Agenda
Draft 2016-2017 Transmission Plan

Kim Perez
Stakeholder Engagement and Policy Specialist

2016-2017 Transmission Planning Process Stakeholder Meeting
February 17, 2017

2016-2017 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Kim Perez
Overview	Neil Millar
Reliability Projects • SCE Area • PG&E Area • SDG&E Area	 Meng Zhang & Mudita Suri Jeff Billinton Robert Sparks
Economic Planning Study	Yi Zhang
Mid-Term and Long-Term LCR Studies	Catalin Micsa & David Le
Special Studies • 50% RPS Study – In State Portfolios • Risks of early economic retirement of gas fleet • Frequency Response Assessment – Gen Model	 Sushant Barave Abhishek Singh, David Le and Shucheng Liu Irina Green
Wrap-up & Next Steps	Kim Perez

Introduction and Overview
Draft 2016-2017 Transmission Plan and the transmission project approval recommendations

Neil Millar
Executive Director, Infrastructure Development

2016-2017 Transmission Planning Process Stakeholder Meeting
February 17, 2017

2016-2017 Transmission Planning Process

January 2016 | April 2016 | March 2017

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

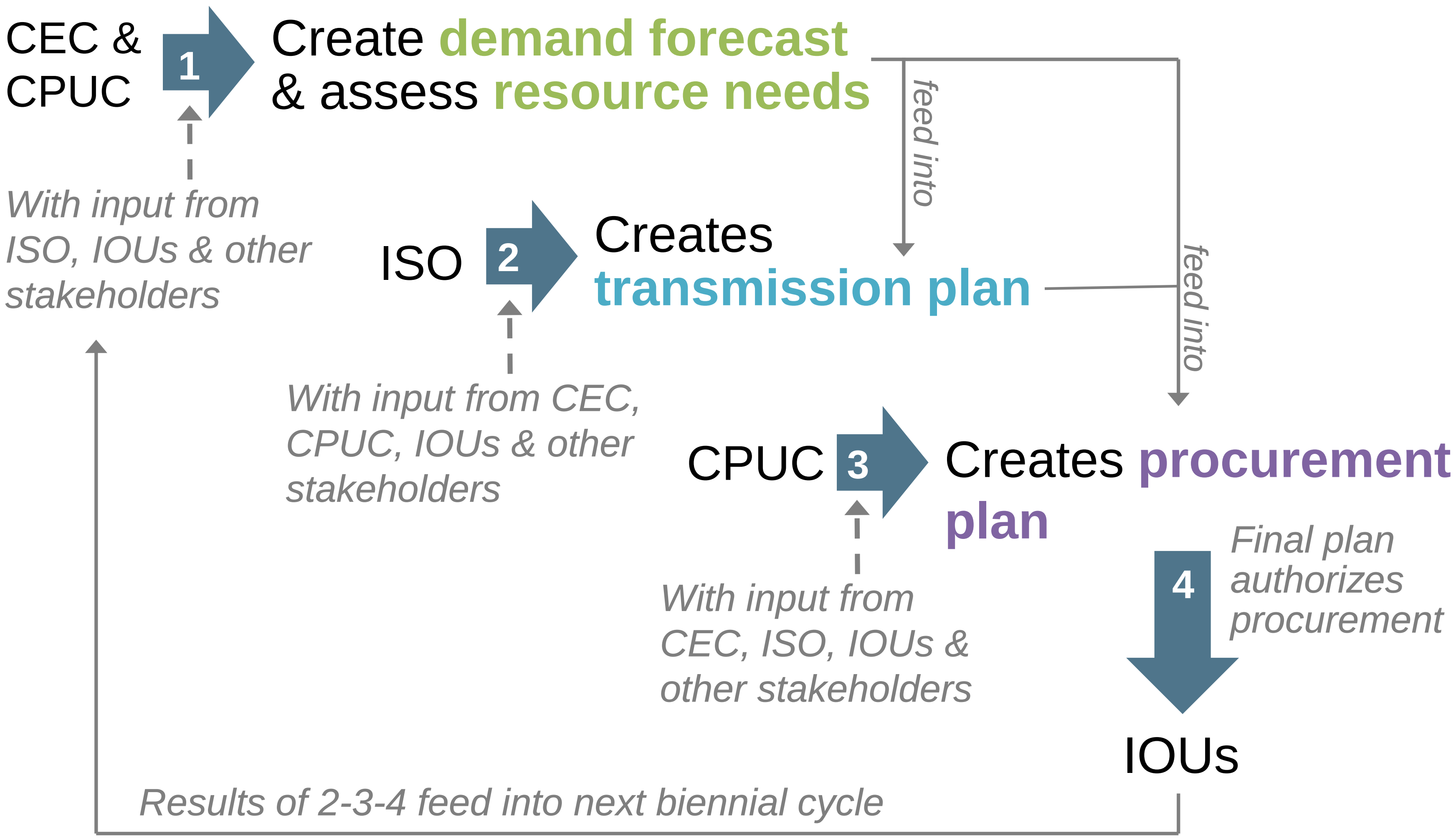
Draft transmission plan presented for stakeholder comment.

ISO Board for approval of transmission plan

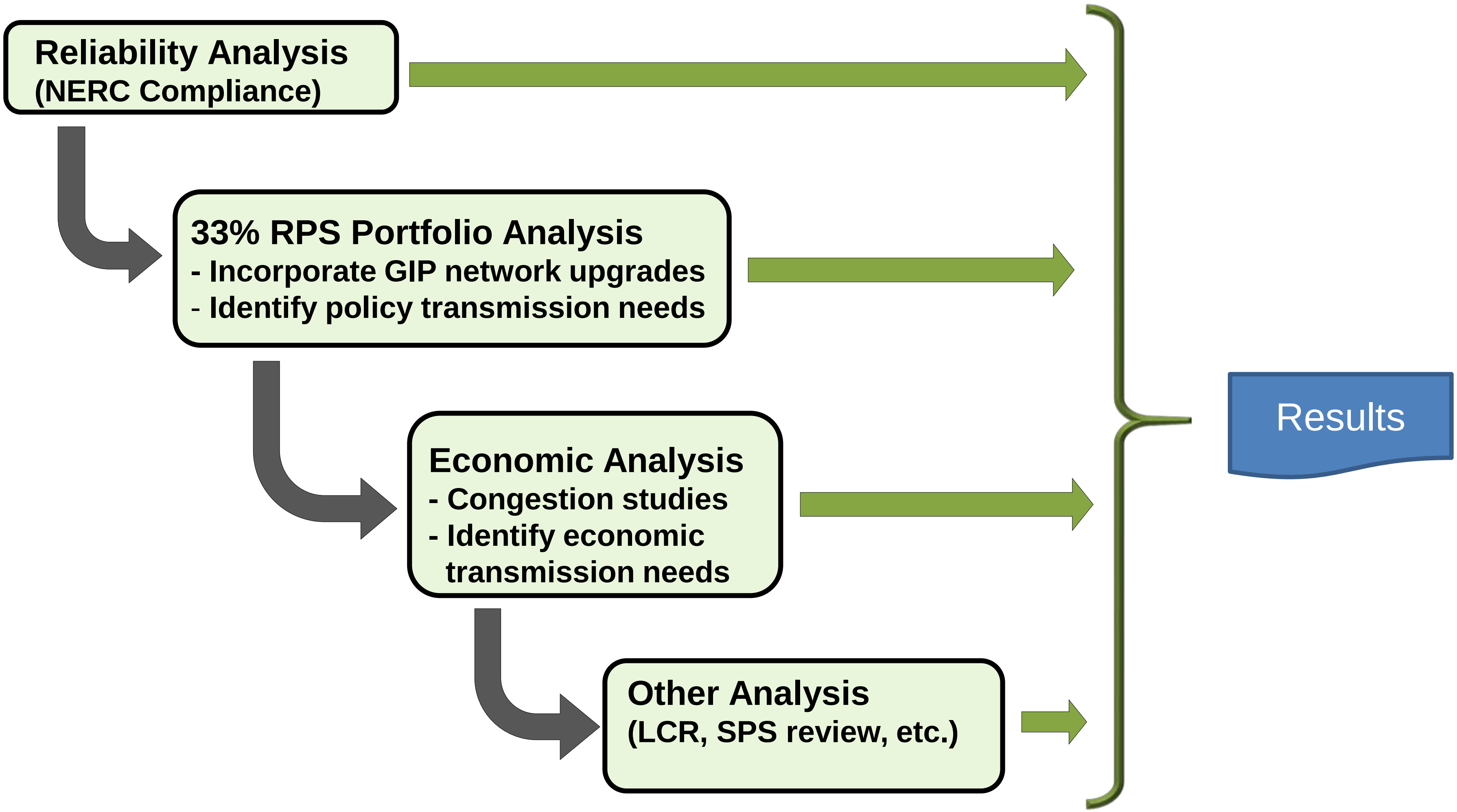
2016-2017 Ten Year Plan Milestones

- Preliminary reliability study results were posted on August 15
- Stakeholder session September 21st and 22nd
- Comments received October 6
  - (slow response resource special study extended to October 10)
- Request window closed October 15
- Preliminary policy and economic study results and update on other issues November 16
- Comments received November 30
- Draft plan posted January 31 2017
- Today's session to review draft plan
- Comments due by March 3
- Revised draft for approval at March Board of Governor meeting

Planning and procurement overview



Development of 2016-2017 Annual Transmission Plan



Emphasis in the transmission planning cycle:

- A very light capital program, as:
  - reliability issues are largely in hand, especially with load forecasts declining from previous years and behind the meter generation forecasts increasing from previous projections
  - policy work was limited to 33% RPS and portfolios are not yet available for moving beyond 33% (for approvals)
  - economic studies not showing any material new opportunities inside the ISO footprint
- Review of previously approved PG&E projects enabled cancellation of 13 projects and further review found necessary for 15 more. One SDG&E project also requires further reconsideration.
- Continued emphasis on preferred resources, and increased maturity of study processes
- Special studies looking at emerging issues preparing for grid transitioning to low carbon future

The ISO's reliability analysis led to the following:

- Two reliability projects are recommended:
  - Lugo-Victorville 500 kV Upgrade - was found to be needed in the 2015-2016 cycle and coordination with LADWP has taken place ($18 million – SCE portion)
  - Big Creek Rating Increase Project ($6 million)
- In the PG&E service territory:
  - 13 previously approved projects are recommended to be cancelled
  - 15 have been identified as needing further review and scoping
- One project in the SDG&E needs further review

Renewable Portfolio Standard Policy Assumptions

- Portfolio direction received from the CPUC and CEC on June 13, 2016:

  “Recommend reusing the "33% 2025 Mid AAEE" RPS trajectory portfolio that was used in the 2015-16 TPP studies, as the base case renewable resource portfolio in the 2016-17 TPP studies”

  “Given the range of potential implementation paths for a 50 percent RPS, it is undesirable to use a renewable portfolio in the TPP base case that might trigger new transmission investment, until more information is available.”

- The ISO focused only on the Imperial, Baja and Arizona areas due to changes in transmission plans in the Imperial Irrigation District from the 2015-2016 Transmission Plan.

- Portfolios to be used in the ISO’s informational 50% RPS special studies were provided by CPUC staff.

Policy and Economic driven solutions:

- There were no policy-driven requirements identified
  - A marginal potential overload was identified that could be mitigated by a modest 20 MW reduction in deliverability
  - Given the modest shortfall in deliverability and the objective of reviewing reinforcement requirements when 50% policy renewable generation portfolios are available, mitigations are not recommended at this time for policy purposes
- There were no economically driven requirements identified

Other considerations:

- No regional transmission solutions recommended for approval are eligible for competitive solicitation
- Transmission Access Charge model to be incorporated into final draft transmission plan – model preparation and data collection in progress

Six special studies were undertaken in this cycle:

Presentations today:

- Update on Continuation of frequency response efforts through improved modeling *(in progress – update today)*
- Risks of early economic retirement of gas fleet
- 50% Renewable Generation (in-state analysis and coordination)

Not being presented today:

- 50% Renewable Generation (out of state and Interregional Transmission Project evaluation) *(February 28 session)*
- Large scale storage benefits *(February 28 session)*
- Slow response resources in local capacity areas *(moving to parallel track anticipated, technical results will continue)*
- Gas/electric reliability coordination *(presented in November)*

Recommendations for Reliability Projects

East of Lugo Area

Meng Zhang

Sr. Regional Transmission Engineer

2016-2017 Transmission Planning Process Stakeholder Meeting

February 17th, 2017

Recommended for Approval

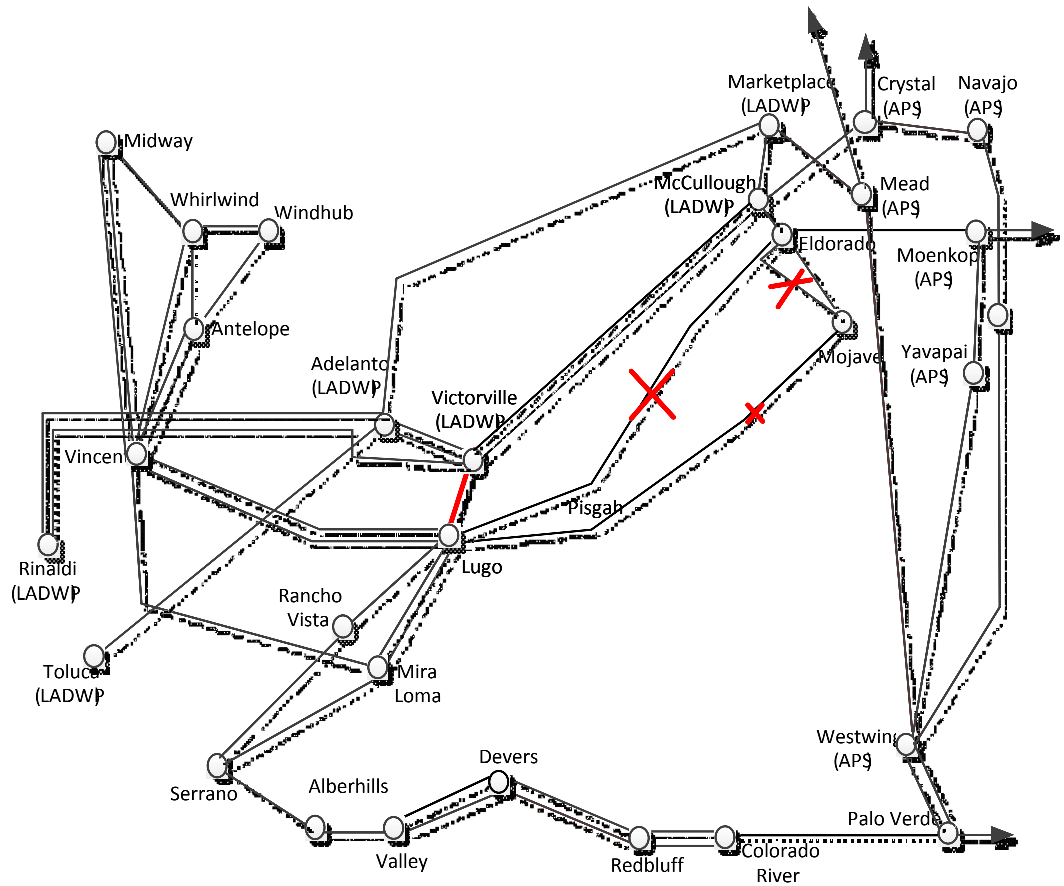
Project Name	Type of Project	Submitted By	Cost of Project
Lugo – Victorville 500kV Upgrade (SCE Portion)	Reliability	SCE	$18 million for SCE portion

Background

- The project was found needed in both 2015/16 and 2016/17 transmission planning cycles.
- SCE submitted the project in 2015 Request Window.
- Over the course of 2016, the ISO worked with SCE and LADWP to coordinate the next steps on developing this project, as the line is jointly owned by SCE and LADWP and the upgrade will be performed on facilities owned by each respective party.
- LADWP plans to fund their portion of the Lugo – Victorville 500kV Line Upgrade project.

Lugo – Victorville Thermal Issues

- Lugo – Victorville 500kV Line is observed to be overloaded following multiple P6 contingencies in all base cases except 2021 summer light load case.
- The line is also overloaded following Eldorado – Lugo 500kV single line outage in the 2021 heavy renewable sensitivity case.
- In the post-transient study, the line is observed to be overloaded following loss of both Lugo – Mohave and Eldorado – Lugo lines in all summer peak cases.



Lugo – Victorville 500 kV Line Upgrade Project Summary

Need:

- Address thermal overloads on the line identified in the 2016-2017 TPP process.
- Contribute to an increase in the WECC Path 46-West of River rating by approximately 1000 MW as well as an increase in the WECC Path 61 Lugo – Victorville 500kV Line.
- 33% RPS policy-driven study also identified this line as a constraint for delivering resources from multiple renewable zones.
- The accrued congestion cost of the line since January 2013 was found to be approximately $61 million.
- In the post-2020 timeframe, congestion management will be a challenge with the retirement of the bulk of OTC generating units in the western LA Basin and potential retirement of generation over 40-year old.

Lugo – Victorville 500 kV Line Upgrade Project Summary (Cont.)

Project Scope:

- Upgrade terminal equipment at both substations and removing ground clearance limitations. SCE's portion includes upgrading four (4) transmission towers and replacing terminal equipment at Lugo substation. Post the project, the Lugo – Victorville Line normal and 4-hour emergency ratings will be increased from 3000 Amps to 3710 Amps and 4480 Amps respectively.

Other Alternatives Considered :

- Congestion Management
- Operating Procedure 6610 – Bypassing series capacitors on LADWP lines

Expected In-Service Date: 12/31/2018

Recommendations for Reliability Projects: Tehachapi and Big Creek Corridor Area

Mudita Suri

Regional Transmission Engineer

2016-2017 Transmission Planning Process Stakeholder Meeting

February 17th, 2017

Recap - Tehachapi and Big Creek Corridor Area Reliability Assessment Summary

- The assessment identified:
  - No concerns in any Study Base Case Scenarios.
  - No concerns in Sensitivity Scenarios S1, S2, S3, and S4.
  - Thermal Overloads in Sensitivity Scenario 5 (extreme low hydro)
    - Magunden-Vestal 230 kV 1 or 2

      The Magunden-Vestal 230 kV 1 or 2 line is overloaded under one Category P1, one P3, four P6, and one P7 outages.
    - Rector-Vestal 230 kV 1 or 2

      The Rector-Vestal 230 kV 1 or 2 lines are overloaded under one Category P3 and four P6 outages.

As per the study plan, drought generation assumptions were simulated for Big Creek hydro (base case and sensitivity).

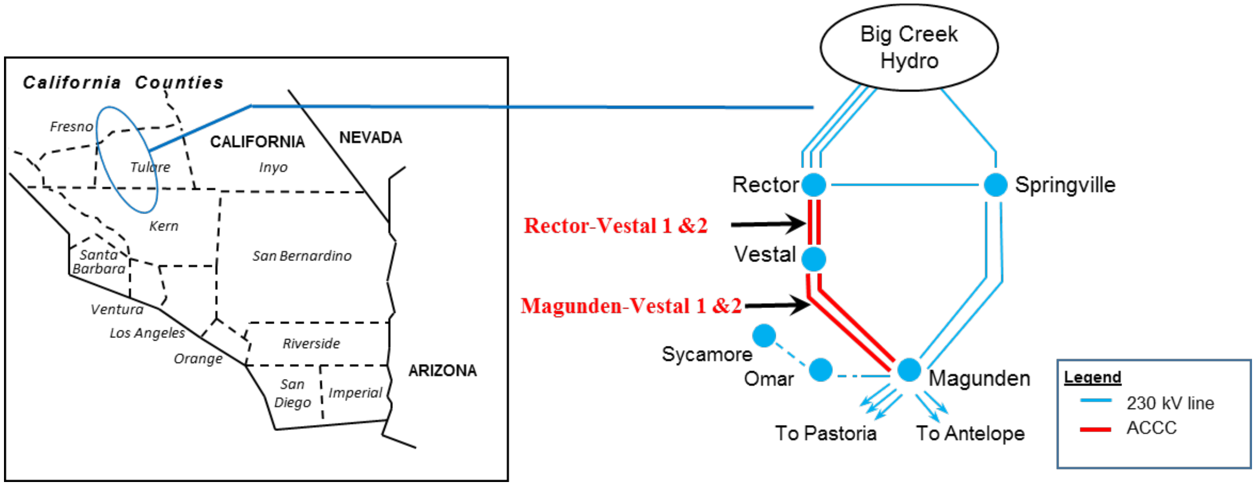
2021 Summer Peak- Low Hydro Sensitivity

- **Objective:** To simulate extreme low hydro drought generation condition
- **Methodology**: Worst hydro generation periods (during peak load hours) were analyzed from 2015 Summer to evaluate lowest generation amounts
- **Generation Assumption**: Total Big Creek generation to simulate worst 2015 hydro periods = 330MW (240MW hydro)

P1 (N-1) contingency of either the Magunden-Vestal No. 1 or No. 2 230 kV line resulted in an overload requiring up to 170MW of load shed

Projects found to be needed:

Project Name	Type of Project	Submitted By	Cost of Project
Big Creek Corridor Rating Increase	Reliability	SCE	$6 million



Big Creek Corridor Rating Increase Project

- **Existing TLRR Program:**
  - SCE decided to reconductor the Magunden-Vestal No. 1 and No. 2 and Rector-Vestal No. 1 and No. 2 230 kV lines using an Aluminum Conductor Composite Core (ACCC) conductor (714 kcmil “Dove”) as part of the CPUC approved Transmission Line Rating Remediation (TLRR) program to address the GO95 clearance issues.

- **Project Scope:**
  - The Request Window project will incrementally upgrade four transmission structures and terminal equipment at Magunden and Vestal Substations and achieve a 4-hr emergency rating of 1520 Amps (currently 936 Amps) on the four 230 kV transmission lines.

- **Other Alternatives Considered** :
  - Status quo (Big Creek SPS)
  - Pittman Hill 230 kV Substation Project
- **Expected In-Service**: 12/31/2018

Factors Considered in the Alternative Analysis

1. Existing TLRR program
2. Economics/Cost
3. Outage time
4. Transient Stability issues
5. PG&E system benefits
6. Path 26 Benefits

Project Review PG&E Area

J.E.(Jeff) Billinton
Manager, Regional Transmission - North

2016-2017 Transmission Planning Process Stakeholder Meeting
February 17, 2017

Projects for Approval

- No projects are recommended for approval

- The ISO will be conducting further voltage analysis to assess reactive needs on the system in 2017-2018 TPP

Oakland Area

- The ISO is working with the Oakland generator owner to assess the expected life of the existing generation prior to recommending any alterative developments as the existing generation and previously approved projects mitigate the issues in the area.

- The alternatives that the ISO assessed in the 2015-2016 transmission planning process are remain valid to address the identified need. The preferred alternative at this time is a combination of transmission and non-transmission mitigation solutions:
  - the P2 bus-tie breaker contingencies would be addressed by installing an additional bus-tie breakers at Moraga, Station X and Claremont; and,
  - the P6 contingencies would addressed by the procurement of preferred resources in the area. This could involve a portfolio of demand response, energy efficiency, distributed generation and storage to meet the area requirements based upon the load profile.

- The ISO will continue to work with the Oakland generator owner and reassess the situation assess in the 2017-2018 transmission planning process.

Project Review

- ISO conducted studies using base cases for 2026 without the previously approved transmission projects
  - Conducted sensitivity studies
    - behind the meter PV off to represent the PV peak shift; and
    - behind the meter PV off and with the without AAEE

Project Cancelations

- Based on this analysis, the ISO found that 13 projects are no longer required based on reliability and local capacity requirements and deliverability assessments.
- The ISO recommends cancelling these projects:
  - Pease-Marysville #2 60 kV Line
  - Almaden 60 kV Shunt Capacitor
  - Monta Vista – Los Gatos – Evergreen 60 kV Project
  - Lockheed No. 1 115 kV Tap Reconductor
  - Mountain View/Whisman-Monta Vista 115 kV Reconductoring
  - Stone 115 kV Back-tie Reconductor
  - Kearney - Kerman 70 kV Line Reconductor
  - Cressey - North Merced 115 kV Line Addition
  - Taft-Maricopa 70 kV Line Reconductor
  - Natividad Substation Interconnection
  - Soledad 115/60 kV Transformer Capacity
  - Tesla-Newark 230 kV Path Upgrade
  - Vaca Dixon-Lakeville 230 kV Reconductoring

Projects on Hold

- The following four projects are in the late stages of design, siting, and permitting, and continuing the design, siting and permitting activities will assist in the review.

