# Agenda

*Kim Perez*
*Stakeholder Engagement and Policy Specialist*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

# 2015-2016 Draft Transmission Plan Stakeholder Meeting - Today's Agenda

| Topic | Presenter |
|---|---|
| Opening | Kim Perez |
| Introduction & Overview | Neil Millar |
| Recommended Reliability Projects | ISO Engineers |
| 50% RPS Special Study | Sushant Barave |
| Frequency Response | Irina Green |
| Mid-Term and Long-Term LCR for LA Basin, Big Creek/Ventura and San Diego areas | David Le |
| Gas-Electric Coordination Transmission Planning Studies for Southern California | David Le |
| Large Scale Energy Storage Special Study | Shucheng Liu |
| Economic Planning Study Final Recommendation | Yi Zhang |
| Wrap-up and Next Steps | Kim Perez |

California ISO

# Introduction & Overview
# Transmission Plan Development

*Neil Millar*

*Executive Director, Infrastructure Development*

*2015-2016 Transmission Planning Process Stakeholder Meeting*

*February 18, 2016*

# 2015-2016 Transmission Planning Cycle

**April 2015** — **March 2016** — **October 2016**

**Coordination of Conceptual Statewide Plan**

**ISO Board Approval of Transmission Plan**

**Phase 1**

**Development of ISO unified planning assumptions and study plan**

- Incorporates State and Federal policy requirements and directives
- Demand forecasts, energy efficiency, demand response
- Renewable and conventional generation additions and retirements
- Input from stakeholders
- Ongoing stakeholder meetings

**Phase 2**

**Technical Studies and Board Approval**

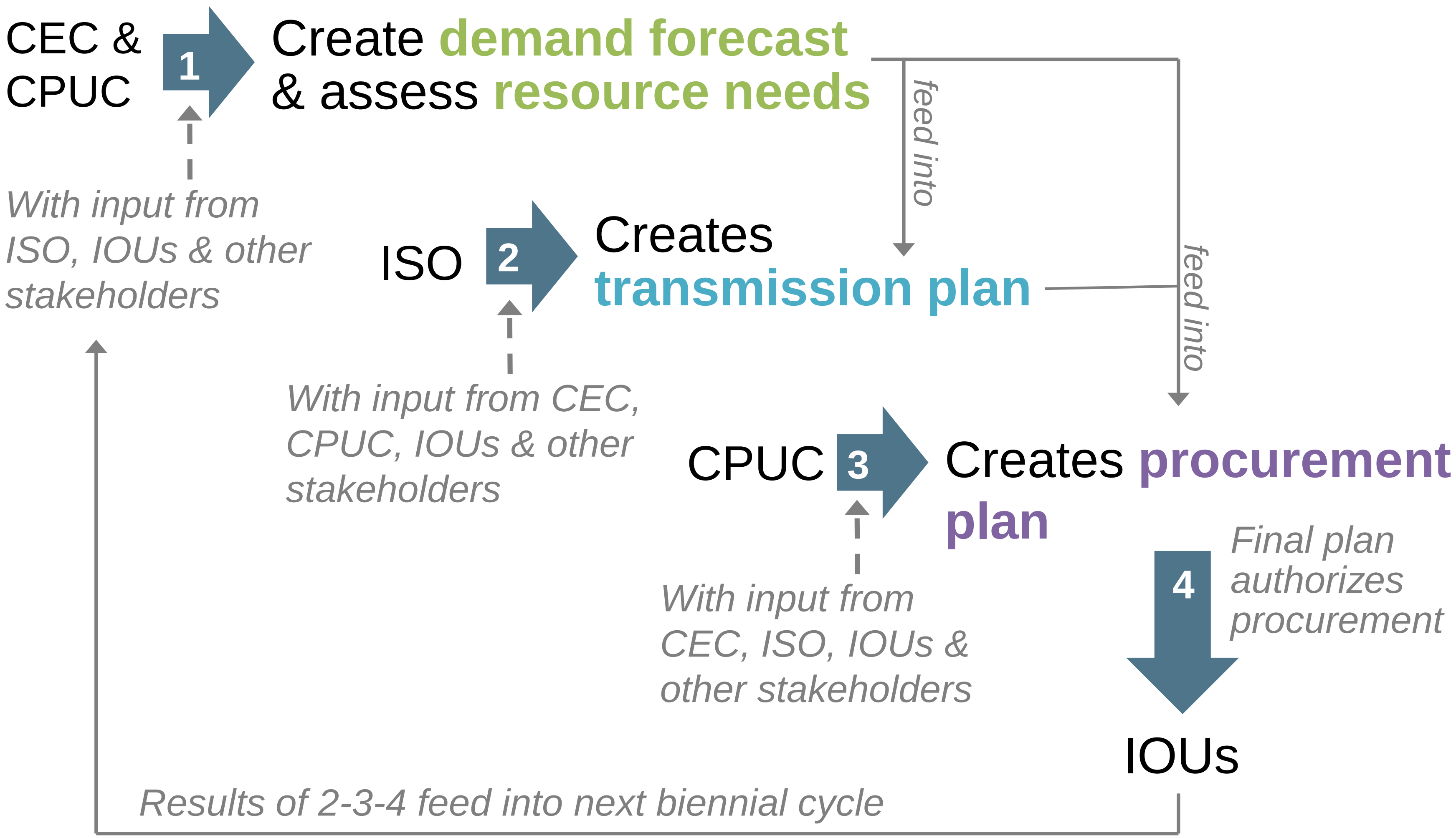
- Reliability analysis
- Renewable delivery analysis
- Economic analysis
- Publish comprehensive transmission plan
- ISO Board approval

**Phase 3**

**Receive proposals to build identified reliability, policy and economic transmission projects.**

**Continued regional and sub-regional coordination**

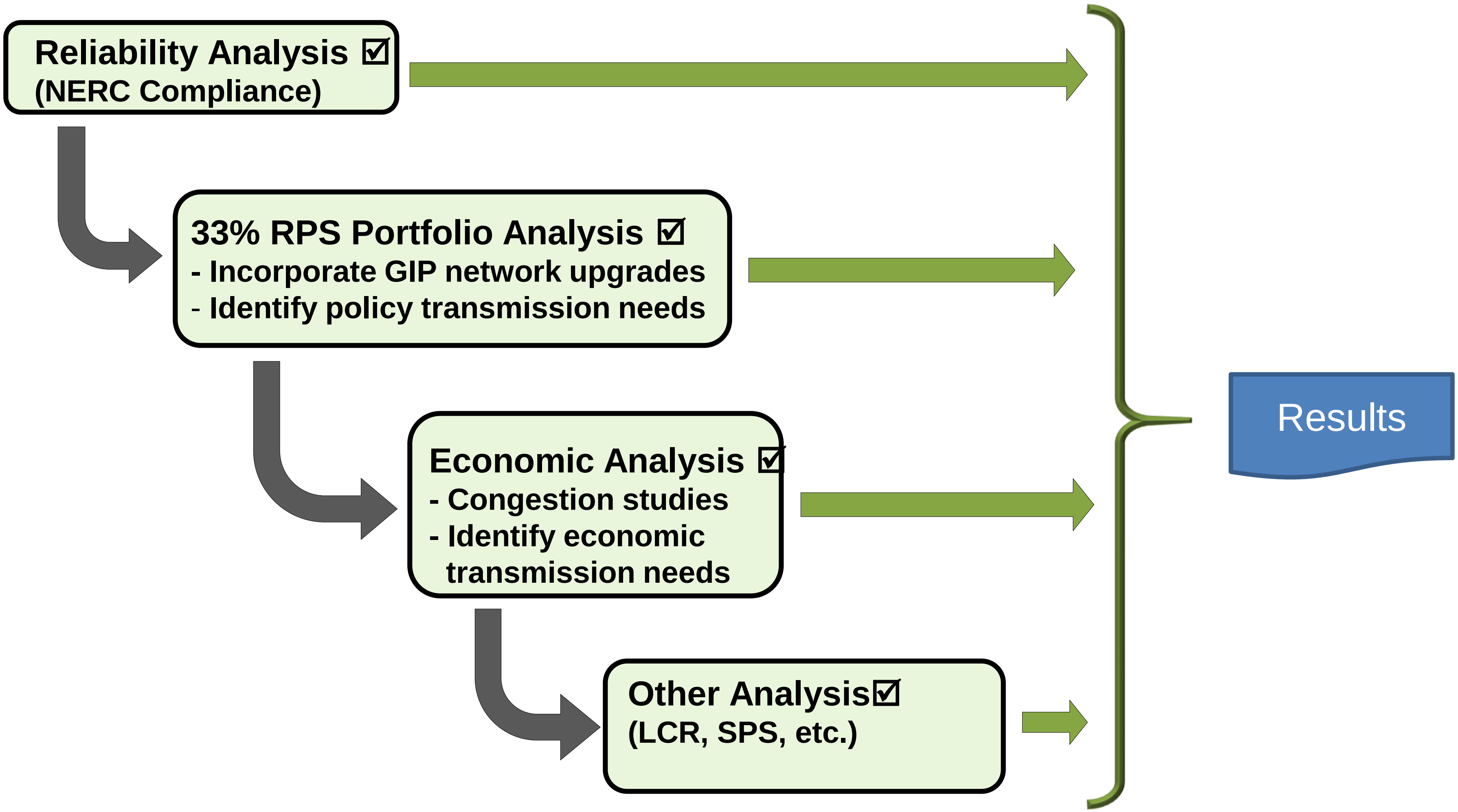
# Planning and procurement overview



# Emphasis in the transmission planning cycle:

- A relatively light capital program, as:
  - reliability issues are largely in hand
  - policy work was limited to 33% RPS and portfolios are not available yet for moving beyond 33% (for approvals)
  - economic studies not showing any material new opportunities
- Results updated  in the LA Basin and San Diego area – sub area issue identified and addressed
- A review of older previously approved PG&E projects enabled cancellation of 13 “local” sub-transmission projects
- 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
  - 50 percent “energy only” study
  - Frequency response study
  - Gas/electric coordination preliminary study

# Development of 2015-2016 Annual Transmission Plan



# Summary of Needed Reliability Driven Transmission Projects

| | 2010/11 Plan | | 2011/12 Plan | | 2012/13 Plan | | 2013/14 Plan | | 2014/15 Plan | | **2015/16 Plan** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | # | Cost (million) | # | Cost (million) | # | Cost (million) | # | Cost (million) | # | Cost (million) | **#** | **Cost (million)** |
| Pacific Gas & Electric | 23 | $683 | 22 | $610 | 31 | $1,168 | 15 | $536.4 | 2 | $254 | **7** | **$202** |
| Southern California Edison Co. | 0 | $0 | 3 | $25 | 0 | 0 | 2 | $712.0 | 1 | $5 | **1** | **$10** |
| San Diego Gas & Electric Co. | 9 | $515 | 5 | $56 | 5 | $175 | 11 | $584.0 | 4 | $93 | **6** | **$94** |
| Valley Electric Association | | | | | | | 1 | 0.1 | 0 | 0 | **0** | **0** |
| **Total** | **32** | **$1,198** | **30** | **$691** | **36** | **$1,343** | **29** | **$1,832.5** | **7** | **$352** | **14** | **$306** |

# 14 reliability-driven projects are recommended for approval

- 5 were approved after the December 17-18 Board of Governors meeting and review at the November 16 Stakeholder meeting
- The remaining 9 (bolded text) require Board of Governor approval
- The Lugo-Victorville 500 kV upgrade was found to be needed but is not being recommended for approval at this time - coordination with LADWP will take place before approval is recommended.

| No. | Project Name | Service Area | Expected In-Service Date | Project Cost |
|---|---|---|---|---|
| 1 | Panoche – Ora Loma 115 kV Line Reconductoring | PG&E | May-21 | $20 M |
| 2 | **Bellota 230 kV Substation Shunt Reactor** | PG&E | Dec 2020 | $13-19 M |
| 3 | **Cottonwood 115 kV Substation Shunt Reactor** | PG&E | Dec 2019 | $15-19 M |
| 4 | **Delevan 230 kV Substation Shunt Reactor** | PG&E | Dec 2020 | $19-28 M |
| 5 | **Ignacio 230 kV Reactor** | PG&E | Dec 2020 | $23.4-35.1 M |
| 6 | **Los Esteros 230 kV Substation Shunt Reactor** | PG&E | Dec 2020 | $24-36 M |
| 7 | **Wilson 115 kV SVC** | PG&E | Dec 2020 | $35-45 M |
| 8 | 15 MVAR Capacitor at Basilone Substation | SDG&E | Jun-16 | $1.5-2 M |
| 9 | 30 MVAR Capacitor at Pendleton Substation | SDG&E | Jun-17 | $2-3 M |
| 10 | **Bay Boulevard Third 230/69 kV Transformer Bank** | SDG&E | Jun-18 | $13-18 M |
| 11 | Reconductor TL 605 Silvergate – Urban | SDG&E | Jun-18 | $5-6 M |
| 12 | **Second Miguel – Bay Boulevard 230 kV Transmission Circuit** | SDG&E | Jun-19 | $20-45 M |
| 13 | **TL600: “Mesa Heights Loop-in + Reconductor** | SDG&E | Jun-18 | $15-20 M |
| 14 | Eagle Mountain Shunt Reactors | SCE | Dec-18 | $10 M |

# 13 existing predominantly local PG&E projects are being cancelled – including 11 cancelled by ISO management

- Bay Meadows 115 kV Reconductoring (Greater Bay Area)
- Cooley Landing - Los Altos 60 kV Line Reconductor (Greater Bay Area)
- Del Monte - Fort Ord 60 kV Reinforcement Project (Central Coast & Los Padre)
- Kerckhoff PH #2 - Oakhurst 115 kV Line (Fresno)
- Mare Island - Ignacio 115 kV Reconductoring Project (North Coast & North Bay)
- Monta Vista - Los Altos 60 kV Reconductoring (Greater Bay Area)
- **Monta Vista - Wolfe 115 kV Substation Equipment Upgrade (Greater Bay Area)**
- **Newark - Applied Materials 115 kV Substation Equipment Upgrade (Greater Bay Area)**
- Potrero 115 kV Bus Upgrade (Greater Bay Area)
- Taft 115/70 kV Transformer #2 Replacement (Kern)
- Tulucay 230/60 kV Transformer No. 1 Capacity Increase (North Coast & North Bay)
- West Point - Valley Springs 60 kV Line Project (Second Line) (Central Valley)
- Woodward 115 kV Reinforcement (Fresno)

# Policy and Economic driven solutions:

- There were no policy-driven requirements identified
  - Note that the Coolwater-Lugo project and the Imperial Valley Collector Station have been cancelled.
- 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 – PTO data collection in progress
- The 2015-2016 plan is based on the IID system model provided by IID in the spring. IID have since submitted new base cases as comments in October – those changes will be assessed in next year's transmission plan.

# Reliability Projects for Approval and Recommended for Cancelation
## *Pacific Gas & Electric Area*

*Vera Hart*
*Jeff Billinton*
*Regional Transmission - North*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

# Projects found to be needed:

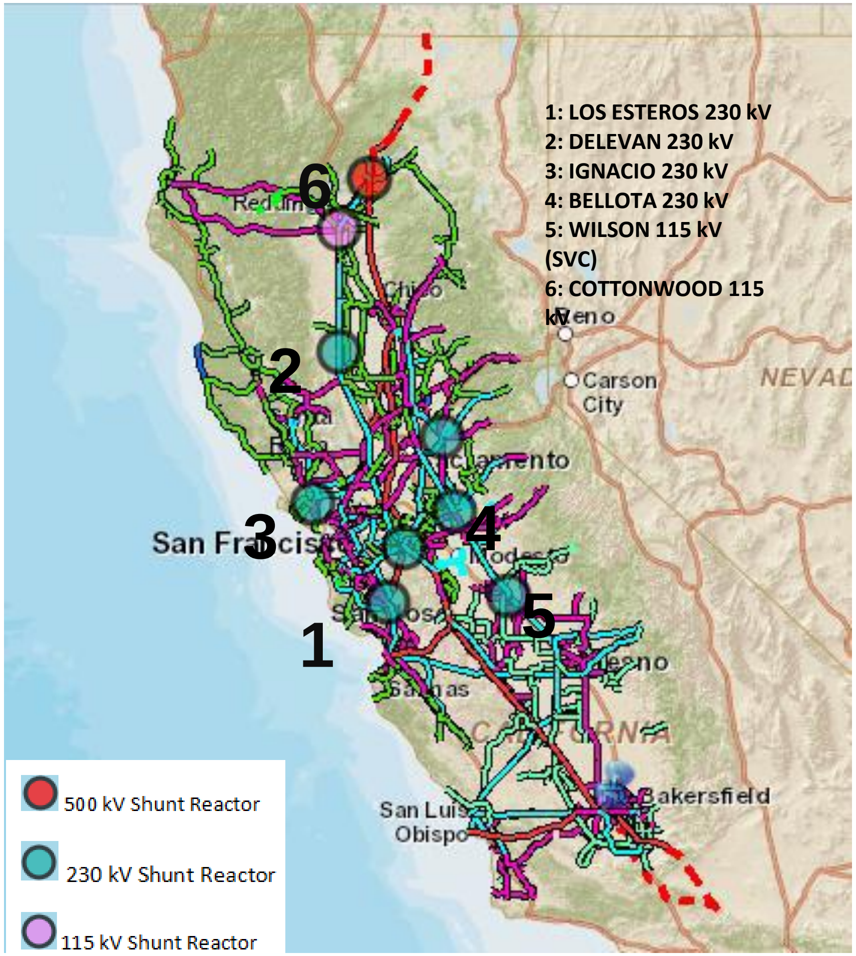
- 1 reliability-driven project was identified as being needed and reviewed at November 16, 2015 Stakeholder Meeting :
  - Panoche-Oro Loma 115 kV Line Project. The project is less than $50 million and has been approved by the ISO management.
- 6 additional reliability-driven projects have been identified as being needed and are recommended for approval – set out on next slides.

