback to the working group noted the White Paper upgrade and the 2021 White Paper upgrade (new 500 kV Magunden substation with an
SCE Eastern	Colorado River 500/230 kV	1,035	1,414	(221)	None	1,370	$ 67	(52)	Larger	None	Similar	Medium	analysis is needed to confirm. CPUC staff identify the White Paper upgrade as an effective solution to this exceedance over alternatives such as remapping the
	Colorado River-Red Bluff	11,521*	11,521*	(832)	None	1,170	$ 357	None	Larger	None	Similar	Low	of the identified and already approved upgrade. CAISO staff have identified a New 500 kV Colorado River-Red Bluff line with a $357million cost estimate from previous studies that could alleviate an exceedance. However, given the relatively small size of exceedance compared to capacity of constraint and comparable,
	Devers-Red Bluff	9,050*	16,158*	(4,988)	None	3,000^	$ 1,022^	(2,260)	Larger	None	Similar	High	exceedance of the identified and already approved upgrade. The size of the exceedance indicates that an additional upgrade is likely needed. In feedback to the working group CAISO staff noted the previously identified 2021 White Paper upgrade that could provide an estimated 3,000 MW of additional capacity
East of Pisgah	GLW 230kV Area	2,185*	2,752*	(520)	None	-	$ -	(173)	Larger	None	Similar	Low	Amount of resources mapped results in an exceedance of the identified and already approved upgrade. Amount mapped within this constraint aligns with previous amounts mapped in the 22-23 TPP sensitivity portfolio, but exceedance is larger than that observed
	Lugo-Victorville Area	10,100	9,600	(4,066)	None	6,800	$ 2,165	(1,144)	Larger	None	Similar	High	effective solution to this exceedance over alternatives such as remapping the resources to other locations.
SDG&E	Chicarita 138 kV	301	301	(487)	None	700	$ 100	(600)	Similar	None	Similar	High	Upgrade is likely needed to alleviate exceedance. CPUC staff identify the White Paper upgrade as an effective solution to this exceedance over alternatives such as
	Internal San Diego Area	1937*	1,006*	(116)	None	-	$ -	None	Larger	None	Similar	Low	Per CAISO staff feedback exceedance is likely to not trigger an additional upgrade and already approve upgrade is sufficient, but TPP analysis is necessary to confirm.
	Encina - San Luis Rey 230 kV	2,688*	2,668*	(254)	None	-	$ -	None	Larger	None	Similar	Low	
	San Luis Rey-San Onofre 230 kV Line	2,837*	6,174	(85)	None	-	$ -	None	Larger	None	Similar	Low	
	Silvergate - Bay Blvd 230 kV	796	929	(690)	None	4,754	$ 30	(51)	Larger	None	Similar	High	Upgrade is likely needed to alleviate exceedance. CPUC staff identify the White Paper upgrade as an effective solution to this exceedance over alternatives such as remapping the resources to other locations.
	Silvergate-Old Town 230 kV	1,221	1,221	(347)	None	2,522	$ 283	None	Larger	None	Similar	High	
	Talega 230 kV	1,205	1,205	(433)	None	2,201	$ 211	(480)	Similar	None	Similar	High	

*Includes capability increase from TPP approved upgrade

** Includes calculations from IRP baseline resources not in mapped portfolio numbers

Non-CPUC Jurisdictional Approved Integrated Resource Plans

- Non-CPUC jurisdictional approved IRP will be incorporated in the analysis with the CPUC busbar mapped IRP base portfolio
- Northern California Power Agency (NCPA) provided the 2023 Inter-Agency Resource Plan (2023 IARP) adopted by the NCPA Commission for use in the 2024-2025 Transmission Plan.
- Non-CPUC jurisdictional approved IRP can be submitted into the comments for inclusion in the 2024-2025 transmission planning process study plan

Agenda

- Policy-driven assessment objectives and scope
- Description of portfolios transmitted by the CPUC
- Deliverability assessment methodology and assumptions

On-peak deliverability assessment

- Examines deliverability of portfolio resources selected as FCDS in accordance with the on-peak deliverability assessment methodology