- However, the ISO is recommending that the project sponsors do not proceed with filings for permitting and certificates of public convenience and necessity for the following projects until the ISO completes the reviews:

  - Midway-Andrew 230 kV Project
  - Spring Substation
  - Wheeler Ridge Junction Substation
  - Lockeford-Lodi Area 230 kV Development

Projects on Hold

- For the following projects, all development activities are recommended to be put on hold until a review is complete.
  - Gates-Gregg 230 kV Line (see additional information in section 2.5.9.1)
  - Watsonville Voltage Conversion
  - Atlantic-Placer 115 kV Line
  - Vaca-Davis Voltage Conversion Project
  - Northern Fresno 115 kV Area Reinforcement
  - South of San Mateo Capacity Increase
  - Evergreen-Mabury Conversion to 115 kV
  - New Bridgeville Garberville No. 2 115 kV Line
  - Cottonwood-Red Bluff No. 2 60 kV Line Project and Red Bluff Area 230 kV Substation Project
  - Kern PP 115 kV Area Reinforcement
  - Wheeler Ridge-Weedpatch 70 kV Line Reconductor

Gates-Gregg 230 kV Line

- Increased behind the meter PV has changed the load profile in the area and would allow increased pumping during the day time periods, particular in the off-peak seasons when there is a potential for oversupply on the system.
- Fresno area reliability need has been pushed back at least 10 years
- The ISO reviewed the benefits of the increased pumping capability on renewable integration and in particular avoided potential renewable curtailment during periods of oversupply. Although there are economic benefits for renewable integration, the economic savings are not presently sufficient to justify the cost of the project.
- Also, there are uncertainties regarding renewable integration needs, and these need to be assessed further and taken into account. The ISO will study these issues in the 2017-2018 planning cycle. Given these uncertainties, the ISO is not recommending cancelling the project at this time despite despite recommending that no further development action be taken until the review is completed.

SDG&E Area

Robert Sparks
Manager, Regional Transmission - South

2016-2017 Transmission Planning Process Stakeholder Meeting
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Projects for Approval

- No projects are recommended for approval

- Mission-Penasquitos 230 kV circuit project will be re-evaluated in the 2017-2018 planning cycle

Economic Planning Study Final Results

Yi Zhang
Regional Transmission Engineer Lead

2016-2017 Transmission Planning Process Stakeholder Meeting
February 17, 2017

Steps of economic planning studies

Economic planning studies

(Step 1)
Unified study assumptions

(Step 2)
Development of production cost model

(Step 3)
Preliminary study results

(Step 4)
Final study results

Economic planning study requests

Major changes since last stakeholder meeting

- Modeled additional scheduled outages and associated derate of COI capacity, provided by COI facility owners
  - Annual events were added into the base database as the part of the baseline assumptions
  - Two sensitivities with modeling additional scheduled outages
    - Events that may happen every two to three years
    - Events that may happen every four to six years

Congestions

No	Aggregated congestion	2026	
		Costs (M$)	Duration (hr)
1	BOB SS (VEA) - MEAD S 230 kV line	23.72	600
2	PG&E LCR	9.73	684
3	Path 26	5.03	320
4	PG&E/TID Exchequer	1.68	651
5	J.HINDS-MIRAGE 230 kV line #1	1.09	187
6	COI	0.84	120
7	Path 45	0.63	655
8	SCE LCR	0.49	34
9	Path 15/CC	0.44	120
10	PG&E/Sierra MARBLE transformer	0.08	79
11	PGE& CAMANCH-BELLOTA 230 kV line	0.06	2
12	Inyo-Control	0.05	66
13	IID-SDGE	0.02	219
14	SDGE ECO-Miguel 500 kV line	0.01	1
15	Path 24	0.00	1

Evaluating economic planning study requests

- Six study requests have been accepted and evaluated
- Evaluations followed the ISO Tariff Section 24.3.4.1
- Detail evaluation results can be found in the transmission plan report
- COI congestion was further investigated

COI modeling enhancement

- Planning nomograms developed in ISO’s 2013~2014 TPP
  - Considered impact of both Northern CA hydro and renewable on COI flow and limit

- Additional scheduled outages and associated derate of COI capacity, provided by COI facility owners

COI congestion analysis

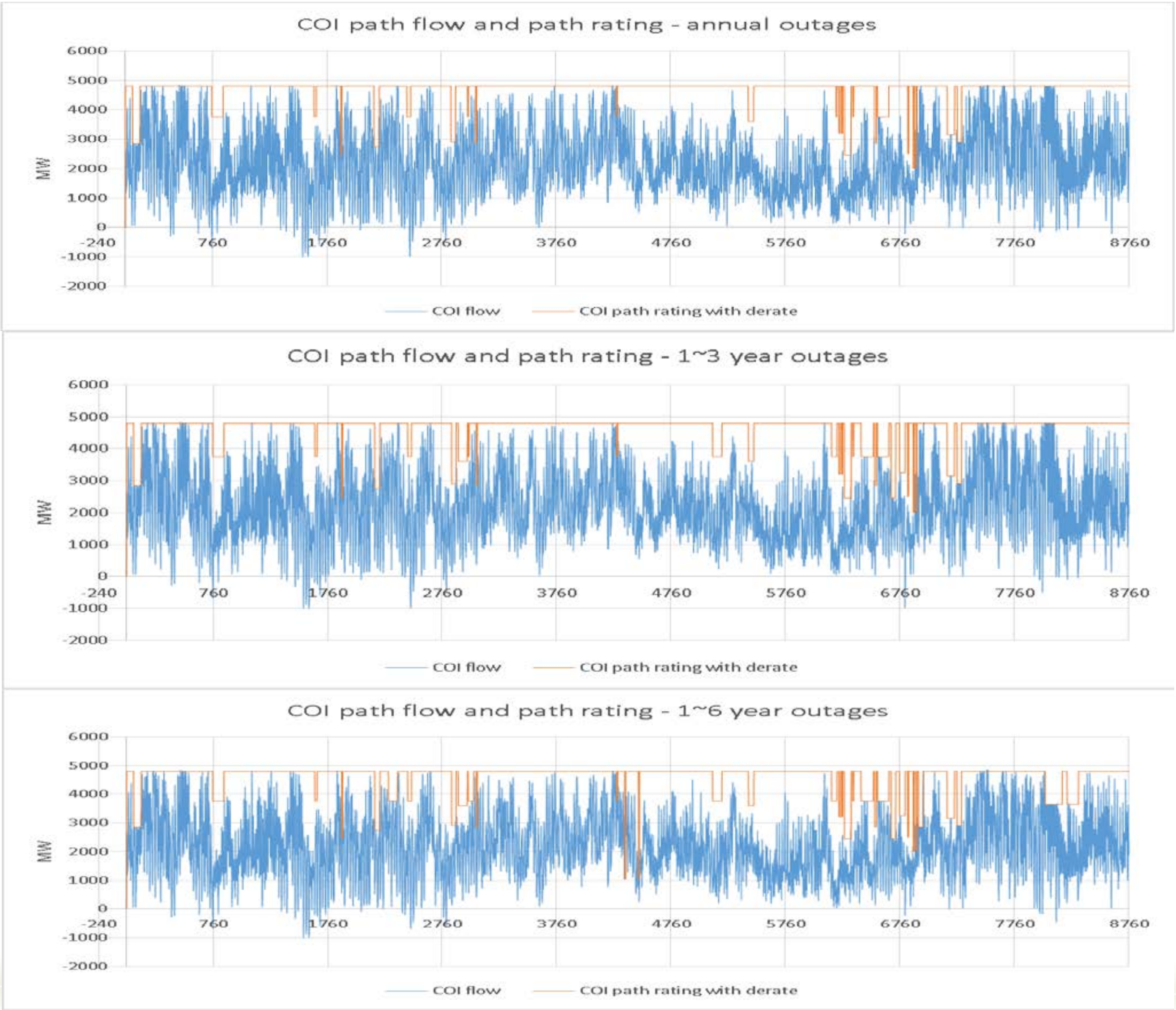
COI Congestion Breakdown in Baseline Study

Constraints Name	Type	Costs (M$)	Duration (Hrs)
P66 COI	Interface	0.440	89
ISO v COI Summer 1-2	Nomogram	0.164	12
ISO v COI Summer 1-1	Nomogram	0.150	11
ISO v COI Summer 3-2	Nomogram	0.064	6
ISO v COI Summer 3-1	Nomogram	0.022	2

COI congestion comparison with additional outages modeled

COI Outage group	Cost ($M)	Hours
Base (annual outage)	0.84	120
1~3 year	0.93	124
1~6 year	1.19	185

COI flow and limit in production cost simulation results



Summary

- No economic upgrade recommended for approval in the 2016~2017 planning cycle
- COI modeling was enhanced
  - Provided an enhanced framework for any future studies on COI congestion
- Congestion analysis and economic assessment in future planning cycles to take into account
  - Improved WECC production cost modeling
  - Further consideration of suggested changes to ISO economic modeling
  - Further clarity on 50% renewable energy goal
  - Interregional transmission planning process

2021 and 2026 Final LCR Study Results – Northern Areas and Summary of Findings

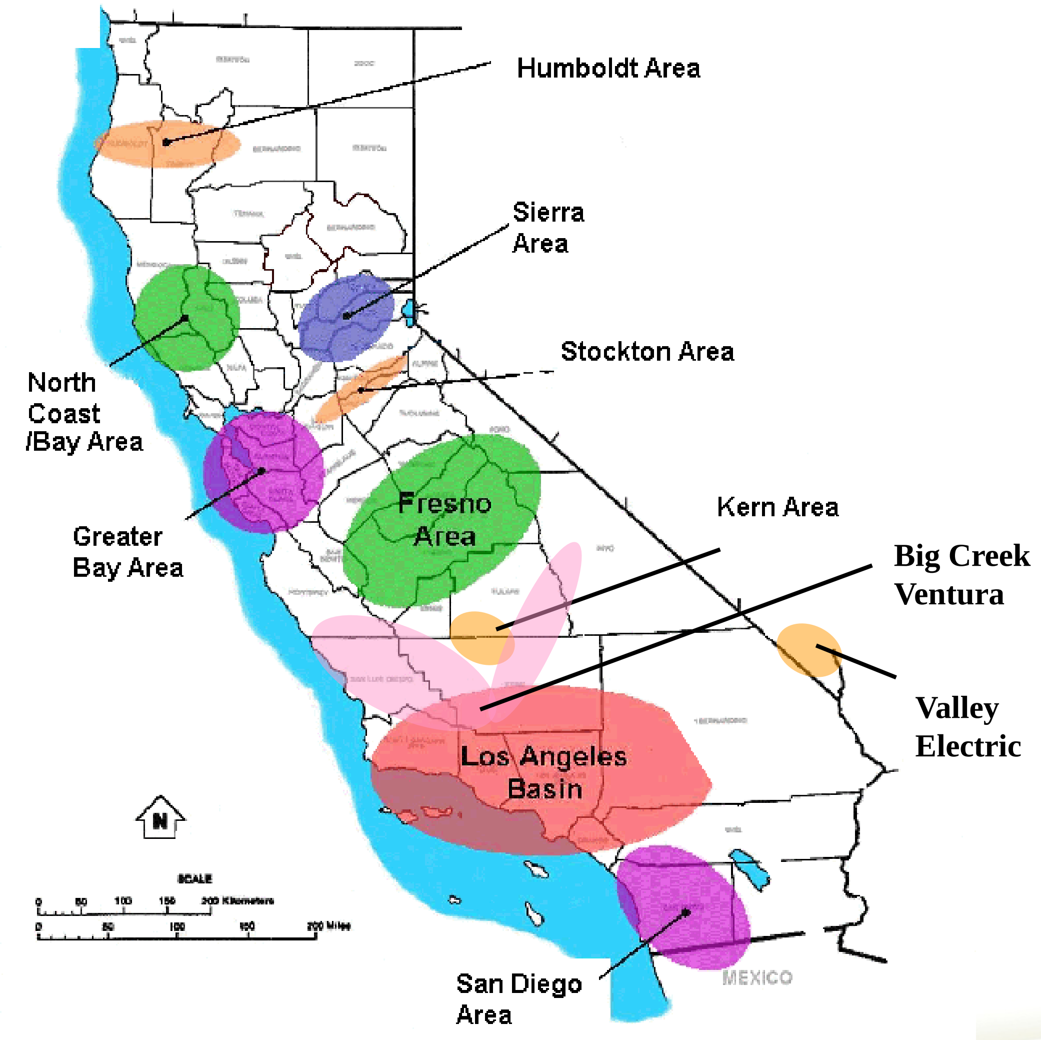
Catalin Micsa

Senior Advisor Regional Transmission Engineer

Stakeholder Meeting

February 17, 2017

LCR Areas within CAISO



Input Assumptions, Methodology and Criteria

See October 29, 2015 stakeholder teleconference - for study assumptions, methodology and criteria. The latest information along with the 2017 LCR Manual can be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx .

Transmission system configuration – all-projects with EDRO up to June 1

Generation – all-generation with COD up to June 1 of study year

Load Forecast – 1 in 10 local area peak (based on latest CEC forecast)

Criteria – see report for details

Methodology

1. Maximize Imports Capability into the local area
2. Maintain path flows
3. Maintain deliverability for deliverable units
4. Load pocket – fix definition
5. Performance levels B & C (if equal category B is most stringent)

Total 2017 Final LCR Needs

	Qualifying Capacity			2017 LCR Need Based on Category B			2017 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	20	198	218	110	0	**110**	157	0	**157**
North Coast/ North Bay	128	722	850	721	0	**721**	721	0	**721**
Sierra	1176	890	2066	1247	0	**1247**	1731	312*	**2043**
Stockton	149	449	598	340	0	**340**	402	343*	**745**
Greater Bay	1070	8792	9862	4260	232*	**4492**	5385	232*	**5617**
Greater Fresno	231	3072	3303	1760	0	**1760**	1760	19*	**1779**
Kern	60	491	551	137	0	**137**	492	0	**492**
LA Basin	1615	8960	10575	6873	0	**6873**	7368	0	**7368**
Big Creek/Ventura	543	4920	5463	1841	0	**1841**	2057	0	**2057**
San Diego/ Imperial Valley	239	5071	5310	3570	0	**3570**	3570	0	**3570**
Total	5231	33565	38796	20859	232	**21091**	23643	906	**24549**

Total 2021 Final LCR Needs

	Qualifying Capacity			2021 LCR Need Based on Category B			2021 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	20	198	218	121	0	**121**	169	0	**169**
North Coast/ North Bay	128	722	850	205	0	**205**	480	0	**480**
Sierra	1176	890	2066	1094	0	**1094**	1475	211*	**1686**
Stockton	197	532	729	146	0	**146**	364	40*	**404**
Greater Bay	933	5970	6903	2448	0	**2448**	5194	0	**5194**
Greater Fresno	231	3295	3526	731	0	**731**	1160	0	**1160**
Kern	15	106	121	91	0	**91**	105	0	**105**
LA Basin	1615	6180	7795	6697	0	**6697**	6898	0	**6898**
Big Creek/Ventura	517	3160	3677	2325	0	**2325**	2398	0	**2398**
San Diego/ Imperial Valley	263	4577	4840	4357	0	**4357**	4357	0	**4357**
Total	5095	25630	30725	18215	0	**18215**	22793	251	**23044**

Total 2026 Final LCR Needs

	Qualifying Capacity			2026 LCR Need Based on Category B			2026 LCR Need Based on Category C with operating procedure		
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed****	**Deficiency**	**Total (MW)**
Humboldt	20	198	218	123	0	**123**	171	0	**171**
North Coast/ North Bay	128	722	850	201	0	**201**	547	0	**547**
Sierra	1176	890	2066	472	0	**472**	1004	0	**1004**
Stockton	172	532	704	183	0	**183**	516	0	**516**
Greater Bay	933	5970	6903	3226	0	**3226**	5544	188*	**5732**
Greater Fresno	231	3295	3526	1474	0	**1474**	1474	0	**1474**
Kern	15	566	581	391	0	**391**	392	0	**392**
LA Basin	1615	6180	7795	7234	0	**7234**	7234	0	**7234**
Big Creek/Ventura	517	3160	3677	2310	0	**2310**	2528	0	**2528**
San Diego/ Imperial Valley	263	4577	4840	4649	0	**4649**	4649	0	**4649**
Total	5070	26090	31160	20263	0	**20263**	24059	188	**24247**

California ISO

Humboldt Area

Humboldt Overall Need:

2021 Load: 195 MW
2021 Resources: 218 MW
2021 LCR Need: 169 MW
Contingency: Cottonwood – Bridgeville 115 kV line + 115 kV Gen tie to the Humboldt Bay Units
Limiting component: Thermal overload on Humboldt - Trinity 115 kV line

2026 Load: 193 MW
2026 Resources: 218 MW
2026 LCR Need: 171 MW

Changes: Mostly due to load forecast.

North Coast/North Bay Area

NCNB sub-area need:

2021 Eagle Rock: 213 MW
2026 Eagle Rock: 217 MW
Contingency: Geyser #3-Geyser#5 and Cortina-Mendocino 115 kV lines
Limiting component: Thermal overload on the Eagle Rock-Cortina 115 kV

2021 Fulton: 310 MW
2026 Fulton: 363 MW
Contingency: Fulton-Ignacio and Fulton-Lakeville 230 kV lines
Limiting component: Thermal overload on the Lakeville #2 60 kV line

Changes: Mostly due to load forecast.

North Coast/North Bay Area

NCNB (Lakeville) Overall Need:

2021 Load: 1318 MW
2021 Resources: 850 MW
2021 LCR Need: 480 MW
Contingency: Vaca Dixon-Tulucay and Vaca Dixon-Lakeville 230 kV lines
Limiting component: Thermal overload on the Eagle Rock-Cortina 115 kV line and possible overload on the Eagle Rock-Fulton 115 kV line as well as Moraga-Sobrante 115 kV line

2026 Load: 1491 MW
2026 Resources: 850 MW
2026 LCR Need: 547 MW

Changes: Mostly due to load forecast.

Sierra Area

Sierra sub-area need:

2021 Drum-Rio Oso: No need Rio Oso 230/115 kV transformer upgrade
2026 Drum-Rio Oso: No need Rio Oso 230/115 kV transformer upgrade

2021 South of Rio Oso: 761 MW
Contingency: Rio Oso-Gold Hill and Rio Oso-Atlantic #1 230 kV lines
Limiting component: Thermal overload on Rio Oso-Lincoln 115 kV line
2026 South of Rio Oso: 282 MW
Contingency: Rio Oso-Gold Hill and Rio Oso-Atlantic #1 230 kV lines
Limiting component: Thermal overload on Rio Oso-Atlantic #2 230 kV line

2021 South of Palermo: 1686 MW
Contingency: Table Mountain-Rio Oso and Colgate-Rio Oso 115 kV lines
Limiting component: Thermal overload on Pease-Rio Oso 115 kV line

2026 South of Palermo: No need South of Palermo reinforcement

Sierra Area

Sierra sub-area need:

2021 Placerville: No need - Missouri Flat-Gold Hill 115 kV reconductoring
2026 Placerville: No need - Missouri Flat-Gold Hill 115 kV reconductoring

2021 Placer: 62 MW
Contingency: Gold Hill-Placer #1 with Chicago Park unit out
Limiting component: Thermal overload on the Drum-Higgins 115 kV line
2026 Placer: No need – New Atlantic-Placer 115 kV line

2021 Peace: 68 MW
2026 Peace: 82 MW
Contingency: Palermo-Pease and Pease-Rio Oso 115 kV lines
Limiting component: Thermal overload on Table Mountain-Pease 60 kV

Changes: Mostly due to new transmission projects.

Sierra Area

Sierra (South of Table Mountain) Overall Need:

2021 Load:	1822 MW
2021 Resources:	2066 MW
2021 LCR Need:	1686 MW

Contingency: Table Mt.-Rio Oso and Table Mt.-Palermo 230 kV lines
Limiting component: Thermal overload Caribou-Palermo 115 kV line

2026 Load:	2108 MW
2026 Resources:	2066 MW
2026 LCR Need:	1004 MW

Contingency: Table Mt.-Rio Oso and Table Mt.-Palermo 230 kV lines
Limiting component: Thermal overload Table Mt.-Pease 115 kV line

Changes: Mostly due to new transmission projects.

Stockton Area

Stockton sub-area need:

2021 Stanislaus: 146 MW
Contingency: Bellota-Riverbank-Melones 115 kV with Stanislaus unit out
Limiting component: Thermal overload on Riverbank Jct.-Manteca 115 kV
2026 Stanislaus: 70 MW
Contingency: Bellota-Riverbank-Melones and Riverbank Jct.-Manteca 115
Limiting component: Thermal overload on Melones Jct.-Avena Tap 115 kV

2021 Peace: 312 MW
2026 Peace: 484 MW
Contingency: Tesla-Vierra and Tesla-Schulte #2 115 kV lines
Limiting component: Thermal overload on Tesla-Schulte #1 115 kV

Changes: Due to both load growth and new transmission projects.

Stockton Area

Stockton sub-area need:

2021 Lockeford: 65 MW
Contingency: Lockeford-Industrial and Lockeford-Lodi #2 60 kV lines
Limiting component: Thermal overload on Lockeford-Lodi #3 60 kV
2026 Lockeford: No need – Lockeford-Lodi area 230 kV development

2021 Weber: 27 MW
2026 Weber: 32 MW
Contingency: Stockton A-Weber #1 & #2 60 kV lines
Limiting component: Thermal overload on Stockton A-Weber #3 60 kV

Changes: Due to both load growth and new transmission projects.

Stockton Area

Stockton Overall Need:

Sum of sub-area needs:

2021 Load:	1186 MW
2021 Resources:	729 MW
2021 LCR Need:	404 MW
2026 Load:	1269 MW
2026 Resources:	704 MW
2026 LCR Need:	516 MW

Changes: Mostly due to load growth and new transmission projects.

Bay Area

Bay Area sub-area need:

2021 Oakland: 98 MW real-time – 72 MW per study
2026 Oakland: 98 MW real-time – 76 MW per study
Contingency: C-X #2 and C-X #3 115 kV cables
Limiting component: Thermal overload on Moraga-Claremont 115 kV lines

2021 LLagas: 6 MW
2026 LLagas: 30 MW
Contingency: Metcalf-Morgan Hill and Springs 230/115 kV transformer
Limiting component: Thermal overload Metcalf-Green Valley-Llagas 115 kV

Changes: Due to both load growth and new transmission projects.

Bay Area

Bay Area sub-area need:

2021 San Jose: 404 MW
2026 San Jose: 257 MW
Contingency: Metcalf-Evergreen #1 and #2 115 kV lines
Limiting component: Thermal overload - San Jose Sta “A”-”B” 115 kV line

2021 South Bay-Moss Landing: 2043 MW
2026 South Bay-Moss Landing : 2427 MW
Contingency: Tesla-Metcalf and Moss Landing-Los Banos 500 kV lines
Limiting component: Thermal overload Las Aguillas-Moss Landing 230 kV

Changes: Due to both load growth and new transmission projects.

Bay Area

Bay Area sub-area need:

2021 Ames and Pittsburg: 2097 MW
2026 Ames and Pittsburg: 2102 MW
Contingency: Newark-Ravenswood and Tesla-Ravenswood 230 kV lines
Limiting component: Thermal overload on Newark-Ames 115 kV lines

2021 Contra Costa: 956 MW
2026 Contra Costa: 1105 MW
Contingency: Tesla-Kelso 230 kV and Gateway out of service
Limiting component: Thermal overload Delta Sw Yard-Tesla 230 kV line

Changes: Due to both load growth.

Bay Area

Bay Area Overall Need:

Sum of sub-area needs:

2021 Load:	9644 MW
2021 Resources:	6903 MW
2021 LCR Need:	5194 MW
2026 Load:	10190 MW
2026 Resources:	6903 MW
2026 LCR Need:	5732 MW

Changes: Mostly due to load forecast.

Fresno Area

Fresno sub-area need:

2021 Hanford: 12 MW
2026 Hanford: 17 MW
Contingency: Mc Call-Kingsburg #2 and Henrietta #3 230/115 kV transf.
Limiting component: Thermal overload on Mc Call-Kingsburg #1 115 kV

2021 Coalinga: 48 MW
2026 Coalinga: 83 MW
Contingency: Gates #5 230/70 kV and Panoche-Schindler #1 & #2
Limiting component: Voltage instability

Changes: Due to load growth.

Fresno Area

Fresno sub-area need:

2021 Borden: 10 MW
2026 Borden: 5 MW
Contingency: Borden #4 230/70 kV and Friant-Coppermine 70 kV line
Limiting component: Thermal overload on Borden #1 230/70 kV transf.

2021 Reedley: No need – New Mc Call-Reedley #2 115 kV line
2026 Reedley: No need – New Mc Call-Reedley #2 115 kV line

2021 Herndon: No need – Northern Fresno 115 kV area reinforcement
2026 Herndon: No need – Northern Fresno 115 kV area reinforcement

Changes: Due to new transmission projects.

Fresno Area

Fresno (Wilson) Overall Need:

2021 Load: 3240 MW
2021 Resources: 3526 MW
2021 LCR Need: 1160 MW
Contingency: Panoche-Tranquility & Gates-Mustang #1 230 kV lines
Limiting component: Thermal overload Wilson-Oro Loma 115 kV line

2026 Load: 3653 MW
2026 Resources: 3526 MW
2026 LCR Need: 1474 MW
Contingency: Melones-North Merced with one Helms unit out
Limiting component: Voltage instability.

Changes: Mostly due to new transmission projects. The overloads on the Panoche to Wilson 115 kV corridor are worst at Path 15 high S-N flows; therefore the LCR requirement herein are under-estimated.

Kern Area

Kern area (sub-area) need:

2021 Load: 216 MW
2021 Resources: 121 MW
2021 Kern Oil LCR need: 105 MW
Contingency: Kern PP-Magunden-Witco and Kern PP-7th Standard 115 kV
Limiting component: Thermal overload on Kern PP-Live Oak 115 kV line
2026 Kern Oil: No need – North East Kern Voltage Conversion

2021 South Kern PP: No need – Kern PP 230 kV area reinforcement and Midway-Kern #1, 3 & 4 230 kV line capacity increase
2026 Load: 1084 MW
2026 Resources: 581 MW
2026 South Kern PP LCR Need: 392 MW
Contingency: Midway-Semitropic-Smyrna and Lerdo-Kern Oil-7th Standard
Limiting component: Thermal overload on Semitropic D – E 115 kV bus

Changes: Due to load new transmission projects.