# Recommended for Approval

- 6 additional reliability-driven projects have been identified as being needed and are recommended for approval:

| Project Name | Type of Project | Submitted By | Cost of Project |
|---|---|---|---|
| Los Esteros 230 kV Substation Shunt Reactor | Reliability | PGE | $24M-$36M |
| Delevan 230 kV Substation Shunt Reactor | Reliability | PGE | $19M-$28M |
| Ignacio 230 kV Substation Shunt Reactor | Reliability | PGE | $23.4M-$35.1M |
| Bellota 230kV Substation Shunt Reactor | Reliability | PGE | $13M-$19M |
| Cottonwood 115kV Substation Shunt Reactor | Reliability | PGE | $13M-$19M |
| Wilson 115kV Substation SVC | Reliability | PGE/CAISO | $35M-$45M |

# PGE- Reactors




**Submitted by:** PGE

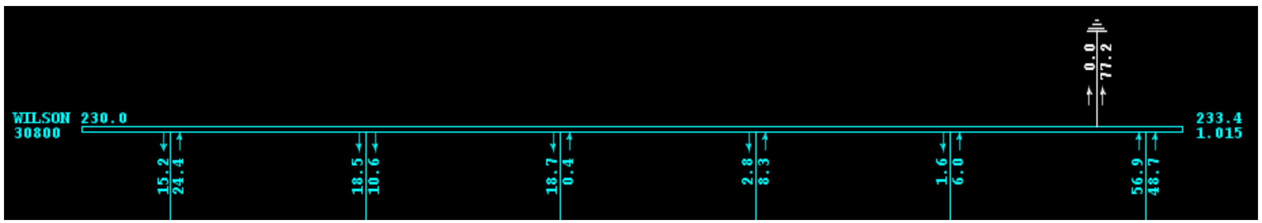
**Need:** NERC Category P0 (2020 Minimum Load Case) and RT data showing High Voltage in those areas

**Project Scope:**

- Shunt Reactor at Los Esteros 230 kV
  - 250 Mvar
  - Expected in Service date: 2020
  - Cost: $24M-$36M
- Shunt Reactor at Delevan 230kV reactor
  - 200Mvar
  - Expected in Service date: 2020
  - Cost: $19M-$28M
- Shunt Reactor at Ignacio 230kV Reactor
  - 150Mvar,
  - Expected in Service date: 2020
  - Cost: $23.4M-$35.1M
- Shunt Reactor at Bellota 230kV reactor
  - 100Mvar
  - Expected in Service date: 2020
  - Cost: $13M-$19M
- Shunt Reactor at Cottonwood 115kV reactor
  - 100Mvar
  - Expected in Service date: 2019
  - Cost: $13M-$19M

Other Reactor projects being considered for the next planning cycle: Round Mountain 500kV, Tesla 230kV and Goldhill 230kV reactors.

# Wilson 115kV SVC




**Submitted by:** CAISO

**Need:** NERC Category P0 (2020 Minimum Load Case) and RT data showing High Voltage in Northern Fresno Area

**Project Scope:**
Remove the current Wilson 75Mvar 115kV Capacitor and Install a 100 MVAR SVC at Wilson 115 kV substation.

**Cost:** ~$35M-$45M

**Other Considered Alternatives:**
Status Quo
Reactor at Wilson 230kV (Submitted by PGE)

-Operating Wilson 230kV reactor in conjunction with Wilson 115kV existing Capacitor, and Borden SVC located 22miles from Wilson, would pose considerable coordination challenges.

**Expected In-Service**: 2020

# Previously Approved Projects in PG&E area recommended to be cancelled

# Assessment Methodology

- Reviewed the need based upon:
  - Reliability Standards
    - NERC, WECC and ISO Planning Standards
  - LCR requirements
  - Deliverability

- Analysis conducted on topology of system in 2017 base case (with only projects already moving forward in-service) with load escalated to 2025 forecast
  - Assessment done with and without AAEE

# Projects canceled by ISO management

- 11 projects were identified at November 16, 2016 Stakeholder Meeting that were no longer required based on reliability, LCR and deliverability assessment:
  - Bay Meadows 115 kV Reconductoring
  - Cooley Landing - Los Altos 60 kV Line Reconductor
  - Del Monte - Fort Ord 60 kV Reinforcement Project
  - Kerckhoff PH #2 - Oakhurst 115 kV Line
  - Mare Island - Ignacio 115 kV Reconductoring Project
  - Monta Vista - Los Altos 60 kV Reconductoring
  - Potrero 115 kV Bus Upgrade
  - Taft 115/70 kV Transformer #2 Replacement
  - Tulucay 230/60 kV Transformer No. 1 Capacity Increase
  - West Point - Valley Springs 60 kV Line Project (Second Line)
  - Woodward 115 kV Reinforcement
- All of the above projects were originally approved by ISO management in past transmission planning cycles and have been cancelled.

# Additional projects recommended to be cancelled

- 2 additional projects have also been identified as no longer required based on reliability, LCR and deliverability assessment and are recommended to be cancelled:
  - Monta Vista – Wolfe 115 kV Substation Equipment Upgrade
  - Newark – Applied Materials 115 kV Substation Equipment Upgrade
- Recommendation is to cancel the above projects in the 2015-2016 TPP
  - All of the above projects were approved by ISO management in past transmission planning cycles

# Recommendations for Reliability Projects less than $50 Million
## *SCE Area*


*Sushant Barave*

*Senior Regional Transmission Engineer*

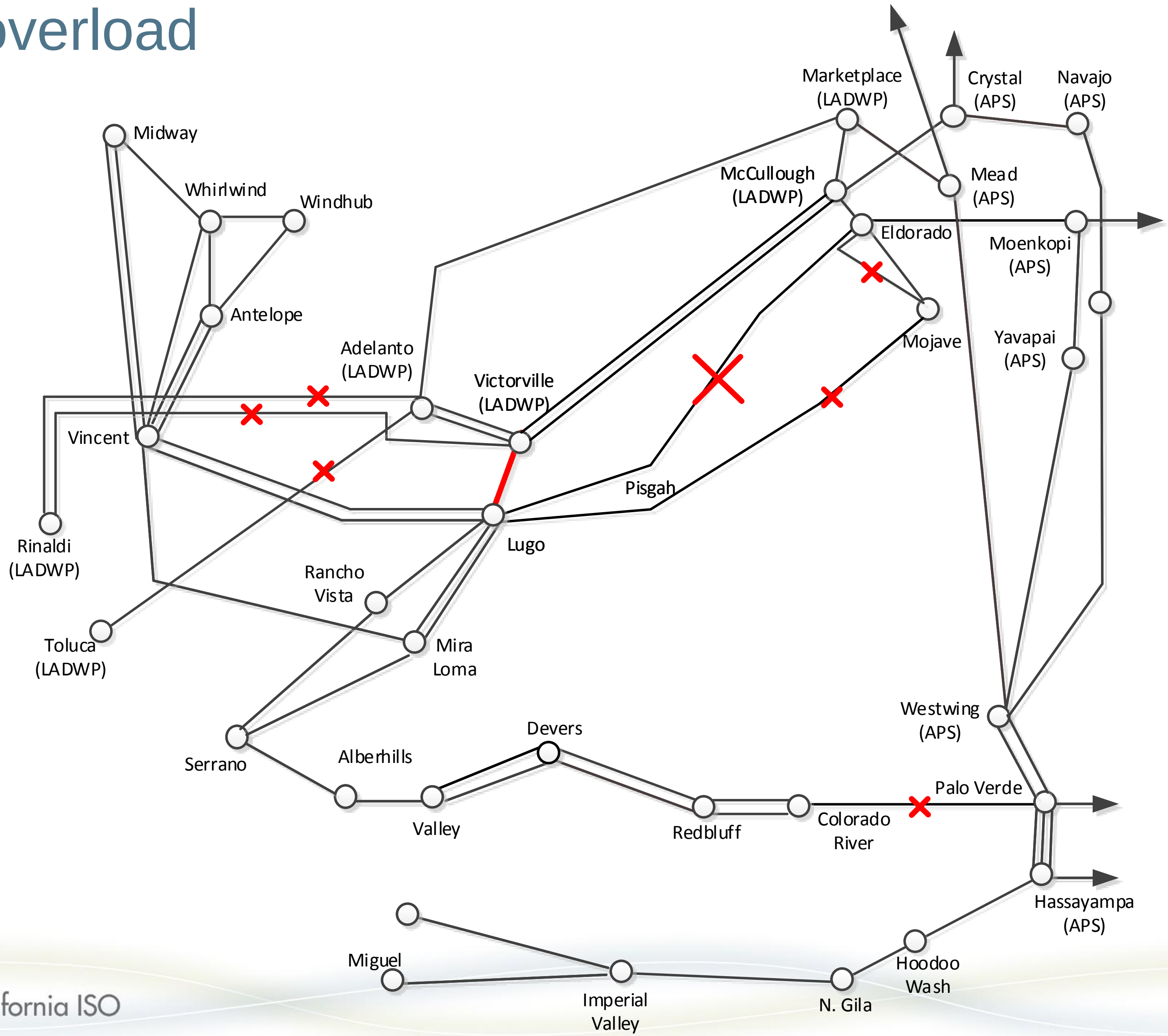

*2015-2016 Transmission Planning Process Stakeholder Meeting*

*February 18, 2016*

# Projects found to be needed:

| Project Name | Type of Project | Submitted By | Cost of Project |
|---|---|---|---|
| Lugo – Victorville 500 kV Upgrade | Reliability | SCE | SCE's segment: $18 million<br>LADWP's segment: $ 16 million |
| | | | |
| | | | |

# Several scenarios demonstrate Lugo – Victorville 500 kV overload



# Lugo – Victorville 500 kV upgrade summary

**Need:**
- Thermal overload on Lugo – Victorville 500 kV line identified in several scenarios
- Post-2020 timeframe: Congestion management will be a challenge
  Retirement of the bulk of OTC generating units in the western LA Basin and potential retirement of generation > 40-year old
- 33 percent RPS policy-driven studies identified this facility as a limiting constraint for delivering resources from multiple renewable zones
- Accrued congestion cost of this constraint since January 2013 was found to be $43 million

**Project Scope:**
- Increase the rating by upgrading terminal equipment at both substations and removing ground clearance limitations.
- The SCE portion: Replace four (4) transmission towers and terminal equipment at Lugo substation.

**Other Alternatives Considered :**
- Status quo (congestion management)

**Expected In-Service**: 12/13/2018

ISO intends to commence the coordination process with LADWP and SCE, and seek approval once the coordination has taken place.

# Recommendations for Reliability Projects less than $50 Million

## *San Diego Gas & Electric Area*

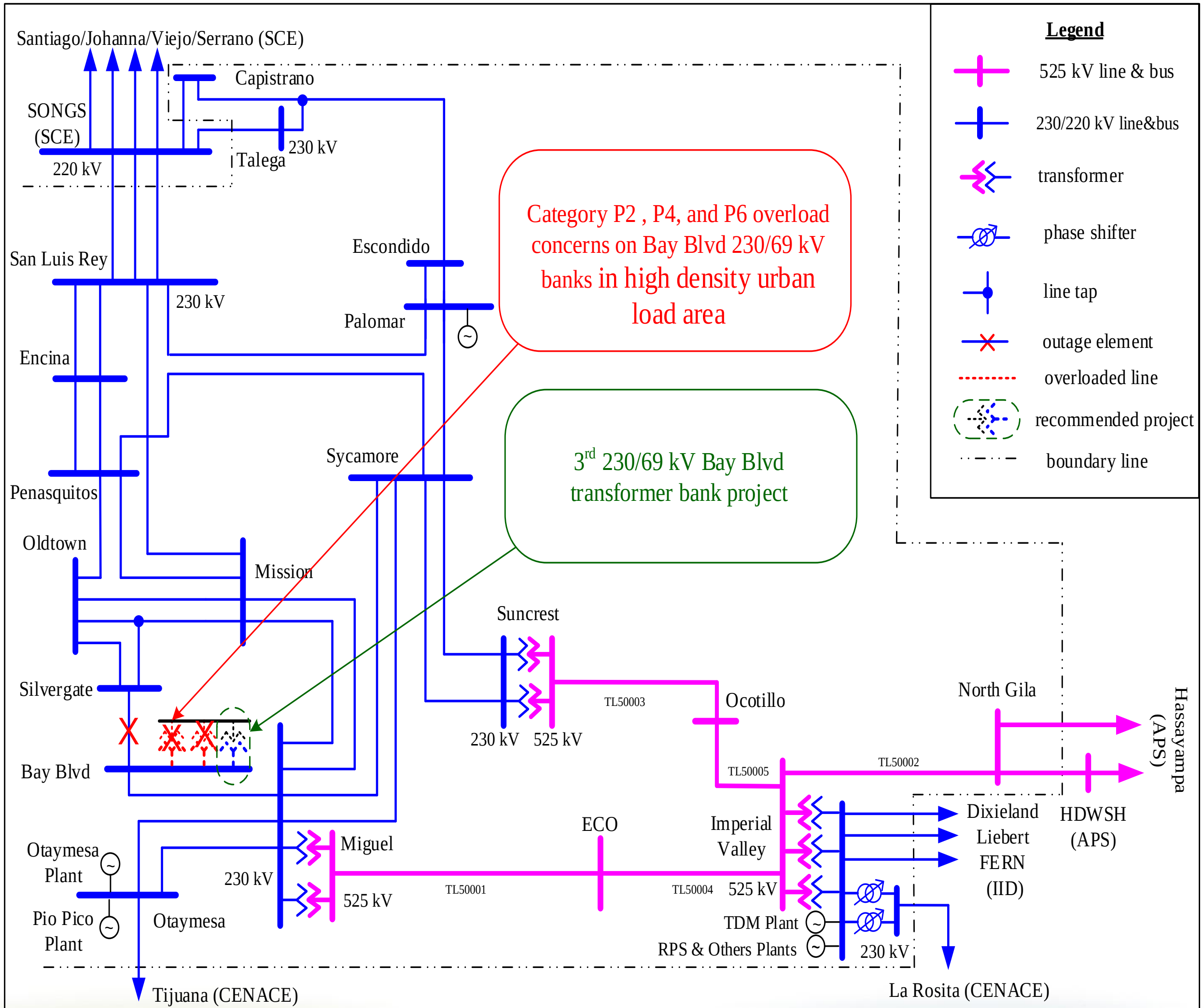
*Frank Chen*
*Senior Regional Transmission Engineer*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

# Recommended for Approval

| Project Name | Type of Project | Submitted By | Cost of Project |
|---|---|---|---|
| Third Bay Boulevard 230/69 kV Transformer Bank | Reliability | CAISO/SDG&E | $13~18 Millions |
| Second Miguel – Bay Boulevard 230 kV Transmission Circuit | Reliability | SDG&E | $20~45 Millions |

# Third Bay Boulevard 230/69 kV Bank




**Need:**
- Category P2, P4, and P6 overloads on Bay Bvld 230/69 kV Transformer #1 and #2 in high density urban load area

