California ISO

Agenda
Unified Planning Assumptions & Study Plan

Kaitlin McGee
Sr. Stakeholder Engagement and Policy Specialist

2023-2024 Transmission Planning Process Stakeholder Meeting
February 28, 2023

2023-2024 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Kaitlin McGee
Overview & Key Issues	Binaya Shrestha
Reliability Assessment	Preethi Rondla
Policy Assessment	Nebiyu Yimer
Economic Assessment	Yi Zhang
Frequency Response Assessment	Chris Fuchs
Wrap-up & Next Steps	Kaitlin McGee

Overview
Unified Planning Assumptions & Study Plan

Binaya Shrestha
Manager, Regional Transmission North

2023-2024 Transmission Planning Process Stakeholder Meeting
February 28, 2023

2023-2024 Transmission Planning Process

January 2023 | **April 2023** | **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

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2023-2024 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 14
- Final Study Plan to be posted on March 31
- 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 16
  - Comments to be submitted by December 4
- Draft transmission plan to be posted on March 31, 2024
- Stakeholder meeting in April
  - Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at May Board of Governor meeting

2023-2024 Transmission Planning Process Key Inputs

- On February 23, 2023 CPUC adopted a base portfolio for 2033 and 2035 and a sensitivity portfolio for 2035 for use in the 2023-2024 TPP

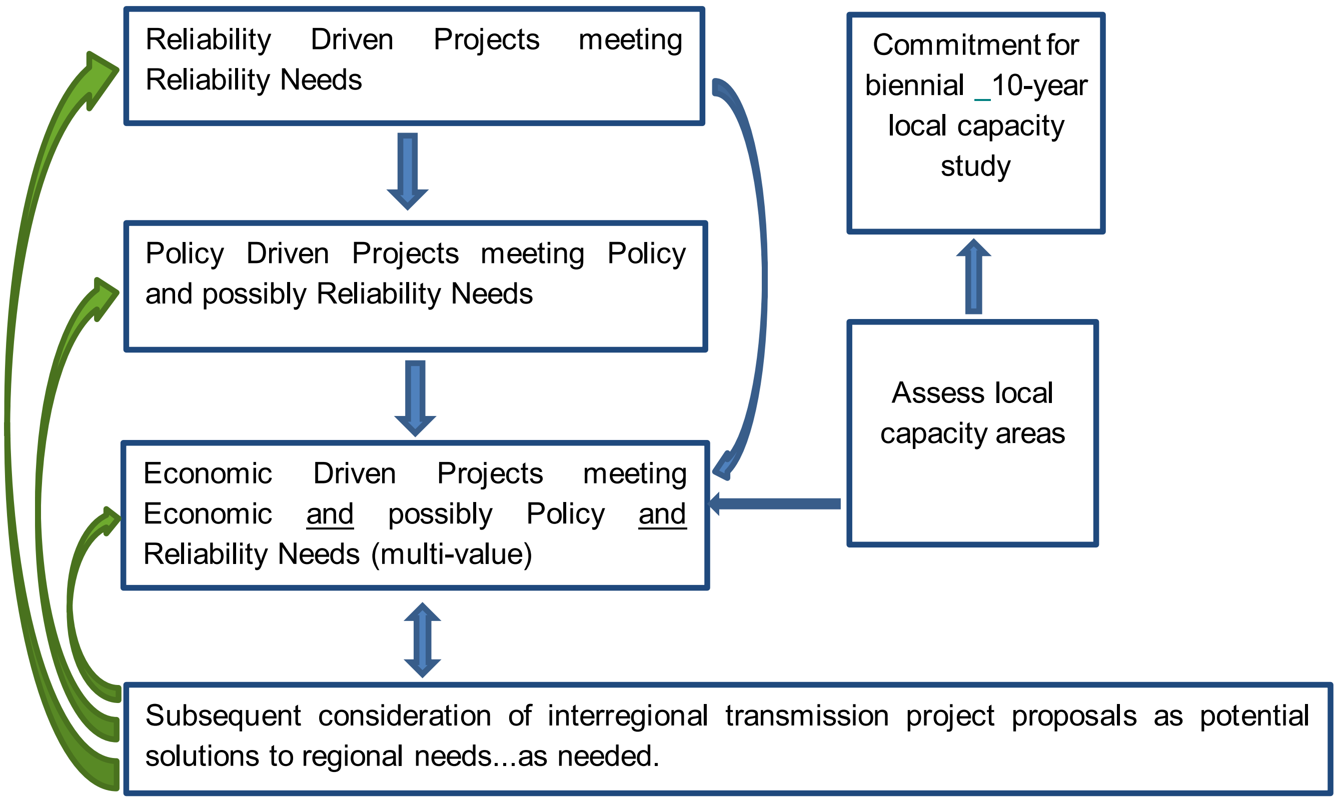
  https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

  - Baseline portfolio
    - Reliability, Policy and Economic Assessments
  - Sensitivity portfolio
    - For special study

- 2022 IEPR California Energy Demand forecast adopted by the CEC on January 25, 2023