- Assessment identifies transmission upgrades or other solutions needed to ensure deliverability
  - Other alternatives to be considered include: RAS and other operating solutions and excluding undeliverable portfolio battery storage where applicable per CPUC's guidance

- Informs future portfolio development

Study scenarios in on-peak deliverability assessment

- Highest system need (HSN) scenario
  - Represents the scenario when capacity shortage is most likely to occur
  - Transmission upgrades identified for the base portfolio are recommended as policy driven upgrades
- Secondary system need (SSN) scenario
  - Represents the scenario when capacity shortage risk increases if variable resources are not deliverable during periods when the system depends on their high output for resource adequacy.
  - Transmission upgrades identified for the base portfolio will go through a comprehensive economic, policy, and reliability benefit analysis to be considered for approval as a policy driven or economic upgrade.

Modeling assumptions for HSN scenario

Selected Hours	HE19 ~ 22 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC
Non-Intermittent Resources	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Resources	Study amount set to 20% exceedance level during the selected hours
Import	MIC data with approved and requested expansions and expansions needed to accommodate non-ISO resources in the portfolios

Modeling assumptions for SSN scenario

Select Hours	HE15 ~ 18 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC adjusted to peak consumption hour
Non-Intermittent Generators	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Study amount set to 50% exceedance level during the selected hours, but no lower than the average QC ELCC factor during the summer months
Import	Highest import schedules for the selected hours plus approved and requested expansions and expansions needed to accommodate non-ISO resources in the portfolios

On-peak assessment maximum resource dispatch

Resource type	HSN			SSN		
	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	3.0%	10.6%	10.0%	40.2%	42.7%	55.6%
Wind	33.7%	55.7%	66.5%	11.2%	20.8%	16.3%
OOS Wind (NM, WY, ID)	67%			35%		
Offshore Wind	83%			45%		
Energy storage	100% or 4-hour equivalent if duration is < 4-hour			50% or 4-hour equivalent if duration is < 4-hour		
Non-Intermittent resources	NQC					

California ISO

Off-peak deliverability assessment

- Used to identify transmission constraints that would result in excessive renewable curtailment in accordance with the off-peak deliverability methodology
- Off-peak deliverability constraints are identified if the following adjustments do not alleviate the overload:
  - Dispatching existing energy storage in charging mode
  - Turning off thermal generators contributing to the overload
  - Reducing imports contributing to the constraint to the level required to support out-of-state renewables in the RPS portfolios
- Potential transmission upgrades needed to mitigate off-peak deliverability constraints are identified
  - Other alternatives to be considered include RAS and other operating solutions and dispatching portfolio energy storage in charging mode
- The constraints and the identified transmission upgrades are considered as candidates for a more thorough evaluation using production cost simulation

System wide dispatch assumptions in off-peak deliverability assessment

Load	55% ~ 60% of summer peak load
Imports	~6000 MW total
System-Wide Generator Dispatch Level	
Wind	44%
Solar	68%
Energy Storage	0
Hydro	30%
Thermal	15%

Increase Local Area Renewable Output

- After balancing load and resource under the system-wide conditions, the renewable generation in a local study area is increased to identify transmission constraints.
- General local study areas include
  - PG&E : North of GBA, GBA, Fresno and Kern
  - SCE/VEA/GWL/DCRT: Northern, North of Lugo, East of Pisgah, Eastern
  - SDGE: Inland and East of Miguel
- Off-peak deliverability assessment is performed for each study area separately.

Study Area Wind/Solar Off-Peak Dispatch Assumptions

- The study area wind/solar dispatch assumptions are based on the 90% energy production level of existing generators inside the study area.
- If more than 70% of the study area capacity is wind, then the study area is deemed to be a wind area; otherwise it is treated as a solar area.