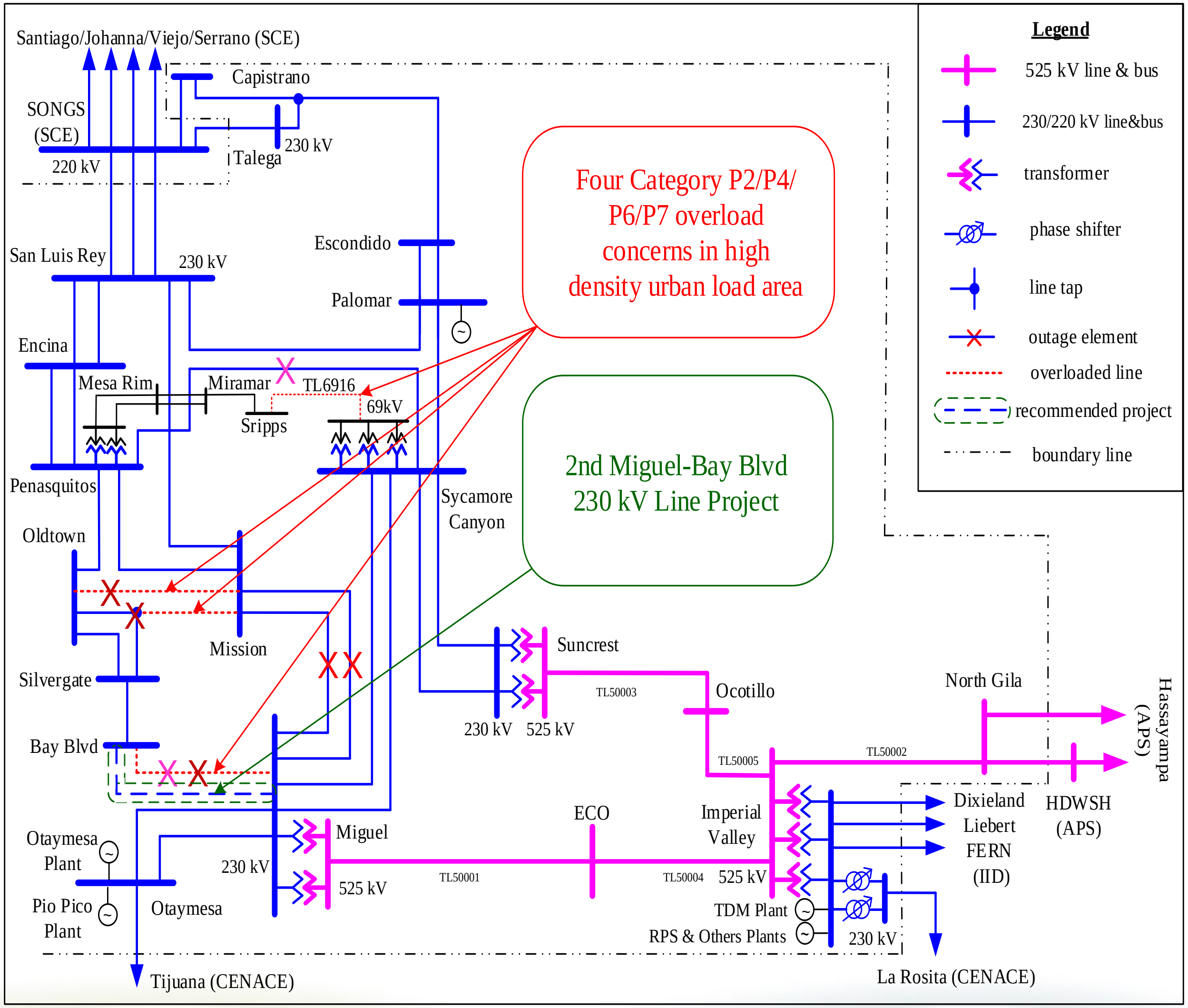
**Project Scope**:
- adding a 230 kV and a 69 kV position at Bay Blvd 230/69 kV substation
- Installing 3rd 230/69 kV transformer bank in Bay Blvd substation

**Cost:** $13-18 million

**Other Considered Alternatives:**
- Alt.1: adding 2nd Silvergate-Bay Blvd 230 kV line by upgrading existing TL13815 underground section and re-configuring the 138/69 kV system
- Alt. 2: adding a 230/138 kV bank in Bay Blvd substation, looping Telegraph Canyon-Grant Hill line into the 138 kV bus at Bay Blvd

**Expected In-Service**: June 2018

# Second Miguel – Bay Boulevard 230 kV Line




**Need:**
- Category P2, P4, and P7 overloads on Miguel-Bay Blvd 230 kV line
- Category P6 overloads on Mission-Old Town 230 kV lines
- Category P6 overload on Sycamore – Scripps 69 kV line without Miramar Energy Facility

**Project Scope**:
- add 230 kV line positions at Miguel and Bay Blvd 230 kV substations
- string a new 10-mile 230 kV OH circuit on existing double circuit 230kV structures between Miguel and Bay Boulevard 230 kV

**Cost:** $20-45 million

**Other Considered Alternatives:**
- Alt.1: Southern SDG&E 230 kV reinforcement
- Alt. 2: adding a 230/138 kV bank in Bay Blvd substation, looping Telegraph Canyon-Grant Hill line into the 138 kV bus at Bay Blvd

**Expected In-Service**: June 2019

# Recommendations for Reliability Projects less than $50 Million
## *San Diego Gas & Electric Sub-Transmission*


*Charles Cheung*

*Senior Regional Transmission Engineer*

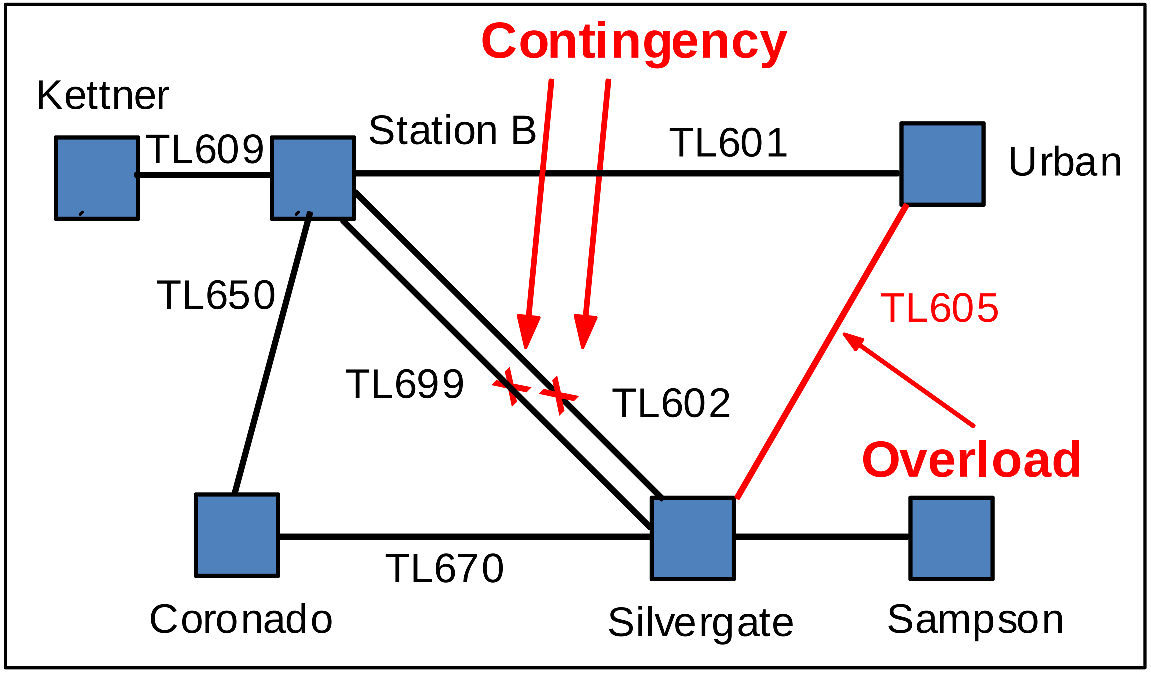

*2015-2016 Transmission Planning Process Stakeholder Meeting*

*February 18, 2016*

# Recommended for Approval

| Project Name | Type of Project | Submitted By | Cost of Project |
|---|---|---|---|
| Reconductor TL 605 Silvergate-Urban | Reliability | SDG&E | $5~6 M |
| TL600: “Mesa Heights Loop-in + Reconductor” | Reliability | SDG&E | $15~20 M |

# Reconductor TL 605 Silvergate-Urban




**Need:** Mitigate thermal overload on TL605 for the N-1-1 of TL602 and TL699 (SG-B ckt 1 & 2), starting in 2018, No generation available to re-dispatch

**Project Scope:** Reconductor TL605 to a minimum continuous rating of 137 MVA

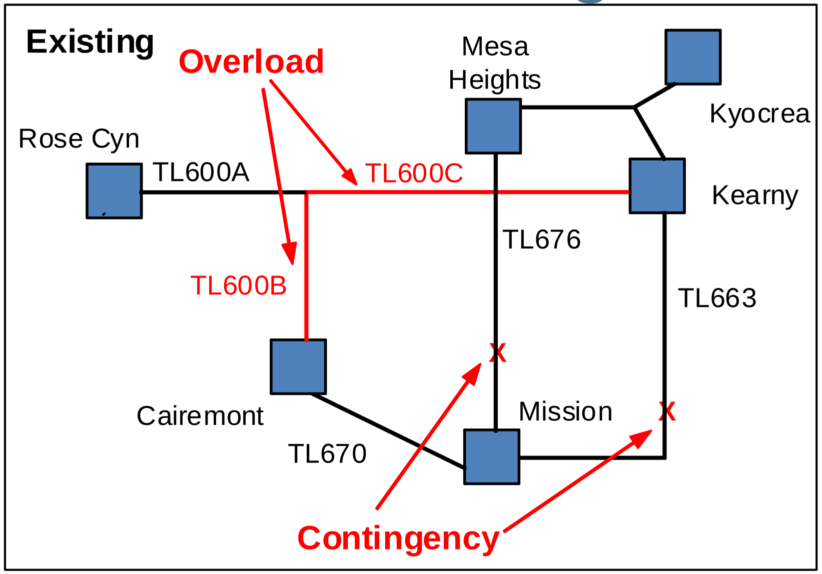
**Cost:** $5-6 million

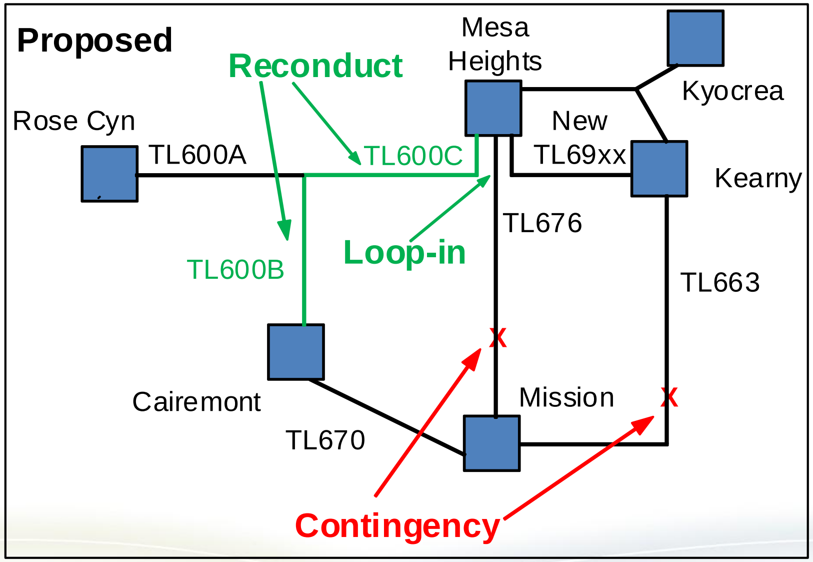
**Other Considered Alternatives:** Drop Load about 20 MW for 2018

**Expected In-Service**: June 2018

**Interim Plan:** Drop Load

# TL600: “Mesa Heights Loop-in + Reconductor”




**<u>Need:</u>**

- Category P6 Overloads on TL600 due to N-1-1 of TL663 and TL676 in 2017, 2020 and 2025 Peak cases, Mitigate the LCR need in the Mission area after Kearny units retired

**<u>Project Scope</u>:**

- Loop-in TL600C into Mesa Heights
- Reconductor ~2.2 miles Clairemont-Mesa Heights to a minimum of 150 MVA
- Reconductor ~.7 miles Clairemont Tap – Clairemont to a minimum of 102 MVA

**<u>Cost:</u>** $15-20 million

**<u>Other Considered Alternatives:</u>** Keep Kearny Gens for congestion management, new SPS to shed load

**<u>Expected In-Service</u>**: June 2018

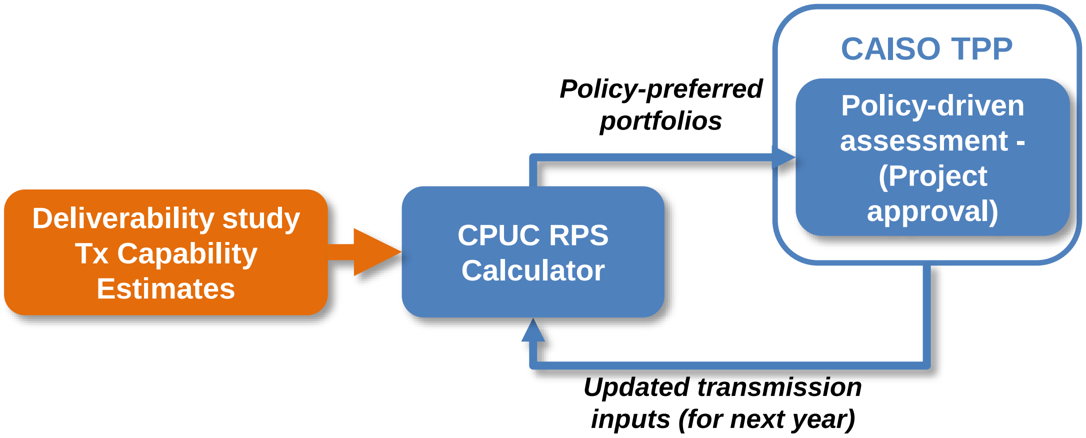
# 50% RPS Special Study

*Sushant Barave*
*Senior Regional Transmission Engineer*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

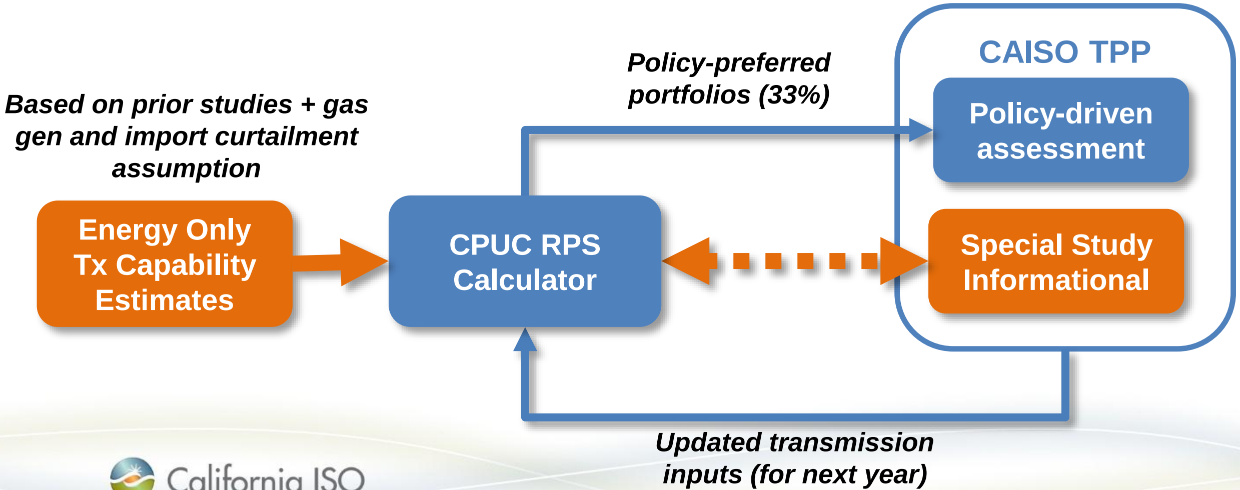
# Study tested ISO estimates of generation that could be delivered on an “energy only” basis – moving to 50%

