Agenda
Unified Planning Assumptions & Study Plan

Jody Cross
Stakeholder Engagement and Policy Specialist

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

2019-2020 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Jody Cross
Overview & Key Issues	Jeff Billinton
Reliability Assessment	Binaya Shrestha
Policy Assessment	Sushant Barave
Economic Assessment	Yi Zhang
Wrap-up & Next Steps	Jody Cross

California ISO

Overview
Unified Planning Assumptions & Study Plan

Jeff Billinton

Sr Manager, Regional Transmission - North

2019-2020 Transmission Planning Process Stakeholder Meeting

February 28, 2019

2019-2020 Transmission Planning Process

January 2019 | April 2019 | March 2020

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

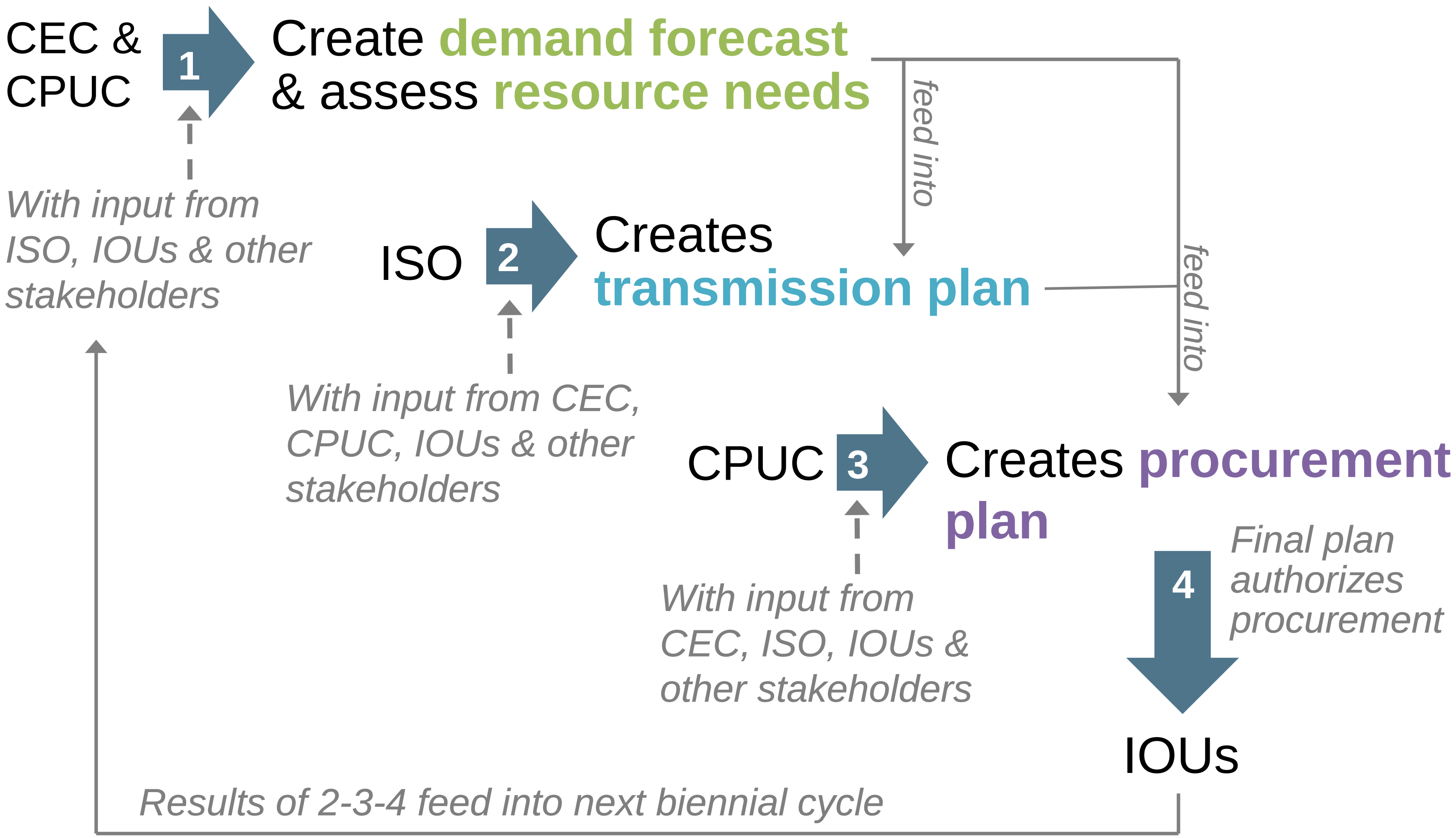
ISO Board for approval of transmission plan