  https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2

Studies are coordinated as a part of the transmission planning process



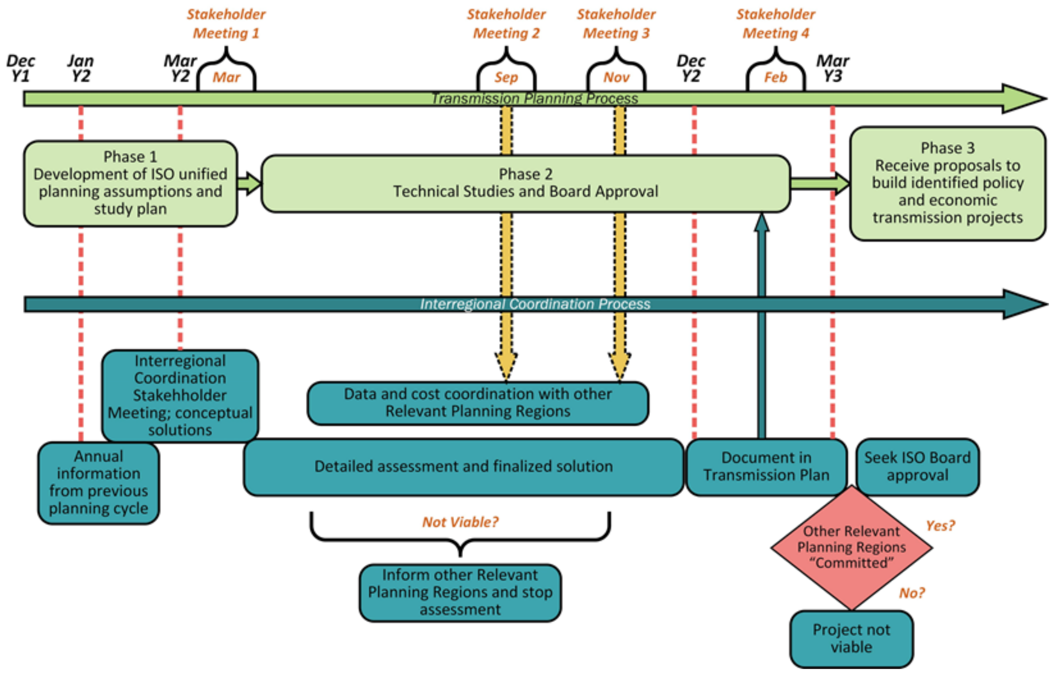
2023-2024 Transmission Plan Study Plan

- Reliability Assessment to identify reliability-driven needs
- Policy Assessment to identify policy-driven needs
- Economic Planning Study to identify needed economically-driven elements
- Other Studies
  - Maximum Import Capability expansion requests
  - Long-term Congestion Revenue Rights
  - Frequency response

Interregional Transmission Coordination - Year 2 of 2

- Participate in a western planning regions' stakeholder meeting.
- Based on the initial assessment of ITP in the previous year's TPP cycle, the ISO will determine whether to further evaluate the project during the odd year of the planning cycle.

Odd 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 14, 2023
  - 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) and the MW quantity 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

Special Studies

- The has not identified any specials studies for the this planning cycle.
- The ISO is planning on conducting an update to the 20-Year Transmission Outlook in parallel with the 2023-2024 transmission planning process.

Study Information

- Final Study Plan will be posted on 2023-2024 transmission planning process webpage on March 31st
  http://www.caiso.com/planning/Pages/TransmissionPlanning/2023-2024TransmissionPlanningProcess.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
2023-2024 TPP Draft Study Plan

- Comments due by end of day March 14, 2023 including:
  - Economic study requests and
  - Maximum Import Capability (MIC) expansion requests are to be submitted with comments

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

https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2023-2024-Transmission-planning-process

Reliability Assessment
Unified Planning Assumptions & Study Plan

Preethi Rondla

2023-2024 Transmission Planning Process Stakeholder Meeting
February 28, 2023

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
  - 12 years planning horizon
    - near-term: 2025 to 2028
    - longer-term: 2029 to 2035*

- Study Years
    - near-term: 2025 and 2028
    - longer-term: 2035*

* *A 12-year planning horizon, 2035 is selected as the long-term study year as the CEC's IEPR goes out to 2035, which is only 2 years beyond the typical 10-year horizon for the long-term study for this TPP cycle. 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.*

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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 2022-2035 adopted by California Energy Commission (CEC) on January 25, 2023 will be used:
  - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
  - Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Fuel Substitution (AAFS)
    - Consistent with CEC 2022 IEPR
    - Mid AAEE, AATE and mid AAFS will be used for system-wide studies
    - Low AAEE, mid AATE and high AAFS will be used for local studies
  - CEC forecast information is available on the CEC website at:
    https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2?utm_medium=email&utm_source=govdelivery

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 case with AAEE Scenario 2, AAFS Scenario 4 and AATE Scenario 3 load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the local capacity requirement (LCR) areas.
  - The 1-in-5 weather year, mid demand baseline with AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3 load forecasts will be used for system studies
  - The 1-in-2 weather year, mid demand baseline with AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3 load forecasts 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

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

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

Load Forecast Assumptions
BTM-PV, BTM-Storage, AAEE, AAFS and AATE

- Similar to previous cycles, BTM-PV will be modeled explicitly in the 2023-2024 TPP base cases.
  - Amount of the BTM-PV to be modeled will be based on 2022 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 2023-2024 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

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

Transportation Electrification

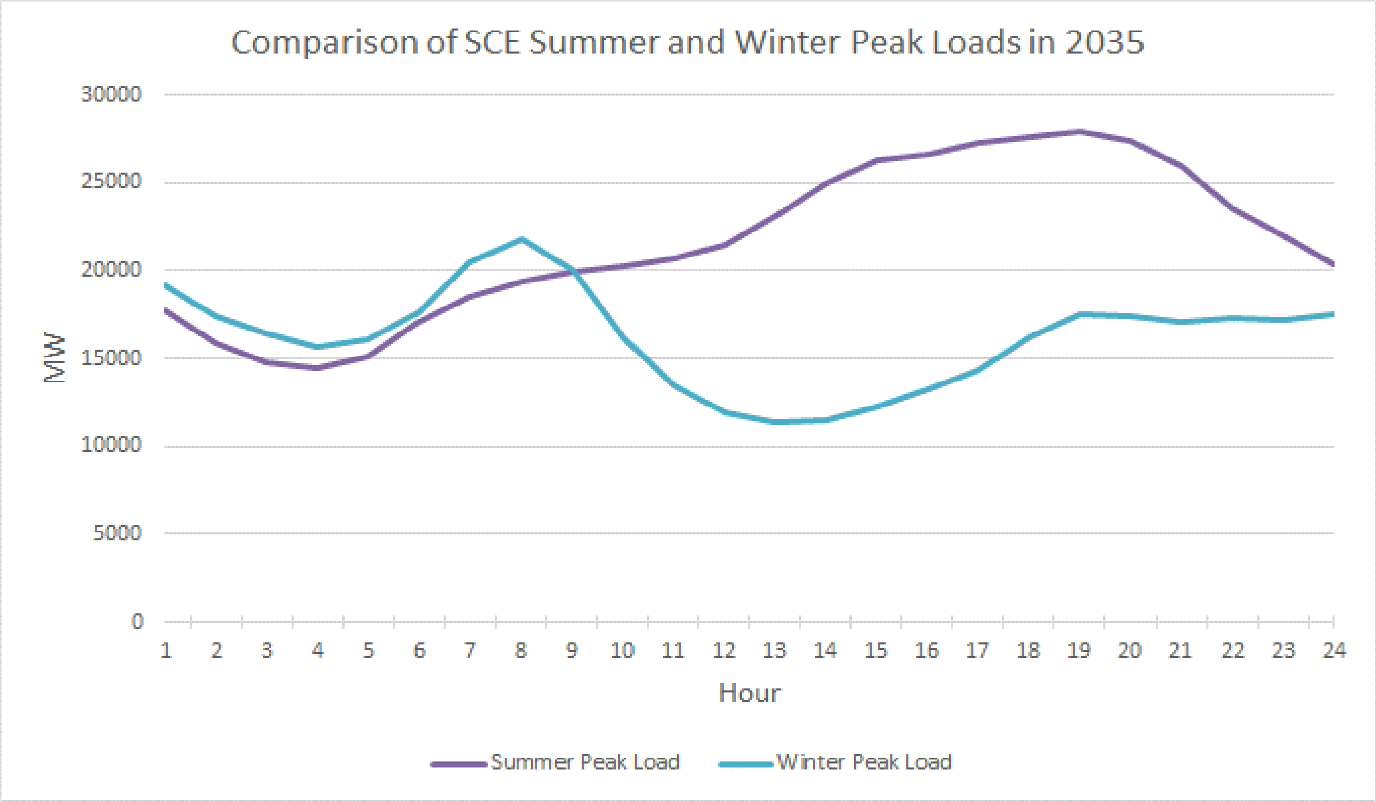
- 2022 IEPR California Energy Demand Update (CEDU) adopted the CEC's modification of the transportation energy demand forecast.
  - Included the large increases in zero-emission vehicles (ZEVs) due to recent state goals for (ZEVs), combined with strong supporting regulatory and programmatic initiatives;
  - Included the forecast recent market trends and increasing consumer demand for ZEVs that align with state policies and goals.
- The Baseline Transportation Electrification (TE) demand forecast includes the following:
  - economic and demographic inputs, as well as vehicle choice models and vehicle travel models, providing the determination for total vehicle stock and transportation energy demand for light-duty (LD) and medium- and heavy-duty (MDHD) sectors;