Wind/Solar Dispatch Assumptions in Wind Area

	Wind	Solar
SDG&E	69%	68%
SCE	64%	
PG&E	63%	

Wind/Solar Dispatch Assumptions in Solar Area

	Solar	Wind
SDG&E	79%	44%
SCE	77%	
PG&E	79%	

Offshore Wind	100%
OOS Wind	67%

Study year

- The study years for the policy driven assessment in this planning cycle will be 2034 and 2039

Preliminary results

- Preliminary results of the assessment will be presented at the November 14 stakeholder meeting

California ISO

Economic Assessment
Unified Planning Assumptions & Study Plan

Yi Zhang

2024-2025 Transmission Planning Process Stakeholder Meeting
February 28, 2024

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)

- WECC is projected to release new ADS PCM using the 2034 Load & Resource submittals in June 2024
- The unified planning assumptions will be used to update the CAISO system model
- 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 Hitachi Energy GridView software on the CAISO's planning PCM

- Congestion analysis and renewable curtailment analysis
  - The analysis results will be considered in finalizing the selection of high priority areas for economic assessment, 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 and curtailment 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

- Economic benefit assessment is based on TEAM
  - Production cost benefit
  - 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

Frequency Response Assessment and Data Requirements Draft 2024-2025 Transmission Plan

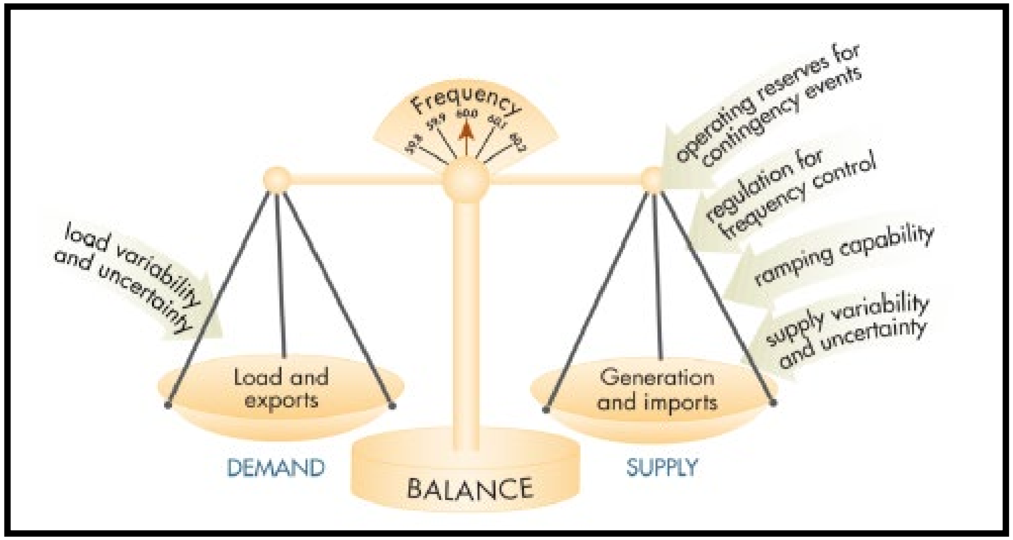
Chris Fuchs
Regional Transmission North

2024-2025 Transmission Planning Process Stakeholder Meeting
February 28, 2024

Overview

- Basics of frequency response (will focus on under-frequency events)
- ISO frequency response study results in previous TPPs
- ISO frequency response study results 2023-2024 TPP - impact of frequency response from Inverter Based Resources (IBRs) and Battery Energy Storage Systems (BESS)