California ISO

2019-2020 Transmission Plan Milestones

- Draft Study Plan posted on February 22
- 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 25 and 26
- Comments to be submitted by October 9
- Request window closes October 15
- Preliminary policy and economic study results on November 18
- Comments to be submitted by December 2
- Draft transmission plan to be posted on January 31, 2019
- Stakeholder meeting on February
- Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at March Board of Governor meeting

Planning and procurement overview



2019-2020 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
- Local Capacity Requirements
  - Near-Term (2020); and
  - Mid-Term (2024)
- Long-term Congestion Revenue Rights

Key Issues in 2019-2020 Transmission Plan Cycle:

- ISO will incorporate renewable portfolios from the CPUC
  - Baseline portfolio
    - Reliability, Policy and Economic Assessments
  - Sensitivity portfolios
    - Policy Assessment
- Interregional Transmission Planning Process
  - In year two (odd year) of 2 year planning cycle
- No special studies are planned for 2019-2020 transmission planning process
- As a follow up to 2018-2019 transmission planning process, the remaining LCR areas will be assessed for alternatives to gas-fired generation

Study Information

- Final Study Plan will be posted on 2019-2020 transmission planning process webpage on March 31st
  http://www.caiso.com/planning/Pages/TransmissionPlanning/2019-2020TransmissionPlanningProcess.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

Stakeholder comments

- Stakeholders requested to submit comments to: regionaltransmission@caiso.com
- Stakeholder comments are to be submitted within two weeks after stakeholder meetings: **by March 14**
- ISO will post comments and responses on website

Reliability Assessment
Unified Planning Assumptions & Study Plan

Binaya Shrestha

Regional Transmission Engineer Lead

2019-2020 Transmission Planning Process Stakeholder Meeting

February 28, 2019

Planning Assumptions

- Reliability Standards and Criteria
  - California ISO Planning Standards
  - NERC Reliability Criteria
    - TPL-001-4
    - NUC-001-3
  - WECC Regional Criteria
    - TPL-001-WECC-CRT-3

Planning Assumptions *(continued)*

- Study Horizon
  - 10 years planning horizon
    - near-term: 2020 to 2024
    - longer-term: 2025 to 2029

- Study Years
    - near-term: 2021 and 2024
    - longer-term: 2029

Study Areas

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

Transmission Assumptions

- Transmission Projects
  - Transmission projects that the ISO has approved will be modeled in the study base case
  - Canceled and on-hold projects will not be modeled
- Reactive Resources
  - The study models the existing and new reactive power resources in the base cases to ensure that realistic reactive support capability will be included in the study
- Protection Systems
  - The major new and existing SPS, safety nets, and UVLS that will be included in the study
  - Continue to include RAS models and work with PTOs to obtain remaining RAS models.
- Control Devices
  - Several control devices were modeled in the studies

Load Forecast Assumptions
Energy and Demand Forecast

- California Energy Demand Updated Forecast 2018-2030 adopted by California Energy Commission (CEC) on January 9, 2019 will be used:
  - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
  - Additional Achievable Energy Efficiency (AAEE) and Additional Achievable PV (AAPV)
    - Consistent with CEC 2018 IEPR
    - Mid AAEE/AAPV will be used for system-wide studies
    - Low AAEE/AAPV will be used for local studies
  - CEC forecast information is available on the CEC website at:
    http://www.energy.ca.gov/2018_energypolicy/documents/

Load Forecast Assumptions
Energy and Demand Forecast (continued)

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

Load Forecast Assumptions
Methodologies to Derive Bus Level Forecast

- The CEC load forecast is generally provided for the larger areas and does not provide the granularity down to the bus-level which is necessary in the base cases for the reliability assessment
- The local area load forecast are developed at the bus-level by the participating transmission owners (PTOs) .
- Descriptions of the methodologies used by each of the PTOs to derive bus-level load forecasts using CEC data as a starting point are included in the draft Study Plan.