Transportation Electrification (cont’d)

- The Baseline Transportation Electrification (TE) demand and energy forecast includes the following (cont’d):
  - other inputs for vehicle attributes (i.e., price, range, refueling time, model availability) and incentives for ZEVs, such as federal tax credits, state rebates and rewards, and high-occupancy vehicle access incentives;
- The Additional Achievable Transportation Electrification (AATE) demand and energy forecast includes the following:
  - expansion of original IEPR forecasting approach used for transportation;
  - CARB regulations such as Advanced Clean Fleets and other existing rules.

Winter Peak Demands in the Long Term Forecast for SCE

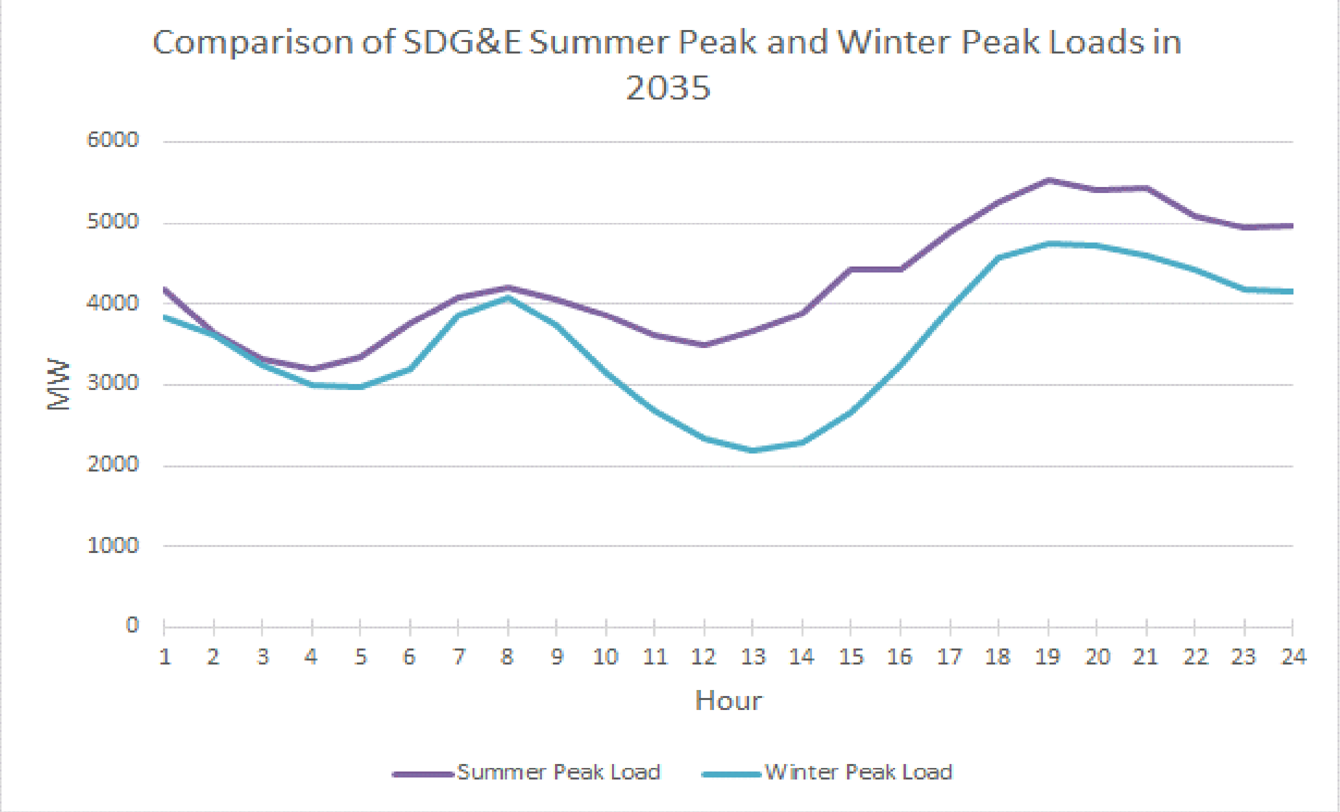
The winter peak loads associated with the Local Reliability hourly demand forecast increase over time to be at approximately 78% of the summer peak load in 2035 for SCE. Baseline scenarios for SCE Metro Area will include 2035 winter-peak scenario.



https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2

Winter Peak Demands in the Long Term Forecast for SDG&E

The winter peak loads associated with the Local Reliability hourly demand forecast increase over time to be at approximately 86% of the summer peak load in 2035 for SDG&E. Baseline scenarios for SDG&E Area will include 2035 winter-peak scenario.