Continuous Supply and Demand Balance



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

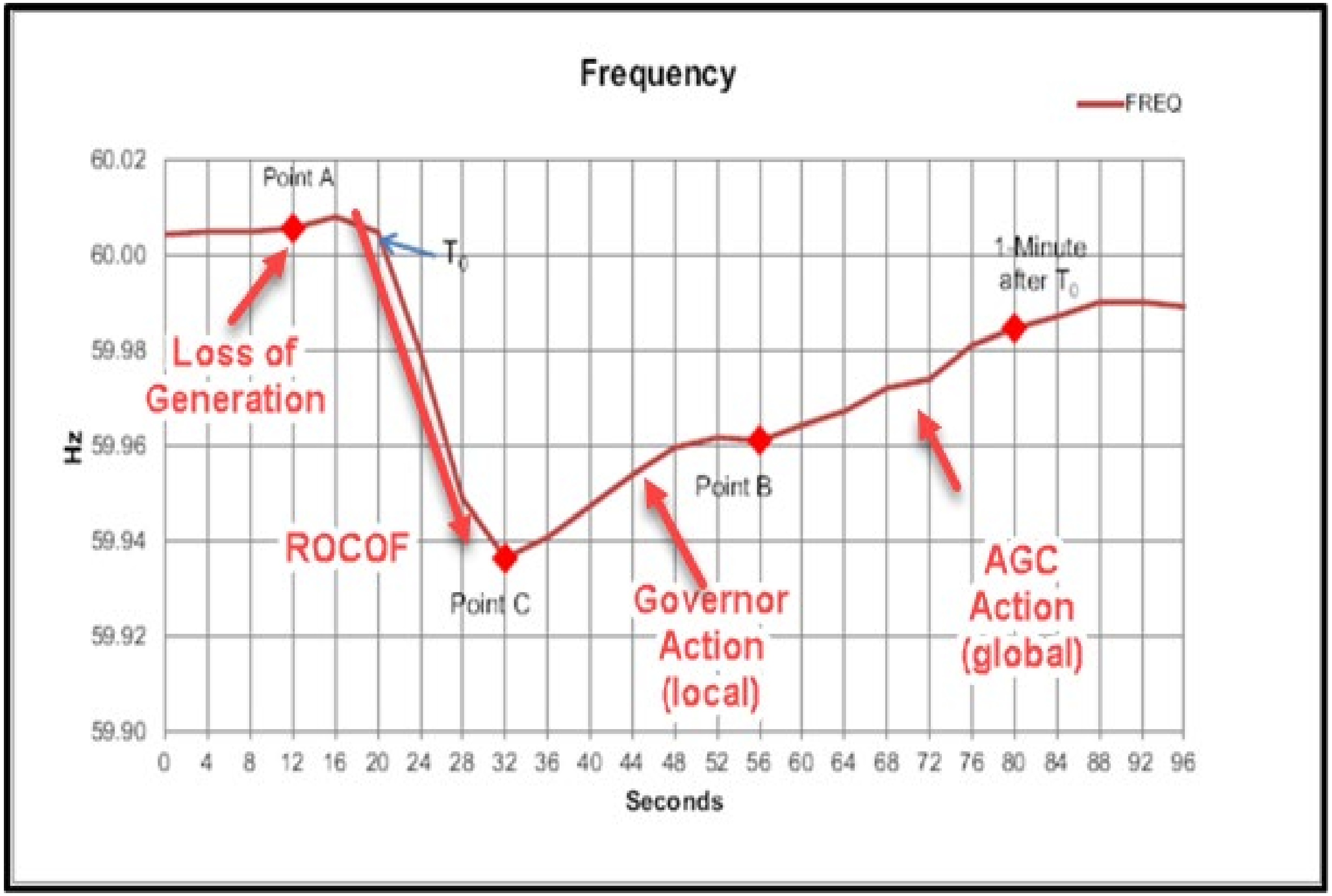
$$\sum Load = \sum Generation$$

During system disturbances/outages this balance is upset

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

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

Standard Frequency Event Progression



Point C – nadir
Point B – settling frequency

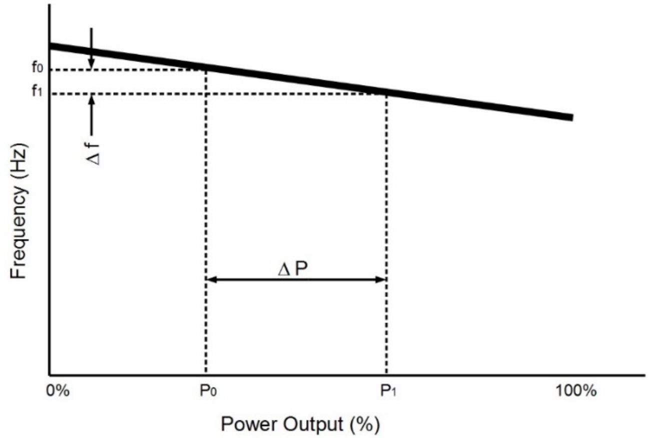
Nadir needs to be higher than the 1st set-point for Under Frequency Load Shedding (59.5 Hz)

Generator Response to Frequency Events

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

Governor Droop Curve

- Droop is the ratio of the frequency change to generator output change. The smaller the droop, the higher the individual response, but system-wide generation response becomes erratic and uncoordinated if it is too small. Droop is typically in the 3%-5% range.