Load Forecast Assumptions
Behind-the-meter PV (BTM-PV)

- Similar to previous cycles, BTM-PV (both the baseline and AAPV) will be modeled explicitly in the 2019-2020 TPP base cases.
  - Amount of the BTM-PV to be modeled will be based on 2018 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.

Load Forecast Assumptions
AAEE & AAPV

- AAEE will be modeled using the CEC provided busbar allocations.
- AAPV will be modeled explicitly similar to the baseline PV.
  - Amount of the AAPV to be modeled will be based on 2018 IEPR data.
  - Location to model AAPV will be identified based on information from PTO on future growth and BTM-PV capacity by forecast climate zone information from CEC.
  - Output of the AAPV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

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

- CPUC draft Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies
  - *(not available at this time)*
- Renewable resources base scenario
  - The CPUC ruling included recommendations regarding the resource portfolio(s) for the ISO to utilize in the 2019-2020 TPP.
  - Although the final portfolios have not been transmitted to the ISO at the time of posting of this study plan, the ISO expects that the CPUC will transmit a “reliability base” portfolio to be used in the 2019-2020 TPP.
  - This portfolio is expected to correspond to a statewide electric sector GHG reduction target of 42 million metric tons (MMT) by 2030 as set forth in Senate Bill (SB) 350.
  - The ISO expects that this “reliability base” portfolio will be the same as the “base” portfolio that will be transmitted for the purpose of being studied as part of the policy-driven assessment.

Generation Assumptions

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

Generation Assumptions
Generation Retirements

- <u>Nuclear Retirements</u>
  - Diablo Canyon will be modeled off-line based on the OTC compliance date
- <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.
- <u>Other Retirements</u>
  - Unless otherwise noted, assumes retirement based resource age of 40 years or more. List included in Appendix A of the draft study plan.

Generation Assumptions

OTC Generation

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

- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table 3.7-6 in the draft study plan; and
- All other OTC generating units will be modeled off-line beyond their compliance dates, as illustrated in Table 3.7-6, or per proposed retirements by the generation owners to proceed on repowering projects that have been approved by the state regulatory agencies.

Generation Assumptions

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

PTO Area	Project	Capacity (MW)	First Year to be Modeled
SCE	Huntington Beach Energy Project Unit 6 (CCGT) *	644	2021
	Alamitos Energy Center Unit 8 (CCGT) *	640	2021
SDG&E	Carlsbad Peakers*	500	2021

Notes:

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

Preferred Resources
Demand Response

- Demand Response
  - Only program that can be relied upon to mitigate post first contingency are counted
  - 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.
  - Section 6.6 of the CAISO 2017-2018 Transmission Plan provides a status update on the progress to identify the necessary characteristics for slow response local capacity resources, such that the resources can be relied upon to meet reliability needs.

Preferred Resources
Energy Storage

- Energy Storage
  - Amounts consistent with D.13-10-040
  - Existing and proposed energy storage that will be procured by IOUs including approved by CPUC in response to Resolutions E-4791 and E-4949 are also included
  - Not included in starting cases (no location data available), unless already procured by the LSEs as part of the LTPP process
  - Locational information to be provided by CPUC for storage procured to-date
  - Effective busses will be identified using the residual capacity for potential development after reliability concerns have been identified

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)	3,220	
Path 66 (N-S)	4,800	
Path 15 (N-S)	-5,400	Spring Off Peak
Path 26 (N-S_	-3,000	
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
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3,220	3,220	
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 10,100	Summer Peak
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	400	0 to 250	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
	2021	2024	2029
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	Summer Peak, Spring Off-Peak	Summer 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, Spring Off-Peak	Summer Peak
Kern	Summer Peak, Spring Off-Peak	Summer 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
Southern California Bulk Transmission System	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
Valley Electric Association	Summer Peak, Spring Off-Peak	Summer 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		
		2021	2024	2029	2021	2024	2029	2021	2024	2029	2021	2024	2029	2021	2024	2029
PG&E	Summer Peak	7/22 HE 18	7/2 HE 19	See CAISO	17%	3%	See CAISO	10%	2%	See CAISO	83%	70%	See CAISO	100%	100%	See CAISO
PG&E	Spring Off Peak	4/3 HE 13	4/6 HE 13	See CAISO	80%	81%	See CAISO	100%	98%	See CAISO	55%	2%	See CAISO	34%	29%	See CAISO
PG&E	Winter Off peak			11/10 HE 4			0%			0%			3%			54%
PG&E	Winter peak	12/13 HE 19	12/9 HE 19	12/10 HE 19	0%	0%	0%	0%	0%	0%	16%	2%	9%	75%	76%	75%
SCE	Summer Peak	9/3 HE 16	9/7 HE 16	9/4 HE 19	44%	44%	0%	52%	56%	0%	36%	62%	54%	100%	100%	100%
SCE	Spring Off Peak	4/4 HE 12	5/3 HE 20		80%	0%		99%	0%		52%	46%		33%	69%	
SDG&E	Summer Peak	9/1 HE 19	9/4 HE 19	9/5 HE 19	0%	0%	0%	0%	0%	0%	0%	72%	22%	100%	100%	100%
SDG&E	Spring Off Peak	4/10 HE 13	5/3 HE 20		79%	0%		79%	0%		78%	80%		27%	69%	
VEA	Summer Peak	9/3 HE 16	9/7 HE 16	9/4 HE 19	44%	44%	0%	52%	56%	0%				100%	100%	100%
VEA	Spring Off Peak	4/4 HE 12	5/3 HE 20		80%	0%		99%	0%					33%		