https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2

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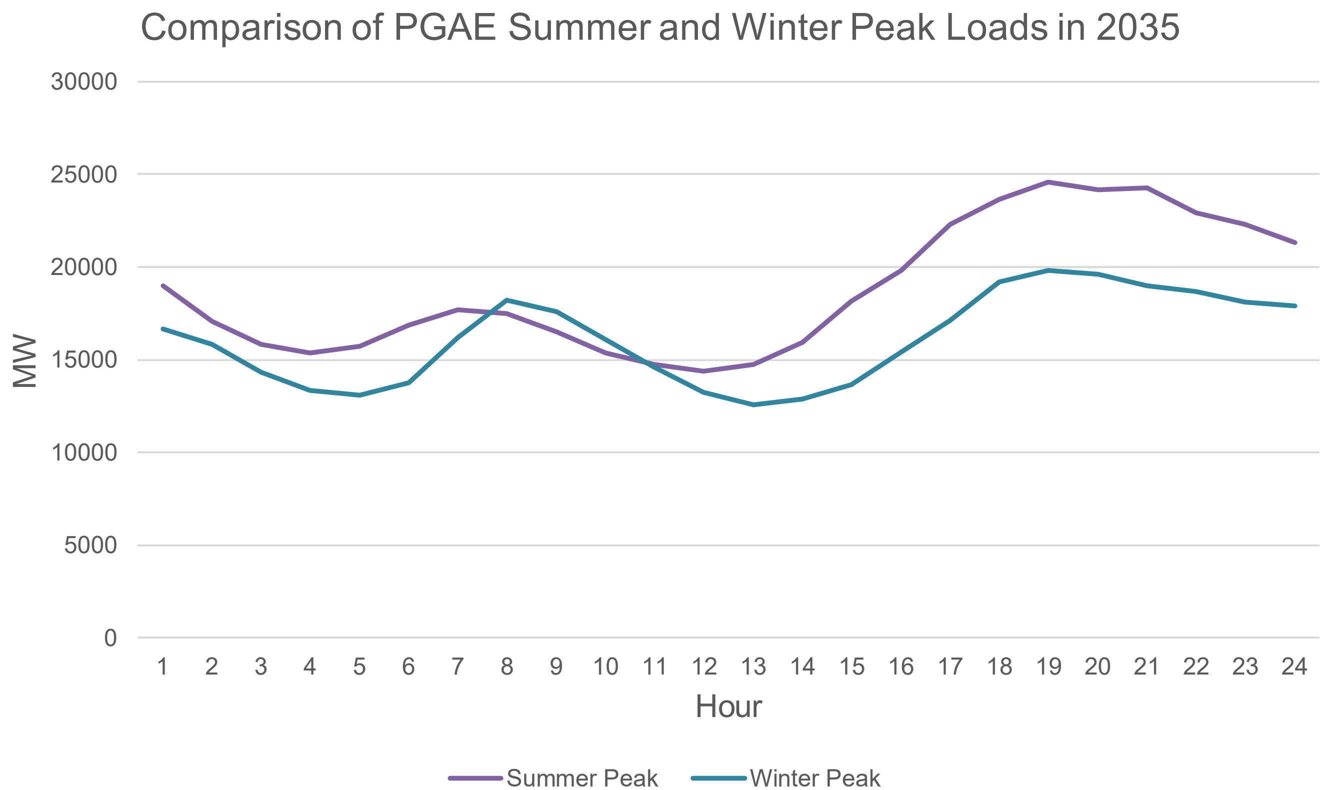
Winter Peak Demands in the Long Term Forecast for PGAE

The winter peak loads associated with the Local Reliability hourly demand forecast increase over time to be at approximately 81% of the summer peak load in 2035 for PG&E. Baseline scenarios for PG&E Coastal areas include winter-peak scenario for all study years.



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

- On February 23, 2023 CPUC adopted a base portfolio for 2033 and 2035 and a sensitivity portfolio for 2035 for use in the 2023-2024 TPP

  https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

  - Baseline portfolio
    - Reliability, Policy and Economic Assessments
  - Sensitivity portfolio
    - For special study

- 2022 IEPR California Energy Demand forecast adopted by the CEC on January 25, 2023

  https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2

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

- <u>Nuclear Retirements</u>
  - Diablo Canyon will be modeled online in near and mid-term scenarios and offline in the long-term scenarios based on the expansion.
- <u>Once Through Cooled Retirements</u>
  - Separate slide below for OTC assumptions
- <u>Renewable and Hydro Retirements</u>
  - Assumes these resource types stay online unless there is an announced retirement date.

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 that have been approved for compliance schedule extension to meet CAISO system capacity need for 2022-2024 timeframe
  - Generating units with approved Track 2 mitigation plan

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)	3,210	
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	3,210	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

Study Scenarios - *Base Scenarios*

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2025	2028	2035
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	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 Summer Off-Peak 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 Summer Off-Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak 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

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Study Scenarios - *Base Scenarios (Cont.)*

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2025	2028	2035
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer 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 Summer Off-Peak Spring Off-Peak	Summer 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		
		2025	2028	2035	2025	2028	2035	2025	2028	2035	2025	2028	2035	2025	2028	2035
PG&E	Summer Off Peak	N/A	7/27 HE16	N/A	N/A	68%	N/A	N/A	77%	N/A	N/A	35%	N/A	N/A	87%	N/A
PG&E	Summer Peak	7/24 HE 19	7/27 HE 19	See CAISO	5%	5%	See CAISO	11%	11%	See CAISO	54%	54%	See CAISO	100%	100%	See CAISO
PG&E	Spring Off Peak	4/24 HE 20	4/1 HE 13	See CAISO	0%	89%	See CAISO	0%	85%	See CAISO	47%	24%	See CAISO	66%	16%	See CAISO
PG&E	Winter Off peak	N/A	N/A	11/10 HE 4	N/A	N/A	0%	N/A	N/A	0%	N/A	N/A	18%	N/A	N/A	47%
PG&E	Winter peak	12/8 HE 19	12/11 HE 19	12/10 HE 19	0%	0%	0%	0%	0%	0%	25%	25%	25%	75%	76%	79%
SCE	Summer Off Peak	N/A	9/5 HE 15	N/A	N/A	74%	N/A	N/A	80%	N/A	N/A	23%	N/A	N/A	98%	N/A
SCE	Summer Peak	9/2 HE 16	9/5 HE17	9/4 HE 19	55%	33%	0%	76%	53%	0%	24%	26%	44%	100%	100%	100%
SCE	Spring Off Peak	4/23 HE 20	4/2 HE 12	See CAISO	0%	94%	See CAISO	0%	84%	See CAISO	55%	24%	See CAISO	66%	24%	See CAISO
SCE	Winter Peak	N/A	N/A	2/7 HE 08	N/A	N/A	8%	N/A	N/A	31%	N/A	N/A	39%	N/A	N/A	78%
SDG&E	Summer Off Peak	N/A	9/6 HE 15	N/A	N/A	64%	N/A	N/A	70%	N/A	N/A	25%	N/A	N/A	82%	N/A
SDG&E	Summer Peak	9/3 HE 19	9/6 HE 19	9/5 HE 21	0%	0%	0%	0%	0%	0%	18%	18%	30%	100%	100%	100%
SDG&E	Spring Off Peak	5/27 HE 20	5/14 HE 13	See CAISO	0%	97%	See CAISO	0%	89%	See CAISO	49%	29%	See CAISO	75%	14%	See CAISO
SDG&E	Winter Peak	N/A	N/A	12/10 HE 19	N/A	N/A	0%	N/A	N/A	0%	N/A	N/A	10%	N/A	N/A	86%
VEA	Summer Peak	9/2 HE 16	9/5 HE17	See CAISO	55%	33%	See CAISO	83%	51%	See CAISO	24%	26%	See CAISO	100%	100%	See CAISO
VEA	Spring Off Peak	4/23 HE 20	4/2 HE 12	See CAISO	0%	94%	See CAISO	0%	84%	See CAISO	55%	24%	See CAISO	66%	24%	See CAISO
PTO	Scenario	Day/Time			BTM-PV			Transmission Connected PV [1]			Transmission Connected Wind			% of non-coincident PTO managed peak load		
					PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2035 Summer Peak	9/4 HE 19			0%	0%	0%	0%	0%	0%	38%	39%	26%	97%	100%	97%
CAISO	2035 Spring Off Peak[2]	4/1 HE 13			89%	94%	91%	85%	89%	87%	24%	33%	38%	12%	19%	9%