2021 and 2026 Final LCR Study Results – Southern Areas

David Le

Senior Advisor Regional Transmission Engineer

Stakeholder Meeting #4

February 17, 2017

Big Creek/Ventura Area

Big Creek/Ventura sub-area need:

2021 Rector: 429 MW
2026 Rector: 429 MW
Contingency: One of Rector-Vestal 230 kV lines with Eastwood unit out-of-service
Limiting component: Thermal loading remaining Rector-Vestal 230 kV line

Changes: No changes between the two years

2021 Vestal: 746 MW
2026 Vestal: 693 MW
Contingency: One of Magunden-Vestal 230 kV lines with Eastwood unit out-of-service
Limiting component: Thermal overload remaining Magunden-Vestal 230 kV line

Changes: due to changes in loads in the subarea

Big Creek/Ventura Area

Big Creek/Ventura sub-area needs:

2021 Santa Clara: 253 MW (with Ellwood), 326 MW (without Ellwood)
2026 Santa Clara: 253 MW (with Ellwood), 326 MW (without Ellwood)
Contingency: Pardee-Santa Clara and Moorpark-Santa Clara #1&2 230 kV lines
Limiting component: Voltage instability
Notes: Ellwood generation project is under consideration by the CPUC for long-term local capacity procurement for Application No. 14-11-016

Changes: No changes between the two years

2021 Moorpark: 536 MW
2026 Moorpark: 536 MW
Contingency: Moorpark-Pardee #3 and Moorpark-Pardee #1 & 2 230 kV lines
Limiting component: Voltage instability

Changes: No changes between the two years

Big Creek/Ventura Area

Big Creek/Ventura Overall Need:

2021 Load: 3849 MW
2021 Resources: 3677 MW
2021 LCR Need: 2398 MW
Contingency: Lugo-Victorville 500 kV line and one of Sylmar-Pardee 230 kV lines
Limiting component: Thermal overload on the other Sylmar-Pardee 230 kV line

2026 Load: 3973 MW
2026 Resources: 3677 MW
2026 LCR Need: 2528 MW

Changes: Due to changes in adjusted managed peak

LA Basin Area

LA Basin sub-area need:

2021 El Nido: 359 MW
2026 El Nido: 305 MW
Contingency: La Fresa-El Nido #1 and #2 230 kV lines
Limiting component: Thermal loading on the La Fresa-La Cienega 230 kV line

2021 Western LA Basin: 4069 MW
Contingency: Mesa-Redondo and Mesa-Lighthipe 230 kV lines
Limiting component: Thermal loading on the Mesa-Laguna Bell #1 230 kV line

2026 Western LA Basin: 4136 MW
Contingency: Mesa-Redondo and Mesa-Lighthipe 230 kV lines
Limiting component: Thermal loading on the Mesa-Laguna Bell #1 230 kV line

Changes: due to changes in adjusted managed peak

LA Basin Area

LA Basin sub-area need:

2021 West of Devers: No need due to Mesa Loop-in & West of Devers project
2026 West of Devers: No need due to Mesa Loop-in & West of Devers project

2021 Valley-Devers: No need due to Colorado River-Delaney 500 kV line
2026 Valley-Devers: No need due to Colorado River-Delaney 500 kV line

2021 Valley: No need due to Colorado River-Delaney 500 kV line
2026 Valley: No need due to Colorado River-Delaney 500 kV line

2021 Eastern: 2829 MW
2026 Eastern: 2841 MW
Contingency: Alberhill-Serrano and Red Bluff-Devers #1 & #2 500 kV lines
Limiting component: Voltage instability

Changes: Due to new transmission projects

LA Basin Area

LA Basin Overall Need:

Share of the Combined LA Basin-San Diego overall need:
2021 Load: 19,506 MW
2021 Resources: 7,795 MW
2021 LCR Need: 6,898 MW
Contingency: Mesa-Redondo and Mesa-Lighthipe 230 kV lines
Limiting component: Thermal loading on the Mesa-Laguna Bell #1 230 kV line

Share of the Combined LA Basin-San Diego-Imperial Valley overall need:
2026 Load: 19,243 MW
2026 Resources: 7,795 MW
2026 LCR Need: 7,234 MW
Contingency: Imperial Valley-North Gila 500 kV line with TDM out of service
Limiting component: Thermal overload of the El Centro-Imperial Valley 230 kV line

Changes: due to changes in the adjusted managed peak for San Diego area for 2026 timeframe

San Diego/Imperial Valley Area

San Diego/Imperial Valley sub-area need:

2021 El Cajon: 7 MW
2026 El Cajon: 14 MW
Contingency: El Cajon-Jamacha and Murray-Garfield 69 kV lines
Limiting component: Thermal loading on the El Cajon-Los Coches 69 kV line

2021 Pala: 13 MW
2026 Pala: 34 MW
Contingency: Pendleton-San Luis Rey and Lilac-Pala 69 kV lines
Limiting component: Thermal loading on the Monserate-Morro Hill Tap 69 kV line

Changes: due to higher adjusted managed peak

San Diego/Imperial Valley Area

San Diego/Imperial Valley sub-area need:

2021 Mission: No LCR need due to the Mesa Heights Loop-in 69 kV project
2026 Mission: No LCR need due to the Mesa Heights Loop-in 69 kV project

2021 Esco: No LCR need due to the Artesian 230 kV sub. & second Poway-Pomerado 69 kV line
2026 Esco: No LCR need due to the Artesian 230 kV sub. & second Poway-Pomerado 69 kV line

2021 Miramar: No LCR need due to the second Miguel-Bay Blvd. 230 kV line
2026 Miramar: No LCR need due to the second Miguel-Bay Blvd. 230 kV line

2021 Border: 73 MW
2026 Border: 84 MW
Contingency: Bay Blvd. - Otay #1 & #2 69 kV lines
Limiting component: Thermal overload Imperial Beach-Bay Blvd. 69 kV line

Changes: due to new transmission projects (first three subareas) and higher adjusted managed peak (for the Border subarea)

San Diego/Imperial Valley Area

San Diego sub-area need:

Part of the Combined LA Basin-San Diego overall need:
2021 LCR Need: 2,514 MW
Contingency: Mesa-Redondo and Mesa-Lighthipe 230 kV lines
Limiting component: Thermal loading on the Mesa-Laguna Bell #1 230 kV line

Part of the Combined LA Basin-San Diego-Imperial Valley overall need:
2026 LCR Need: 2,807 MW
Contingency: Imperial Valley-North Gila 500 kV line with TDM out of service
Limiting component: Thermal loading on the El Centro-Imperial Valley 230 kV line

Changes: due to higher adjusted managed peak forecast

San Diego/Imperial Valley Area

San Diego/Imperial Valley area need:

2021 Load: 4,980 MW
2021 Resources: 4,840 MW
2021 LCR Need: 4,357 MW
Contingency: Imperial Valley-North Gila 500 kV line with TDM out of service
Limiting component: Thermal loading on the El Centro-Imperial Valley 230 kV

Part of the Combined LA Basin-San Diego-Imperial Valley overall need:
2026 Load: 5,307 MW
2026 Resources: 4,840 MW
2026 LCR Need: 4,649 MW

Changes: due to higher adjusted managed peak forecast

Valley Electric Area

- No category B issues were observed in this area
- Category C and beyond –
  - No common-mode N-2 issues were observed
  - No issues were observed for category B outage followed by a common-mode N-2 outage
  - All the N-1-1 issues that were observed can either be mitigated by the existing UVLS or by an operating procedure

Your comments and questions are welcome.

For written comments, please send to: RegionalTransmission@caiso.com

50% RPS Special Study– In-state Results and Status of Out of State Studies

Sushant Barave, Songzhe Zhu, Binaya Shrestha
Regional Transmission

2016-2017 Transmission Planning Process Stakeholder Meeting
February 17, 2017

50% RPS special study

A. **Background and assumptions**
   Objectives, study process, portfolios and transmission capability assumptions

B. **Reliability assessment** (all portfolios)
   Power flow assumptions, specific hours to model (snapshots identification), CA results and interregional coordination

C. **Deliverability assessment** (only FCDS portfolios)
   Impact of peak shift, deliverability assessment results

D. **Renewable curtailment and congestion results**
   Total renewable curtailment, Curtailment caused due to transmission congestion (import sensitivity), curtailment by zones

E. **Summary / Conclusions / Next steps**

A. BACKGROUND AND ASSUMPTIONS

1. Objectives behind the 50% special study
2. Study process overview
3. Portfolio assumptions
4. Transmission capability assumptions
5. An update on inter-regional study coordination

Primary objectives

- to continue investigating the transmission impacts of moving beyond 33 percent RPS assuming procurement based on
  - Deliverability Status – Energy Only (EODS) or Full Capacity (FCDS)
  - Resource location – In-state or Out-of-state (OOS)

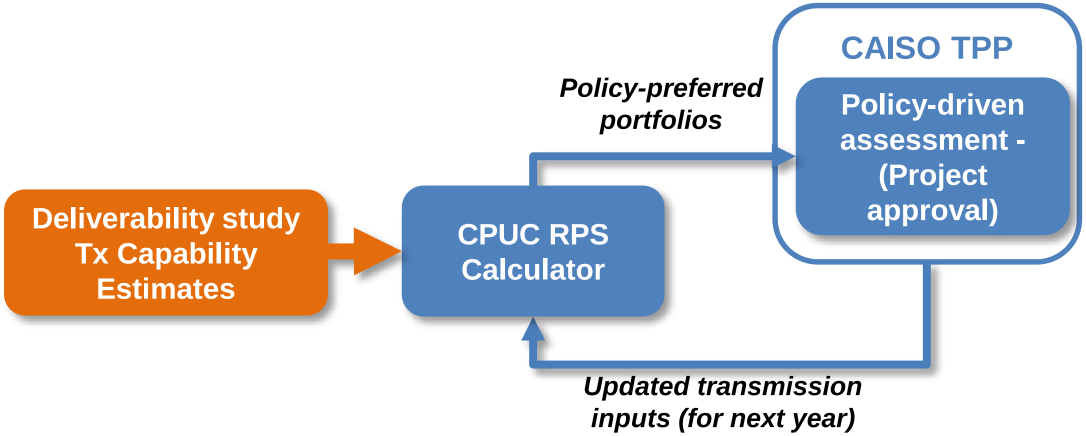
- to test the transmission capability estimates used in RPS calculator v6.2 and update these for future portfolio development

- to examine the transmission implications of meeting part of the 50 percent RPS obligation by relying on renewable resources outside of California and foster a higher degree of coordination with regional planning entities for the OOS portfolio modeling and assessment

- does not provide basis for procurement/build decisions in 2016-17 TPP cycle;
- is intended to be used to develop portfolios for consideration by ISO in future TPP cycles; and,
- explores potential policy direction on various related issues but does not attempt to predict how those issues will ultimately be addressed.

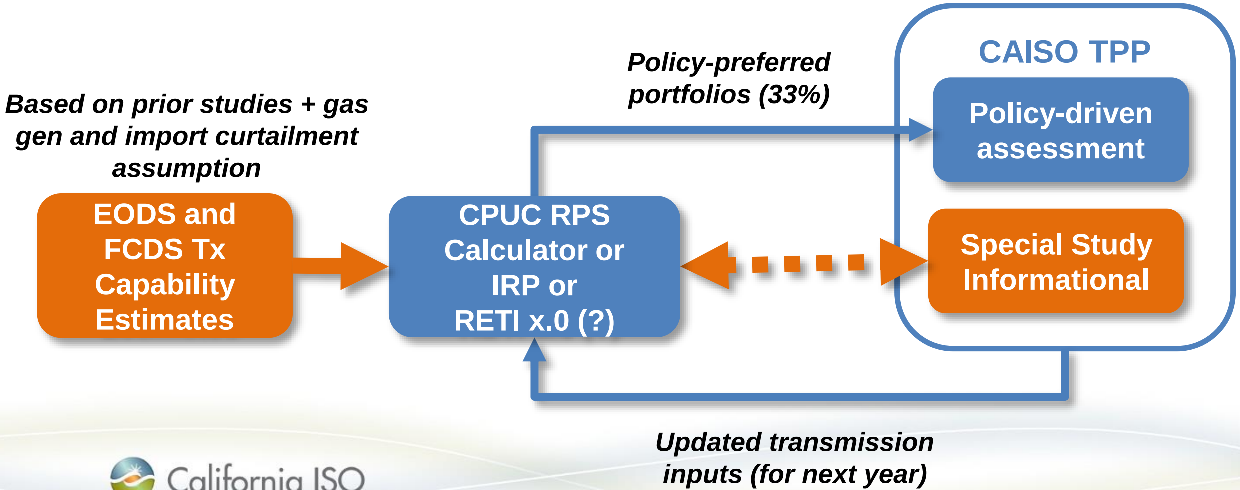
50% RPS special study is an informational effort intended to inform resource development in the future

Existing policy-driven planning process



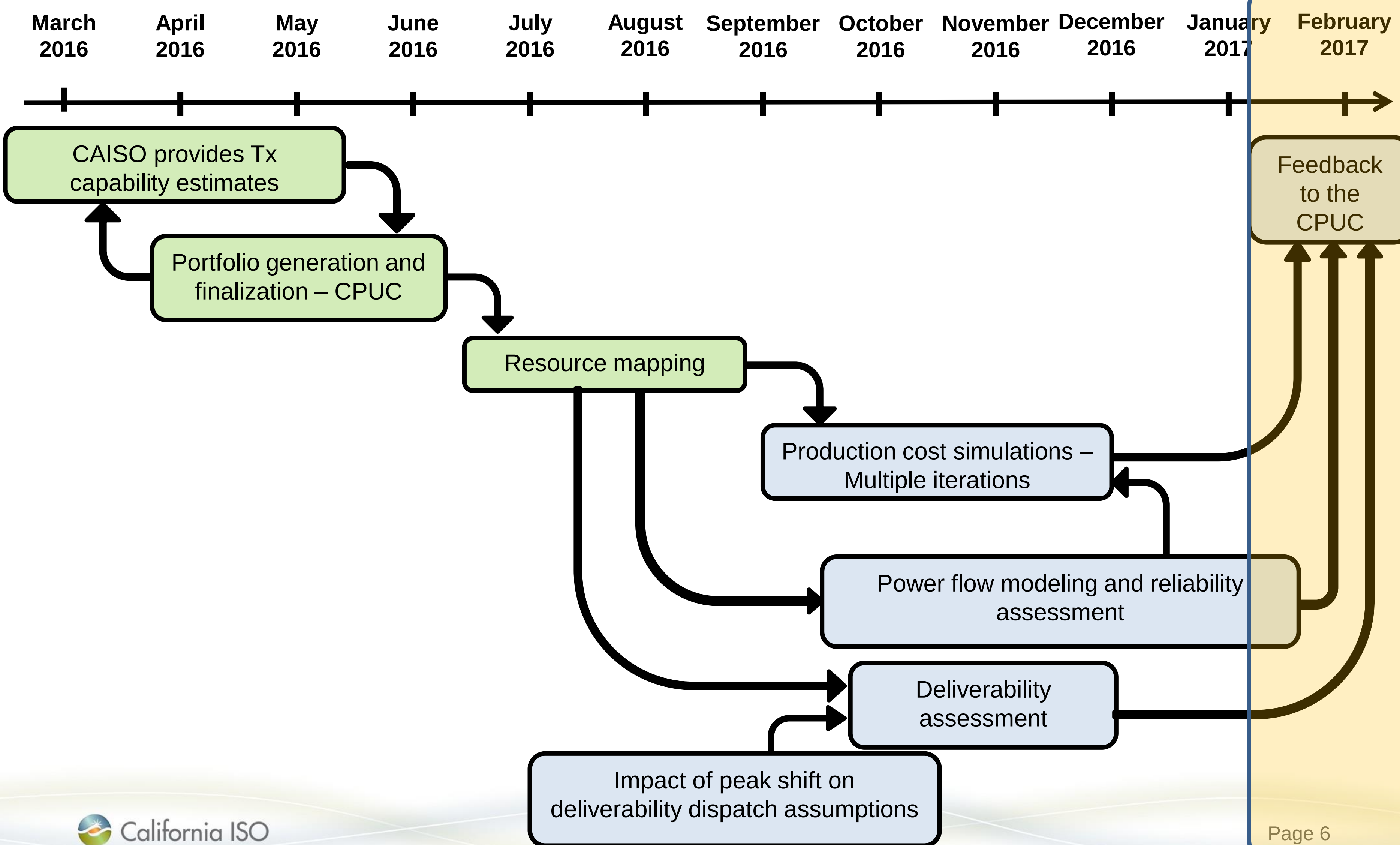
- ❑ Iterative process used to achieve 33% RPS goals
- ❑ This process results in policy-driven transmission upgrade approval
- ❑ Most procured generation assumed to have FCDS

Iterative process used to test and refine 50% RPS portfolios

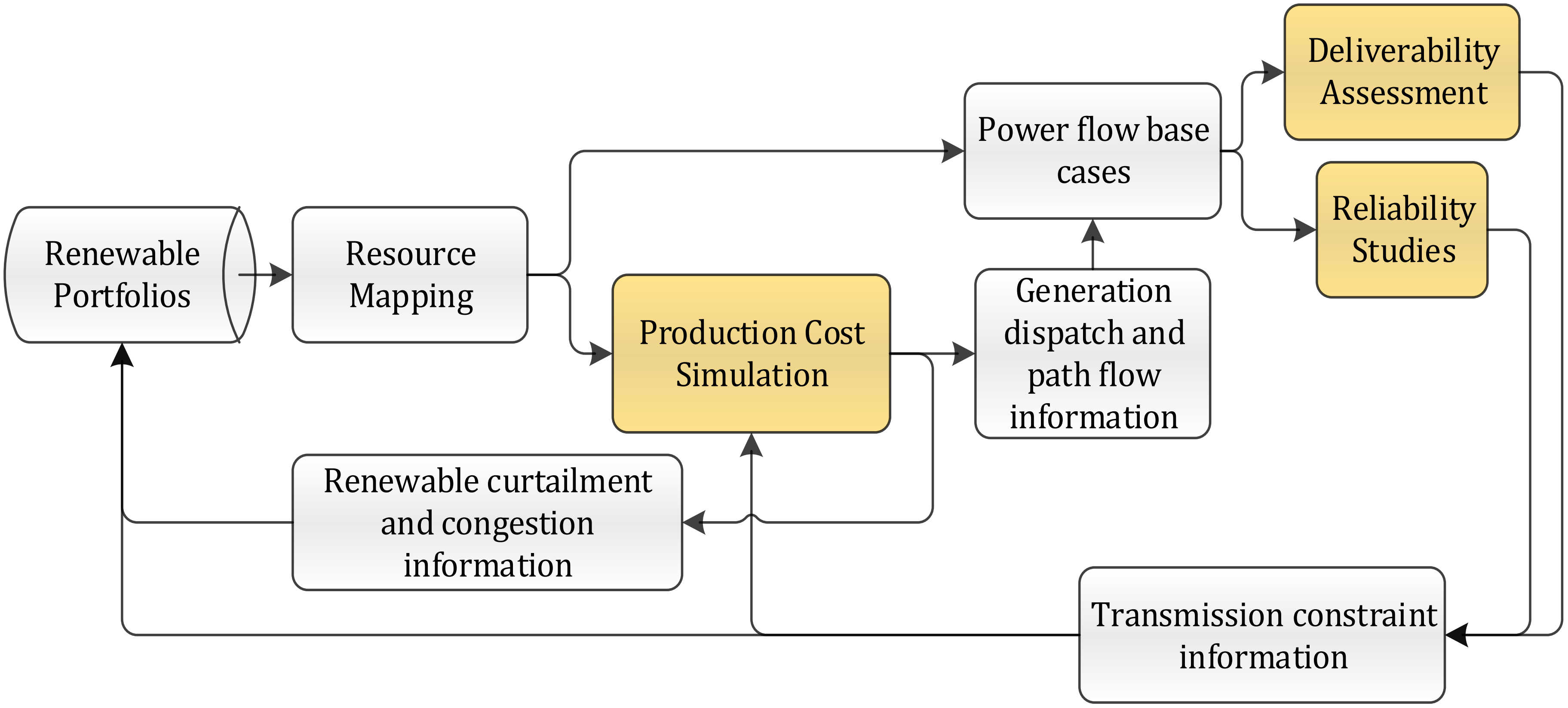


- ❑ Strictly an informational effort
- ❑ Procured gen assumptions based on geography (in-state or OOS) and deliverability status (EODS or FCDS)
- ❑ ***Objective***
  - To test and revise the transmission (Tx) capability numbers provided by CAISO
  - Preliminary transmission stress-test

50% RPS portfolios provided by the CPUC were used to assess the feasibility and transmission implications



The study is an iterative process that ties together three types of technical assessments



The study scope involves evaluation of four portfolios across three key performance metrics

Portfolio Assumptions

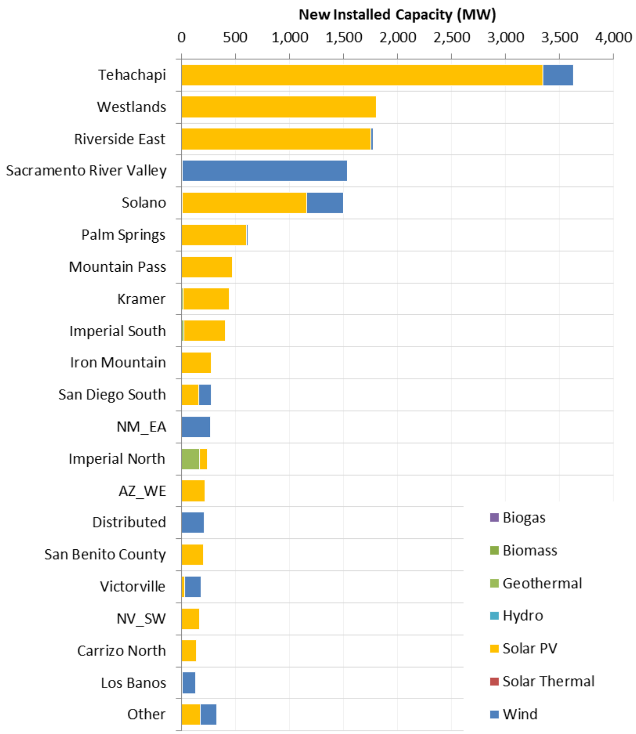
	In-state FCDS	In-state EODS	Out-of-state FCDS	Out-of-state EODS
Geography	CA - only	CA - only	CA + out-of-state	CA + out-of-state
Deliverability	FCDS	EODS	FCDS	EO
Out-of-state resources	None	None	WY and NM wind	WY and NM wind

Performance Assessment

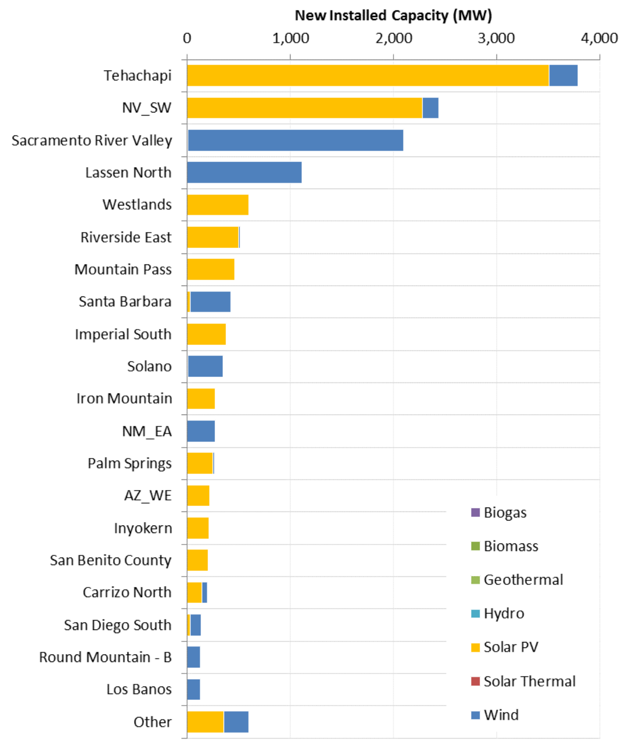
Assessment	In-state Full Capacity (FCDS)	In-state Energy Only (EODS)	Out-of-state FCDS/EODS
Reliability Assessment	✓	✓	✓
Deliverability Assessment	✓	✗	✓
Production Cost Simulation	✓	✓	✓

In-state FCDS and EODS portfolios are quite different; OOS FCDS and EODS portfolios did not vary by much*