<u>*Existing policy-driven planning process*</u>



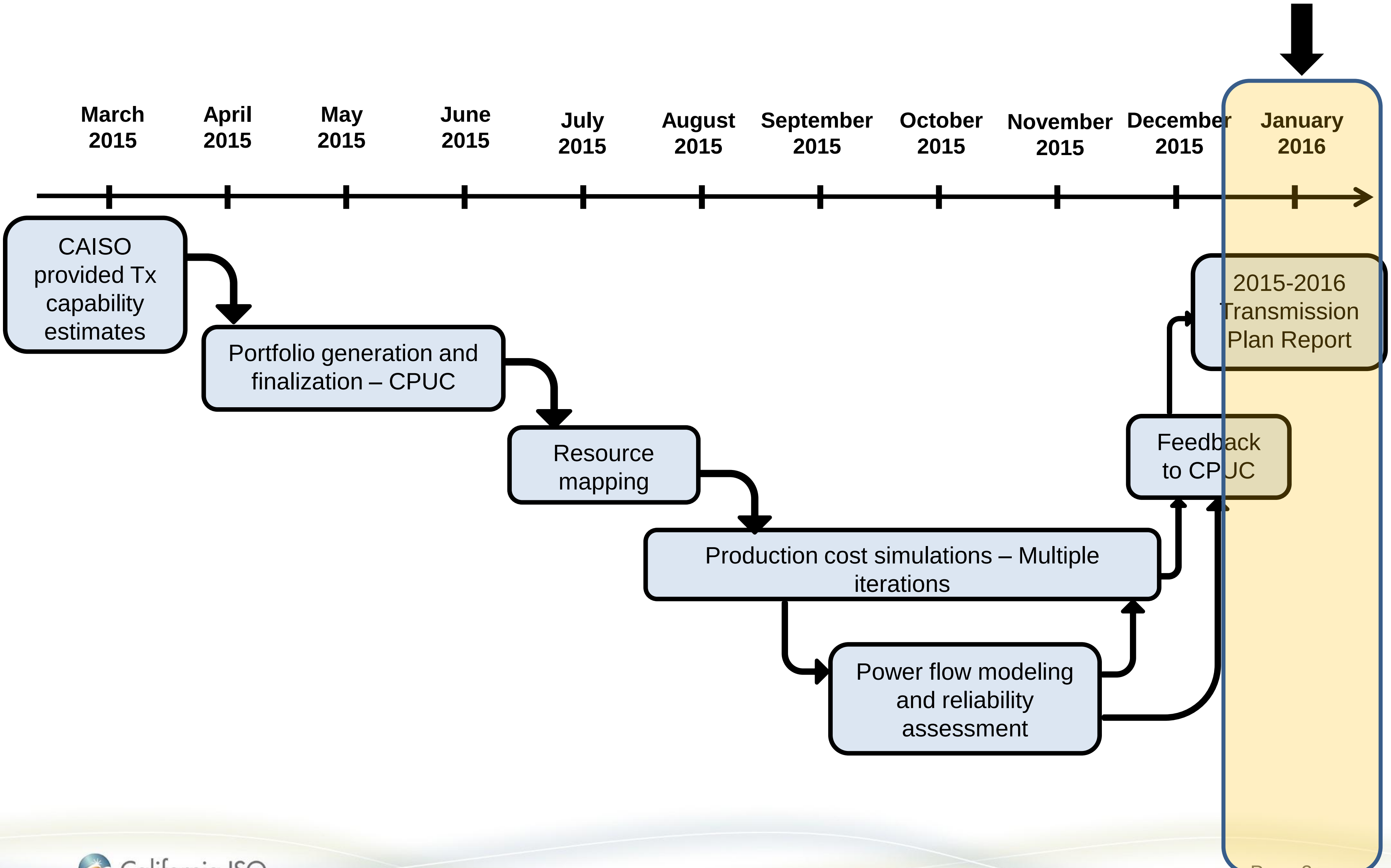

- ❑ Iterative process used to achieve 33% RPS goals
- ❑ This process results in policy-driven transmission upgrade approval
- ❑ Most procured generation assumed to have FCDS

<u>*Iterative process used to test preliminary 50% RPS portfolios*</u>



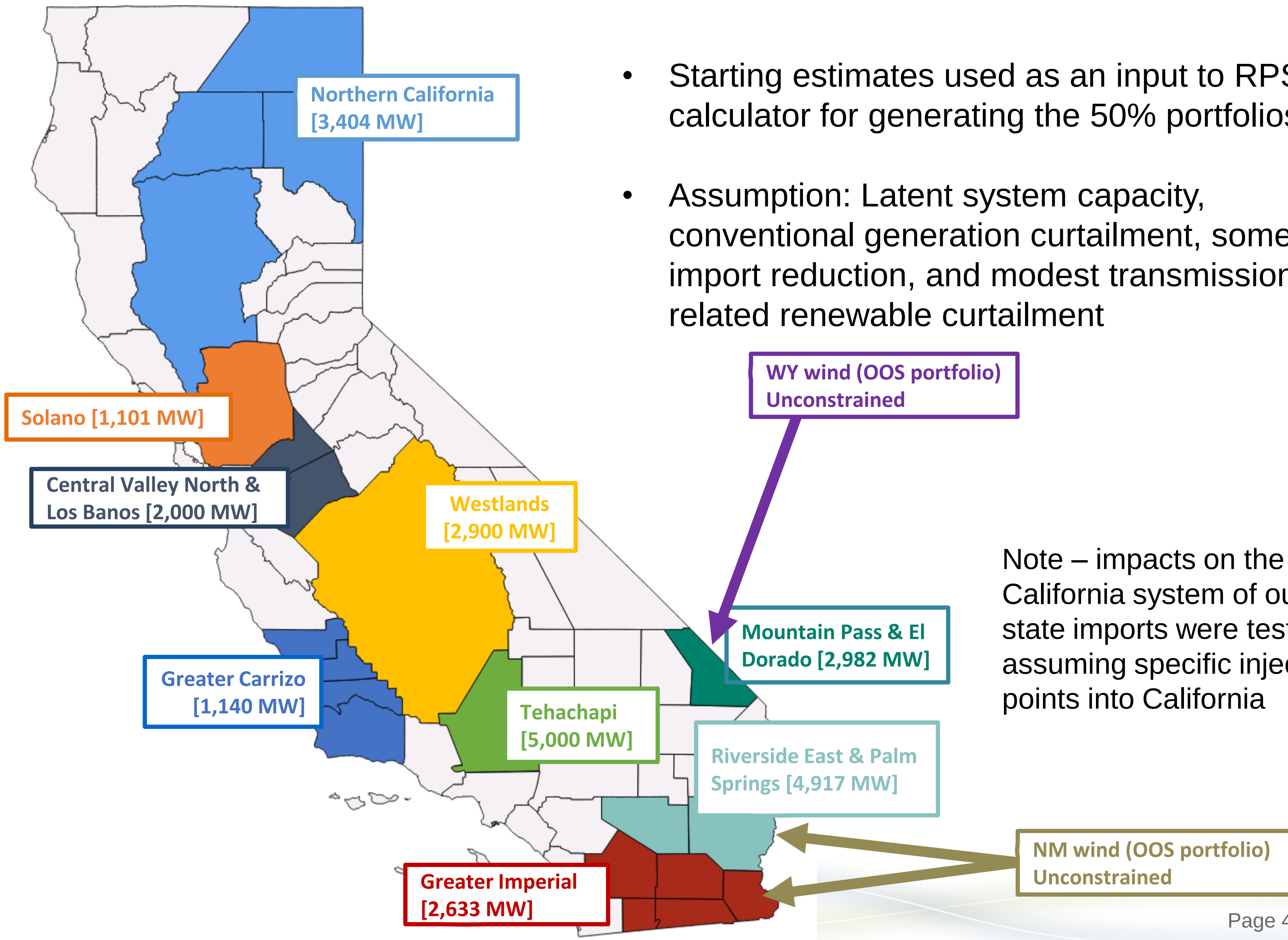

- ❑ Strictly an informational effort
- ❑ Procured gen assumed to be EO
- ❑ ***<u>Objective</u>***
  - To test and revise the transmission (Tx) capability numbers provided by CAISO
  - Preliminary transmission stress-test

# 50% Special study timeline (in 2015-2016 planning cycle)



# Initial transmission capability estimates for “energy only” resources

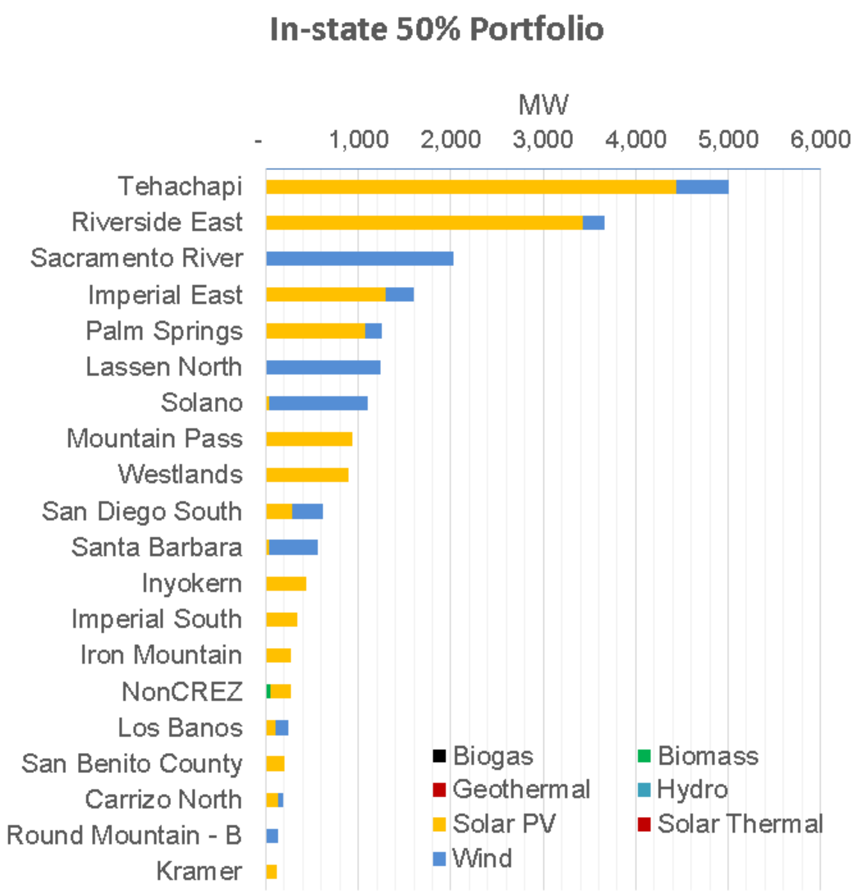
- Starting estimates used as an input to RPS calculator for generating the 50% portfolios
- Assumption: Latent system capacity, conventional generation curtailment, some import reduction, and modest transmission-related renewable curtailment

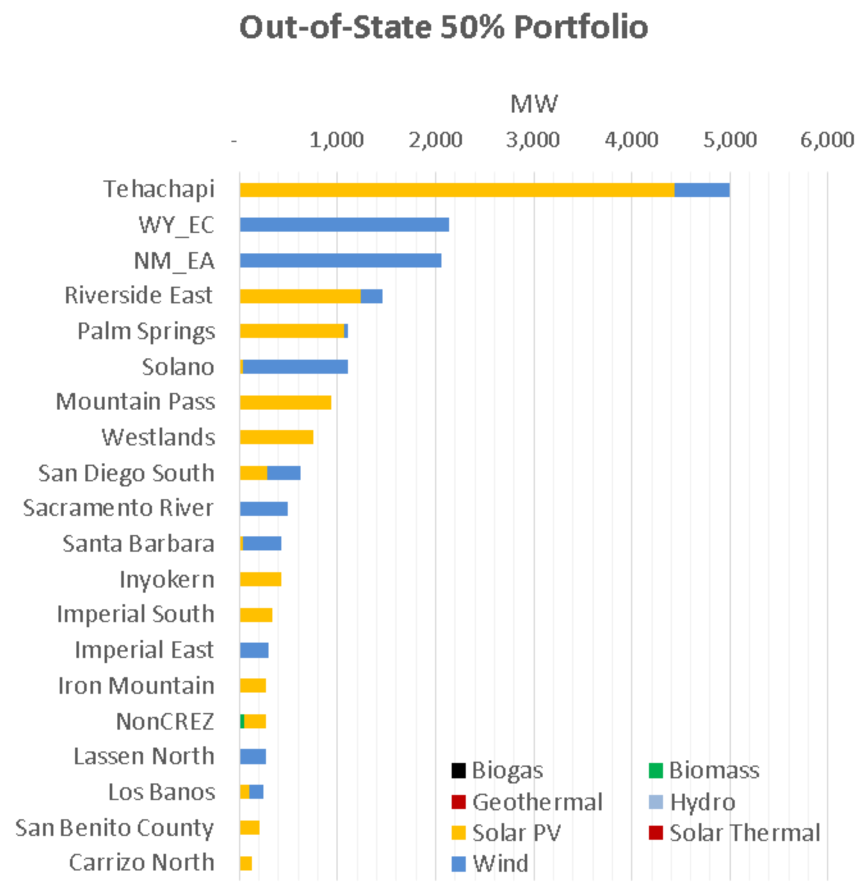



Note – impacts on the California system of out of state imports were tested by assuming specific injection points into California

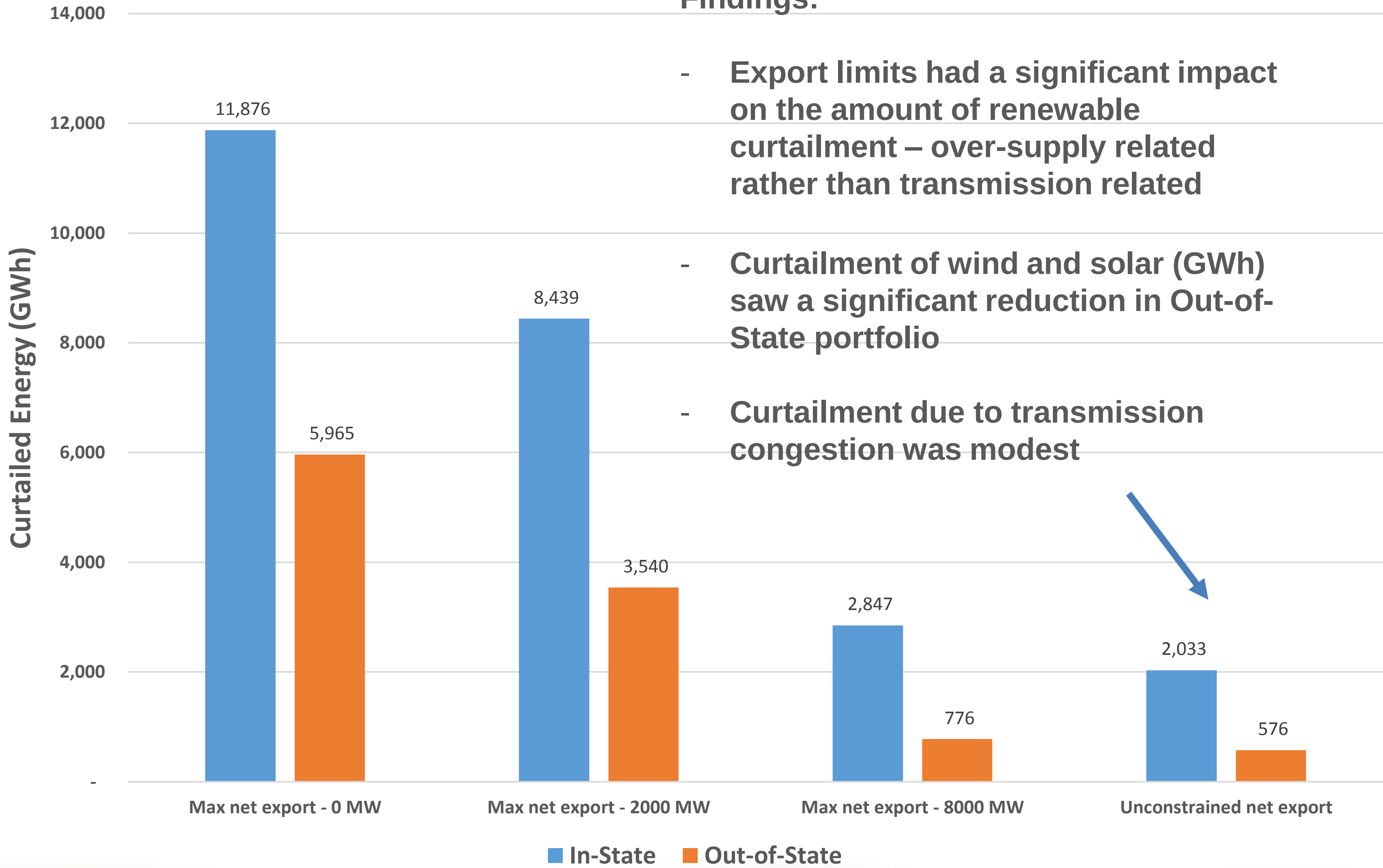
# Portfolios selected for the special study