Study Scenarios - *Sensitivity Studies*

Sensitivity Study	Near-term Planning Horizon		Long-term Planning Horizon
	2025	2028	2035
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	-	
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	
Summer Off peak with heavy renewable output	-	VEA Area	

California ISO

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	2025 Summer Peak	5%	99%	11%	99%	54%	62%	Solar and wind dispatch increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level	2025 Spring Off-Peak	0%	0%	0%	0%	47%	47%	Different import levels on COI and P26.
	Summer Peak with high CEC forecasted load	2028 Summer Peak	5%	5%	11%	11%	54%	54%	Load increased by turning off AAEE
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2025 Summer Peak	55%	99%	76%	99%	24%	67%	Solar and wind dispatch increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2025 Spring Off-Peak	0%	0%	0%	0%	55%	55%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2028 Summer Peak	33%	33%	53%	53%	26%	26%	Load increased per CEC high load scenario
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2025 Summer Peak	0%	96%	0%	96%	18%	51%	Solar and wind dispatches increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2025 Spring Off-Peak	0%	0%	0%	0%	49%	49%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2028 Summer Peak	0%	0%	0%	0%	18%	18%	Load increased per CEC high load scenario
VEA	Summer Peak with heavy renewable output	2025 Summer Peak	N/A	N/A	51%	99%	19%	67%	Solar and wind dispatch increased to 20% exceedance values
	Spring Off-peak with heavy renewable output	2028 Spring Off-Peak	N/A	N/A	0%	0%	73%	73%	Storage charging
	Summer Peak with forecasted load addition	2028 Summer Peak	N/A	N/A	38%	38%	22%	22%	Load increase reflect future load service request

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
2025	Summer Peak	2025 Heavy Summer 3	10/29/2021
	Winter Peak	2022-23 Heavy Winter 3	3/25/2022
	Spring Off-Peak	2023 Heavy Spring 1	4/8/2022
2028	Summer Peak	2028 Heavy Summer 2	5/5/2022
	Winter Peak	2027-28 Heavy Winter 2	5/6/2022
	Spring Off-Peak	2024 Light Spring 2	11/18/2022
2035	Summer Peak	2033 Heavy Summer 1	09/02/2022
	Spring Off-Peak	2033 Light Spring 1	01/28/2022

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

2023-2024 Transmission Planning Process Stakeholder Meeting

February 28, 2023

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
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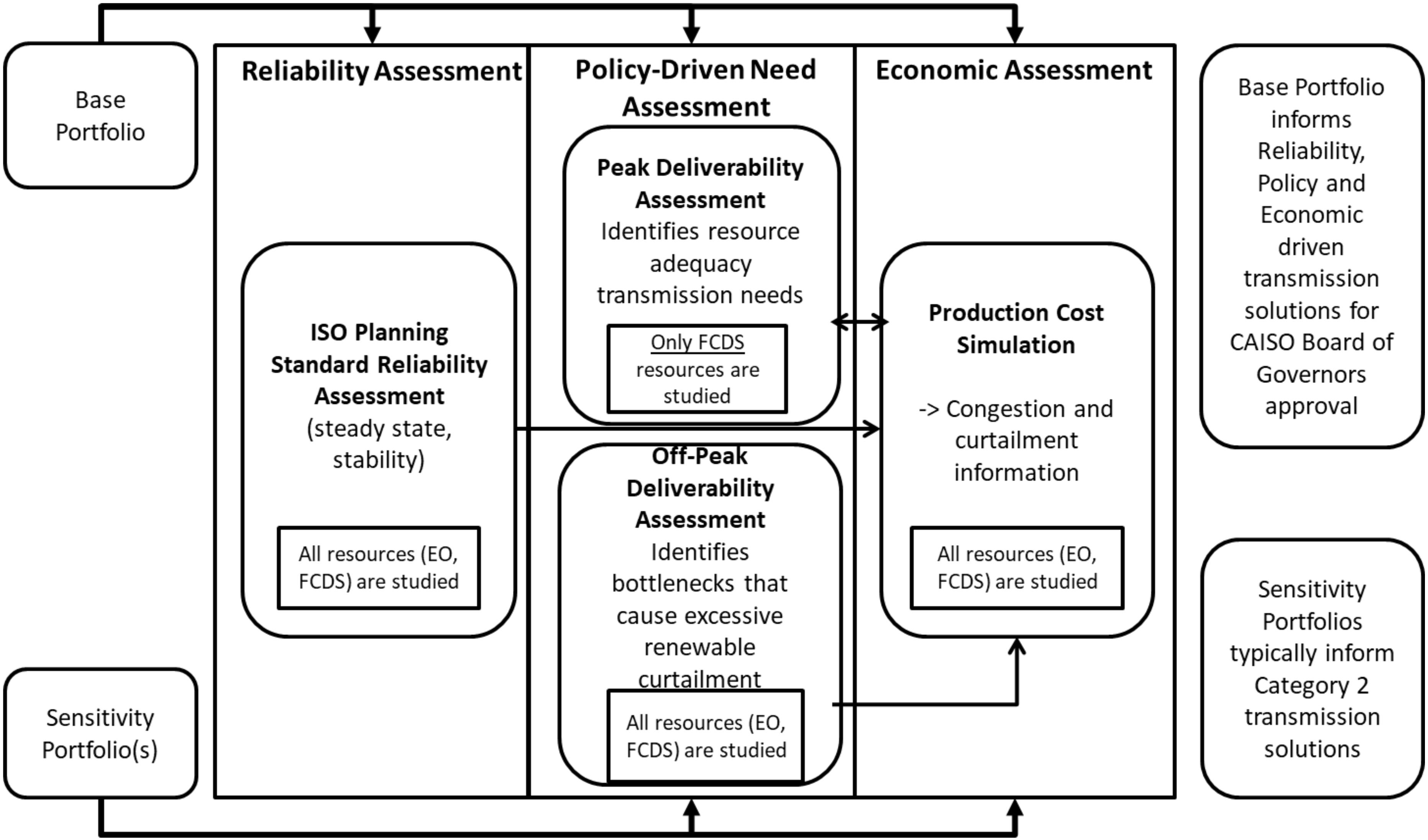
Objectives and scope