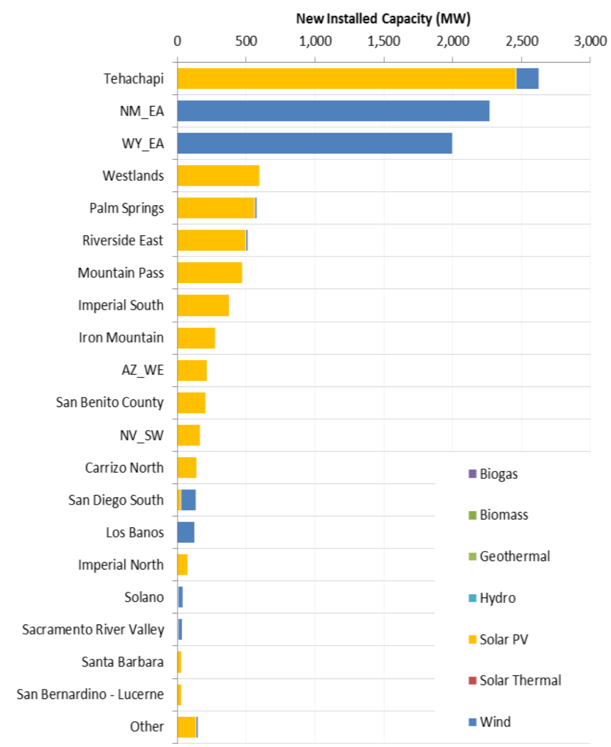
In-state FCDS



In-state EODS



Out-of-state FCDS/EODS



***RPS calculator v6.2 was used to generate the portfolios**

Comparison of 50% RPS portfolios (2015-2016 TPP vs 2016-2017 TPP)

Portfolio	2015-2016 TPP		2016-2017 TPP		
	In-state EODS	Out-of-state EODS	In-state FCDS	In-state EODS	Out-of-state EODS/FCDS
MW Capacity	21,567	19,174	14,842	14,814	11,093

This reduction in portfolio size is a function of several factors including but not limited to:

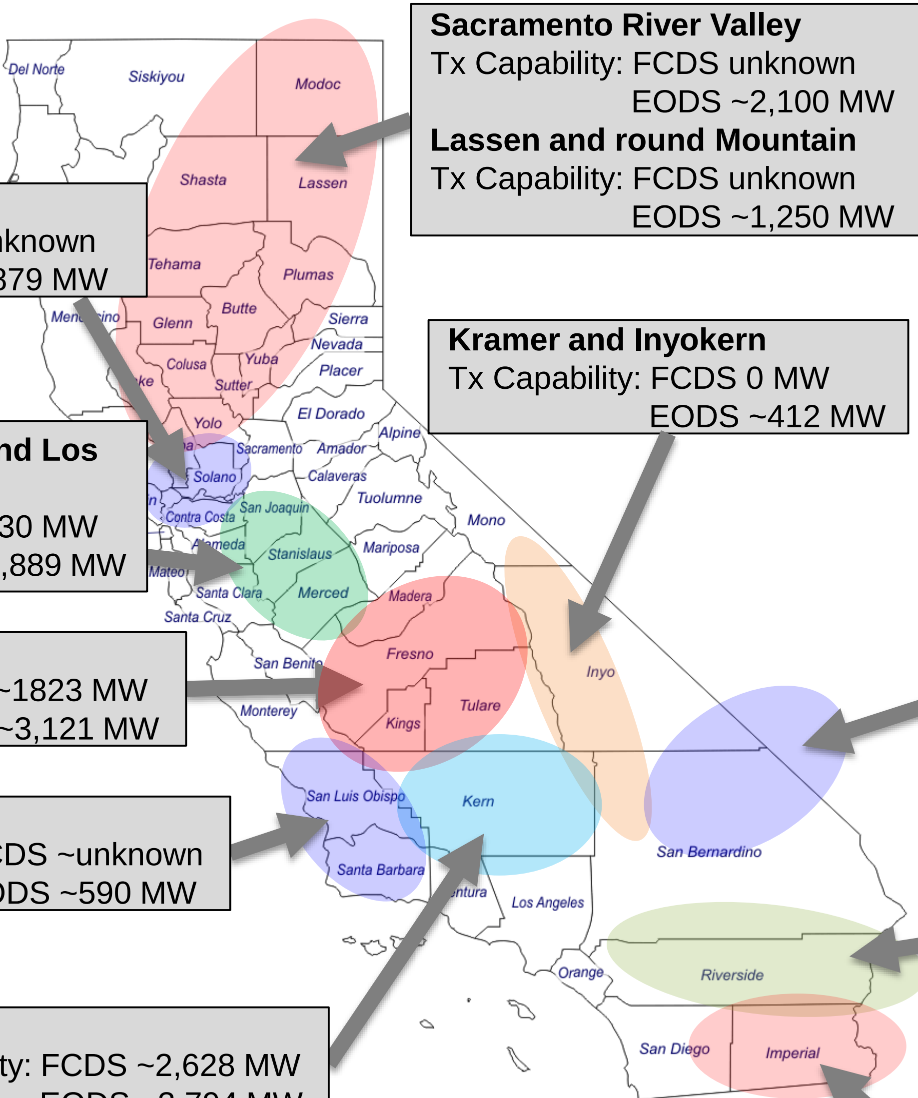
- a lower load forecast was used compared to the one used in 2015-2016 transmission planning process;
- a higher level of behind-the-meter generation was assumed; and
- new renewable generation achieving commercial operation by January 2016 was not included in the new resource portfolios.

Summary of transmission capability estimates and capability utilization in portfolios*

Renewable Zones	Transmission Capability Estimate (MW)		New renewable resources modeled (MW)		
	FCDS	EODS	In-State FCDS	In-State EODS	Out-of-state EODS/FCDS
Central Valley North and Los Banos	130	1,889	130	126	126
El Dorado and Mountain Pass	535	2,735	916	3,177	916
Greater Carrizo	Unknown	590	143	197	143
Greater Imperial	523	1,849	649	379	454
Kramer & Inyokern	0	412	624	211	0
Lassen and Round Mountain	Unknown	1,250	0	1,250	0
Riverside East & Palm Springs	2,450	4,754	2,395	779	1,094
Sacramento River Valley	36	2,099	1,536	2,099	36
Solano	Unknown	879	1,500	348	41
Tehachapi	2,628	3,794	3,625	3,791	2,625
Westlands	1,823	3,121	2,015	1,228	839

*** This table does not include some resources that do not exactly map to the zones considered for estimating transmission capability. So the numbers will not add up to match the exact portfolio amount.**

Initial transmission capability estimates in CA



Sacramento River Valley
Tx Capability: FCDS unknown
EODS ~2,100 MW

Lassen and round Mountain
Tx Capability: FCDS unknown
EODS ~1,250 MW

Solano
Tx Capability: FCDS unknown
EODS ~879 MW

Kramer and Inyokern
Tx Capability: FCDS 0 MW
EODS ~412 MW

Central Valley North and Los Banos
Tx Capability: FCDS ~130 MW
EODS ~1,889 MW

Westlands
Tx Capability: FCDS ~1823 MW
EODS ~3,121 MW

Nevada SW, Mountain Pass and Eldorado
Tx Capability: FCDS ~535 MW
EODS ~2,735 MW

Greater Carrizo
Tx Capability: FCDS ~unknown
EODS ~590 MW

Riverside East and Palm Springs
Tx Capability: FCDS ~523 MW
EODS ~1,849 MW

Tehachapi
Tx Capability: FCDS ~2,628 MW
EODS ~3,794 MW

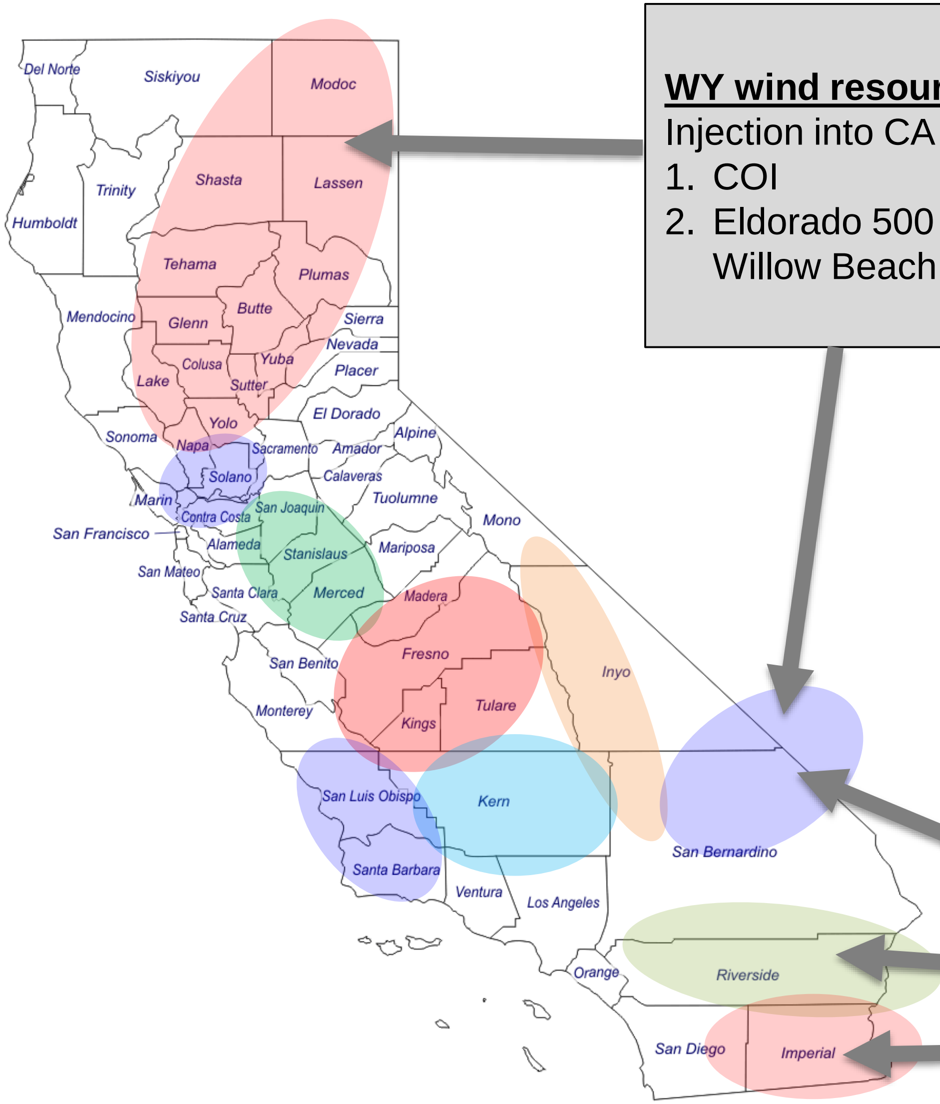
Greater Imperial
Tx Capability: FCDS ~523 MW
EODS ~1,849 MW

Starting estimates used as an input to RPS calculator for generating the 50% portfolios

Assumption: Latent system capacity, conventional generation curtailment, some import reduction, and modest transmission-related renewable curtailment

Note – impacts on the California system of out of state imports were tested by assuming specific injection points into California

Expected injection points from out-of-state resources into CA



<u>WY wind resources (~2,000 MW)</u>

Injection into CA could primarily utilize –

1. COI
2. Eldorado 500 kV, Mead 230 kV and Willow Beach scheduling points

<u>NM wind resources (~2,000 MW)</u>

Injection into CA could primarily utilize –

1. Palo Verde corridor

Out-of-state portfolio assessment – Interregional coordination

- NTTG and WestConnect provided resource location information for ~2,000 MW wind in WY and ~2,000 MW wind in NM
- Out-of-state portfolio models were shared with the western planning regions as part of the interregional coordination work
- CAISO is working with subject matter experts from the other western planning regions on reviewing production simulation results to identify specific stressed system conditions to be considered in the CAISO assessment
- NTTG provided transmission system contingencies to test the impact of the out-of-state portfolio on the affected part of the NTTG area
- CAISO continues to work with WestConnect on identifying certain system contingencies to test the out-of-state portfolio on the affected part of the WestConnect area
  - During 2017 WestConnect will run a “High Renewables” scenario that models a California 50% out-of-state case

Out-of-state portfolio assessment – evaluation of system outside of CA

- Key hours were selected from 2015-2016 TPP production simulation runs to focus on CA imports and CA transmission utilization
- ISO studies indicate consideration of additional hours are needed to account for changing resource assumptions outside of CA
- Additional production simulation modeling is needed to identify transmission constraints outside of CA
- Additional production simulation “hours” that are reflective of the WY and NM regions are needed to test resource delivery from these areas
  - An update will be provided in the February 28 stakeholder meeting

B. RELIABILITY ASSESSMENT

1. Base case assumptions

2. Power flow snapshots identification

3. Northern CA constraints

4. Southern CA constraints

North and South bulk reliability cases were merged to model the 50% portfolio snapshots

- Starting base cases
  - Base cases for the year 2026 developed for 2016-2017 ISO annual reliability assessment were used as a starting point
- Load assumption
  - The study snapshots were identified based on high transmission system usage hours under high renewable dispatch in respective study areas, and the corresponding load levels were modeled.
- Transmission assumption
  - Similar to the ISO Annual Reliability Assessments for NERC Compliance, the 50 percent special study modeled all transmission projects approved by the ISO
- Dispatch assumption
  - Please refer to the next slide (snapshot identification)

Several "powerflow snapshots" were selected based a combination of renewable potential and stressed path flows

GridView Simulations

8760 Hours of production cost simulation results

Subset of hours with the maximum renewable potential (dispatch + curtailment)

Prior study experience and engineering judgement

Within this subset, selected hours with reasonably stressed major path flows

Special considerations e.g. high COI and high WY wind

Scenario	Northern CA	Southern CA
In-state FCDS	None (focus was on deliverability assessment)	March 18 – Hr 13
In-state EODS	March 19 – Hr 19	March 18 – Hr 13
Out-of-state FCDS/EODS	June 15 – Hr 05 (High COI and high WY wind)	November 29 – Hr 12

Summary of Northern CA reliability assessment of 50% portfolios

- In-state EODS portfolio with high wind was the focus (deliverability assessment expected to capture the impact under a daytime snapshot)
- Local overloads in Central Valley area
- Northern CA issues noticed last year were eliminated due to refinements in location selection for resources within those zones
- Transient stability issues due to overvoltage
  - Modeling issues
  - Need for reactive power absorption
- Potential mitigations
  - Local upgrades triggered through GIDAP
  - Pre-contingency redispatch and/or Remedial Action Schemes (RAS)
  - Small amount of pre-contingency curtailment

Comparison with last year's portfolio amounts in Northern CA – significant reduction in a few zones

Zone	2015-2016 TPP		2016-2017 TPP		
	In-state EODS	OOS EODS	In-state FCDS	In-state EODS	OOS
Westlands	894	749	1808	599	599
Sacramento River Valley*	2027	493	1536	2099	36
Solano	1101	1101	1500	348	41
San Benito County	207	207	207	207	207
Carrizo North	182	126	143	197	143
Los Banos	240	240	130	126	126
Lassen North*	1244	268	0	1117	0
Santa Barbara	558	433	0	423	34
Round Mountain - B	133	0	0	133	0

* 2016-2017 50% portfolios did incorporate the recommendations to revisit locational distribution of resources within Northern CA to avoid reliability issues which were noticed last year.

Summary of Southern CA reliability assessment of 50% portfolios

- Issues noticed in Tehachapi, Mountain Pass, Eldorado and VEA areas

- In-state EODS portfolio resulted in the most number of reliability issues

- Potential mitigations
  - Local upgrades triggered through GIDAP
  - Pre-contingency redispatch and/or Remedial Action Schemes (RAS)
  - Curtailment after the first N-1 contingency in case of N-1-1 issues
  - Facility upgrade

Comparison with last year's portfolio amounts in Southern CA – significant reduction in almost all zones

Zone	2015-2016 TPP		2016-2017 TPP		
	In-state EODS	OOS EODS	In-state FCDS	In-state EODS	OOS
Tehachapi	5000	5000	3625	3791	2625
Riverside East	3661	1465	1774	514	514
Palm Springs	1256	1106	621	264	580
Mountain Pass	933	933	475	462	475
NV_SW	#N/A	#N/A	166	2439	166
Iron Mountain	276	276	276	276	276
Inyokern	432	432	0	219	0
Kramer	120	0	441	0	0
Imperial East	1595	303	#N/A	#N/A	#N/A
Imperial South	341	341	406	379	379
San Diego South	622	622	275	139	139

Summary of Southern CA reliability assessment of 50% portfolios – Tehachapi area

Scenario	Limiting Element	Contingency	Type	Overload (%)	Comment
In-State-EODS, In-State-FCDS, OOS	MIDWAY- WIRLWIND 500kV (Path 26)	Base Case	N-0	119%	Series compensation on P26 may need to be revisited. ~1300 MW curtailment needed.
In-State-EODS, In-State-FCDS, OOS	NEENACH - TAP 85 66kV	Base Case	N-0	114%	~900 MW curtailment
In-State-EODS, In-State-FCDS	ANTELOPE- VINCENT 500kV 1	ANTELOPE- VINCENT 500kV 2 & MIDWAY - WIRLWIND 500kV	N-1-1	100.87%	~400 MW curtailment after the first N-1
In-State-EODS, In-State-FCDS	ANTELOPE- VINCENT 500kV 2	ANTELOPE- VINCENT 500kV 1 & MIDWAY - WIRLWIND 500kV	N-1-1	100.91%	
In-State-EODS, In-State-FCDS	ANTELOPE - WIRLWIND 500kV	MIDWAY - WIRLWIND 500kV & WIRLWIND - VINCENT 500kV	N-1-1	122.40%	~1300 MW curtailment after the first N-1
In-State-EODS, In-State-FCDS	ANTELOPE - WIRLWIND 500kV	VINCENT - WIRLWIND 500kV & ANTELOPE - WINDHUB 500kV	N-1-1	130.75%	
In-State-EODS, In-State-FCDS	ANTELOPE - WIRLWIND 500kV	ANTELOPE - WINDHUB 500kV & MIDWAY - WIRLWIND 500kV	N-1-1	131.00%	

Summary of Southern CA reliability assessment of 50% portfolios – Tehachapi area contd.

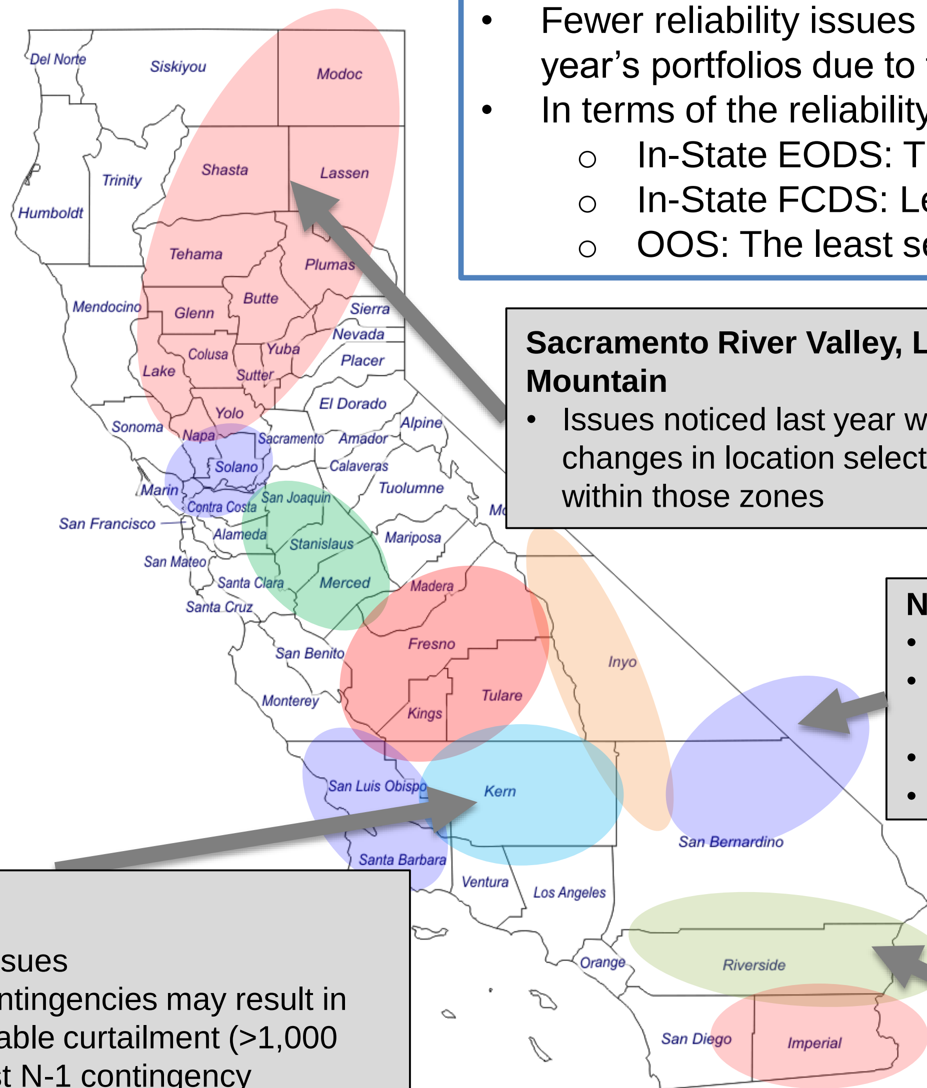
Scenario	Limiting Element	Contingency	Type	Overload (%)	Comment
In-State-EODS, OOS	MAGUNDEN - ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & ANTELOPE - PARDEE 230kV 1	N-1-1	123.50%	~2500MW curtailment after the first N-1 without Big Creek Gen 1150 MW curtailment after the first N-1 with Big Creek.
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & BAILEY - PARDEE 230kV 1	N-1-1	106.10%	~1400-1900 MW curtailment after the first N-1. Pastoria RAS is only effective when PEF Gen is online
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & BAILEY - PASTORIA 230kV 1	N-1-1	107.20%	
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	MAGUNDEN - ANTELOPE 230kV 2 & PARDEE-PASTORIA-WARNETAP 230kV	N-1-1	107.50%	
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	PARDEE - VINCENT 230kV & MAGUNDEN - ANTELOPE 230kV 2	N-1-1	103.50%	
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	MIDWAY - WIRLWIND 500kV & MAGUNDEN - ANTELOPE 230kV 3	N-1-1	101.20%	~400 MW curtailment after the first N-1. SPS not adequate.
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	WIRLWIND - VINCENT 500kV & MAGUNDEN - ANTELOPE 230kV 4	N-1-1	100.50%	
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	ANTELOPE - VINCENT 500kV 1 & MAGUNDEN - ANTELOPE 230kV 5	N-1-1	101.60%	~400 MW curtailment after the first N-1. SPS is adequate.
In-State-EODS	MAGUNDEN - ANTELOPE 230kV 1	ANTELOPE - VINCENT 500kV 2 & MAGUNDEN - ANTELOPE 230kV 5	N-1-1	101.70%	

Summary of Southern CA reliability assessment of 50% portfolios – Mountain Pass, Eldorado and VEA areas

Scenario	Limiting Element	Contingency	Type	Overload (%)	Comment
In-State EODS	Northwest - Mercury Sw 138kV Line	Northwest - Desert View 230kV or Innovation - Desert View 230kV	N-1	146%	Need to add a new RAS to curtail generation at Desert View and Innovation. ~150 MW generation trip.
In-State EODS	Mead - Bob SS 230kV Line	Base Case	N-0	168%	Facility upgrade or N-0 curtailment.
		Northwest - Desert View 230kV Line	N-1	140%	Facility upgrade or N-1 SPS to trip ~600 MW generation or pre-contingency curtailment.
		Ivanpah - Mt Pass 115kV Line	N-1	130%	
In-State & OOS	Mead - Bob SS 230kV Line	Eldorado 500/230kV Bank 5	T-1	344%	Existing Ivanpah RAS not sufficient. Pre-contingency curtailment (~1300 MW)

Reliability impact on CA transmission

- Fewer reliability issues (mostly local) compared to last year's portfolios due to the reduced size of portfolios
- In terms of the reliability impacts on CA transmission –
  - In-State EODS: The most severe
  - In-State FCDS: Less severe
  - OOS: The least severe



Sacramento River Valley, Lassen and round Mountain
- Issues noticed last year were eliminated due to changes in location selection for resources within those zones

Nevada SW, Mountain Pass and Eldorado
- In-State EODS issues
- Issues noticed in Eldorado and VEA system under N-0 and N-1 conditions
- Severe overload in VEA
- May results in curtailment >600 MW

Tehachapi
- In-State EODS issues
- Several N-1-1 contingencies may result in significant renewable curtailment (>1,000 MW) after the first N-1 contingency
- Challenges in taking maintenance outages

Riverside East and Palm Springs
- Issues noticed last year eliminated due to halving of resource amounts in these zones

Summary of reliability assessment of 50% portfolios - adequate interconnection capability

- Fewer reliability issues (mostly local) compared to last year's portfolios due to the reduced size of portfolios
  - In-state EODS portfolio is more severe than In-state FCDS in certain areas
  - OOS portfolio resulted in the least number of reliability issues within CA

- Potential mitigation measures
  - Moderate generation redispatch under N-1 conditions
  - Local upgrades triggered through GIDAP
  - Series compensation balancing on P26 in certain hours
  - Reactive power absorption capability

- In Tehachapi area, several N-1-1 contingencies may result in significant renewable curtailment
  - A potential challenge for taking maintenance outages

C. DELIVERABILITY ASSESSMENT

1. Impact of peak shift on exceedance values assumptions

2. Southern CA deliverability constraints

3. Northern CA deliverability constraints

4. Out-of-state import deliverability evaluation (MIC)

Purpose of the Deliverability Assessment

- Preliminarily evaluate the incremental transmission needs beyond the 33% for the 50% renewable portfolio
- Not intended for making any transmission planning project approval decisions

- ○ The ISO requested information from CPUC to begin consideration of potential adjustments to the input assumptions to the study on a preliminary basis.
- ○ Information was utilized to gain insight into potential adjustments that may be needed to the input assumptions for future deliverability assessments.
- ○ This experimental work was intended to directionally evaluate the incremental transmission needs beyond 33 percent renewable.
- ○ Preliminary information was utilized to explore a preliminary methodology and is not intended to be used for making any transmission planning project approval decisions and is focused only on moving beyond 33 percent RPS to 50 percent RPS.