	Scenario	Day/Time	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2029	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	Summer Peak	9/4 HE 19	0%	0%	0%	0%	0%	0%	93%	54%	22%	93%	100%	97%
CAISO	Spring Off Peak	4/7 HE 13	80%	81%	79%	100%	98%	98%	55%	54%	22%	21%	26%	17%

Study Scenarios - *Sensitivity Studies*

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2021	2024	2029
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Off 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 Main	-
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 Main	-	-
Summer Peak with high SVP forecasted load			PG&E Greater Bay Area
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off peak with heavy renewable output		VEA Area	
Retirement of QF Generations	-	-	PG&E Local Areas

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 high CEC forecasted load	2024 Summer Peak	3%	3%	2%	2%	70%	70%	Load increased by turning off AAEE
	Off peak with heavy renewable output and minimum gas generation commitment	2024 Spring Off-peak	81%	99%	98%	99%	2%	64%	Solar and wind dispatch increased to average of 20% exceedance values
	Summer Peak with heavy renewable output and minimum gas generation commitment	2021 Summer Peak	17%	99%	10%	99%	83%	83%	Solar and wind dispatch increased to 20% exceedance values
	Retirement of QF Generations	2029 Summer Peak	3%	3%	2%	2%	82%	82%	All QF facilities in local areas turned off
	Summer Peak with high SVP forecasted load	2029 Summer Peak	3%	3%	2%	2%	82%	82%	Use SPV's forecast for 2029
SCE	Summer Peak with high CEC forecasted load	2024 Summer Peak	44%	44%	56%	56%	62%	62%	Load increased per CEC high load scenario
	Off peak with heavy renewable output and minimum gas generation commitment	2024 Spring Off-peak	0%	91%	0%	99%	46%	67%	Solar and wind dispatch increased to 20% exceedance values with net load unchanged at 69% of summer peak
	Summer Peak with heavy renewable output and minimum gas generation commitment	2021 Summer Peak	44%	91%	52%	99%	36%	67%	Solar and wind dispatch increased to 20% exceedance values
SDG&E	Summer Peak with high CEC forecasted load	2024 Summer Peak	0%	0%	0%	0%	72%	72%	Load increased per CEC high load scenario
	Off peak with heavy renewable output and minimum gas generation commitment	2024 Spring Off-peak	0%	96%	0%	96%	80%	80%	Solar dispatch increased to 20% exceedance values with net load unchanged at 69% of summer peak
	Summer Peak with heavy renewable output and minimum gas generation commitment	2021 Summer Peak	79%	96%	79%	96%	78%	78%	Solar dispatch increased to 20% exceedance values
VEA	Summer Peak with forecasted load addition	2021 Summer Peak	44%	44%	52%	52%	-	-	Load increase reflect future load service request
	Summer Peak with forecasted load addition	2024 Summer Peak	44%	44%	56%	56%	-	-	Load increase reflect future load service request
	Off-peak with heavy renewable output	2024 Spring Off-peak	80%	80%	99%	99%	-	-	Modeled active GIDAP projects in the queue