- RPS calculator v6 was used to generate the portfolios



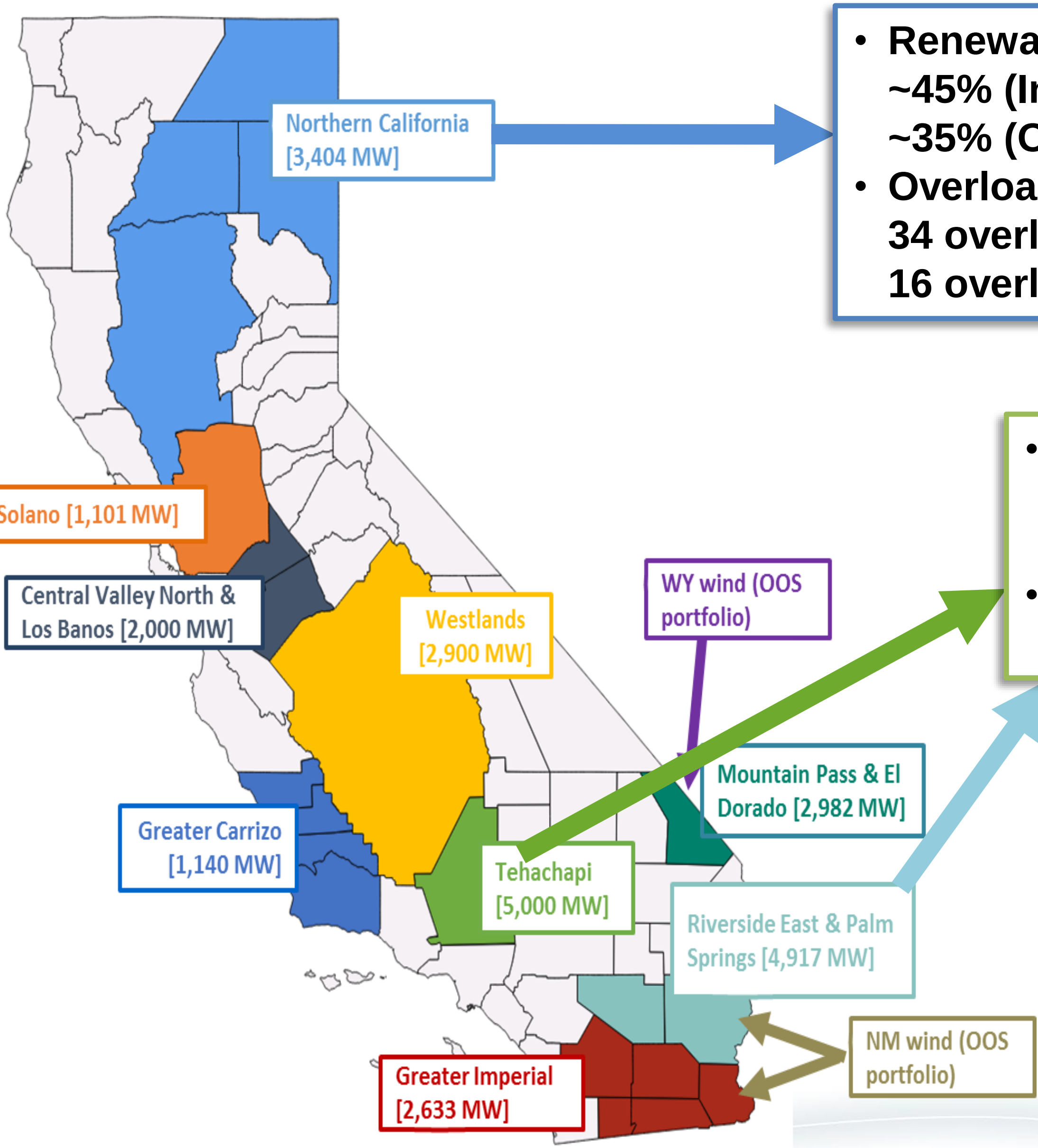
# Curtailment was tested for a range of export assumptions




**Findings:**

- **Export limits had a significant impact on the amount of renewable curtailment – over-supply related rather than transmission related**
- **Curtailment of wind and solar (GWh) saw a significant reduction in Out-of-State portfolio**
- **Curtailment due to transmission congestion was modest**

# Salient observations




- **Renewable Energy curtailed:**
  **~45% (In-state)**
  **~35% (OOS)**
- **Overloads:**
  **34 overloads (In-state)**
  **16 overloads (OOS)**

- **Several N-1-1 and a few N-2 issues require pre-contingency renewable curtailment (>1,000 MW)**
- **Maintenance conditions could pose challenges**

**Solano, Santa Barbara, Westlands, Northern CA**
- Wide-spread overloads on sub-transmission
- Curtailment due to this congestion – not captured

# Conclusion

- Transmission capability estimates for the all the zones appear to be reasonable for developing future portfolios for additional transmission studies, with the following refinements –

  - **Northern CA zone:**
    - We recommend splitting this zone into smaller zones and updating the transmission capability numbers

  - **Tehachapi and Riverside zones:**
    - At risk of substantial renewable curtailment (>1000 MW) under maintenance scenarios
    - But RPS calculator seems to treat these as high value resources, so we do not want to reduce the transmission capability estimate at this point.

  - **Solano, Westlands, Santa Barbara zones:**
    - Obvious issues on <230 kV system
    - As long as local upgrades or collector stations deliver these resources to 230 kV system in these zones, the transmission capability numbers are good.
    - Incorporate specific delivery points in RPS calculator

# Next steps

- CAISO will work with the CPUC to incorporate the following into the RPS calculator
  - Refinements to transmission capability estimates
  - Specific delivery points for resources in zones which resulted in widespread local reliability issues

- 2016-2017 Special Study:
  - We do anticipate further special studies
  - Detailed scope will consider the CPUC's decisions regarding the next steps for the RPS calculator, study objectives, and consideration of these final results of 2015-2016 special study
  - We will need to consider the potential impact of transmission related curtailment on conventional generation
  - We anticipate an out-of-state resource portfolio to be part of this special study

# Frequency Response Study

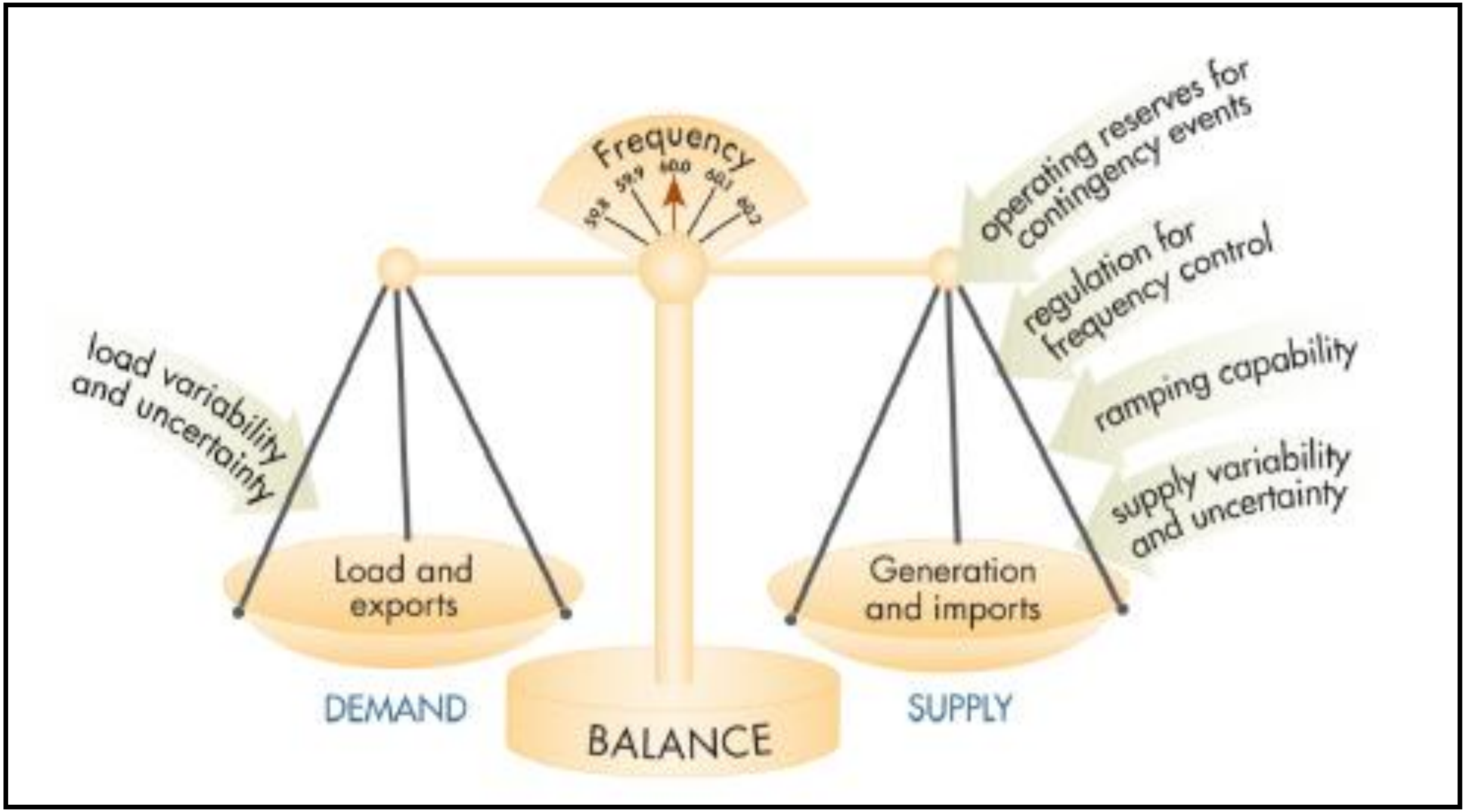
*Irina Green*
*Senior Advisor Regional Transmission Engineer*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

# Presentation Summary

- Frequency response basics
- Study assumptions, methodology and goals
- Study results and conclusions

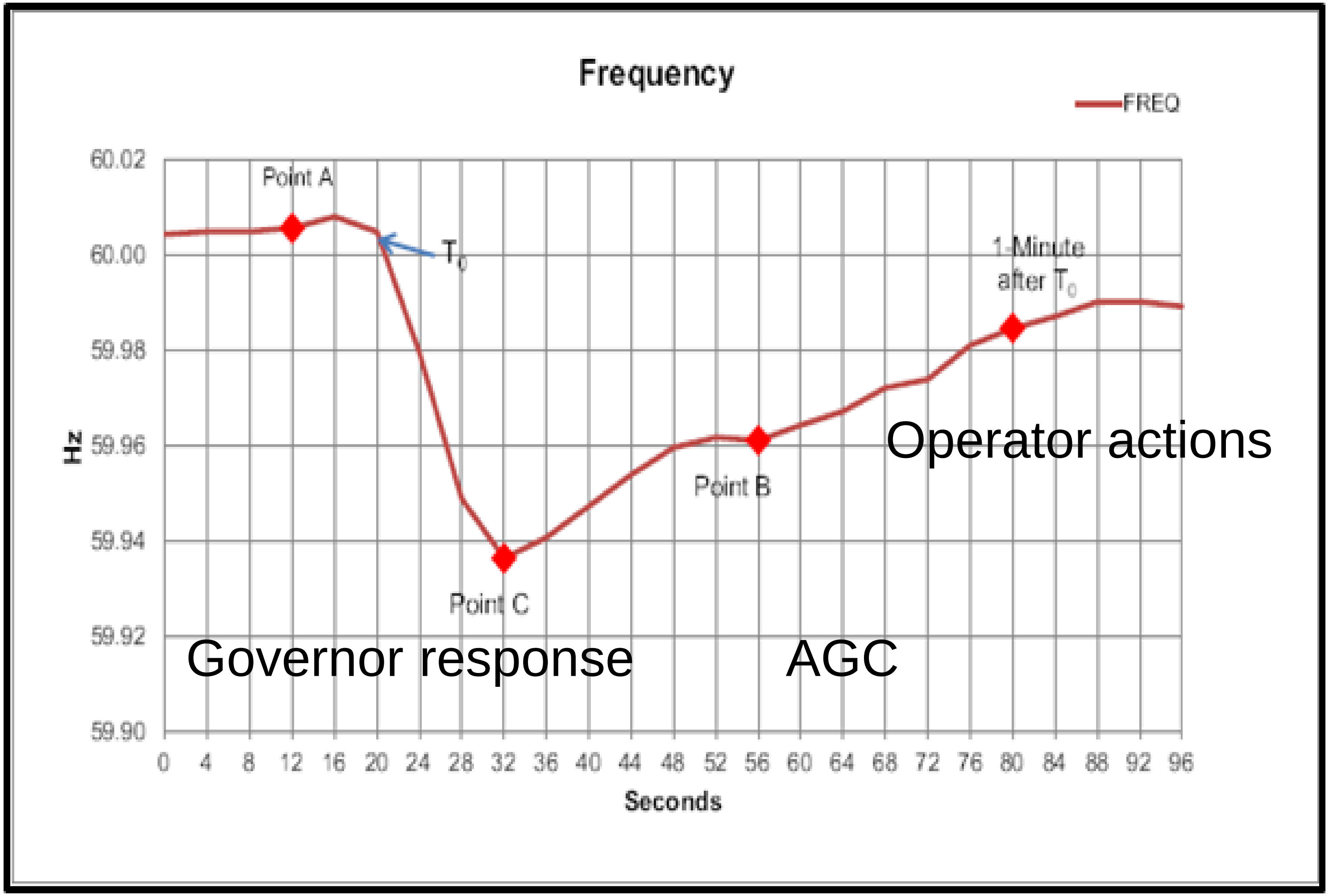
# Continuous Supply and Demand Balance



# Governor Response

- Each generating unit will contribute to system regulation according to the overall gain set in the governor control loop
- Each governor is acting to control speed, increasing its output when frequency is below the set point
- Droop = Change in percent frequency per change in percent output, e.g.,
  - *Frequency drops to 59.9 Hz, with 5% droop setting, unit responds with ([60-59.9]/60)/0.05 = 3.33% of rated power*
- Governor response has enormous impact on frequency regulation
- Poor system frequency regulation can lead to load shedding, generator trips
- For meaningful studies of off-nominal frequency events, it is essential to properly characterize the response of each generator

# Primary Frequency Response




Point C – nadir

Point B – settling frequency

Nadir needs to be higher than set-point for UFLS (59.5 Hz)

# Frequency Response Obligation (FRO)

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

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

- FRO for the Interconnection is established in BAL-003-1 Frequency Response & Frequency Bias Setting Standard
- For WECC, FRO is 858 MW/0.1Hz
- Balancing Authority FRO allocation

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

- For the CAISO, FRO is approximately 30% of WECC FRO (258 MW/0.1Hz)

# Other Frequency Response Metrics

- The headroom is defined as a difference between the maximum capacity of the unit and the unit's output.
  - To have an adequate frequency response, sufficient headroom is needed
- Kt - the ratio of generation that provides governor response to all generation running on the system
  - It is used to quantify overall system readiness to provide frequency response.
  - Kt is defined as the ratio of power generation capability of units with governors to the MW capability of all generation units.

# Study assumptions and metrics

- Starting case: off–Peak spring case of 2025 from 2015-2016 Transmission Plan
- Load modeled with WECC composite load models
- Latest WECC dynamic models for renewable generation
- Contingency studied: simultaneous loss of two Palo Verde nuclear units
- Determine Frequency Response Measure (FRM) for WECC and ISO
- The impact of unit commitment on frequency response
- The impact of generator output level on governor response
  - Headroom or unloaded synchronized capacity
  - Speed of governor response
  - Kt - ratio of generators with governor response to total generation
- Sensitivity studies: case with 50% of renewable generation

# Frequency Response Study

- Study goal – determine if the ISO can meet its FRO with the most severe contingency
- FRO determined by NERC in 2015 was lower than the FRO in 2014
  - 949 MW/0.1 Hz for WECC, 285 MW/0.1Hz for the ISO in 2014
  - 858 MW/0.1 Hz for WECC, 258 MW/0.1Hz for the ISO in 2015
- Determine required headroom on frequency-responsive units for the ISO to meet its FRO
- Determine the ratio of frequency responsive units for the ISO to meet its FRO
- Compare study results with responses for actual disturbances

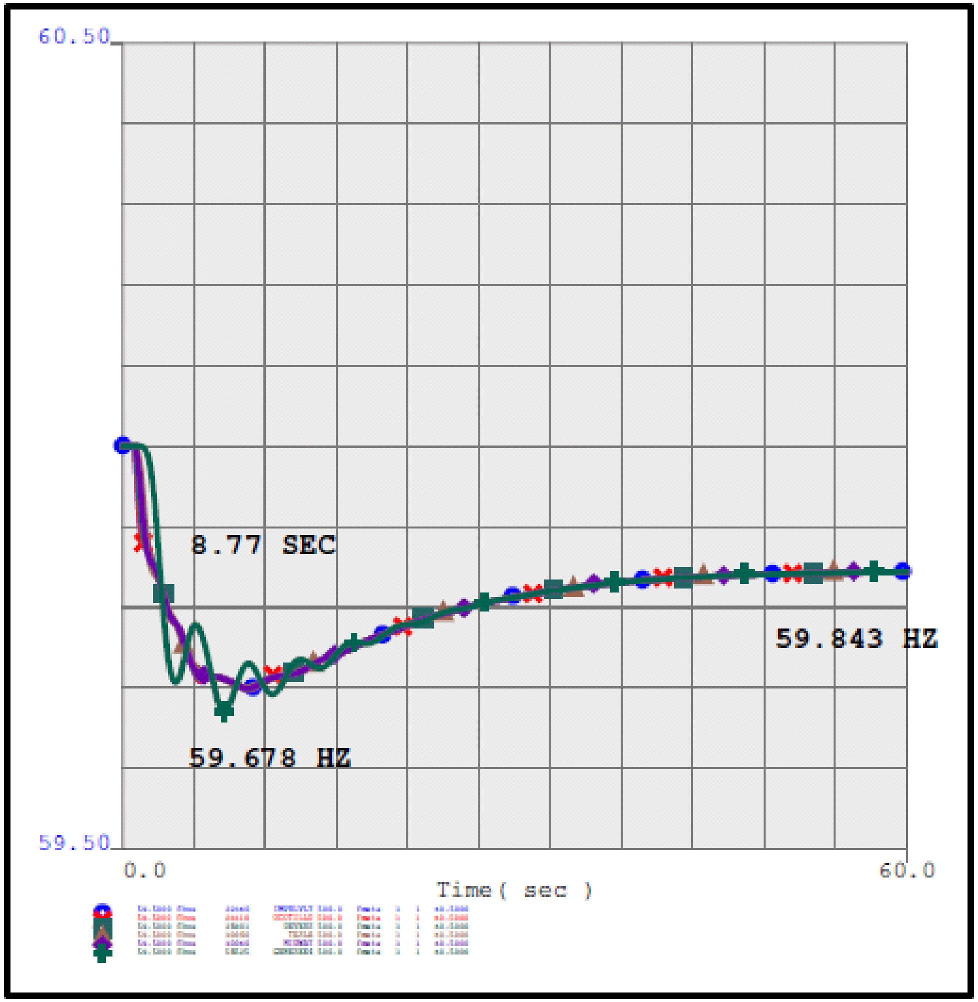
# Study Methodology

- Starting case: Spring off-peak 2025
- Study an outage of two Palo Verde Units, run dynamic stability simulation for 60 seconds
- Determine Frequency Response Measure (FRM) for WECC and for the ISO and compare it with Frequency Response Obligation (FRO)
- If FRO is met, reduce headroom and determine at which conditions (headroom and ratio of generators with responsive governors) the FRO will not be met
- If FRO is not met, increase headroom and determine at which conditions, the FRO will be met
- Determine required headroom and ratio of generators with responsive governors to meet the ISO's FRO