Key Principles of the Deliverability Assessment Methodology

- Capacity resources within a given sub-area must be exportable to other parts of the Control Area experiencing a resource shortage due to forced generation outages
- Aggregate of generation can be transferred to aggregate of the ISO Control Area Load
- Deliverability is tested under a system condition during which capacity resources are mostly needed

Changes Affecting Deliverability Assessment

- In what hour will the capacity need be the highest?
  - From peak consumption to peak sale due to increased behind-the-meter distributed generation
- How may the wind and solar resources be counted for RA in future?
  - From exceedance value to equivalent load carrying capacity approach

CPUC Provided Load and Renewable Data

- The forecast through 2026 is based on historical weather (35 years), load (5 years), the CEC yearly load forecast and Behind-the-Meter PV (BTMPV) capacity forecasts
- The forecast data includes:
  - Load hourly profile by region
  - BTMPV capacity and hourly output profile by region
  - Wind and solar capacity and output percentile data from May through September every year by region and by technology

CPUC Peak Load Shift Analysis

- Definition of Sale: load consumption minus BTMPV output
- ISO coincident peak sale hour shifts from hour ending 18 in 2025 to hour ending 19 in 2026

Wind and Solar Modeling

- Based on observation and the principles of the deliverability assessment, the exceedance outputs for wind and solar in the 3-hour window around the ISO coincident peak sale was used
- There are two exceedance levels used in deliverability assessment: 50% exceedance and 20% exceedance
- The 50% exceedance level is typically used to access area deliverability issues, while the 20% level is used for smaller local generation pocket issues
- This special study focused on area deliverability issues so wind and solar resources were tested up to their 50% exceedance output

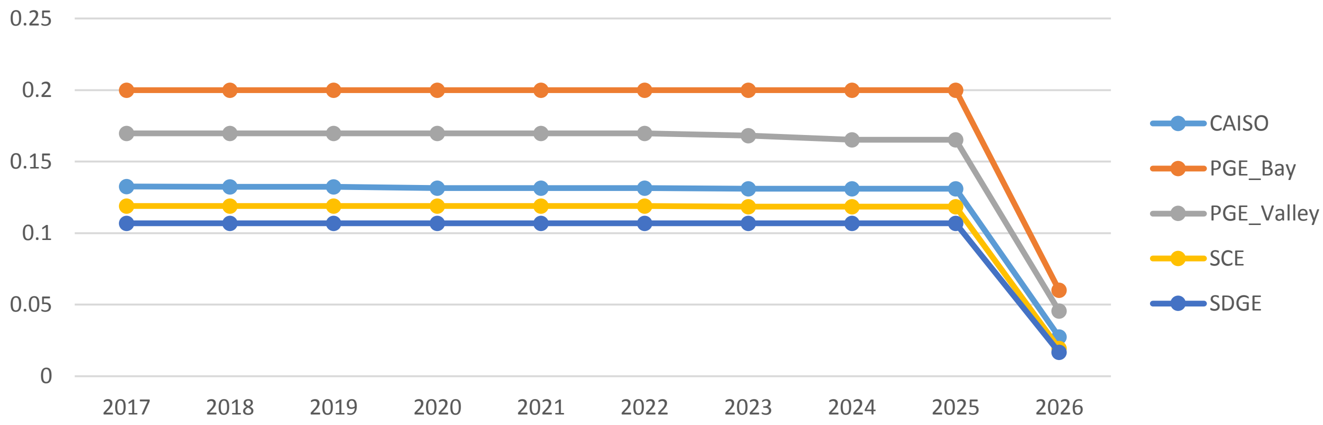
Wind and Solar Modeling (Cont.)

- The 50% exceedance level was applied per region and per technology, i.e. all generators with the same technology in the same region were modeled with the same exceedance factor
- Technology focus
  - PV fixed
  - PV single
  - thermal solar
  - wind
- Regions studied
  - PGE_Bay and PGE_Valley
  - SCE
  - SDGE

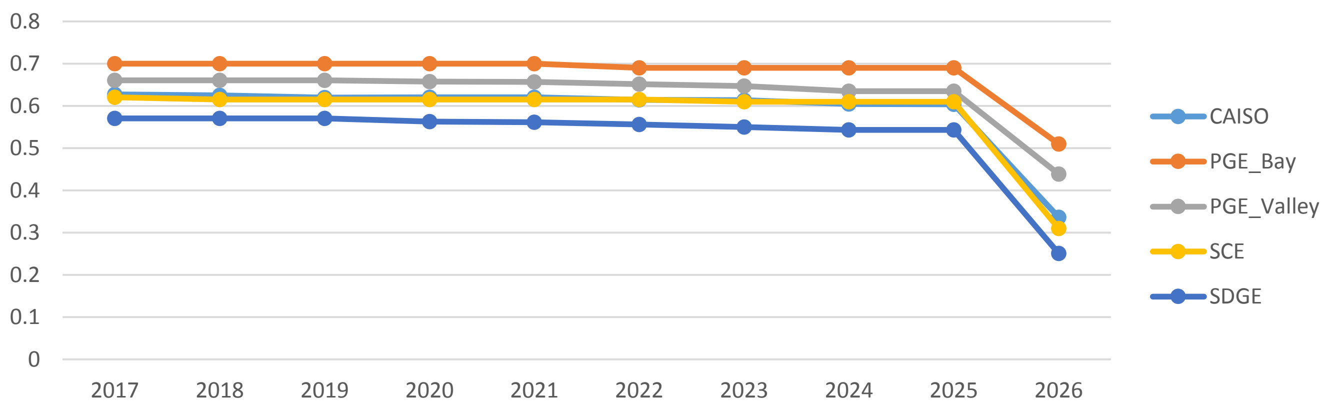
Renewable Outputs around Peak Sale Hour

- Renewable outputs in the 3-hour window around the ISO peak sale hours from 2017 to 2026 were examined
  - 2017 ~ 2025: hour ending 17 to 19
  - 2026: hour ending 18 to 20
- The highest 50% exceedance level was found in the 3-hour window among the monthly value from May to September each year

Wind and Solar 50% Exceedance Levels

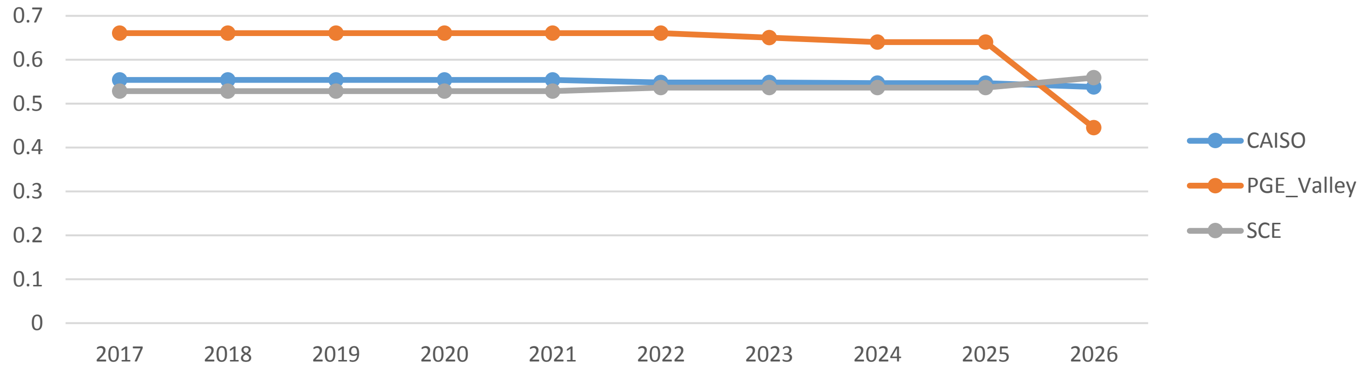


PV Fixed

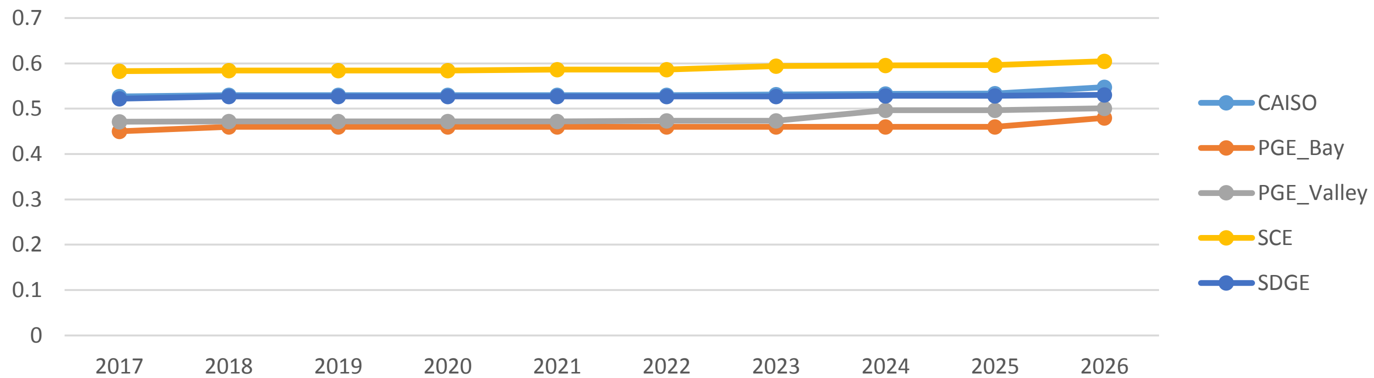


PV Single

Wind and Solar 50% Exceedance Levels



Solar Thermal



Wind

Wind and Solar 50% Exceedance Levels

Year	2025

Max of 50% exceedance	**PGE_Bay**	**PGE_Valley**	**SCE**	**SDGE**
PVFixed	0.20	0.17	0.12	0.11
PVSingle	0.69	0.63	0.61	0.54
SlrThrml		0.64	0.54	
Wind	0.46	0.50	0.60	0.53

Year	2026

Max of 50% exceedance	**PGE_Bay**	**PGE_Valley**	**SCE**	**SDGE**
PVFixed	0.06	0.05	0.02	0.02
PVSingle	0.51	0.44	0.31	0.25
SlrThrml		0.45	0.56	
Wind	0.48	0.50	0.60	0.53

Comparison of Wind and Solar Exceedance Factors

- The 50% exceedance factors compared to what are being used currently in ISO generation interconnection studies and NQC studies

Area	Technology	Current	2025	2026
PG&E	Wind	32% / 37% / 47%	46% / 50%	48% / 50%
	PV Single	92%	63% / 69%	44% / 51%
SCE	Wind	38% / 47%	60%	60%
	PV Single	92% / 93%	61%	31%
SDG&E	Wind	37%	53%	53%
	PV Single	87%	54%	25%

  – Current: exceedance factors based on 1 pm to 6 pm summer month production
  – 2025 and 2026: exceedance factors based on 3-hr window around peak sale hour

Highest Renewable Deliverability Needs through 2026

- Used {the installed capacity x the 50% exceedance factor} as the indication of deliverability need and compared the need through 2026
- The highest ISO renewable deliverability need occurred in 2025
  - In 2026, although the installed renewable capacity is higher than 2025, the total output was lower due to one hour shift of the peak sale
- The highest southern California need occurred in 2025, while the highest northern California need occurred in 2026

Study Scenarios

- 50% renewable study assumptions
  - Achievable in 2030
  - Wind and solar exceedance factor data only available until 2026
- Southern California 41.5% renewable study assumptions
  - Achievable in 2025
  - 2025 wind and solar exceedance factors

Overview of major renewable zones that impact Southern CA

Renewable Zone	In-State FCDS Portfolio MW
Tehachapi	3,635
Riverside East	1,774
Palm Springs	621
Mountain Pass	475
NV_SW	166
Kramer	441
Victorville	183
Iron Mountain	276
Imperial South	406
Imperial North	244
San Diego South	275
AZ_WE	219
NM_EA	272
Total	**8,987**

Deliverability Assessment Results – SCE and VEA Areas

Contingency	Overloaded Facility	Flow & Undeliverable MW		Affected CREZ
		50% renewable with 2026 Factor	**41.5% renewable with 2025 Factor**	
McCullough - Victorville 500kV No. 1 & No. 2	Adelanto - Market Place 500KV	100.85% ~400 MW	101.96% ~850 MW	Arizona, Imperial, Riverside East, Mountain Pass, Nevada C
Coachella - Mirage 230kV & Ramon - Mirage 230kV with RAS	El Centro - IV 230kV	100.77%	<100%	Riverside East (Blythe 161kV), Imperial

Deliverability Assessment Results – SDGE Area

Contingency	Overloaded Facility	Flow & Undeliverable MW		Affected CREZ
		50% renewable with 2026 Factor	41.5% renewable with 2025 Factor	
Imperial Valley-North Gila 500 kV line	Imperial Valley-El Centro 230 kV line	106% ~150 MW	100%	Imperial - IID
Miguel 500/230 kV #1	Miguel 500/230 kV #2		103% (mitigation is SPS and/or 30min rating)	Arizona, Baja, Imperial
Miguel 500/230 kV #2	Miguel 500/230 kV #1		105%(mitigation is SPS and/or 30min rating)	Arizona, Baja, Imperial

Overview of major renewable zones that impact PG&E Area

Renewable Zone	In-State FCDS Portfolio MW
Sacramento River valley	1,536
Solano	1,500
Distributed Generation – Humboldt	6
Distributed Generation – North Coast / North Bay	96
Distributed Generation – North Valley	10
Distributed Generation – Greater Bay Area	6
Distributed Generation – Central Valley	14
Westlands	1,823
Los Banos	130
Carizzo	143
Total	**5,264**

Deliverability Assessment Results – Sacramento River valley CREZ

Sacramento River Valley CREZ	
Total 50% Renewable MW in CREZ	1536 MW
Total 50% Renewable MW not behind any constraint	637 MW

Constraints Affecting 50% Renewables in Sacramento River Valley CREZ			
Overloaded Facility	**Contingency**	**Flow**	**50% Renewable Affected**
Cortina - Vaca 230 kV Line	Delevan-Vaca Dixon No.2 and No.3 230 kV Lines	102%	1082 MW
Cortina 230/115/60 kV Transformer No. 1	Cortina 230/115 kV transformer #4	149%	482 MW
Fulton - Hopland 60 kV (Hopland Jct 60 kV to Cloverdale Jct 60 kV)	Geysers #17-Fulton and Eagle Rock-Fulton-Silverado 115 kV Lines	125%	56 MW

Deliverability Assessment Results – Deliverability Assessment Results – Solano CREZ

Solano CREZ	
Total 50% Renewable MW in CREZ	1500 MW
Total 50% Renewable MW not behind any constraint	1236 MW

Constraints Affecting 50% Renewables in Solano CREZ			
Overloaded Facility	**Contingency**	**Flow**	**50% Renewable Affected**
Las Positas-Newark 230kV Line	Contra Costa – Moraga #1 & #2 230 kV lines	105%	128 MW

Deliverability Assessment Results – Distributed Generation – Humboldt

Distributed Generation – Humboldt	
Total 50% Renewable MW in CREZ	6 MW
Total 50% Renewable MW not behind any constraint	0 MW

Constraints Affecting 50% Renewables in Distributed Generation – Humboldt			
Overloaded Facility	**Contingency**	**Flow**	**50% Renewable Affected**
Trinity-Keswick 60 kV Line	Trinity-Cottonwood 115kV line	102%	6 MW

Deliverability Assessment Results – Distributed Generation – North Coast / North Bay

Distributed Generation – North Coast / North Bay	
Total 50% Renewable MW in CREZ	96 MW
Total 50% Renewable MW not behind any constraint	62 MW

Constraints Affecting 50% Renewables in Distributed Generation – NCNB			
Overloaded Facility	**Contingency**	**Flow**	**50% Renewable Affected**
Fulton - Hopland 60 kV (Hopland Jct 60 kV to Cloverdale Jct 60 kV)	Geysers #17-Fulton and Eagle Rock-Fulton-Silverado 115 kV Lines	125%	56 MW

Deliverability Assessment Results – Distributed Generation – North Valley

Distributed Generation – North Valley	
Total 50% Renewable MW in CREZ	10 MW
Total 50% Renewable MW not behind any constraint	0 MW

Constraints Affecting 50% Renewables in Distributed Generation – North Valley			
Overloaded Facility	**Contingency**	**Flow**	**50% Renewable Affected**
Cortina - Vaca 230 kV Line	Delevan-Vaca Dixon No.2 and No.3 230 kV Lines	102%	1082 MW

Deliverability Assessment Results – Distributed Generation – Greater Bay Area

Distributed Generation – Greater Bay Area	
Total 50% Renewable MW in CREZ	6 MW
Total 50% Renewable MW not behind any constraint	5 MW

Constraints Affecting 50% Renewables in Distributed Generation – Greater Bay Area			
Overloaded Facility	**Contingency**	**Flow**	**50% Renewable Affected**
Las Positas-Newark 230kV Line	Contra Costa – Moraga #1 & #2 230 kV lines	105%	128 MW

Deliverability Assessment Results – Westlands CREZ

Westlands CREZ	
Total 50% Renewable MW in CREZ	1823 MW
Total 50% Renewable MW not behind any constraint	1614 MW

Constraints Affecting 50% Renewables in Westlands CREZ			
Overloaded Facility	Contingency	Flow	50% Renewable Affected
Shepherd-E2 115 kV Line	P7-GREGG-E1_PGE #1 230kV & GREGG-E1_PGE #2 230kV Lines	122%	2.5 MW
Oxford-Oxford Jct 115kV Line	Base Case Overload	185%	207 MW

Out-of-state import deliverability evaluation (MIC)

- Evaluated whether MIC expansion is needed for out-of-state renewables
- Large amount of wind resources in NM and WY
- Sufficient import capacity for NM and WY wind resources

	NM	WY
50% exceedance factor	40.27%	40.76%
Wind Capacity	2200	2000
MIC Need	885.94	815.20
Scheduling Point	PVWEST	ELDORADO500 & MEAD230 & WILLOWBEACH
Remaining Import Capacity after ETC and Pre-RA in 2026	1821	925
MIC Expansion	0	0
Current MIC	3254	1753
Total Target MIC	3254	1753

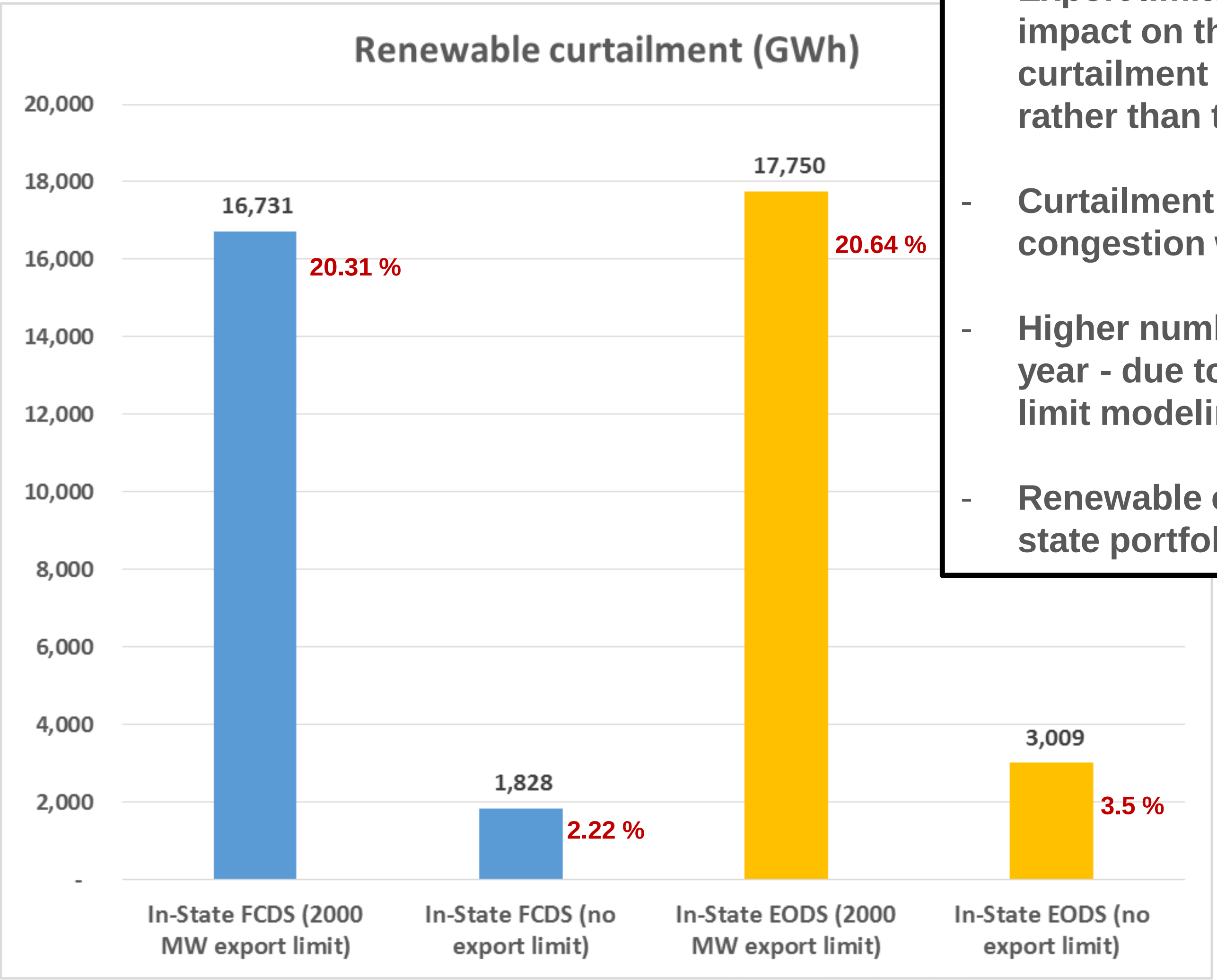
D. RENEWABLE CURTAILMENT AND CONGESTION

- Total renewable curtailment by portfolio and export assumption

- Renewable curtailment by zone

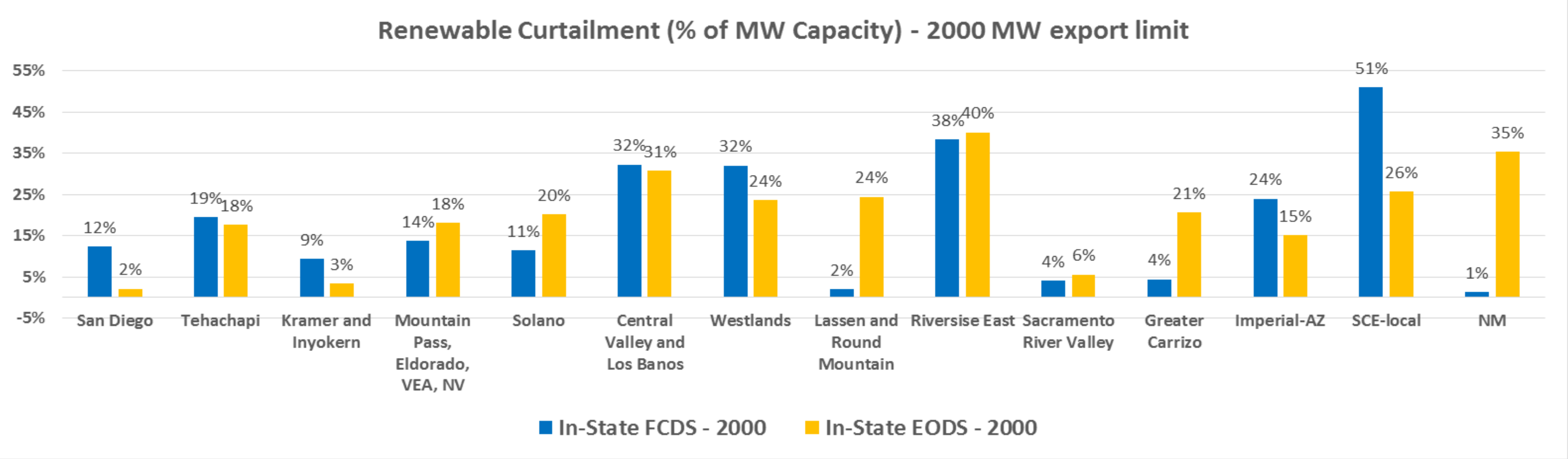
- Summary of transmission constraints causing congestion