- 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

2023-2024 TPP resources portfolios

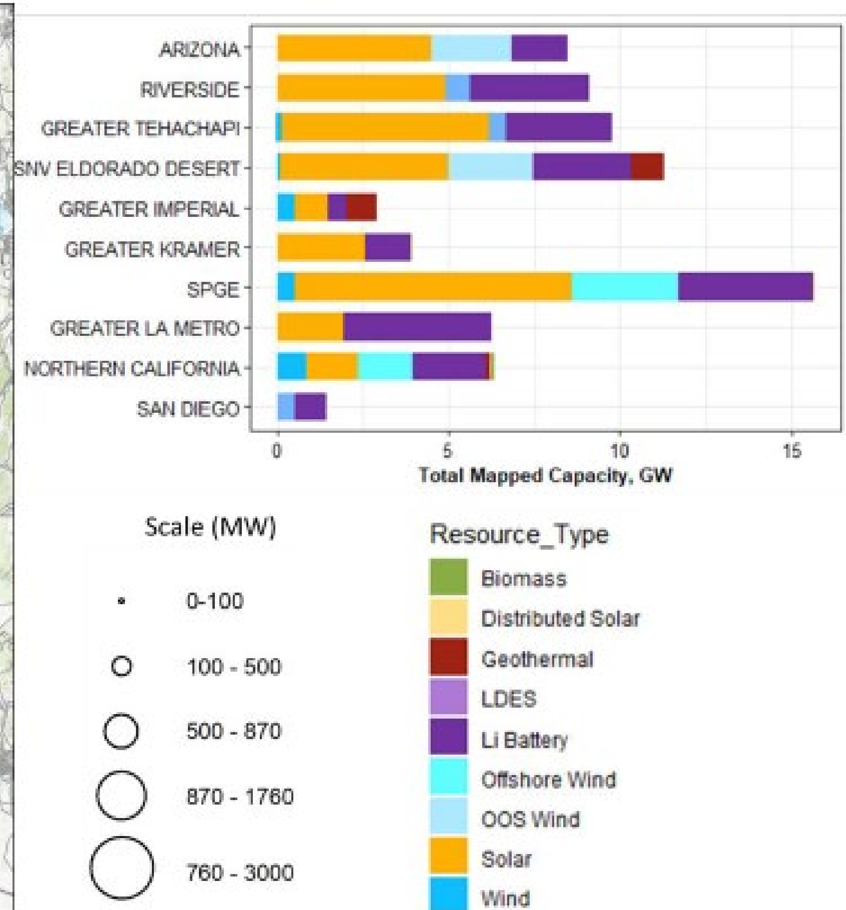
- On February 23, 2023 CPUC adopted a base portfolio for 2033 and 2035 and a sensitivity portfolio for 2035 for use in the 2023-2024 TPP
- The base portfolio is based on a 30 MMT GHG target by 2030 and the 2021 CEC demand forecast utilizing the additional transportation electrification (ATE) assumptions.
- The sensitivity portfolio is based on the same GHG target and load forecast assumptions and is intended to test the transmission needs associated with 13.4 GW of offshore wind
- The portfolio data and modeling assumptions are available on the CPUC website[1] and include
  - Resource to substation bus mapping workbook complete with ISO transmission capability estimate exceedances
  - In-development resources list (includes some new online resources)
  - Retirement list of thermal generation units

1 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

Total and incremental generic resource additions
(include in-development and new online resources for transmission capability accounting purposes)

Resource Type	Total Resource Summary (including in-development) (FC+EO), MW			Incremental Generic Resources (FC+EO), MW		
	Base 2033	**Base 2035**	**Sensitivity 2035**	**Base 2033**	**Base 2035**	**Sensitivity 2035**
Biomass/Bio gas	134	134	134	112	112	112
Geothermal	1,863	2,037	1,149	1,618	1,792	904
Solar	32,025	39,072	25,871	20,748	27,796	14,594
Wind	3,074	3,074	3,074	2,412	2,412	2,412
OOS Wind	5,618	5,618	5,618	4,828	4,828	4,828
Offshore Wind	3,261	4,707	13,400	3,261	4,707	13,400
Li_Battery	21,730	28,374	23,545	4,847	11,491	6,662
LDES	1,524	2,000	1,000	1,524	2,000	1,000
Total	**69,229**	**85,015**	**73,791**	**39,350**	**55,137**	**43,912**

Final busbar mapping results of the base portfolio for 2035



Modeling Assumptions for the 2023-2024 Transmission Planning Process – CPUC Staff Report February 2023
https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