# Study Results

- For the base case of 2025 Spring off-peak, FRO was met both for WECC and the ISO
  - Response from WECC 1,527 MW/0.1 Hz
  - Response from ISO 284 MW/0.1 Hz
  - WECC Headroom 15,500 MW, 722 responsive units
  - ISO Headroom 2,416 MW, 146 responsive units
  - Responsive generation capacity in WECC 41%
  - Responsive generation capacity in ISO 29%
- The standard was met for this case due to the lower FRO in 2015 compared to 2014
- Subsequent study cases had higher output from renewable units
- Cases with lower headroom had fewer governor responsive units and their dispatch was higher

# Frequency with an outage of two Palo Verde units in the 2025 Spring off-Peak case



# Cases Studied

| | | 2025 Spring off-peak base | Renewables, replacing base loaded | Reduced Headroom in ISO | Reduced Headroom ISO and WECC | Reduced Headroom WECC only | Extreme Low Headroom WECC only |
|---|---|---|---|---|---|---|---|
| LOAD, including pumps and motors | ISO (incl. Muni) | 28,559 | 28,559 | 28,559 | 28,559 | 28,559 | 28,559 |
| | Total WECC | 96,382 | 96,382 | 96,382 | 96,382 | 96,382 | 96,382 |
| GENERATION, TOTAL | ISO (incl. Muni) | 29,134 | 29,183 | 29,171 | 29,182 | 29,183 | 29,183 |
| | Total WECC | 99,406 | 99,451 | 99,445 | 99,457 | 99,454 | 99,472 |
| GENERATION, RESPONSIVE GOVERNORS | ISO (incl. Muni) DISPATCH | 6,570 | 6,570 | 6,197 | 6,205 | 6,570 | 6,570 |
| | ISO (incl. Muni) CAPACITY | 9,196 | 9,196 | 7,333 | 7,333 | 9,196 | 9,196 |
| | Total WECC, DISPATCH | 31,499 | 31,471 | 31,127 | 31,359 | 31,555 | 30,974 |
| | Total WECC, CAPACITY | 47,018 | 46,986 | 45,157 | 40,572 | 42,144 | 39,131 |
| RENEWABLES, NON RESPONSIVE | ISO (incl. Muni) | 4,752 | 7,318 | 7,318 | 7,318 | 7,318 | 7,318 |
| | Total WECC | 9,172 | 11,738 | 11,738 | 11,738 | 11,738 | 11,738 |
| CONVENTIONAL, NON RESPONSIVE | ISO (incl. Muni) | 17,812 | 15,295 | 15,656 | 15,659 | 15,295 | 15,295 |
| | Total WECC | 58,735 | 56,242 | 56,580 | 56,450 | 56,161 | 56,760 |
| DISPATCH OF RESPONSIVE GENERATION, % OF CAPACITY | ISO (incl. Muni) | 71.4% | 71.4% | 84.6% | 84.6% | 71.4% | 71.4% |
| | Total WECC | 67.0% | 67.0% | 68.9% | 77.3% | 74.9% | 79.2% |
| Kt - ratio of responsive generation to total | ISO (incl. Muni) | 28.9% | 28.9% | 24.2% | 24.2% | 28.9% | 28.9% |
| | Total WECC | 40.9% | 40.9% | 39.8% | 37.3% | 38.3% | 36.4% |

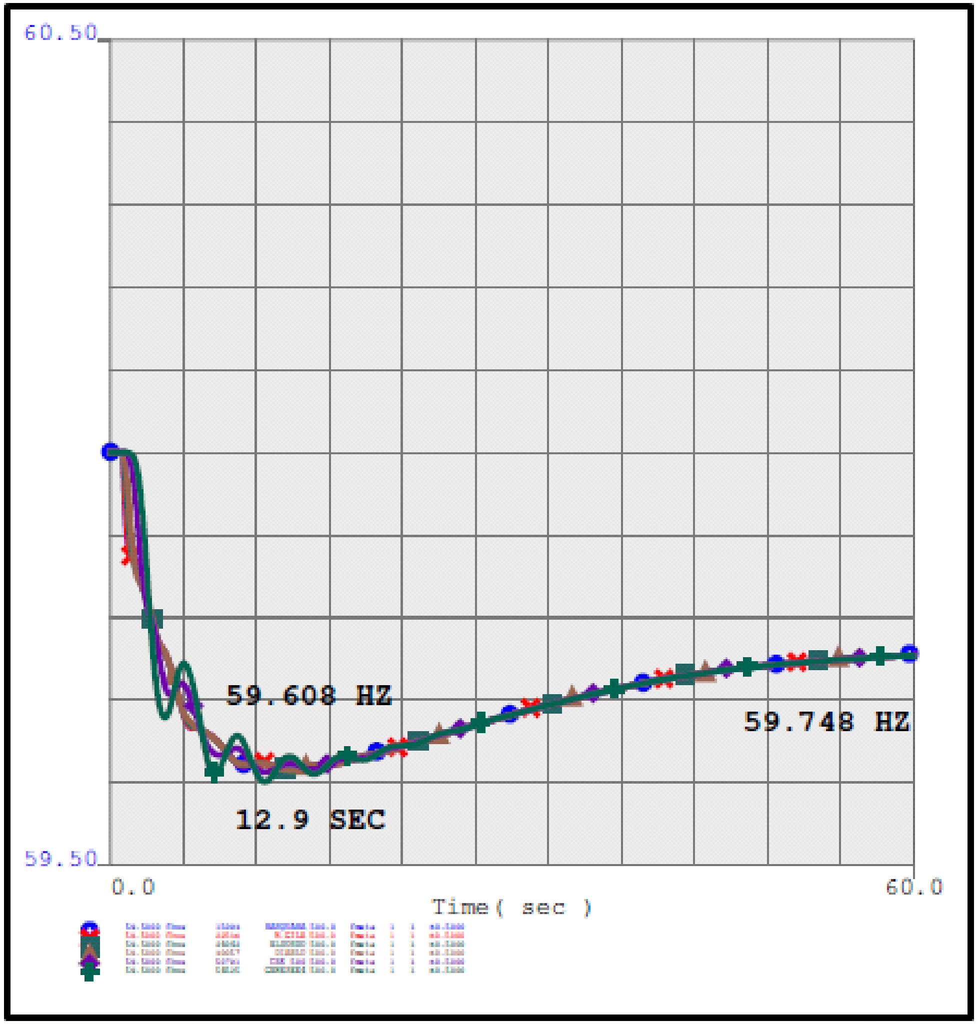
No difference in frequency response if increase in wind and solar PV is compensated by decrease in base loaded generation (first two cases)

# Study Results – Cases with Reduced Headroom

- ISO only, settling frequency 59.839 Hz, nadir 59.700 Hz
  - ISO headroom 1,000 MW, total WECC 14,000 MW
  - Kt, ISO 24%, total WECC 40%
  - FRM – ISO 196 MW/0.1 Hz, WECC 1,433 MW/0.1Hz
- ISO and WECC, settling frequency 59.768 Hz, nadir 59.642 Hz
  - ISO headroom 1,000 MW, total WECC 9,200 MW
  - Kt, ISO 24%, total WECC 37%
  - FRM – ISO 166 MW/0.1 Hz, WECC 989 MW/0.1Hz
- WECC only, settling frequency 59.791 Hz, nadir 59.658 Hz
  - ISO headroom 2,416 MW, total WECC 10,620 MW
  - Kt, ISO 29%, total WECC 38%
  - FRM – ISO 276 MW/0.1 Hz, WECC 1,104 MW/0.1Hz
- WECC extreme low, settling 59.748 Hz, nadir 59.608 Hz
  - ISO headroom 2,416 MW, total WECC 8,175 MW
  - Kt, ISO 29%, total WECC 36%
  - FRM – ISO 263 MW/0.1 Hz, WECC 883 MW/0.1Hz

Extreme case

# Frequency with an outage of two Palo Verde units in the case with extreme low WECC headroom




ISO minimum values to provide frequency response within the FRO:

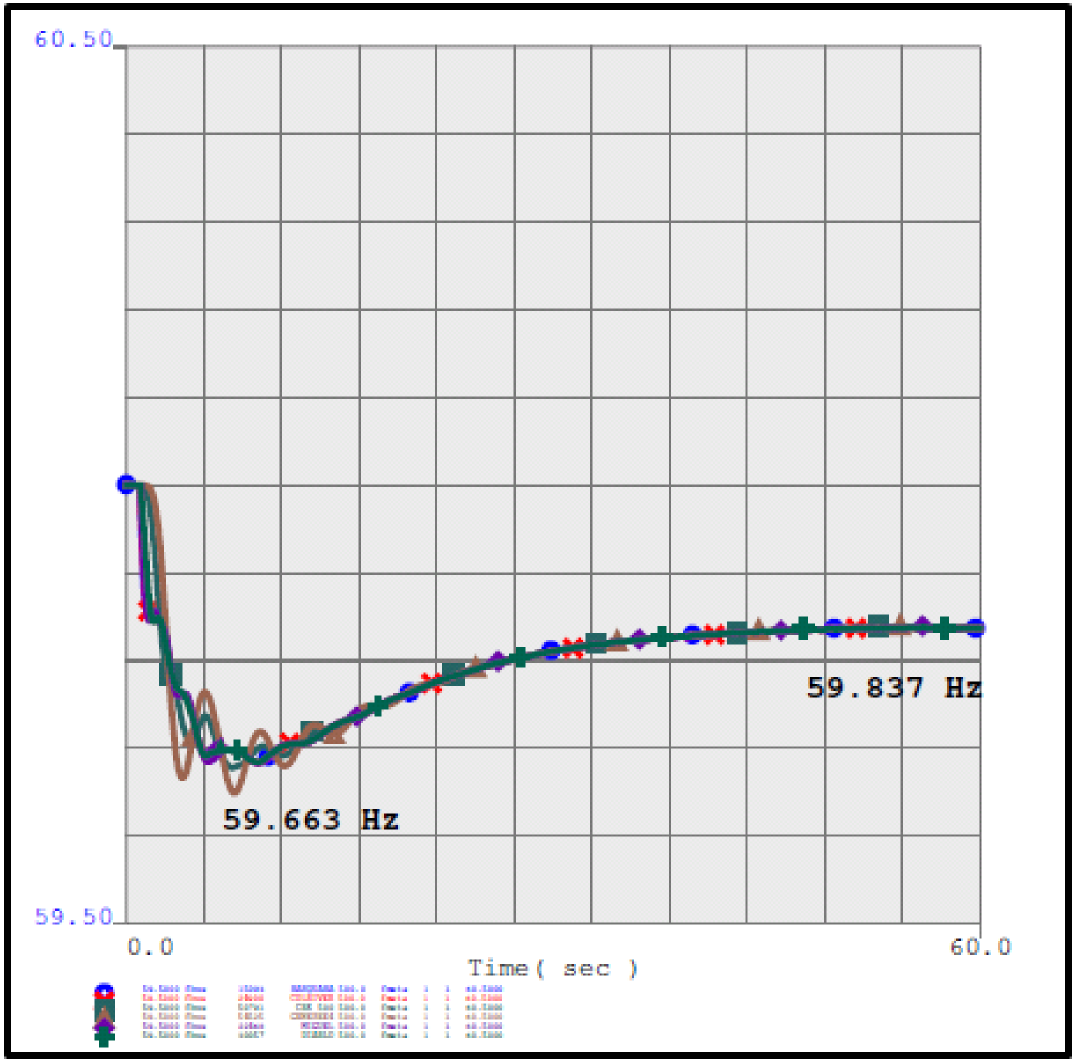
Headroom 2500 MW,

Percentage responsive generation capacity 30%

Average generation dispatch on responsive units in this case -70%

With lower dispatch, required headroom will be higher

# Sensitivity Case with 50% Renewables




Frequency response WECC - 1436 MW/0.1 Hz, within FRO

ISO 116 MW/0.1 Hz – significantly deficient

# Conclusions

- Frequency response from WECC is within its Frequency response obligation
- Acceptable frequency response from ISO for 2025 Spring off-peak, but not with 50% of renewable generation
- Optimistic results compared with measured response to actual disturbances, although average response is close to what is expected
- If the unit is not responding to frequency dips, its technology doesn't matter
- Value of the required headroom substantially depends on the generation dispatch, therefore the required headroom cannot be universally determined
- The exception is when a unit is dispatched close to its capacity, then it will not have sufficient room to respond to frequency dips.

# Conclusions (continued)

- A more universal indicator of the frequency response is the percentage of the frequency responsive capacity versus total generation capacity (metric Kt).
- The study results showed that this metric has to be above 30% in the ISO and approximately above 35% in total of WECC for both ISO and WECC to respond above its Frequency Response Obligations.
- This is in addition to frequency-responsive units not to be dispatched above 90-95% of their capacity to have sufficient room to increase their output in response to frequency decline.
- Governor model validation based on actual measurements is needed

Questions?

Comments?

# Mid-Term and Long-Term LCR for the LA Basin and San Diego Areas
# Long-Term LCR for the Big Creek/Ventura Area

*David Le*

*Senior Advisor Regional Transmission Engineer*

*2015-2016 Transmission Planning Process Stakeholder Meeting*

*February 18, 2016*

# Overview

- Discuss long-term (2025) local capacity requirements for the LA Basin, San Diego and Big Creek/Ventura areas
- Discuss mid-term (2021) local capacity requirements for the LA Basin and San Diego areas
  - Two mid-term scenarios:
    - Mesa Loop-In Project achieving commercial operation prior to summer 2021
    - Mesa Loop-In Project's commercial operation date is delayed beyond summer 2021

# Long-Term Local Capacity Requirements for the LA Basin, San Diego and Big Creek/Ventura Areas

# High-Level Findings

- The ISO's analysis indicated in this planning cycle that the authorized long-term resources, forecast load, and previously-approved transmission projects working together continue to meet the forecast reliability needs in the LA Basin and San Diego areas.
- Updated study results identified and addressed a sub-area issue in the western LA Basin.
- However, due to the inherent uncertainty in the significant volume of preferred resources and other conventional mitigations, the situation is being continually monitored in the Southern California Reliability forum in case additional measures are needed.

# Los Angeles Basin and San Diego local capacity requirement areas

Current OTC installed capacity 3,806 MW (retired in the mid and long-term LCR studies)


Current OTC installed capacity 946 MW (retired in the mid and long-term LCR studies)

# Summary of Long Term Procurement Plan Assumptions for Local Capacity in the LA Basin and San Diego Areas

- Summary of SCE's and SDG&E's procurement from LTPP Tracks 1 and 4

| LTPP Tracks 1 & 4 Assumptions | LTPP EE (MW) | Behind the Meter Solar PV (NQC MW) | Storage 4-hr (MW) | Demand Response (MW) | Conventional resources (MW) | Total Capacity (MW) |
|---|---|---|---|---|---|---|
| CPUC Decisions on SCE-submitted procurement selection for the western LA Basin | 124 | 37.9 | 263.6 | 5 | 1,382 | 1,813 |
| SDG&E procurement assumptions | 40 | 0 | 150 | 60 | 800 | 1,050 |

- Assumptions for preferred resources and energy storage in San Diego are provided above as proxy values per discussion with SDG&E at WECC forums for the 2026 TEPPC Common Case production cost model. These proxy values will be updated in the future upon SDG&E's filing at the CPUC for the procurement selection of preferred resources for local capacity needs.