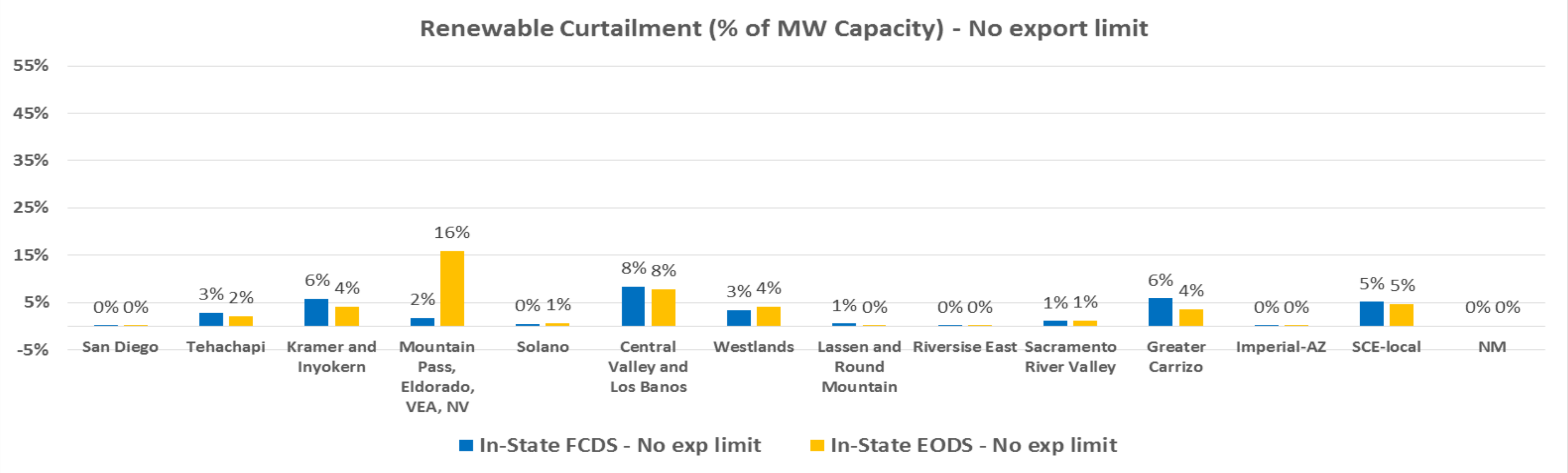
Total renewable curtailment by portfolio



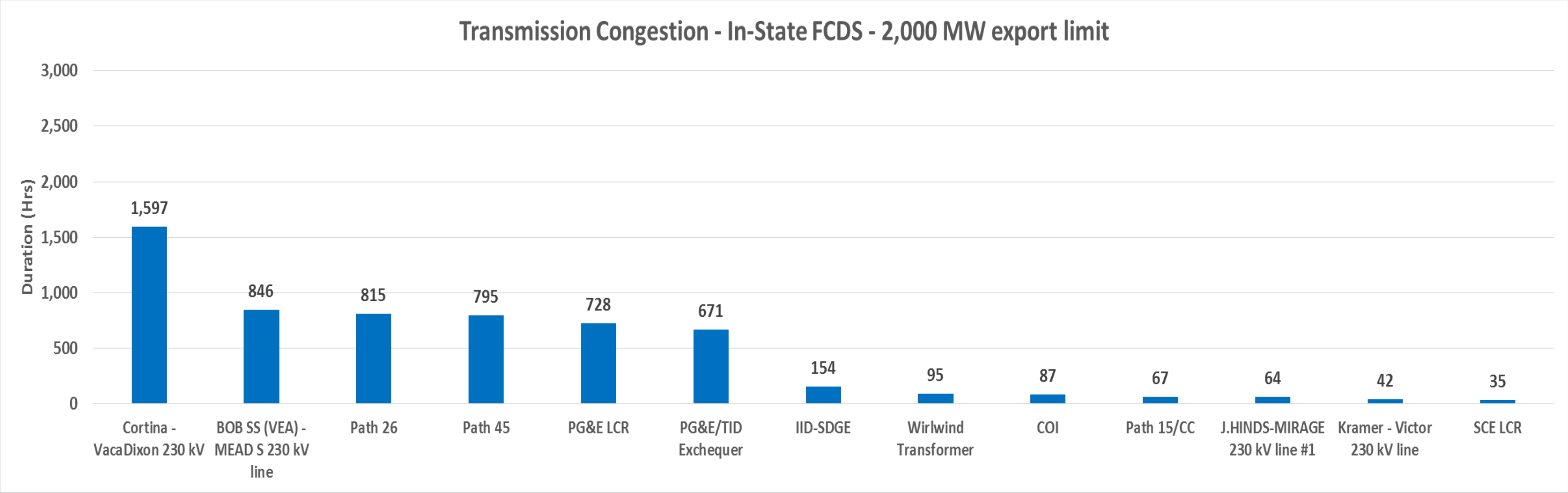
- **Export limits had a significant impact on the amount of renewable curtailment – over-supply related rather than transmission related**
- **Curtailment due to transmission congestion was modest**
- **Higher numbers compared to last year - due to enhanced ISO export limit modeling**
- **Renewable curtailment in out-of-state portfolio is yet to be analyzed**

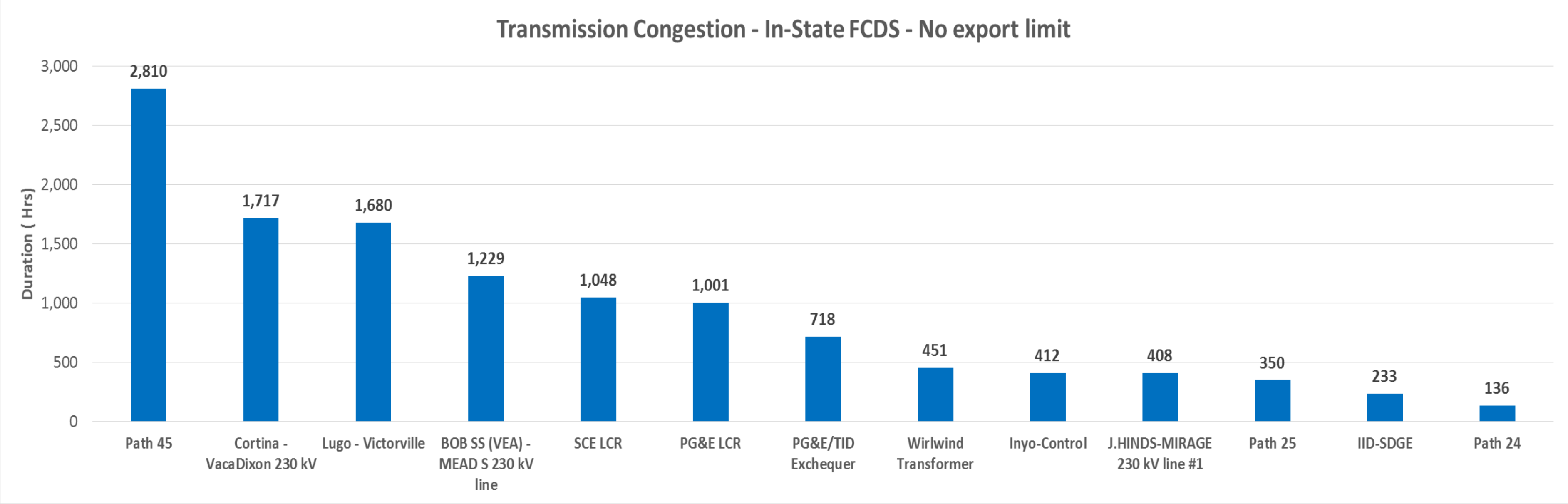
Renewable curtailment by zones ("No export limit" scenarios could be proxies for transmission-related curtailment)



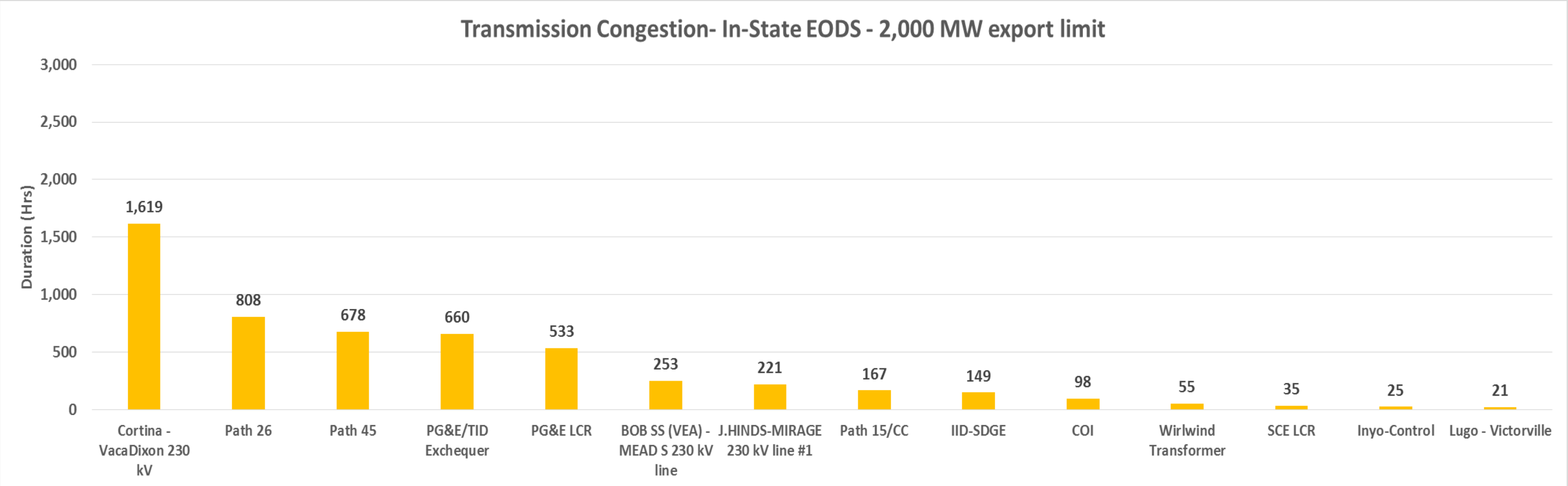


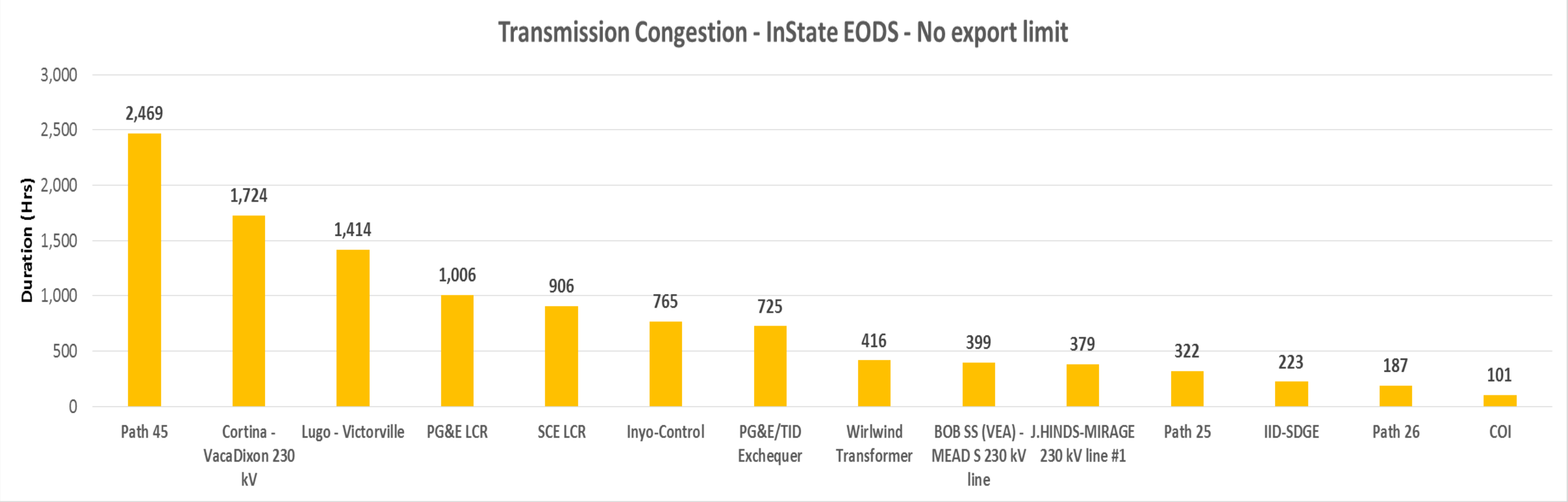
In-State FCDS portfolio showed higher level of congestion within CA as the export constraint was relaxed





Similarly, the In-State EODS portfolio resulted in more congestion within CA as export constraint was relaxed





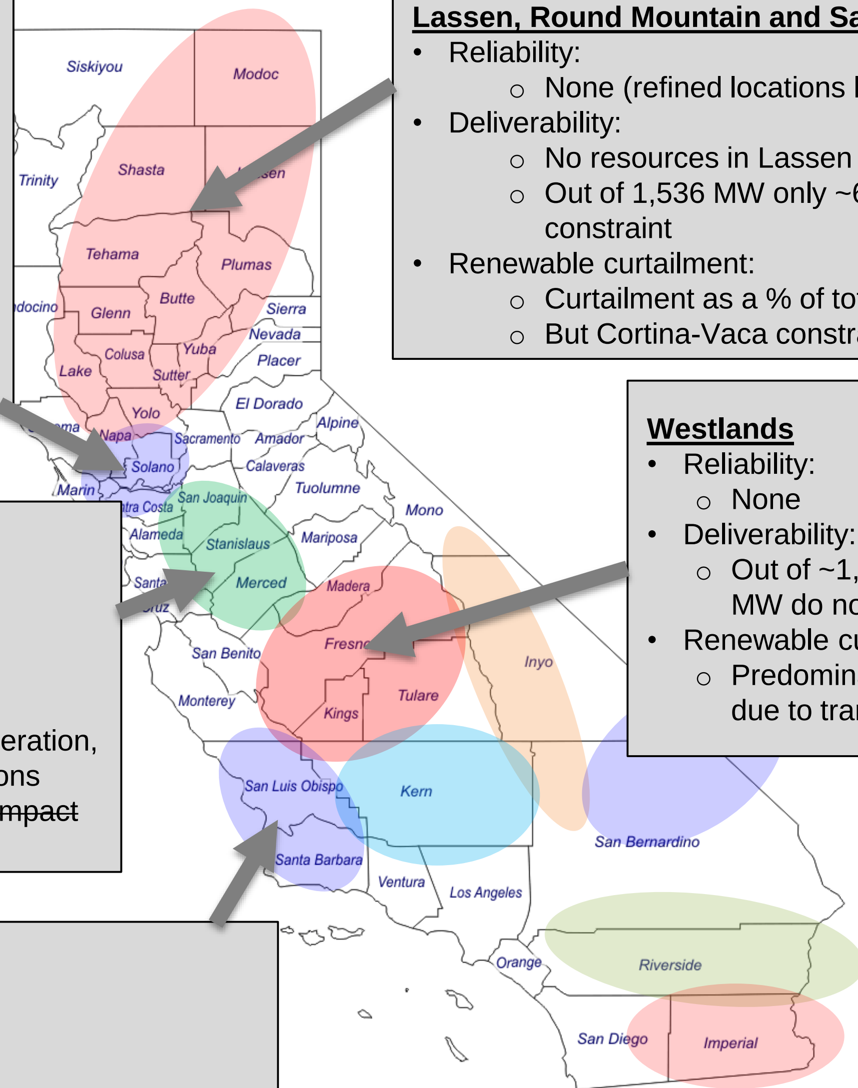
E. SUMMARY OF CONCLUSIONS AND NEXT STEPS

- Summary of constraints by area
  - Reliability
  - Deliverability
  - Curtailment
- Updated transmission capability estimates
- Next steps

Summary of In-State portfolio assessment – Northern CA

Solano
- Reliability:
  - None
- Deliverability:
  - Out of 1,500 MW, approximately 1,200 MW do not contribute to a constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Lassen, Round Mountain and Sac River Valley
- Reliability:
  - None (refined locations last year)
- Deliverability:
  - No resources in Lassen and Rnd Mtn
  - Out of 1,536 MW only ~600 MW do not contribute to a constraint
- Renewable curtailment:
  - Curtailment as a % of total capacity is minor
  - But Cortina-Vaca constraint could be an expensive one

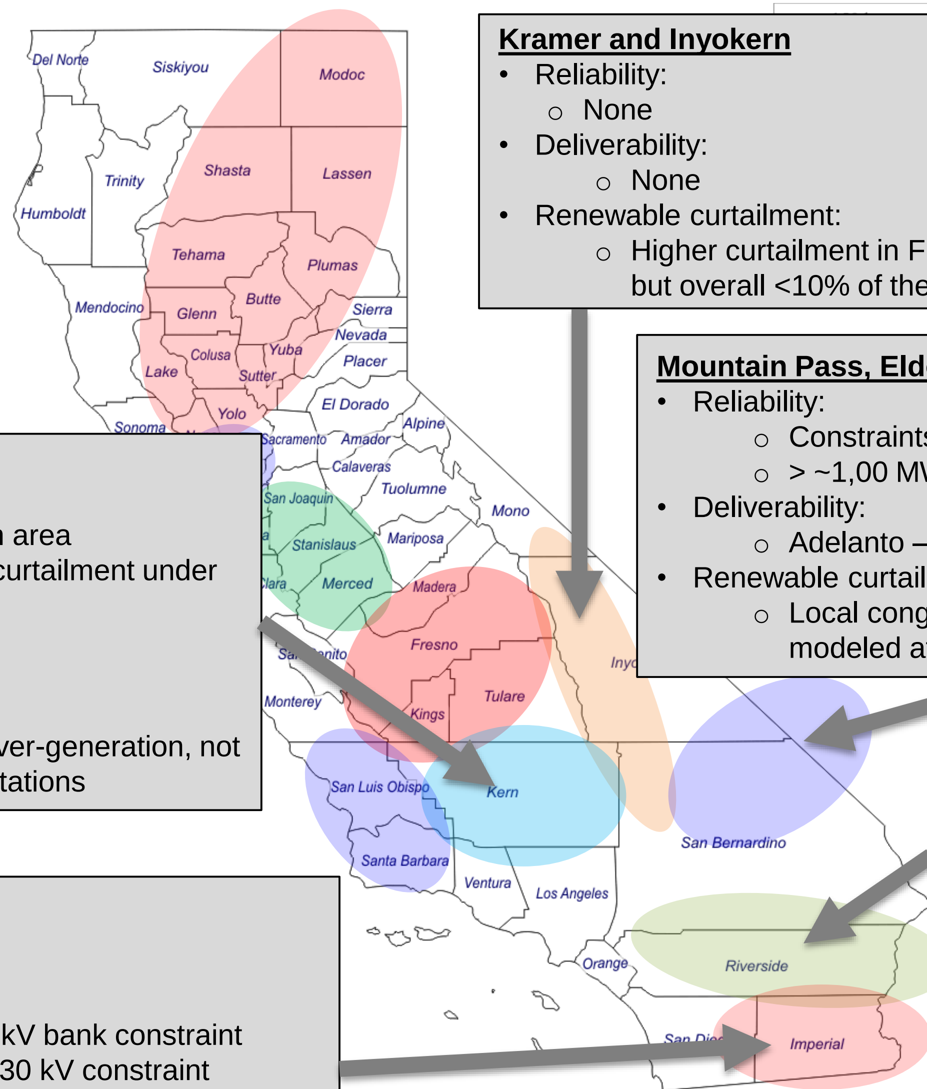


Westlands
- Reliability:
  - None
- Deliverability:
  - Out of ~1,823 MW, approximately 1,600 MW do not contribute to a constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations (~8%)

Cantal Valley and Los Banos
- Reliability:
  - None
- Deliverability:
  - None
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations
  - ~~Cortina-Vaca constraint could impact some generation in this area~~

Greater Carrizo
- Reliability:
  - None
- Deliverability:
  - None
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations
  - Mainly in EODS portfolio

Summary of In-State portfolio assessment – Southern CA



Kramer and Inyokern
- Reliability:
  - None
- Deliverability:
  - None
- Renewable curtailment:
  - Higher curtailment in FCDS portfolio, but overall <10% of the capacity

Mountain Pass, Eldorado, VEA and Southwestern NV
- Reliability:
  - Constraints in VEA and East of Pisgah area
  - > ~1,00 MW curtailment may be needed
- Deliverability:
  - Adelanto – Marketplace 500 kV N-2 constraint
- Renewable curtailment:
  - Local congestion due to large resources modeled at Merchant 230 kV on EODS portfolio

Tehachapi
- Reliability:
  - Overloads in Magunden area
  - More than ~1,900 MW curtailment under N-1-1
- Deliverability:
  - None
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Riverside East and Palm Springs
- Reliability:
  - None (refined locations last year)
- Deliverability:
  - IV – El Centro 230 kV constraint
  - Adelanto – Marketplace 500 kV N-2 constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Greater Imperial
- Reliability:
  - None
- Deliverability:
  - Miguel 230/500 kV bank constraint
  - IV – El Centro 230 kV constraint
  - Adelanto – Marketplace 500 kV N-2 constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Summary of conclusions

Assessment	Key Takeaways		
	In-state FCDS	**In-state EO**	**Out-of-state**
Reliability assessment	• Fewer reliability issues because portfolio resource amounts in most of the zones were less than the amounts at which transmission constraints were expected.	• Tehachapi, Mountain Pass and Eldorado, VEA and Nevada SW zones may experience pre-contingency curtailment under certain scenarios	• The least severe portfolio in terms of reliability issues on CA transmission system • Studies indicate the need for considering different snapshots that take into account the changing resource assumptions outside of CA
Deliverability assessment	• In Northern CA, Solano, Sacramento River Valley and Westlands zones experienced deliverability constraints • In Southern CA, area-wide constraints would limit delivery or resources from Eldorado and Mountain Pass, VEA, Southwestern NV, Riverside East and Greater Imperial zones • There were no transmission capability estimates to start with in some Northern CA zones. These can now be established.	N/A	• Sufficient import capacity exists to delivery out-of-state resources from a scheduling point within CAISO BA to CAISO loads • Deliverability of out-of-state resources upto the CAISO scheduling point was not tested
Renewable curtailment	• Export limits had a significant impact on the amount of renewable curtailment – over-supply related rather than transmission related • More renewable curtailment observed in EODS portfolio than FCDS portfolio • Curtailment due to CA transmission congestion was modest but it did increase with relaxation of export constraint		• Additional production simulation modeling is needed to identify transmission constraints outside of CA

Next steps

- CAISO will work with the CPUC and the CEC to incorporate the findings and conclusions into future portfolio development
- Out-of-state portfolio assessment
  - Additional production cost analysis is needed to assess transmission constraints outside of CA that result from WY and NM energy delivery to CA
  - An update on this portfolio assessment will be provided in the February 28 stakeholder meeting
- Potential assessments in 2017-2018 TPP
  - Out-of-state scenarios based on updated assumptions
  - Coordination with western planning regions on ITP evaluation
  - Further work on deliverability assumptions

Special Study : Risks of Early Economic Retirement of Gas-Fired Generation

Abhishek Singh
David Le
Shucheng Liu
2016-2017 Transmission Planning Process Stakeholder Meeting
February 17, 2017

Overview

- Background Information
- Study scope
- Methodology & different retirement scenarios
  - Scenario 1
  - Scenario 2
  - ZP 26(Midway) gas generation sensitivity
  - Summary of retirement scenarios
- Northern and Central California bulk system impact assessment
  - Production cost results for different scenarios
  - PG&E bulk system impact assessment (ZP 26 gas generation sensitivity only)
- Southern California bulk system impact assessment
- Potential impact on system level requirements

Background Information

- There is potential for an economic early retirement of gas generation due to the increasing levels of renewable generation interconnecting to the electrical grid.
- The study scope and methodology were presented at the ISO 2016-2017 transmission planning process second stakeholder meeting on September 21-22, 2016
  - https://www.caiso.com/Documents/Day2Presentation-2016-2017TransmissionPlanningProcess-PreliminaryReliabilityResults.pdf
- Preliminary screening methodology to identify areas of potential early retirement using the ISO's 2016-2017 production cost models (PCM) with 50% renewable portfolios was also presented.

Study Scope

- Identify the incremental path flow impacts (congestion from PCM) of the retirement scenarios on California transfer paths.
- Identify high level potential path flow impacts on the California transfer paths and the associated RAS (IRAS) using power flow analysis.
- Identify potential system level impacts on ancillary services and flexibility requirements.