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

Generator/BESS Headroom

- Headroom is the difference between the maximum capacity of the unit and the unit's output. Units that don't respond to changes in frequency are considered not to have headroom.
- Solar and Wind plants are designed to extract as much energy from the environment as possible and prefer to operate at capacity if possible. ⟹ minimal headroom.
- Battery Energy Storage Systems (BESS) plants when charging have a large headroom for under-frequency events.
- In effect headroom=pmax-pmin. With pmax=-pmin, can have this much headroom=2*pmax

Governor Frequency Deadband

- Frequency Deadband is a margin (high/low) around 60 Hz and is a means of restricting excessive and usually unrequired control action. Originally a requirement for mechanical governor systems – less of an issue with electronic governor action applied to IBR units.
- the minimum frequency deviation from 60 Hz before governor responds. Deadband is typically 0.012 Hz to 0.036 Hz.

Frequency Response Characterization

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

Frequency Response Obligation (FRO) and Measure (FRM)

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

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

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

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

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

ISO Frequency Response Study Results in Previous TPPs

- All studies assessed primary frequency response for the most severe credible contingency involving frequency disturbance: outage of two Palo Verde nuclear units (single event with highest drop of generator power in WECC system).
- Off-peak cases appeared to be more severe than peak cases because of less frequency-responsive units on-line (ie solar/wind IBRs)
- Paloverde units not dispatched at full output in spring-off-peak cases for 2035.

Previous Studies – Conclusions

- The ISO system meets BAL-003-1.2 requirements under the assumptions studied.
- With lower commitment of the frequency-responsive units, frequency response from the ISO could go below the FRO specified by NERC.
- Compared to the ISO's actual system performance during disturbances, the simulation results seemed optimistic.

ISO Frequency Response Study 2022-2023 TPP Study Background

- With FERC Order 842, all IBRs that sign Large Generation Interconnection Agreements (LGIA) on or after 5/15/2018 will have frequency response capability.
- The majority of the existing IBRs installed prior to 2018 do not provide frequency response.
- 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.

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 2028 & 2035 and identify any performance issues related to frequency response.
- The starting base case was the Spring off-Peak case for 2027 & 2035. 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 at full output was studied.
- Dynamic stability simulations were run for up to 60 seconds.