# Long-term LCR Needs in the LA Basin

## Western LA Basin Sub-area

- Details are available in the Appendix D of the draft 2015-2016 Transmission Plan (https://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx)

| 2025 | QF (MW) | Wind (MW) | Muni (MW) | Market (MW) | RPS DG (NQC MW) | LTPP Track 4 Baseline DR (MW) | Max. Qualifying Capacity (MW) |
|---|---|---|---|---|---|---|---|
| Available existing resources for long-term horizon | 517 | 8 | 588 | 1,285 | 157 | 173 | 2,728 |

| 2025 | Local Resource Capacity Needed (MW) | Potential Resource Deficiency (MW) | Break-downs of Projected 2025 Available Resources for the western LA Basin | | |
|---|---|---|---|---|---|
| | | | Available Existing Resources (MW) | Total CPUC-Approved Procurement for LTPP Tracks 1 & 4 (MW) | Total Available Resources (MW) |
| Category B (Single) | 5,236 | (695) | 2,728 | 1,813 | 4,541 |
| Category C (Multiple) | 5,514 | (973) | 2,728 | 1,813 | 4,541 |

- Category B contingency includes G-1 of the new Alamitos CCGT (640 MW) and N-1 of Mesa-Lighthipe 230kV line (thermal loading concern on Mesa-Laguna Bell #1 230kV); Category C contingency involves N-1-1 of Mesa-Redondo 230kV, followed by Mesa-Lighthipe 230kV line (thermal loading on Mesa-Laguna Bell #1 230kV).
- To mitigate this potential resource deficiency concern, potential options include: (a) additional 687 MW of procurement of LTPP preferred resources (at effective locations) and repurposing of additional of 286 MW of existing DR; OR (b) implement cost effective and small-scale transmission upgrade options.

# Long-term LCR Needs in the LA Basin (cont'd)

## Western LA Basin Sub-area (cont'd)

- Thirteen different options were evaluated to mitigate south of Mesa 230kV lines loading concerns under contingency conditions
  - Details are summarized in Table D7 in the Appendix D of the draft 2015-2016 Transmission Plan (https://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx)
- Options include additional local capacity procurement (up to LTPP Tracks 1 and 4 authorized amounts) and/or additional transmission upgrades were evaluated
  - Option 1 - Local capacity resource procurement option (i.e., the mitigation is entirely composed of adding new resources without new transmission upgrades)
    - An additional 692 MW of preferred resources or energy storage at effective location(s) to be procured beyond the CPUC-approved procurement for the Western LA Basin sub-area.
    - An additional 286 MW of existing demand response beyond the baseline amount of 189 MW needs to be repurposed.
    - This option would mitigate identified loading concern but does not have margin for future load growth.

# Long-term LCR Needs in the LA Basin (cont'd)

**Western LA Basin Sub-area (cont'd)**

- Option 2 - the following are the more effective and potentially lower cost transmission alternatives that were evaluated:
  - Opening new Mesa 500/230kV Bank #2 under contingency conditions; or
  - Re-arranging Mesa – Laguna Bell 230kV lines and opening Laguna Bell – La Fresa 230kV line under contingency conditions; or
  - Installing 10-Ohm series reactors on the Mesa – Laguna Bell #1 230kV line and potentially the Mesa – Redondo 230kV line in the future (i.e., beyond 10-year horizon for this line)
- Of all the evaluated options, the option of installing 10-Ohm series reactors on the Mesa-Laguna Bell #1 230 kV line and potentially the Mesa-Redondo 230kV line appears to be the most effective alternative and potentially has the lowest cost. Variation of this option includes thyristor-controlled series reactor to be inserted upon occurrence of the second N-1 contingency under peak load conditions.
- Both options 1 and 2 above require the development of 250 MW of preferred resources and energy storage in the San Diego area, which are within the authorized ranges already approved by the CPUC as part of the track 1 and track 4 decisions.

# Long-term LCR Needs in the LA Basin (cont'd)

## Eastern LA Basin Sub-area

- Details are available in the Appendix D of the draft 2015-2016 Transmission Plan (https://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx)

| 2025 | QF (MW) | Wind (MW) | Muni (MW) | Market (MW) | RPS DG (NQC MW) | 20-Min DR (MW) | Max. Qualifying Capacity (MW) |
|---|---|---|---|---|---|---|---|
| Available existing resources for long-term horizon | 220 | 60 | 581 | 2,648 | 22 | 0 | 3,531 |

| 2025 | Local Resource Capacity Needed (MW) | Potential Resource Deficiency (MW) | Projected 2025 Available Resources for the eastern LA Basin | | |
|---|---|---|---|---|---|
| | | | Available Existing Resources (MW) | Total CPUC-Approved Procurement for LTPP Tracks 1 & 4 (MW) | Total Available Resources (MW) |
| Category B (Single) | 2,132 | 0 | 3,531 | N/A | 3,531 |
| Category C (Multiple) | 2,805 | 0 | 3,531 | N/A | 3,531 |

- Category B contingency includes a G-1 of Otay Mesa (603 MW) and an N-1 Imperial Valley – North Gila 500kV line (post-transient voltage instability); Category C contingency includes an N-1-2 of Alberhill-Serrano 500kV line, followed by an N-2 of Red Bluff-Devers 500kV lines (post-transient voltage instability).

# Long-term LCR Needs in the LA Basin (cont'd)

## Overall LA Basin LCR Need

- Overall LA Basin LCR Need = Western LA Basin LCR Need + Eastern LA Basin LCR Need
    - Overall LA Basin LCR Need = 5,514 + 2,805 MW
      = 8,319 MW
- The following are observations when compared to the long-term LCR results (for 2024) in the previous 2014-2015 TPP cycle:
    - Overall LCR need is similar (8,350 MW for 2024 from the 2014-2015 TPP 2024 long-term LCR studies)
    - Western LA Basin LCR need is increased by about 600 MW due to impact of higher loading on the 230kV lines south of the new proposed Mesa Substation caused by increased level of renewable resource outputs based on the use of NQC values for RPS portfolio resources (current RA methodology)
    - Eastern LA Basin LCR need is reduced by about 650 MW due to lower forecast demand that reduces potential post-transient voltage instability impact

# Long-Term LCR Needs in the San Diego Sub-Area

## San Diego sub-area LCR Need

| 2025 | QF (MW) | Wind (MW) | Market (MW) | New RPS DG (NQC MW) | DR (MW) | Max. Qualifying Capacity (MW) |
|---|---|---|---|---|---|---|
| Available/anticipated resources | 164 | 9 | 2,621 | 67 | 17 | 2,878 |

| 2025 | Local Resource Capacity Needed (MW) | Potential Resource Deficiency (MW) | Projected 2025 Available Resources for the San Diego Sub-Area (MW) |
|---|---|---|---|
| Category B (Single) | 2,316 | 0 | 2,878 |
| Category C (Multiple) | 3,128 | (250) | 2,878 |

- Category B contingency involves G-1 of Otay Mesa (603 MW) and N-1 of Imperial Valley – North Gila 500kV line (post-transient voltage instability); Category C contingency involves N-1-1 of Mesa-Redondo 230kV, followed by Mesa-Lighthipe 230kV line (thermal loading on Mesa-Laguna Bell #1 230kV).
- To mitigate this potential resource deficiency concern, potential option includes additional local capacity procurement of 250 MW of preferred resources and energy storage in San Diego area (this amount is within the ceiling of 300 MW of preferred resources and energy storage per the CPUC Decisions on LTPP Track 4 and Carlsbad Energy Center).

# Long-Term LCR Needs in the Overall San Diego-Imperial Valley Area

## <u>Overall San Diego-Imperial Valley LCR Need</u>

| 2025 | QF (MW) | Wind (NQC MW) | Market (MW) | New RPS DG (NQC MW) | DR (MW) | Max. Qualifying Capacity (MW) |
|---|---|---|---|---|---|---|
| Available/anticipated resources | 164 | 133 | 4,237 | 67 | 17 | 4,618 |

| 2025 | Local Resource Capacity Needed (MW) | Potential Resource Deficiency (MW) | Projected 2025 Available Resources for the San Diego-Imperial Valley Area (MW) |
|---|---|---|---|
| Category B (Single) | 3,151 | 0 | 4,618 |
| Category C (Multiple) | 4,868 | (250) | 4,618 |

- Category B contingency includes G-1 of Otay Mesa (603 MW) and N-1 of Imperial Valley – North Gila 500kV line (post-transient voltage instability); Category C contingency includes N-1-1 of Mesa-Redondo 230kV, followed by Mesa-Lighthipe 230kV line (thermal loading on Mesa-Laguna Bell #1 230kV).
- To mitigate this potential resource deficiency concern, potential option includes additional local capacity procurement of 250 MW of preferred resources and energy storage in San Diego area (this amount is within the ceiling of 300 MW of preferred resources and energy storage per the CPUC Decisions on LTPP Track 4 and Carlsbad Energy Center).

# Long-term LCR Needs in the Overall San Diego-Imperial Valley Area (cont'd)

- The following are observations when compared to the long-term LCR results (for 2024) in the previous 2014-2015 TPP cycle:
  - Overall LCR need is increased by about 700 MW, of which 250 MW is deficient and can be met by procurement of preferred resources and energy storage.
  - The potential procurement for 250 MW of preferred resources and energy storage is within the maximum procurement authorizations from the CPUC Track 4 and Carlsbad Energy Center Decisions.
- For other small sub-areas within San Diego sub-area (i.e., El Cajon, Mission, Bernardo, Esco, Escondido, Pala, Border, Miramar), please refer to the detailed discussion in the Appendix D of the draft Transmission Plan.
  - For the Mission sub-area, please see Section 2.9 for recommended transmission project (Mesa Heights Loop-In & Reconductor) to eliminate the need to operate the Kearny peakers for meeting 40 MW of local capacity requirements.

# Summary of the assessment of the 2025 long-term LCR study results for the LA Basin and San Diego Areas

<table>
<tr><th>No</th><th>Study Scenarios</th><th>Results</th></tr>
<tr><td colspan="3">Alternatives that Do Meet the Identified LCR Need</td></tr>
<tr><td>1</td><td>• Fully procure LTPP Tracks 1 and 4 resources up to maximum authorizations for SCE (i.e., 2500 MW) and SDG&E (i.e., 1100 MW); and<br>• Repurpose a total of 476 MW of existing demand response (i.e., this amount is approximately 286 MW beyond the baseline assumption of 189 MW in the LTPP Track 4 scoping ruling) with adequate operational characteristics (i.e., 20-minute response) , OR</td><td>Then there is no resource deficiency</td></tr>
<tr><td>2</td><td>Alternatively to the above additional resource procurement scenario:<br>• Implement the CPUC recent decisions for SCE’s procurement (i.e., 1813 MW) for the western LA Basin sub-area, and<br>• Procure additional 250 MW of preferred resources for local capacity in the San Diego sub-area (part of the CPUC maximum authorizations of 300 MW of preferred resources for San Diego), and<br>• Implement small transmission upgrades in the western LA Basin (see discussion for the western LA Basin)</td><td>Then there is no resource deficiency; system is more robust than Scenario # 1</td></tr>
</table>

# Summary of the assessment of the 2025 long-term LCR study results for the LA Basin and San Diego Areas (cont'd)

| No | Study Scenarios | Results |
|---|---|---|
| | **Alternatives that Do NOT Meet the Identified LCR Need** | |
| 3A | • LTPP Tracks 1 and 4 are not fully procured up to maximum authorizations (i.e., current CPUC-approved procurement) for the western LA Basin;<br>• However, fully procure 300 MW of preferred resources in San Diego to complete the San Diego local capacity procurement;<br>• Utilize LTPP Track 4 baseline assumptions for existing demand response (i.e., 190 MW for both western LA Basin and San Diego sub-areas);<br>• But there are no further transmission upgrades in the western LA Basin; ***OR*** | Then there would be resource deficiency |
| 3B | Alternately,<br>• Same scenario as Option 2 but AAEE does not materialize as forecast (i.e., 962 MW in the western LA Basin and 401 MW in San Diego sub-area) , ***OR*** | Then there would be resource deficiency |
| 3C | • Same as Option 3A, but the existing demand response is fully repurposed and used (i.e., 894 MW in the western LA Basin and 17 MW in the San Diego sub-area) | Then there would still be resource deficiency |

# Long-term LCR Needs in the Big Creek/Ventura Area

**Moorpark Sub-Area**

- Details are available in the Appendix D of the draft 2015-2016 Transmission Plan (https://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx)
- LTPP procurement selection assumptions for the long-term LCR studies:

| LTPP Assumptions | LTPP EE (MW) | Behind the Meter Solar PV (NQC MW) | Storage 4-hr (MW) | Demand Response (MW) | Conventional resources (MW) | Total Capacity (MW) |
|---|---|---|---|---|---|---|
| SCE procurement selection assumptions | 6 | 5.66 | 0.5 | 0 | 262 | 274.16 |

- Ellwood generation (54 MW) was assumed as an existing resource.
- The most critical contingency is the loss of Moorpark-Pardee 230kV #3 line, followed by an N-2 of Moorpark-Pardee #1 & 2 230kV lines, causes post-transient voltage instability. This contingency is an LCR criteria contingency.
- The 2025 long-term LCR need was determined to be 516 MW, which has a deficiency of 234 MW (total existing resources, after OTC-related generation retirement, is 282 MW).
- SCE-selected procurement of 274.16 MW, summarized above, would mitigate identified deficiency.
- A total amount of 114 MW of AAEE and a retirement of Ormond Beach and Mandalay were modeled in the power flow studies.

# Long-term LCR Needs in the Big Creek/Ventura Area

## Overall Big Creek/Ventura Area

| 2025 | QF (MW) | Muni (MW) | Market (MW) | New RPS DG (NQC MW) | Max. Qualifying Capacity (MW) |
|---|---|---|---|---|---|
| Available existing resources | 769 | 392 | 2,258 | 248 | 3,667 |

| 2025 LCR Needs | Total Requirements (MW) | Existing Resource Need (NQC MW) | Deficiency without Moorpark Sub-Area Local Capacity Procurement (MW) |
|---|---|---|---|
| | | | |
| Category B (Single) | 2,111 | 2,111 | 0 |
| Category C (Multiple) | 2,689 | 2,455 | 234 |

- Category B contingency includes a G-1 of Pastoria CCGT (715 MW) and an N-1 of Sylmar-Pardee 230kV line (thermal loading concern); Category C contingency includes an N-1-1 of Victorville-Lugo 500kV line, followed by an N-1 of Sylmar-Pardee 230kV line #1 (thermal loading concern on the remaining Sylmar-Pardee 230kV #2 line).
- Deficiency can be mitigated by SCE-selected procurement of 274 MW for the Moorpark sub-area.
- A total amount of 282 MW of AAEE and the retirement of Ormond Beach and Mandalay generation were modeled in the power flow studies.

# Long-term LCR Needs in the Big Creek/Ventura Area (cont'd)

**Other Sub-Areas**

- Please refer to the Appendix D of the draft 2015-2016 Transmission Plan for further details on the Rector, Vestal and Santa Clara sub-areas (https://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx)
- These other sub-areas were determined to have sufficient resources to meet local reliability criteria. Ellwood generation is assumed to be available and on-line for the Santa Clara sub-area local reliability analyses.

# Mid-Term Local Capacity Requirements for the LA Basin and San Diego Areas

# Background Information for the Mid-Term LCR Analyses (2021)

**Study Scenario 1**

- The CEC has published a document regarding an Excel-based projection tool, the Local Capacity Annual Assessment Tool (LCAAT) at (http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205657_20150807T153238_Assessing_Local_Reliability_In_Souther_California_Using_A_Local.pdf)
  - The LCAAT projected that there would be a 526 MW and 77 MW of resource deficiency in the LA Basin by 2021 and 2024, respectively.
  - The time frame of 2021 is the first year in which Alamitos, Huntington Beach and Redondo Beach generation would be retired (and some repowered per the CPUC PPTA approvals).
  - Because of the above indications, the CEC staff requested the ISO to perform power flow related studies to determine if there are resource deficiencies for the 2021 time frame.
  - The power flow analyses have the assumptions that all of the ISO Board-approved transmission projects needed for the OTC and SONGS retirement would meet their respective scheduled in-service dates (see chapter 7 of the draft 2015-2016 Transmission Plan).

# Background Information for the Mid-Term LCR Analyses (2021) – cont'd

**Study Scenario 2**

- Unrelated to the CEC request for the 2021 mid-term LCR analyses, the ISO also is monitoring the progress of the ISO Board-approved transmission projects needed prior to the OTC generation retirement by 12/31/2020 in the LA Basin.
- One of the major ISO Board-approved transmission projects is the Mesa Loop-In Project, which would convert the existing Mesa Substation from 230/66kV to a 500/230/66kV substation.
  - The project is currently going through CEQA environmental review process at the CPUC.
- The Mesa Loop-In Project currently has a scheduled in-service date of December 2020. The Alamitos, Huntington Beach and Redondo Beach generating facilities also have December 31, 2020 as compliance date for OTC plants.
- The ISO performed a sensitivity scenario analysis in which the Mesa Loop-In Project's in-service date is delayed beyond summer 2021 to determine potential resource deficiency and back-up mitigation plan.

# Study Results for the Mid-Term Scenario Study No. 1 (CEC-Requested Study)

| 2021 | Total LCR Requirements (MW) | Total Available Existing Resources | CPUC-Approved Local Capacity Procurement (MW) | Total Projected Available Resources (MW) | Deficiency (MW) |
|---|---|---|---|---|---|
| Western LA Basin | 5,117 | 2,728 | 1,813 | 4,541 | (576) |
| Eastern LA Basin | 2,408 | 3,531 | 0 | 3,531 | 0 |
| Total LA Basin | 7,525 | 6,259 | 1,813 | 8,072 | (576) |

- Mesa Loop-In Project is assumed to meet its scheduled on-line date (December 2020) for this scenario
- Critical contingencies and transmission constraints are the same as for the long-term (2025) LCR analysis because the fundamental assumptions are the same (i.e., OTC generation retirements, approved transmission upgrades)
- The identified deficiency is for the western LA Basin, with about 400 MW less than the identified deficiency for the 2025 time frame.
- Identified deficiency can be mitigated with the same options that were evaluated for the long-term LCR analysis (see slides 7 and 8).