Methodology and Resulting Scenarios

Methodology

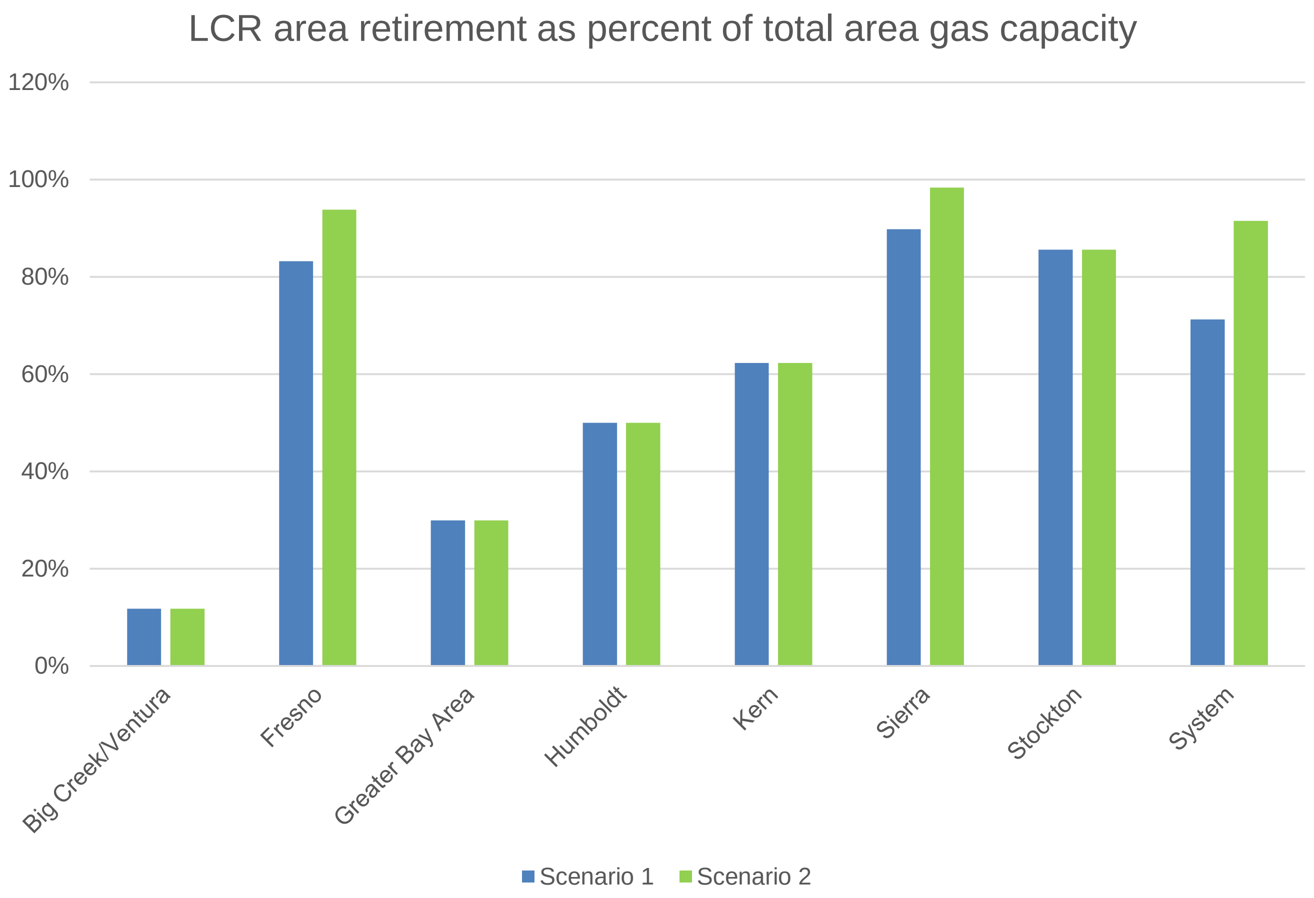
- Criteria
  - Capacity factor below typical historical values, and
  - Generation resources not required to meet Local Capacity Requirement (LCR)
- LCR Information
  - 2020 LCR for PG&E areas
  - 2025 LCR for SCE and SDG&E areas
- LCR generators were selected up to the LCR need based upon the capacity factors in the preliminary production cost modeling screening (Scenario 1)

Methodology and Resulting Scenarios

Methodology –Continued

- A second set of generators (incremental to scenario 1) to meet LCR need that could replace system generators with similar technical specifications was also selected (Scenario 2)
- A smaller set(compared to scenario 1 & 2) of gas fired generators close to Midway area (part of the IRAS scheme) was also selected (ZP 26 gas generation sensitivity)

Methodology and Resulting Scenarios



Total Expected Retirement

Scenario 1= 8265 MW

Scenario 2= 9658 MW

Northern and Central California bulk system impact assessment

Northern and Central California bulk system impact assessment

Production cost results for different scenarios

- Bidirectional congestion duration in Hours on major northern & central California transfer paths.

Total Congestion Costs -Hours				
Transfer Paths	50 Percent Instate FC Portfolio	Scenario 1	Scenario 2	ZP 26 Scenario
COI	87	73	76	36
Path 15	67	31	29	33
Path 26	815	1881	1860	1829

Northern and Central California bulk system impact assessment

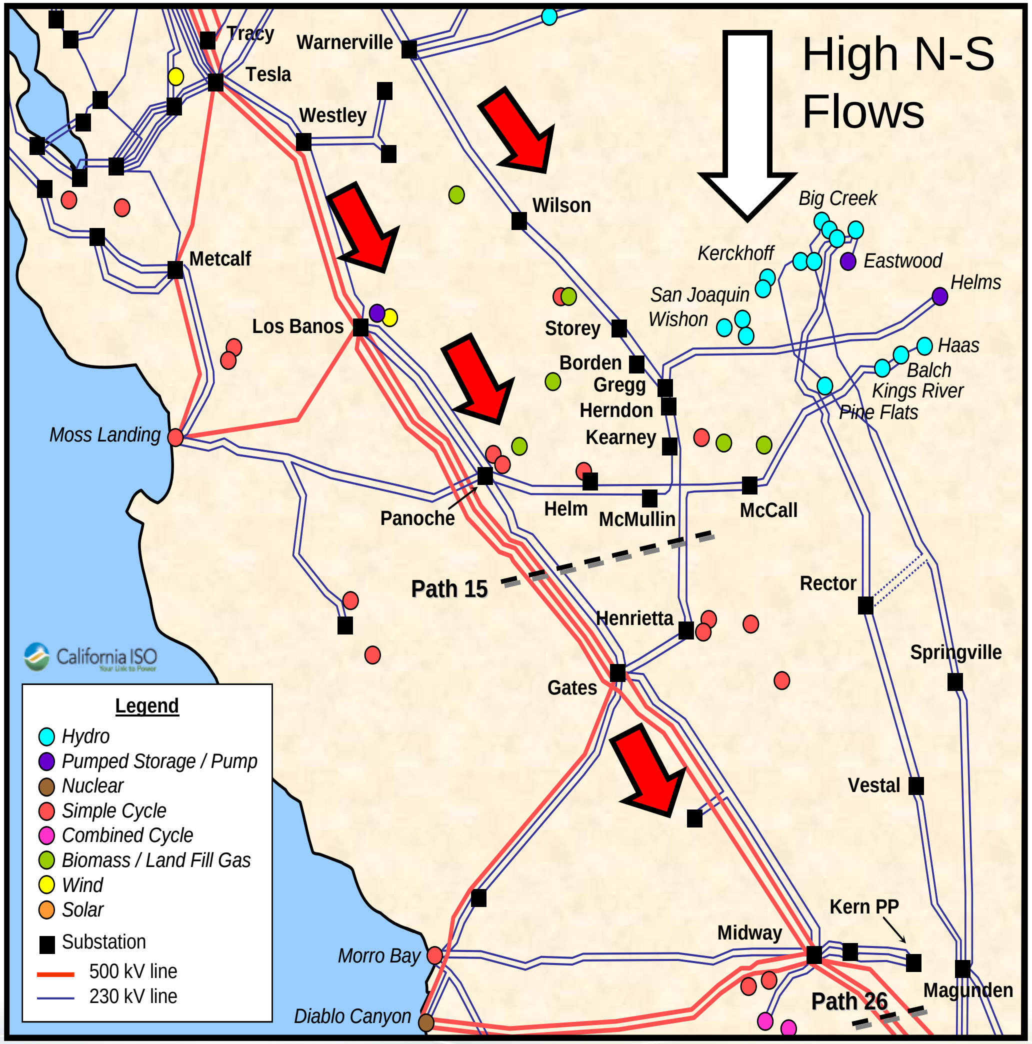
PG&E bulk system impact assessment (ZP 26 gas generation sensitivity only)

- Midway generation retirement scenario only for the following transfer path flows :
  - High South to North
  - High North to South

  High level impacts were assessed on path transfers and existing IRAS scheme.

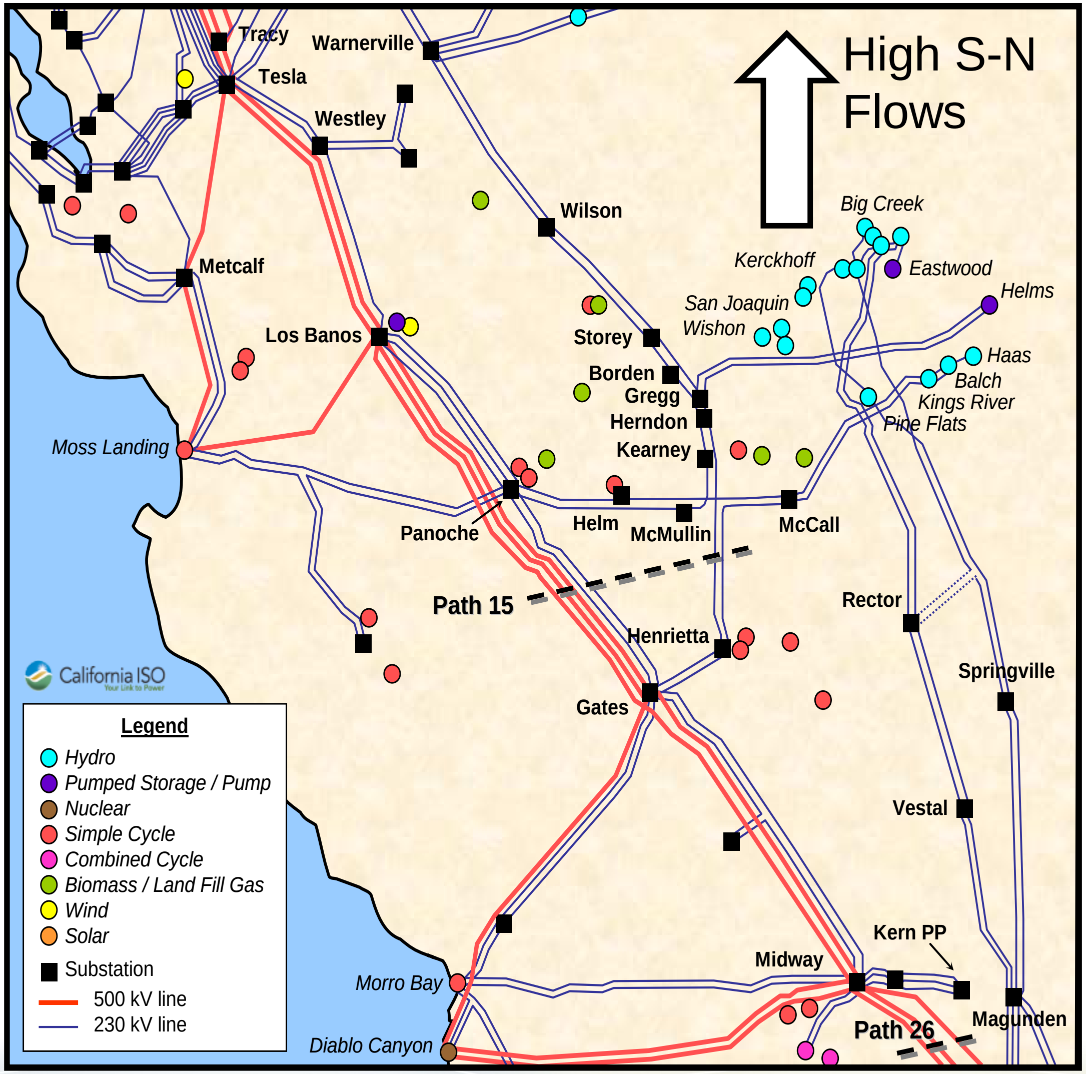
Northern and Central California bulk system impact assessment

- High North to South flows during off-peak load conditions in California.
- Midway retirement scenario resulted in reduced Path 26 flows and required increasing flows North of Midway to achieve pre Midway retirement Path 26 flows.
- IRAS generation arming could potentially require arming higher amount of PG&E north generators for this snapshot.



Northern and Central California bulk system impact assessment

- High South to North flows during off-peak load conditions in California.
- Path 15 flows reduced substantially (~2500 MW) due to Midway generation retirement.
- Path 15 flows could not be stressed further due to limitation of the snapshot. (Load, generation dispatch and P26 at 3000 MW)



Southern California bulk system impact assessment

David Le
Senior Advisor, Regional Transmission Engineer
Regional Transmission South

Screening results for potential economic driven generation retirement in southern California

Area	Sub-area	Number of Units	Type of Generating Units	Maximum Capacity (MW)	Notes
LA Basin	Eastern LA Basin	6	Combustion Turbines	125	Screening results
System	N/A	N/A	Combined Cycle	560	Screening results
System	N/A	N/A	Combined Cycle	830	Supplemental to the screening list due to generation owner expressing long-term viability concerns
LA Basin	Eastern LA Basin	2	Combustion Turbines	89	Supplemental to the screening list due to remaining peaking units located at the same site of the unit assumed to be impacted in the screening assessment
Total				1,604	

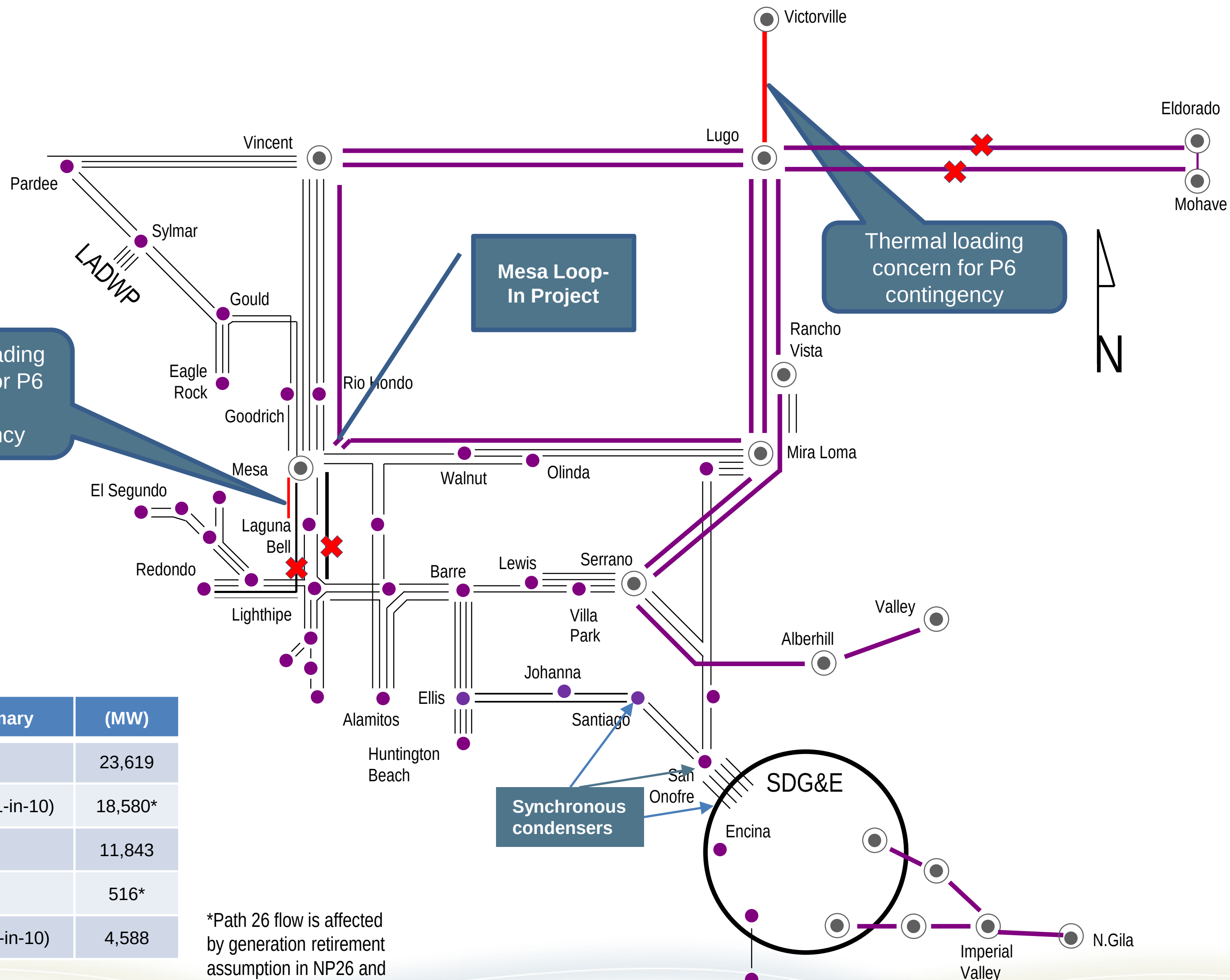
Reliability assessment results for southern California

- The ISO modeled the potential economic driven generation retirement in the power flow study to evaluate potential reliability impact to southern California transmission system
- A 50% RPS in-state full capacity delivery service portfolio study case was prepared for the starting study case
- ISO-Board approved transmission upgrades, as well as CPUC-approved long-term procurement plan for local capacity requirement in the LA Basin and San Diego, are assumed implemented for the retirement of once-through-cooled generation and SONGS
- The reliability assessment identified two potential reliability concerns with solutions discussed in previous transmission planning assessments:

Reliability assessment results for southern California

- Thermal loading concerns on the Lugo – Victorville 500 kV line due to overlapping P6 (N-1-1) contingency (Lugo – Mohave & Eldorado – Lugo 500 kV lines)
  - The ISO identified upgrades for the Lugo – Victorville 500 kV line(currently under development by both SCE and LADWP)
- Potential thermal loading concerns on the south of Mesa 230 kV line (i.e., Mesa – Laguna Bell 230 kV line) due to overlapping P6 (N-1-1) contingency (Mesa – Lighthipe & Mesa – Redondo 230 kV)
  - The thermal loading concern could be mitigated by utilizing an existing 321 MW of 20-minute “fast” demand response in the LA Basin, or
  - Installing a small line series reactor (1 – 2 Ω) on the Mesa – Laguna Bell 230 kV line

Identified transmission reliability concerns



Load / Flow Summary	(MW)
Total SCE load	23,619
Total LA Basin load (1-in-10)	18,580*
Total SCIT	11,843
Path 26 Flow	516*
Total SDG&E load (1-in-10)	4,588

*Path 26 flow is affected by generation retirement assumption in NP26 and ZP26

Summary of Findings

- The following are the potential impacts due to economic driven gas-fired generation retirement:
  - Lower Path 26 (PG&E – SCE) flow due to potential generation retirement in NP26 and ZP26
  - Potential thermal loading concerns for a 230 kV line under overlapping P6 contingency condition in the LA Basin
    - Utilization of the existing “fast” (i.e., 20-minute) demand response, or a small transmission upgrade (i.e., line series reactors), can mitigate this concern
  - Potential thermal loading concerns on a previously identified 500 kV line connecting LADWP and ISO Balancing Authority Area under contingency condition
    - Previously identified transmission upgrades for LADWP and SCE-owned facilities can mitigate this loading concern; LADWP and SCE are in the process of developing the details for the upgrades.

Potential Impact on system level requirements

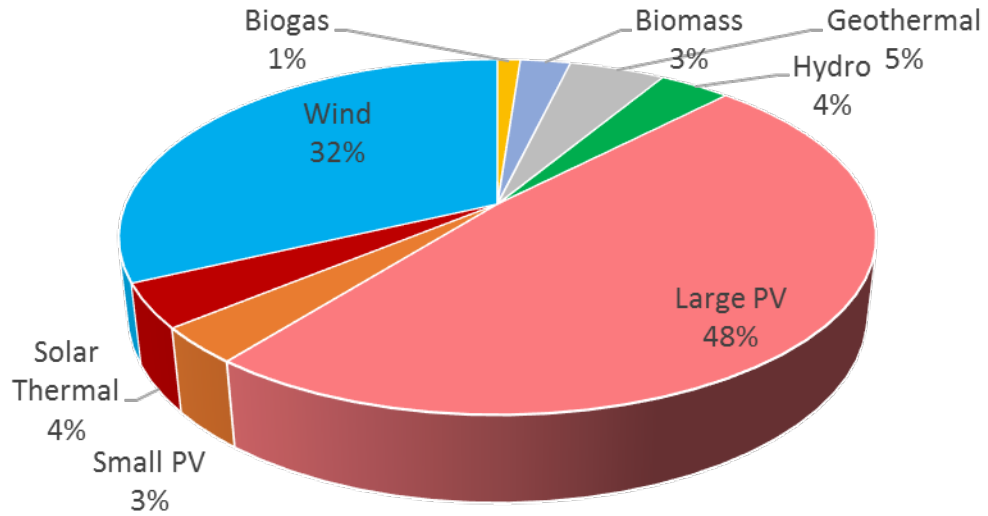
Shucheng Liu, Ph.D.
Principal, Market Development

Load forecast and adjustments

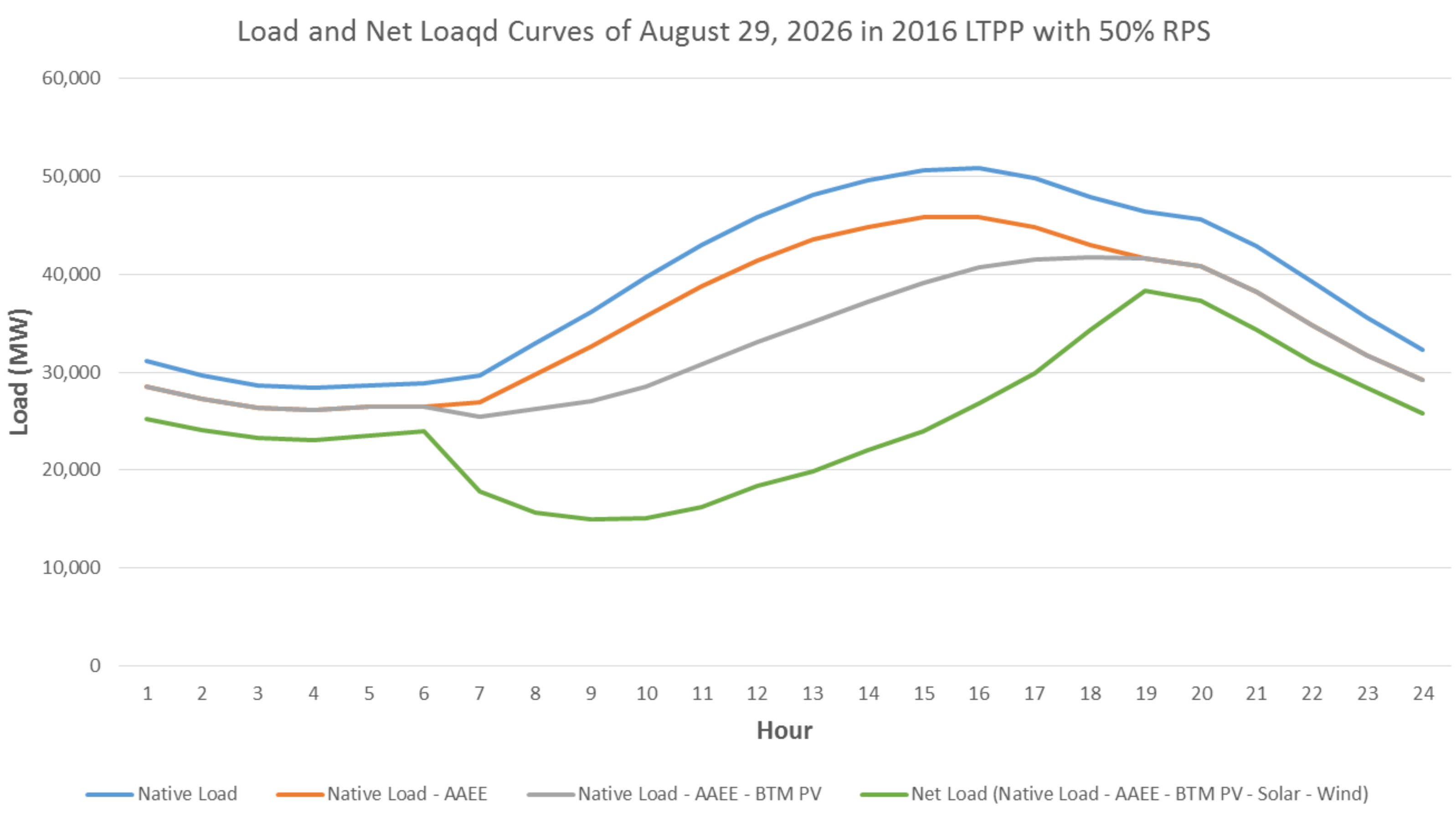
Peak Load (MW)	1-in-2 Peak MW, No AAEE	SB350 AAEE Peak Impact	IEPR BTM PV Peak Impact	Pumping Load Peak Impact	Non-coincident Peak (MW)
IID	1,137	0	40	0	1,177
LDWP	7,022	-1,031	213	0	6,205
PG&E_BAY	8,945	-1,425	694	0	8,214
PG&E_VLY	13,120	-1,850	1,124	-560	11,835
SCE	23,313	-3,786	1,739	-411	20,855
SDGE	4,705	-817	504	0	4,393
SMUD	5,044	-511	120	-142	4,511
TIDC	723	0	70	0	793
CAISO	50,083	-7,877	4,061	-971	45,297
CA	64,009	-9,418	4,504	-1,113	57,982

- 7,601 MW maximum AAEE
- 12,238 MW BTM PV installed capacity

The 50% RPS portfolio – solar is the dominant resource



Net load on the annual peak net load day – illustration of peak shifting due to solar generation