FCDS total and incremental generic resource additions

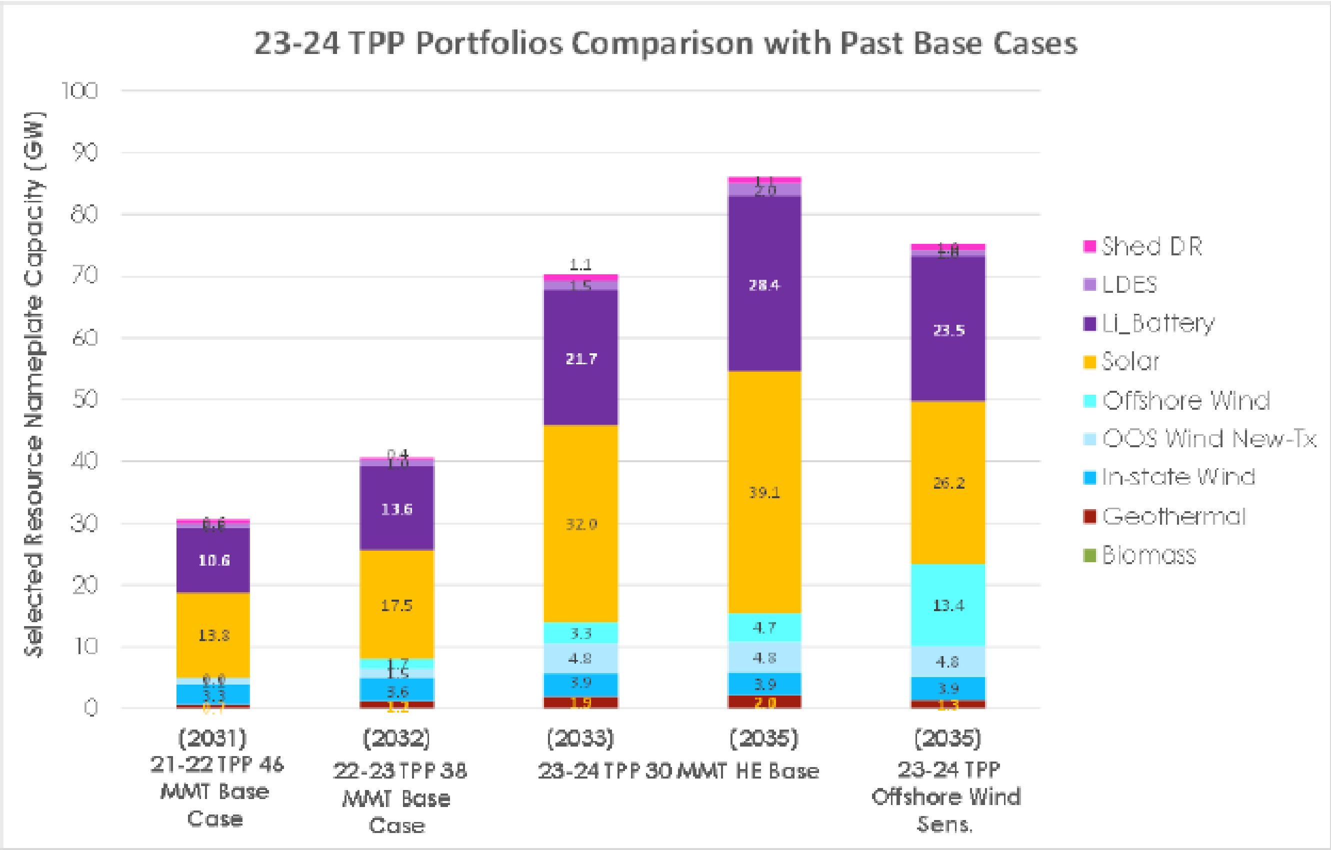
Resource Type	Total FC Resource Summary including in-development, MW			Incremental Generic FC Resources, MW		
	Base 2033	Base 2035	Sensitivity 2035	Base 2033	Base 2035	Sensitivity 2035
Biomass/Biogas	134	134	134	112	112	112
Geothermal	1,863	2,037	1,149	1,618	1,792	904
Solar	14,897	15,761	11,567	9,102	9,966	5,772
Wind	2,511	2,511	2,511	1,848	1,848	1,848
OOS Wind	5,518	5,518	5,518	4,828	4,828	4,828
Offshore Wind	3,100	4,546	13,239	3,100	4,546	13,239
Li_Battery	21,730	28,374	23,545	4,847	11,491	6,662
LDES	1,524	2,000	1,000	1,524	2,000	1,000
Total	**51,277**	**60,880**	**58,663**	**26,980**	**36,583**	**34,366**

In-development and new online resources included in the portfolios

Resource Type	In-development and New Online Resources Included in the Portfolios, MW		
	FC	EO	Total
Biomass/Biogas	22	0	22
Geothermal	245	0	245
Solar	5,795	5,482	11,277
Wind	662	0	662
OOS Wind	690	100	790
Offshore Wind	0	0	0
Li_Battery	16,883	0	16,883
LDES	0	0	0
Total	**24,297**	**5,582**	**29,879**

- Some new online resources are included in the total portfolio for transmission capability accounting purposes

Comparison of current portfolios with past base portfolios



Source:
Modeling Assumptions for the 2023-2024 Transmission Planning Process – CPUC Staff Report February 2023
https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

FCDS capability estimate exceedances by portfolios - Southern areas

Transmission Constraint	Existing System FCDS Capability (MW	Exceedance (Higher of HSN or SSN) (MW)
		2035 Base
Antelope – Vincent 500 kV Constraint	4040	822
Kramer to Victor Area 230 kV Constraint	826	355
Victor to Lugo 230 kV Constraint	1156	86
Lugo 500/230 kV Transformer Constraint	1576	23
Colorado River 500/230 kV Constraint	1490	175
Devers – Red Bluff 500 kV Constraint	5400	2163
Serrano – Alberhill – Valley 500 kV Constraint	5700	4932
GLW-VEA Area Constraint***	1300*	1058
Mohave/Eldorado 500 kV Default Constraint	1560*	1326
East of Miguel Area Constraint	731	397
Encina-San Luis Rey Constraint	1000	1888
Internal San Diego Constraint	968	1217
San Luis Rey-San Onofre Constraint	1500	1388

* Capability estimate is a default rather than an actual limit and reflect the amount of resources studied in the Cluster 13 deliverability studies because the constraint was not found to be binding.

FCDS capability estimate exceedances by portfolios - Northern areas

Transmission Constraint	Existing System FCDS Capability (MW)	Exceedance (Higher of HSN or SSN) (MW)
		2035 Base
Humboldt–Trinity 115 kV	21	145
Cortina–Vaca Dixon 230 kV	454	2213
Contra Costa-Delta 230kV Line	1523	641
Midway – Gates 230 kV Line	1431	1507
Gates 500/230kV Bank #13 Constraint	3151	598
Los Banos 500/230kV Transformer Constraint	1573*	1155
Wilson-Storey-Borden 230 kV	113	1109
Tesla-Westley 230 kV Constraint	1098	339
Morro Bay-Templeton 230kV	1708	2118
Las Aguillas-Panoche 230 kV	334*	783
Los Banos—Gates #1 500 kV Line Constraint	1265*	2683
Moss Landing–Los Banos 230 kV Constraint	1611*	2885
Warnerville-Wilson 230 kV	272*	909
Moss Landing—Las Aguillas 230 kV Constraint	316*	1009
Humboldt Offshore Wind constraint	0*	1446