Study Scenarios

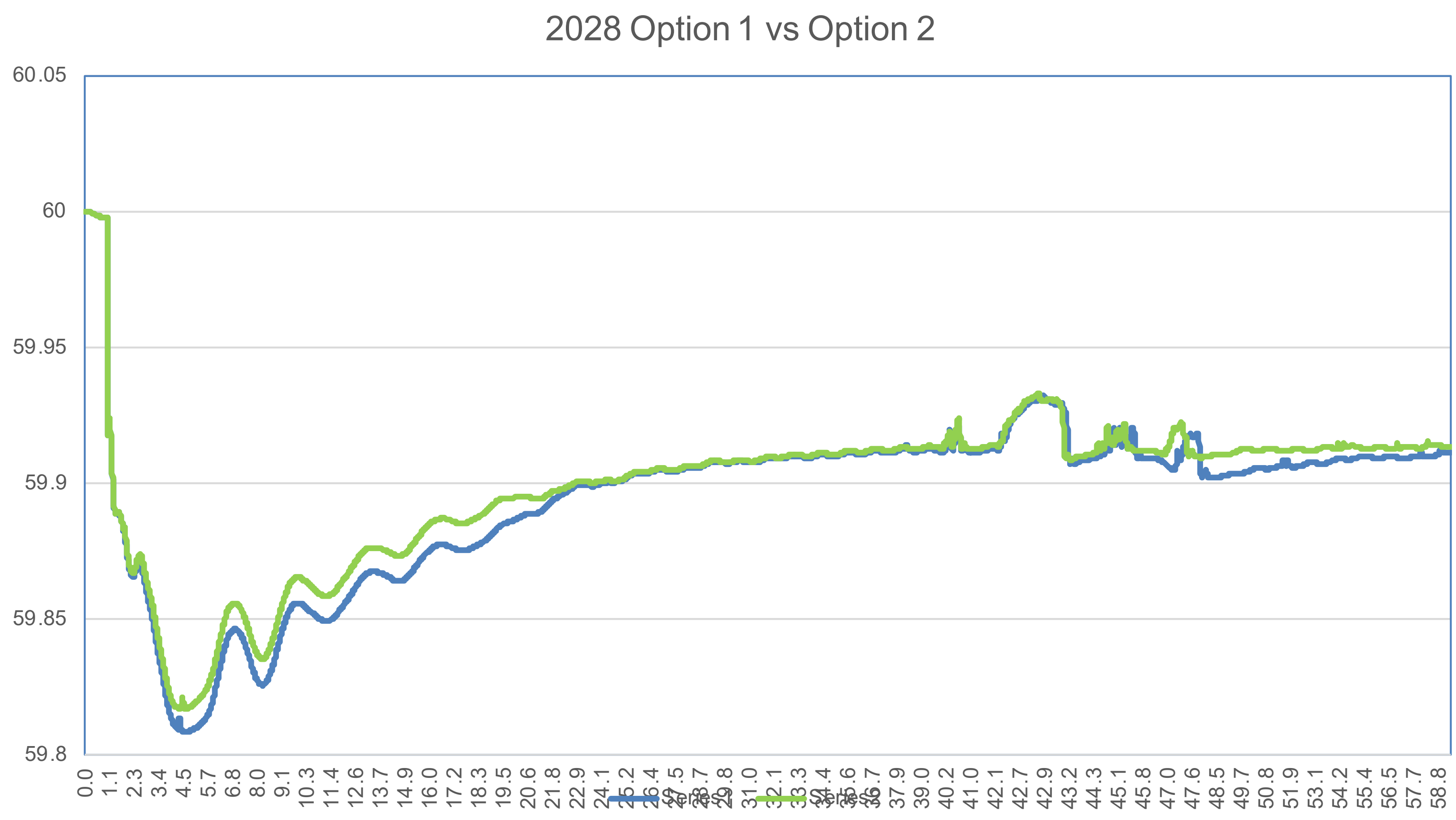
- Cases: Base case 2028/2035 Spring off-Peak and the selected case with reduced headroom.
- BESS are mostly in charging mode except for high spinning reserve scenarios

Scenarios	SC1	SC2	SC3	SC4	SC5
IBR Frequency Control is switched off	✓	-	-	-	-
IBR Frequency Control is switched on	-	✓	-	✓	-
Frequency Control enabled for BESS at 10% headroom	-	-	✓	-	✓
IBR Frequency Control switched on and CAISO at spinning reserve headroom	-	-	-	✓	-
BESS at 10% headroom and CAISO at spinning reserve headroom					✓