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
2021	Summer Peak	19HS3a1
	Winter Peak	20HW1a1
	Spring Off-Peak	21LSP1a1
2024	Summer Peak	24HS2a1
	Winter Peak	24HW2a1
	Spring Off-Peak	24HW2a1
2029	Summer Peak	29HS1a1
	Winter Peak	29HW1a1
	Spring Off-Peak	29HW1a11
	Winter Off-Peak	29HSP1Sa1

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

Technical Studies

- The planning assessment will consist of:
  - Power Flow Contingency Analysis
  - Post Transient Analysis
    - Post Transient Voltage Stability Analysis
      - Post Transient Voltage Deviation Analysis
      - Voltage Stability and Reactive Power Margin Analysis
  - Transient Stability Analysis

Corrective Action Plans

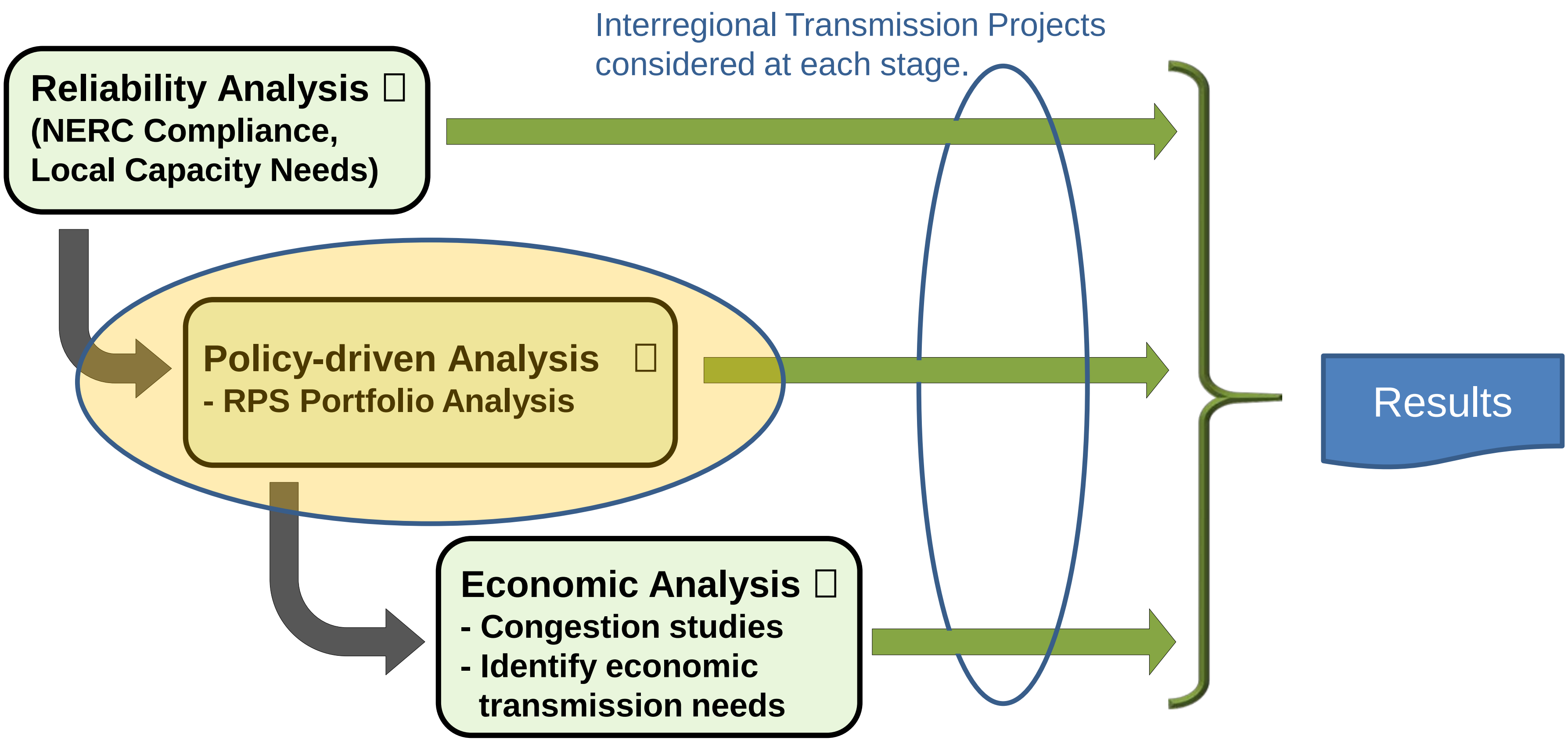
- The technical studies mentioned in this section will be used for identifying mitigation plans for addressing reliability concerns.
- As per ISO tariff, identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards.
  - In making this determination, the ISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as:
    - acceleration or expansion of existing projects,
    - demand-side management,
    - special protection systems,
    - generation curtailment,
    - interruptible loads,
    - storage facilities; or
    - reactive support