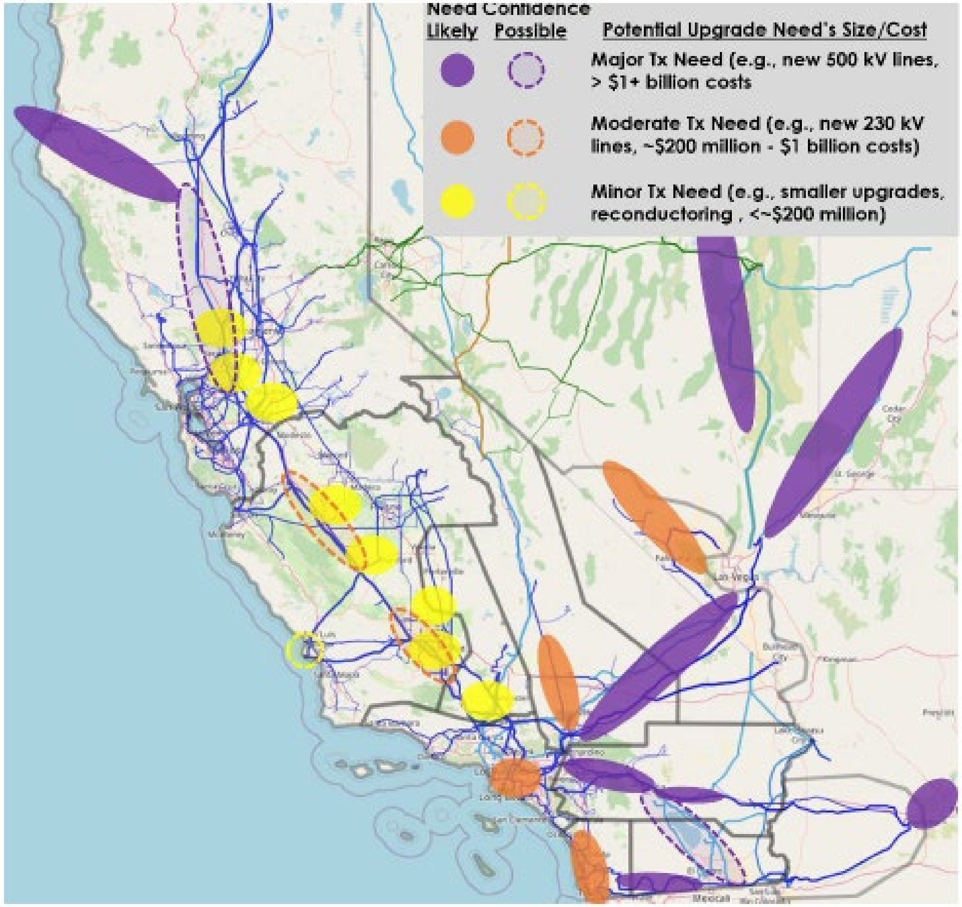
* Capability estimate is a default rather than an actual limit and reflect the amount of resources studied in the Cluster 13 deliverability studies because the constraint was not found to be binding.

EODS capability estimate exceedances by portfolios

Transmission Constraint	Existing System EODS Capability (MW)	EODS Capability Exceedance (MW)
		2035 Base
GLW/VEA Area Constraint	1379*	--
Mohave/Edorado 500 kV Default Constraint	1560*	518
East of Miguel Constraint	950	201
Humboldt – Trinity 115 kV Constraint	63*	99
Woodland – Davis 115 kV Constraint	64*	--
Morro Bay – Templeton 230 kV Constraint	1903*	388
Las Aguillas-Panoche 230 kV	516	--
Moss Landing – Las Aguillas 230 kV	0	314
Humboldt Offshore Wind constraint	0*	1446

* Capability estimate is a default rather than an actual limit and reflect the amount of resources studied in the Cluster 13 deliverability studies because the constraint was not found to be binding.

CPUC staff estimates of location and magnitude of potential transmission upgrades triggered by the 2035 base portfolio based on the exceedances



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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 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 expansion approved in TPP

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

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%
New Mexico Wind	67%			35%		
Wyoming Wind	67%			35%		
Idaho Wind	67%			35%		
Morro Bay OSW	100%			49%		
Humboldt OSW	100%			53%		
Diablo OSW	100%			37%		
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					

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 may include RAS and adding new battery storage (subject to on-peak deliverability)
- The constraints and the identified transmission upgrades are considered as candidates for a more thorough evaluation using production cost simulation

Modeling 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, 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 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 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

- Similar to the reliability assessment, the ISO has selected year 2035 for the policy driven assessment in this planning cycle

Preliminary results

- Preliminary results of the assessment will be presented at the November 16 stakeholder meeting

Economic Assessment
Unified Planning Assumptions & Study Plan

Yi Zhang

2023-2024 Transmission Planning Process Stakeholder Meeting
February 28, 2022

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)

- The CAISO Planning PCM in the 2022-2023 cycle will be used as a starting point
  – Will incorporate validated changes in the ADS PCM
- The unified planning assumptions will be used to update the CAISO system model in the PCM
- 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

California ISO

Frequency Response Assessment
Unified Planning Assumptions & Study Plan

Christopher Fuchs

2023-2024 Transmission Planning Process Stakeholder Meeting

February 28, 2023

Background and Objective

- Majority of the existing Invert Based Resources (IBR) do not provide frequency response but FERC Order 842 now requires that all IBRs that sign LGIAs to have frequency response capability.
- The ability of IBR with frequency control enabled to response to system events with enough available operating headroom is now well-established from prior planning studies.
- The objective of this study is to re-assess the CAISO system frequency response in years 2028 and 2035 and identify any potentially new planning scenario gaps during which contingencies can restrict primary frequency response or during which the system is vulnerable to frequency events.
- Overall the expectation is that the trend with more IBRs on frequency control, we will have a higher nadir than in previous cycles.

Study Models and Assumptions

- Overall study approach is similar to frequency response assessment performed in prior TPP cycles. In this cycle:
  - The frequency response of the system both in year 2028 and year 2035 will be studied.
  - Spring Peak base cases will be used. These typically have high solar output with south to north flow on COI. Also the operation hour is such that BESS units are charging.
  - A review of the frequency response of individual units across the CAISO system will be performed for a number of NERC frequency events.
  - Frequency response from CAISO IBR plants (solar, wind, and storage) in the studies will checked against reference and expected behavior.

Contingency and Monitored Parameters

- The trip of two fully dispatched Palo Verde units will be simulated and the following parameters under each scenario will be monitored:
  - System frequency including frequency nadir and settling frequency after primary frequency response.
  - The total change in IBR output from pre- to post-contingency.
  - The major path flows.
  - Frequency response of the WECC and CAISO (MW/0.1 Hz).
  - Rate of Change of Frequency (ROCOF).
  - State of Charge of BESS installations.

Study Scenarios

- Scenario 1: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched off to establish a baseline.
- Scenario 2: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched on to assess the full capability of the system.
- Scenario 3: Starting with Scenario 1 it will be assumed that the generator headroom in CAISO areas will be set at spinning reserve.
- Scenario 4: Starting with Scenario 2 it will be assumed that the generator headroom in CAISO areas will be set at spinning reserve.
- Scenario 5: Starting with the existing base case, frequency response will be determined with all non-responsive CAISO IBR generators having frequency control switched off.

Next Steps
Unified Planning Assumptions & Study Plan

Kaitlin McGee

Sr. Stakeholder Engagement and Policy Specialist

2023-2024 Transmission Planning Process Stakeholder Meeting

February 28, 2023

2023-2024 Transmission Planning Process Next Steps

- Comments due by end of day **March 14, 2023**

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

https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2023-2024-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 on March 31