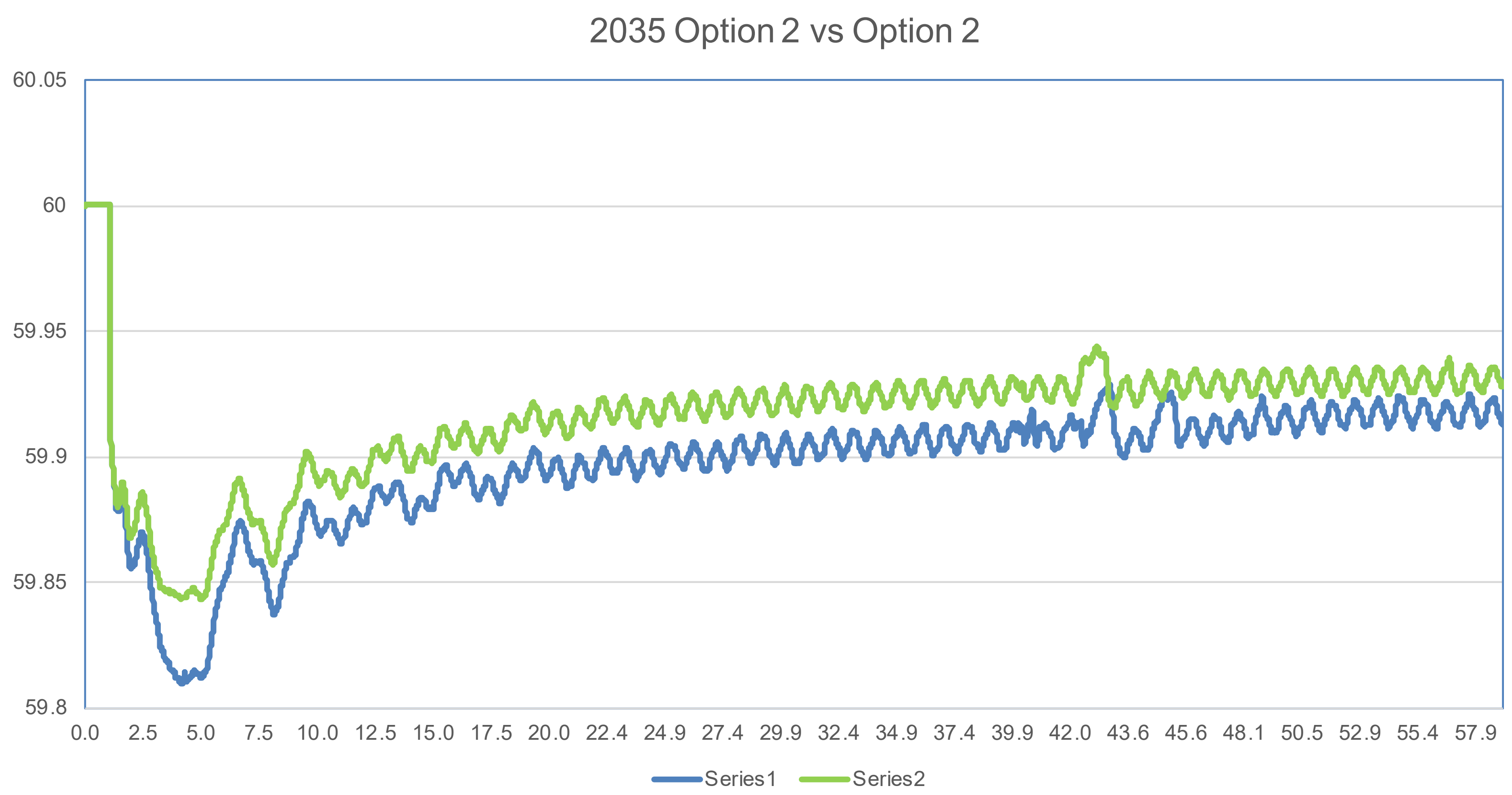
Monitored Values

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

Scenario #1&2: 2028 All IBR On & Off



Scenario #1&2: 2035 All IBR On & Off



System Frequency Observations

- Having frequency response from the BESS improves frequency performance
- The frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz for all scenarios surveyed
- The frequency nadir for 2035 scenarios is > than the 2028 scenarios
- BESS units have a much higher impact in 2035 due to the higher overall proportional of them in the system compared to 2028.

2023-2024 TPP Study Conclusions

- IBR units with frequency response 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 (pre-2018 units do not).
- IBR are effective in enhancing frequency stability and providing compliance with the BAL-003-2 Standard.
- Being in compliance with the BAL-003-2 Standard while having 100% of energy provided by renewable resources in the ISO is possible if the new IBR resources have frequency response and have and adequate headroom.
- Adequate headroom is an important for which only BESS units with an adequate State-of-Charge (SOC) can uniformly provide.
- Luckily frequency events are typically short-lived.

Next Steps
Unified Planning Assumptions & Study Plan

Yelena Kopylov-Alford
Stakeholder Engagement and Policy Specialist

2024-2025 Transmission Planning Process Stakeholder Meeting
February 28, 2024

2024-2025 Transmission Planning Process Next Steps

- Comments due by end of day **March 13, 2024**
- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:

https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2024-2025-Transmission-planning-process

- Economic Study Requests and Maximum Import Capability (MIC) expansion requests are submitted with comments. Confidential information should be referenced in comments and emailed to regionaltransmission@caiso.com
- CAISO will post comments and responses on the website
- Final Study Plan will be posted in April