Policy Assessment
Unified Planning Assumptions & Study Plan

Sushant Barave
Regional Transmission Engineer Lead

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

Evaluation of transmission solutions needed to meet state, municipal, county or federal policy requirements:



Key objectives of the policy-driven assessment in 2019-2020 TPP:

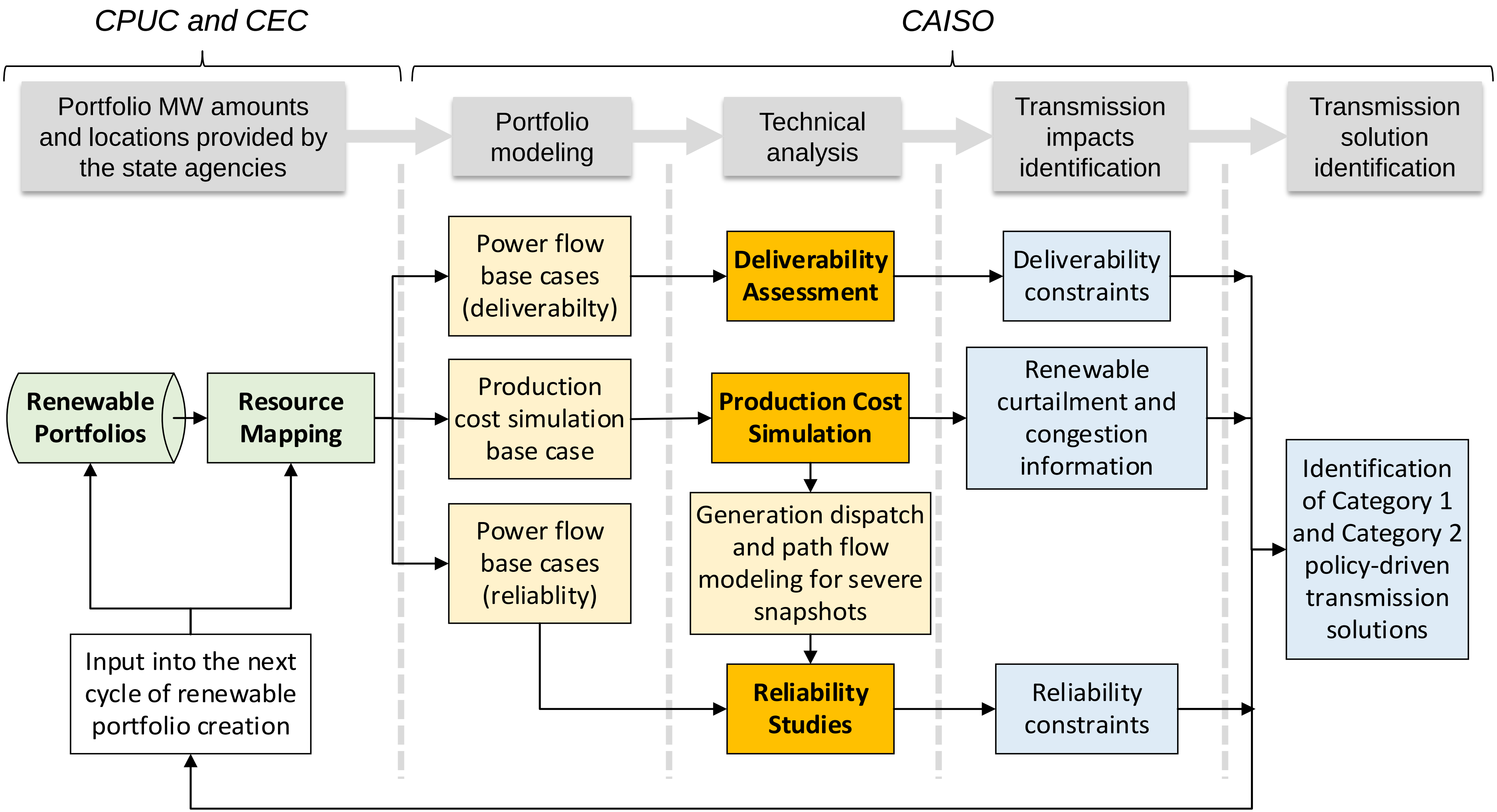
1. Study the transmission impacts of the base and sensitivity portfolios transmitted to the ISO by CPUC
   a. Capture reliability impacts
   b. Test the deliverability of resources selected to be full capacity deliverability status (FCDS)
   c. Analyze renewable curtailment data