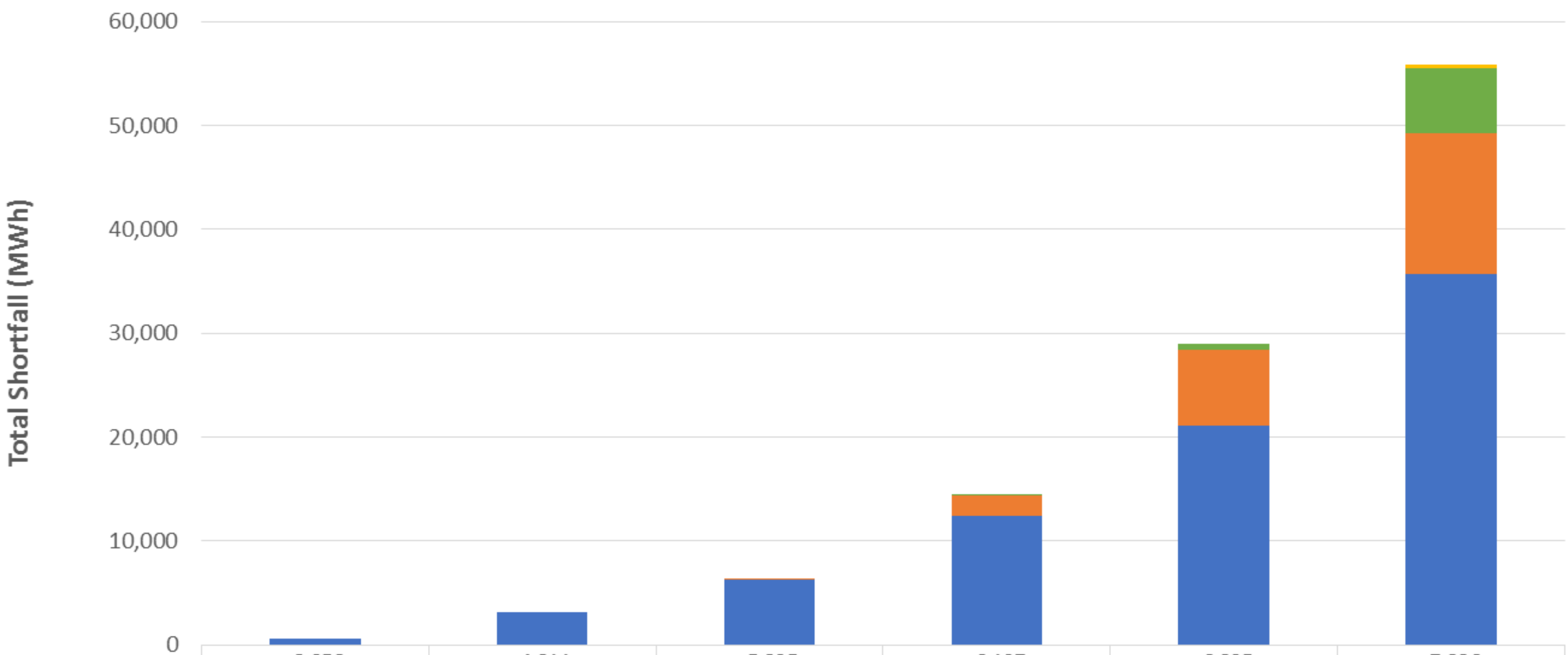


The study simulated six retirement cases

Retirement by Technology (MW)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CCGT	-3,739	-4,325	-4,325	-5,107	-5,107	-5,107
CHP	-219	-286	-751	-751	-840	-1,138
GT	0	-200	-250	-250	-939	-1,632
ST	0	0	0	0	-10	-10
Total	-3,958	-4,811	-5,325	-6,107	-6,895	-7,886

- The candidates for retirement assessment
  - Were selected through a screening using the transmission model
  - Met local capacity requirements and transmission constraints

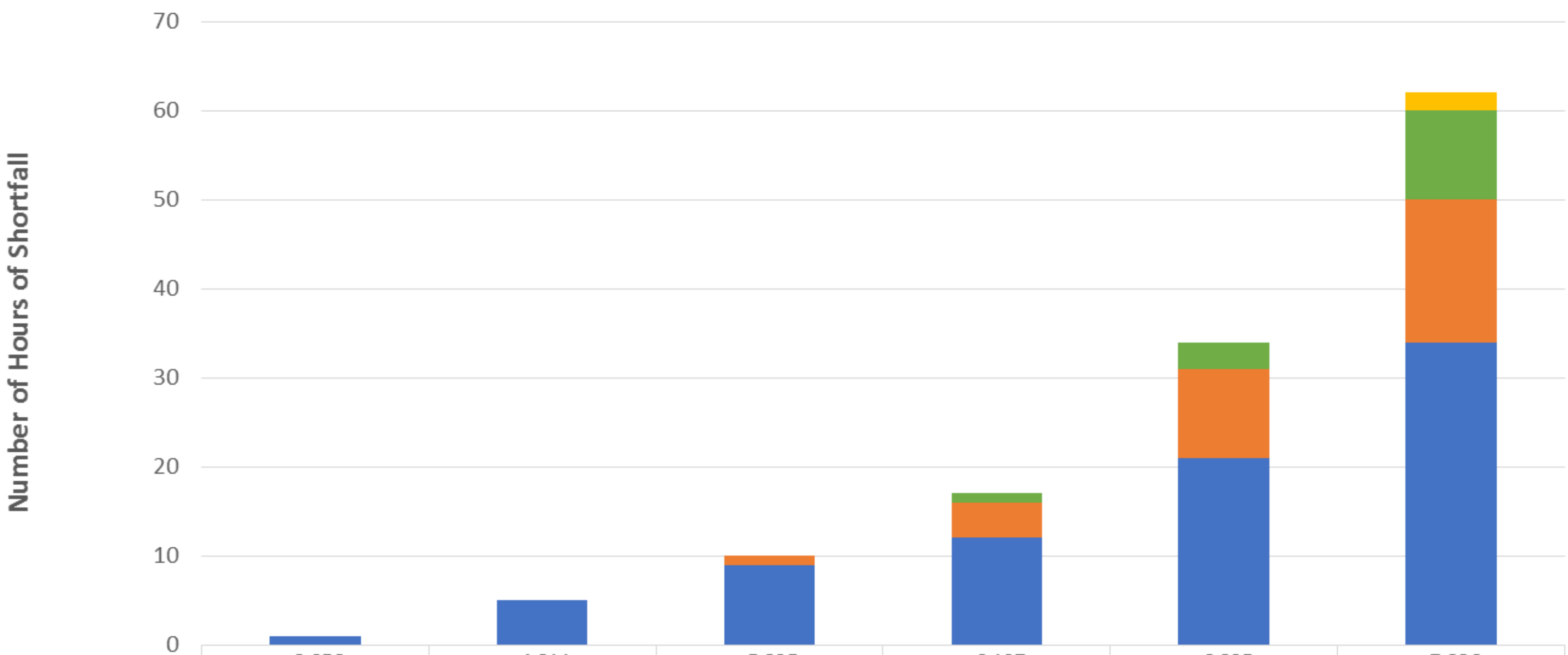
Total load-following and reserve shortfalls by case



	-3,958	-4,811	-5,325	-6,107	-6,895	-7,886
RegulationUp						303
Spining Reserve				12	625	6,208
NonSpin Reserve			107	1,890	7,336	13,545
LoadFollowingUp	636	3,181	6,268	12,436	21,047	35,743

Case (MW retirement)

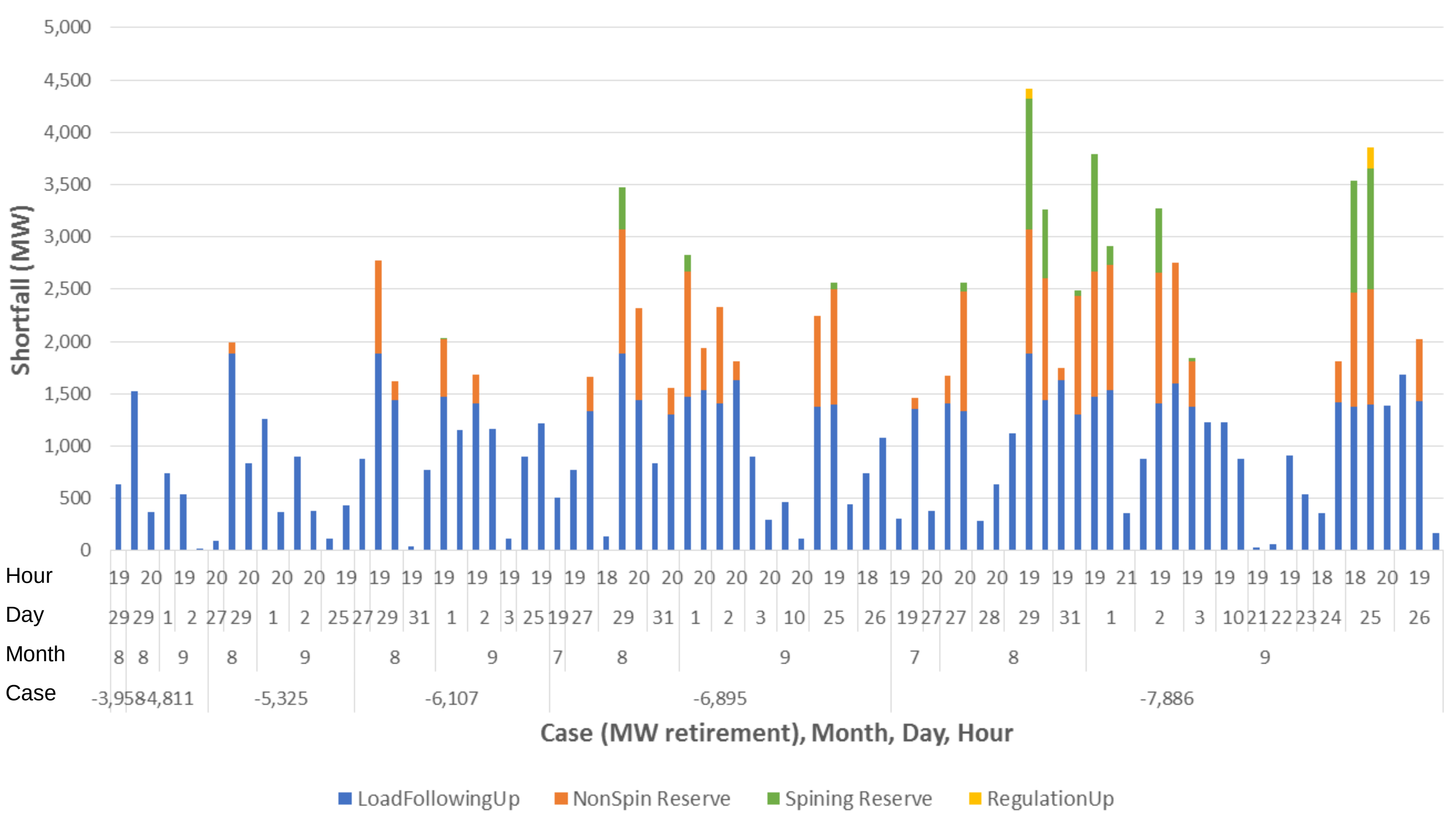
Total number of hours with load-following and reserve shortfalls by case



	-3,958	-4,811	-5,325	-6,107	-6,895	-7,886
RegulationUp						2
Spining Reserve				1	3	10
NonSpin Reserve			1	4	10	16
LoadFollowingUp	1	5	9	12	21	34

Case (MW retirement)

Hourly load-following and reserve shortfalls by case



Summary of Findings

- Unlimited renewable curtailment masks the need for flexible capacity during downward ramping in the morning and upward ramping in the afternoon
- The shortfalls in load-following and reserves reflect the insufficiencies of capacity
- Capacity insufficiencies occur in early evening after sunset, which is the new peak (net) load time
- Capacity sufficiency issues start to emerge between 4,000 to 6,000 MW of retirement.

Questions?

California ISO

Frequency Response Assessment-Generation Modeling Special Study – Update

Irina Green

Senior Advisor, Regional Transmission North

2016-2017 Transmission Planning Process Stakeholder Meeting

February 17, 2017

Drivers for the Study

- Frequency response studies of the 2015-2016 Transmission Plan showed optimistic results regarding frequency response
- Actual measurements of the generators' output were lower that the generators' output in the simulations
- Therefore models update and validation is needed
- New NERC Standards MOD-032-1 and MOD -033-1 require to have accurate validated models
- MOD-032-1 - data submission by equipment owners to their Transmission Planners and Planning Coordinators to support the Interconnection-wide cases
- MOD-033-1 - requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.
- Generation owners are responsible for providing the data, and the ISO is responsible for the model validation

Study Methodology

- Identify missing models or missing model components, also
- Units modeled with obsolete models no longer supported by WECC
- Models that have deficiencies and require upgrades - by comparison of the real time measurements and the simulation results, or if measurements are not available, by unrealistic performance in the simulations
- Identify generators modeled with generic models with typical parameters and obtain more accurate models of the units
- This task is performed in coordination with the System Operations who will provide the real-time measurement data.
- Updated models reported to WECC to be included in the dynamic stability model database.
- Details provided in June 13, 2016 Stakeholder Call material and at the Stakeholder meeting in September 2016

Models with concerns

- Reviewed WECC Dynamic Master File and identified old models, missing models, models with wrong type, or models with typical generic data.
- Based on the transient stability study results for the 2016-2017 TPP, identified renewable projects that were tripped by under- or over-voltage and frequency protection with three-phase faults even if they were supposed to have Fault-Ride-Through Capability.
- Identified thermal units that showed oscillations in transient stability simulations with three-phase faults in their vicinity, most likely caused by errors in exciter models or incorrect tuning (high gains)
- Based on the frequency response studies performed for the 2015-2016 TPP, identified several hydro units with inadequately high frequency response.
- Identified around 400 generators with issues needing resolution by generation owners

Common Errors in Models

- Renewable generators are modeled using the first generation or unapproved models instead of second generation models (RE_ model series).
- Many renewable generators do not have low/high voltage and frequency ride-through models.
- Models are missing for some generators.
- Generators are modeled with typical data.
- Small generators are modeled as 100 MVA.
- Unsatisfactory simulation results, such as oscillations, high governor response.

Work Performed

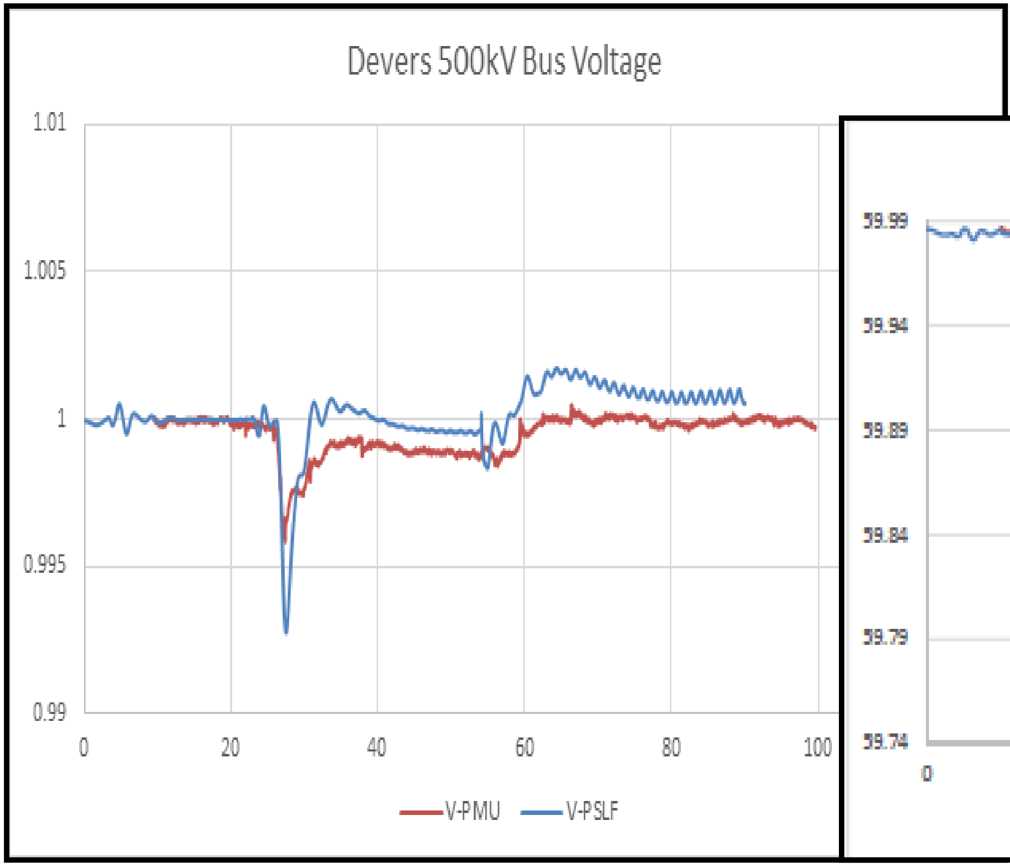
- Obtained the list of generation owners and their contact information
- Contacted the owners whose generators had potential issues, explained their issues and requested to update the models, preferably by testing their units
- Received some responses and test results, updated the models and reported the new models to WECC – done by PTOs
- Small QFs were left modeled with typical data, updated MVA base
- Compared responses observed in Dynamic Security Assessment (DSA) to that in state estimator for events during 2016 and modified baseload flags (blocked governors) – done by Operation Engineering

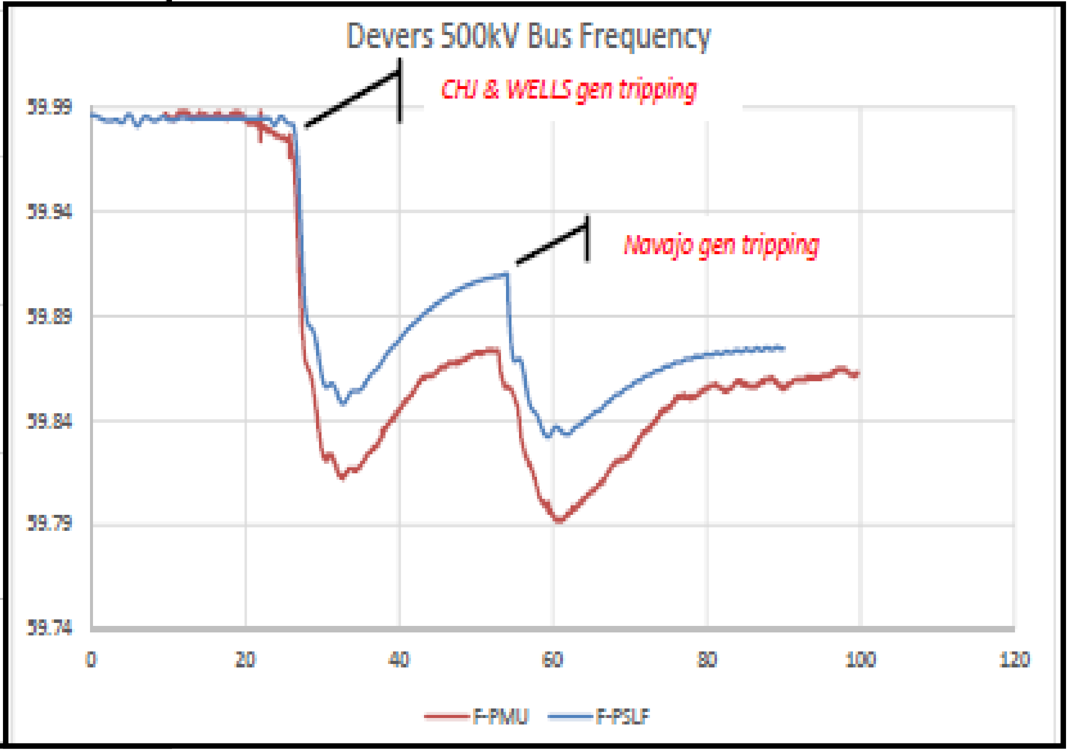
Model Validation, Event March 3, 2016

Time (sec)	Event
3.33	ASHE - SLATT 500 kV line tripped
4.30	ASHE - SLATT 500 kV line restored
5.30	ASHE - SLATT 500 kV line tripped
22.79	Switch SVD at MARION 500 kV
23.25	Open line - BUCKLEY - SLATT 500 kV
23.90	Restore line - BUCKLEY -SLATT 500 kV
26.23	Open line - BUCKLEY –SLATT 500 kV; CHJ and WELLS generators tripped – 944.9 MW
54.14	Navajo units tripped – 844.5 MW

- Total loss of generation 1789.4 MW, WECC–wide frequency dropped to 59.84Hz
- Performed dynamic stability simulation and compared to the measurements obtained from Peak Reliability

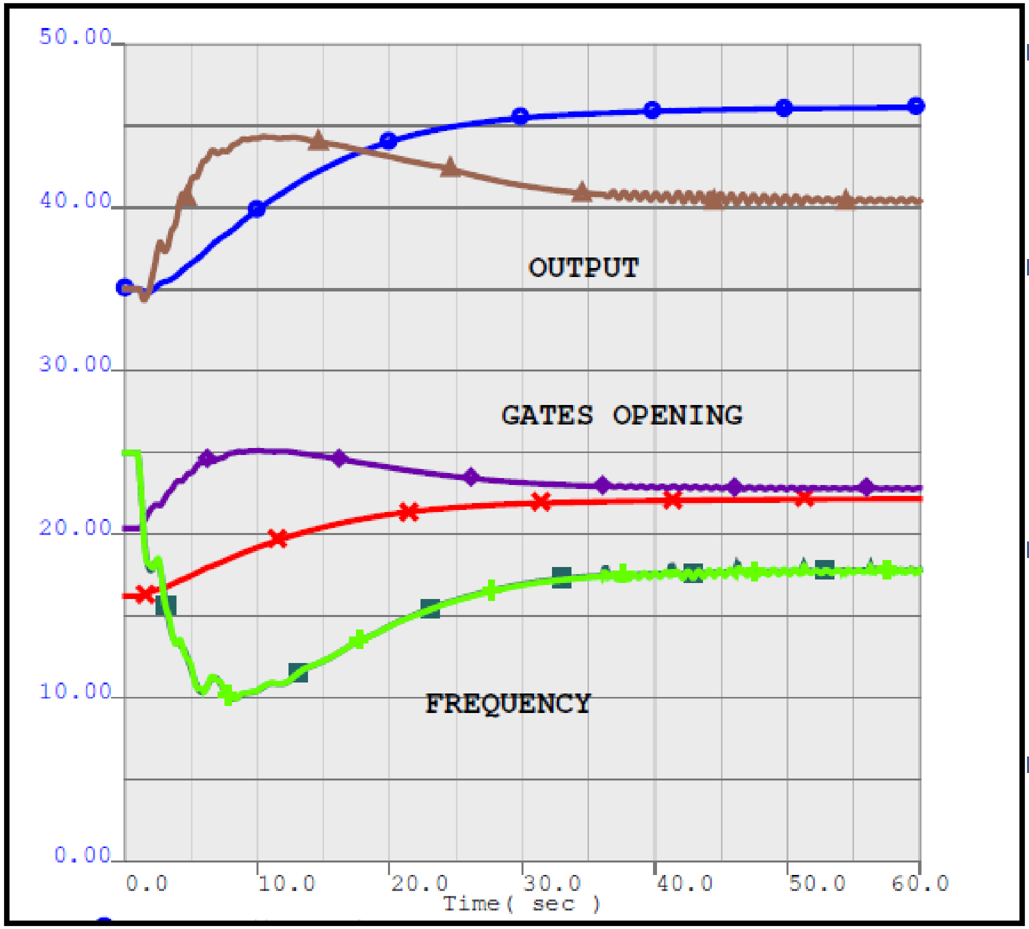
Simulation Results and Comparison
Blue- simulation, Red - Measurements





Lack of measurements on generation plants doesn't allow to determine which exactly units caused the discrepancy

Example,
Hydro Plant was re-tested due to inadequately high frequency response in the simulations



- An outage of two Palo Verde units, loss of 2650 MW of generation
- 2026 Spring off-Peak with 50% renewable generation, out-of-state North case
- Previous testing done in March 2011, latest, in January 2017
- Data prior to the last testing, response 15.3%, new data - response 7.4%
- Possible errors in the new machine data

Conclusions

- Due to the discrepancies between dynamic stability simulations and actual system performance, dynamic stability models need to be updated and validated
- The ISO successfully identified which models need update and is working with the PTOs on the update of the models
- Not having PMU with high resolution on the generating plants appears to be a significant obstacle in validating dynamic stability models and in obtaining correct models. Installing more PMUs will improve the validation process.
- The ISO needs to continue the work on model validation and on updating dynamic stability models.

Future Work

- Analyze responses from the generation owners and update the dynamic database
- Perform dynamic stability simulations to ensure that the updated models demonstrate adequate dynamic stability performance
- Send updated validated models to WECC so that the WECC Dynamic Masterfile could be updated
- Perform validation of models based on real-time contingencies and studies with modeling of behind the meter generation
- Investigate measures to improve the ISO frequency response post contingency. Various contingencies and cases may need to be studied

QUESTIONS?

COMMENTS?

Next Steps

Kim Perez
Stakeholder Engagement and Policy Specialist

2016-2017 Transmission Planning Process Stakeholder Meeting
February 17, 2017

2016-2017 Transmission Planning Process
Next Steps

- Comments due March 3, 2017
  - regionaltransmission@caiso.com
- Stakeholder meeting on February 28, 2017
  - 2016-2017 TPP
    - 50% RPS Special Study – Out of State Portfolio Update
    - Benefits Analysis of Large Energy Storage Special study
  - 2017-2018 Draft Study Plan
- ISO Board Meeting on March 15-16, 2017