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

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

4. Develop a framework based on CPUC-provided objectives for siting generic storage selected in CPUC IRP process

The policy assessment framework relies on three study components to identify transmission impacts and solutions



The ISO expects to receive one "base" portfolio and two "sensitivity" portfolios

- Base portfolio is expected to correspond to a statewide electric sector GHG reduction target of <u>42 million metric ton (MMT)</u>

- Sensitivity portfolios are expected to correspond to a statewide electric sector GHG reduction target of <u>32 MMT</u>

- The CPUC staff will generate the base and sensitivity portfolios using RESOLVE capacity expansion model
  - The ISO will incorporate the portfolios received from the CPUC into the final Study Plan

Economic Assessment
Unified Planning Assumptions & Study Plan

Yi Zhang
Lead Engineer, Regional Transmission - North

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

Economic planning study

- The ISO economic planning study follows the ISO tariff and Transmission Economic Assessment Methodology (TEAM) to do the following studies
  - Congestion and production benefit assessments
  - Local capacity areas assessments
  - Study request evaluations

Congestion and production benefit assessment

- The Production Cost Model development (PCM)
  - ISO planning PCM of 2028 and ADS PCM will be used as starting points, followed by model updates
    - Network models
    - Transmission constraint model
    - Generator model (mainly renewable, and retirement)
    - Load model (new forecasts)
    - Market model
- Contingency and curtailment analysis is based on production cost simulation results
- Production benefit assessment is based on TEAM and production cost simulation results

Local capacity areas assessment

- The ISO undertook a comprehensive review of alternatives to reduce or eliminate local capacity area requirements for gas-fired generation in 22 areas and sub-areas in the 2018-2019 planning cycle
- The assessment of the remaining local capacity areas and sub-areas will be completed in 2019-2020 planning cycle as a continuation of the 2018-2019 planning cycle
- Subsequent recommendations for approval of the identified transmission upgrades will be based on the results of the economic assessments

Local Capacity Areas and Sub-areas

- Humboldt Area
- Stockton Area
  - Stanislaus Sub-area
  - Tesla Belota Sub-area
  - Weber Sub-area
- Bay Area*
  - Oakland Sub-area
  - Contra Costa Sub-area
- Coalinga Sub-area (in Fresno Area)
- Kern Area
  - South Kern PP Sub-area
- LA Basin Area*
  - El Nido Sub-area
  - Western Sub-area
- Big Creak-Ventura Area
  - Santa Clara*

* Considering updating assessment done in 2018-2019 Transmission Plan

Economic planning study requests

- Economic Planning Study Requests are to be submitted to the ISO during the comment period of the draft Study Plan

- The ISO will consider the Economic Planning Study Requests as set out in section 24.3.4.1 of the ISO Tariff

Next Steps
Unified Planning Assumptions & Study Plan

Jody Cross

Stakeholder Engagement and Policy Specialist

2019-2020 Transmission Planning Process Stakeholder Meeting

February 28, 2019

CPUC Portfolios for 2019-2020 Transmission Planning Process

- To supplement the information provided in sections 3.7.2 and 4.2 of the Draft Study Plan, the best available working documentation has been made available by the CPUC, prior to formal consideration and adoption by the Commission, and can be found found at the following link:

http://www.cpuc.ca.gov/General.aspx?id=6442460548

- The resource information contained in the worksheets is subject to change.
- The ISO will incorporate the portfolio information into the Final Study Plan

2019-2020 Transmission Planning Process
Next Steps

- Stakeholders requested to submit comments to: regionaltransmission@caiso.com
- Stakeholder comments are to be submitted within two weeks after stakeholder meetings: **by March 14**
- ISO will post comments and responses on website
- Final Study Plan will be posted on March 31