# Study Results for the Mid-Term Scenario Study No. 1 (cont'd)

| 2021 | Total LCR Requirements (MW) | Total Available Existing Resources (MW) | CPUC-Approved Local Capacity Procurement (MW) | Total Projected Available Resources (MW) | Deficiency (MW) |
|---|---|---|---|---|---|
| San Diego Sub-Area | 3,038 | 2,078 | 800 | 2,878 | (160) |
| San Diego-Imperial Valley | 4,778 | 3,818 | 800 | 4,618 | (160) |

- Mesa Loop-In Project is assumed to meet its scheduled on-line date (December 2020) for this scenario
- Critical contingencies and transmission constraints are the same as for the long-term (2025) LCR analysis because the fundamental assumptions are the same (i.e., OTC generation retirements, approved transmission upgrades)
- The identified deficiency is for the San Diego sub-area, with about 90 MW less than the identified deficiency for the 2025 long-term planning time frame.
- Identified deficiency can be mitigated with the same options that were evaluated for the long-term LCR analysis (see slides 7 and 8, i.e., procurement of preferred resources and energy storage).

# Study Results for the Mid-Term Scenario Study No. 2 (Mesa Loop-In Project Delayed In-Service Date Scenario)

| 2021 | Total LCR Requirements (MW) | Total Available Existing Resources | CPUC-Approved Local Capacity Procurement (MW) | Total Projected Available Resources (MW) | Deficiency (MW) |
|---|---|---|---|---|---|
| Western LA Basin | 5,223 | 2,728 | 1,813 | 4,541 | (682) |
| Eastern LA Basin | 2,230 | 3,531 | 0 | 3,531 | 0 |
| Total LA Basin | 7,453 | 6,259 | 1,813 | 8,072 | (682) |

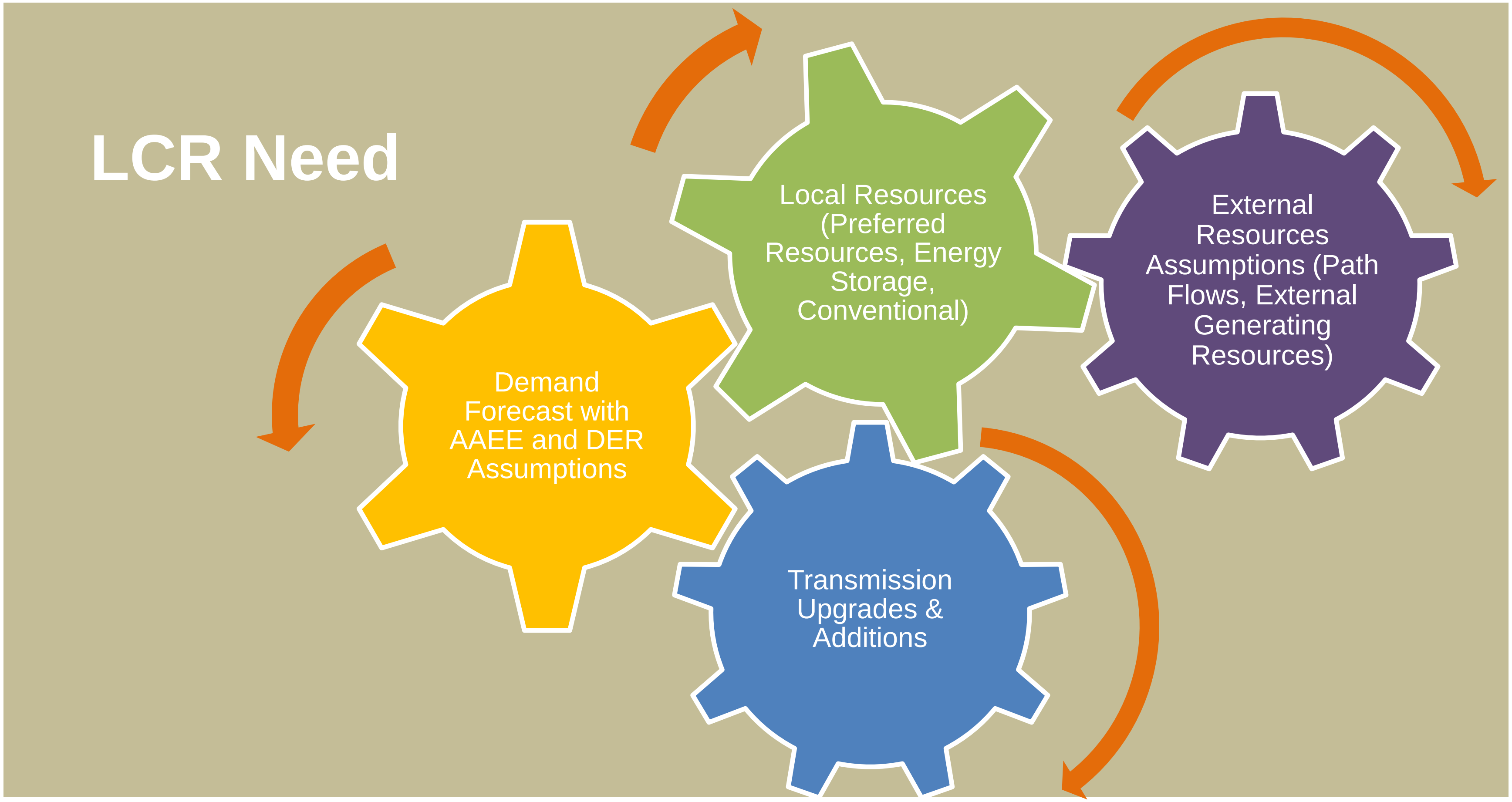
- Mesa Loop-In Project is assumed to be delayed operationally beyond the summer 2021 time frame for this scenario analysis.
- Critical contingencies are the overlapping N-1-1 of the Serrano-Villa Park #2 230kV line, followed by an outage of the Serrano – Lewis #1 or #2 230kV line.
  – The transmission constraint is the thermal loading on the remaining Serrano–Villa Park #1 230kV line.
- The identified deficiency is for the western LA Basin, with about 100 MW more than the identified deficiency for the Scenario #1 (i.e., with Mesa Loop-In Project).
- Potential mitigation may include a temporary extension of the OTC compliance date for the Redondo Beach or Alamitos generating units beyond its December 31, 2020 deadline.

# Study Results for the Mid-Term Scenario Study No. 2 (cont'd)

| 2021 | Total LCR Requirements (MW) | Total Available Existing Resources (MW) | CPUC-Approved Local Capacity Procurement (MW) | Total Projected Available Resources (MW) | Deficiency (MW) |
|---|---|---|---|---|---|
| San Diego Sub-Area | 3,038 | 2,078 | 800 | 2,878 | (160) |
| San Diego-Imperial Valley | 4,778 | 3,818 | 800 | 4,618 | (160) |

- Mesa Loop-In Project is assumed to be delayed operationally beyond the summer 2021 time frame for this scenario analysis.
- Critical contingencies are the overlapping N-1-1 of the Serrano-Villa Park #2 230kV line, followed by an outage of the Serrano – Lewis #1 or #2 230kV line.
  - The transmission constraint is the thermal loading on the remaining Serrano–Villa Park #1 230kV line.
- For simplicity, the ISO assumes the same level of procurement for preferred resources and energy storage as in Scenario No. 1 for the San Diego sub-area for 2021 time frame (160 MW). This amount is a proxy resource addition assumptions, which could change with SDG&E's future submittal to the CPUC for consideration of its preferred resource and energy storage procurement selection.

# Interlocking Relationship of Various Elements/Assumptions Affecting LCR Need



# Gas-Electric Coordination
# Transmission Planning Studies for Southern California

*David Le*

*Senior Advisor Regional Transmission Engineer*

*2015-2016 Transmission Planning Process Stakeholder Meeting*

*February 18, 2016*

# Overview

- Discuss summer reliability assessment
- Discuss winter gas curtailment transmission planning reliability assessment
- Discuss generation ramping impact assessment for system readjustment need under transmission contingency conditions
- Overview of the Aliso Canyon gas leak incident
- Next steps

# Background Information

- Background information and the proposed study plan were provided at the ISO 2015-2016 Transmission Planning Process Stakeholder Meeting No. 2 on September 21 – 22, 2015.
- The following is the link to the presentation:

  https://www.caiso.com/Documents/PresentationPTOProposedMitigationSolutions_Sep22_2015.pdf
- These transmission reliability assessments were performed prior to the Aliso Canyon gas leak incident, which was first discovered on October 23rd, 2015, and before its potential impact became apparent.

# Summer Reliability Assessment

- The ISO originally proposed this study to evaluate potential reliability impact to the electric transmission facilities due to a major gas transmission line outage (e.g. Line 4000) in the LA Basin
  - A total of approximately 1,600 MW of electric generation was curtailed in various amounts at fourteen power plants in the western LA Basin area in the summer 2015
- Further evaluation includes comparing the projected net capacity reduction after the retirement of OTC generating units and repowering projects (i.e., those approved by the CPUC in the LTPP for local RFO) with the amount of curtailment due to a major gas transmission line extended outage.
  - Net Capacity Reduction = {Repowering & new generation projects (CPUC-approved) - OTC generation retirement (since 2015) }
  - See next slide for results of the projected net gas-fired generation capacity reduction in the LA Basin

# Summer Reliability Assessment (cont'd)

| Generating Facility (Total Plant MW) | Owner | Unit | State Water Resources Control Board (SWRCB) Compliance Date | Net Qualifying Capacity (NQC) (MW) | Repowering Projects that Are Completed or Have Obtained CPUC Approval for PPTAs (MW) |
|---|---|---|---|---|---|
| El Segundo | | 4 | 12/31/2015 | -335 | |
| Alamitos (2,011 MW) | AES | 1 | 12/31/2020 | -175 | |
| | | 2 | 12/31/2020 | -175 | |
| | | 3 | 12/31/2020 | -332 | |
| | | 4 | 12/31/2020 | -336 | |
| | | 5 | 12/31/2020 | -498 | |
| | | 6 | 12/31/2020 | -495 | |
| | | New 2x1 CCGT | | | +640 (estimated in-service Summer 2020) |
| Huntington Beach (452 MW) | AES | 1 | 12/31/2020 | -226 | |
| | | 2 | 12/31/2020 | -226 | |
| | | New 2x1 CCGT | | | +644 (estimated in-service Summer 2020) |
| Redondo Beach (1,343 MW) | AES | 5 | 12/31/2020 | -179 | |
| | | 6 | 12/31/2020 | -175 | |
| | | 7 | 12/31/2020 | -493 | |
| | | 8 | 12/31/2020 | -496 | |
| Stanton Energy Reliability Peakers | | | | | +98 (estimated in-service date of Summer 2020) |
| Total Retirement after Summer 2015 | | | | -4,141 | |
| Total Addition & Repowering after Summer 2015 | | | | | +1,382 |
| Total Net Gas-Fired Generation Reduction after Summer 2015 | | | | | -2,759 |

# Summer Reliability Assessment (cont'd)

- Previous slide indicated that approximately 2,800 MW of net gas-fired generation capacity would be reduced in the longer term horizon (i.e., post OTC compliance in 2021 time frame)
  - This amount of net gas-fired capacity reduction is more than the estimated 1,600 MW of generation curtailment that occurred in summer 2015 due to a major gas transmission pipeline extended outage.
  - The reliability assessment for this scenario was evaluated as part of the long-term LCR studies for the LA Basin and San Diego areas (see the presentation on the mid-term and long-term LCR assessment for both of these two areas today)
- The above assessment for the local reliability in the LA Basin and San Diego areas did not include the potential impact of the Aliso Canyon gas leak incident for one of the natural gas storage wells as this occurred after the start of the summer reliability assessments (for the local areas) and before the potential impacts became apparent.

# Winter Gas Curtailment Transmission Reliability Assessment

- A 2021-2022 winter peak study case was prepared for the reliability assessment:
  - Modified from the SDG&E-provided 2020-2021 winter case
  - Mesa Loop-In Project was added to the case
  - Loads were modified to reflect 62% of 2021 summer peak load for SCE and 66% for SDG&E peak loads
  - OTC generating units are retired per the SWRCB's Policy on OTC generation
  - Aging generating resources more than 40-year old are modeled off-line
  - Simulate February 6, 2014 gas curtailment scenario due to cold weather that reduces external gas deliveries to Southern California due to high demand from other states
    - A total of 2,200 MW of gas-fired generation was curtailed for the LA Basin and San Diego areas
      - Approximately 1,300 MW of gas-fired generation resources was curtailed for the LA Basin and about 900 MW was curtailed for the San Diego area
  - Performed steady-state contingency analyses, post-transient and transient stability assessments for both the LA Basin and San Diego areas.

# Winter Gas Curtailment Transmission Reliability Assessment (cont'd)

- The following are the study results for the most critical contingencies:
  - The most critical reliability concern is the potential overloading on the Lugo-Victorville 500kV line due to an N-1-1 contingency of Lugo-Mohave 500kV, followed by Lugo-Eldorado 500kV line
    - The ISO will commence discussion with LADWP and SCE for coordinated funding approach for upgrading the Lugo-Victorville 500kV line
  - The second most critical reliability concern is the potential post-transient voltage instability due to an overlapping N-1-1 contingency of the ECO-Miguel 500kV line, system readjusted, followed by the Ocotillo-Suncrest 500kV line outage.
    - Potential mitigation includes rescheduling voltage control setpoint for the new synchronous condensers located in San Diego as well as the southern Orange County area.
  - With the same N-1-1 contingency as in the second bulleted item above, the other reliability concern would be potential overloading on the of CENACE's La Rosita – Rumorosa 230kV  and the Otaymesa – Tijuana 230kV lines
    - Potential mitigation includes by-passing the series capacitors under pre-contingency condition (these are bypassed for summer load conditions but not yet bypassed for the winter load conditions)
  - The third reliability concern includes transient voltage dips at the Lewis and Valley Substations under the same N-1-1 contingency above.
    - Utilization of the preferred resources (from the LTPP local RFO procurement ) prior to the next N-1 contingency

# Winter Gas Curtailment Transmission Reliability Assessment (cont'd)

| | Reliability Concerns | Contingencies | Type of Analyses | Pre-Mitigated Reliability Concerns | Post-Mitigation Results | Potential Mitigation |
|---|---|---|---|---|---|---|
| 1 | Vincent-Victorville Loading Concerns | P6: Lugo-Mohave, Lugo-Eldorado | Steady-state contingency | 125% loading | 100% loading | -Utilize LTPP preferred resources and existing DR for system readjustment, and -Reschedule 250 MW less on IPPDC lines, or -Upgrade terminal equipment on the line |
| 2 | Miguel 500/230kV Bank | P1: Parallel Miguel 500/230kV Bank | Steady-state contingency | 106% - 108% | 0% | -Opening the circuit breakers for the overloaded bank |
| 3 | Imperial Valley 500/230kV Bk#80 | P6: T-1-1 Bk# 81 and 82 | Steady-state contingency | 158% loading | 98% | -Curtail about 800 MW generation connecting to Imperial Valley, and |
| 4 | Post-transient voltage instability in San Diego and LA Basin | P6: ECO-Miguel 500kV, system readjustment, followed by Ocotillo-Suncrest 500kV line | Post-transient | Post-transient voltage instability | Mitigated post-transient voltage instability concerns | -Reschedule voltage regulation at terminal voltage with 1.05 – 1.1 p.u. for synchronous condensers located in northern San Diego and southern Orange County. |
| 5 | Transient voltage dips beyond acceptable limits at Valley 115kV bus (39%) and Lewis 69kV bus (38%) beyond 30 cycles (i.e., 32 and 33 cycles) | Same as above | Transient stability | Transient voltage dip | Mitigated transient voltage dip concerns | -Utilize LTPP preferred resources and energy storage and baseline DR (190 MW) for system readjustment before the next contingency |
| 6 | La Rosita-Rumorosa 230kV and Otay Mesa – Tijuana 230kV line loading concerns | Same as above | Post-transient | 101% - 103% loading | 92% - 93% | - Bypass series capacitors on the ECO-Miguel 500kV line and Ocotillo-Suncrest 500kV line pre-contingency - Reduce imports via Path 45 from 300 to 200 MW (to ISO BAA) |

# Generation Ramping Impact Assessment

- Generation ramping needs can be attributed to the following:
  - Generation redispatch need following a transmission contingency event in preparation for the next contingency;
  - Future flexible capacity needs to integrate and meet California's 50% RPS
- In this planning cycle (2015-2016), the ISO evaluated and estimated the amount of gas-fired generation redispatch need following the single contingency event in preparation for the next contingency from the long-term LCR study results
  - Generation re-dispatch need = {LCR Need (P6, P3) – LCR Need (P1)}
    - {Potential Preferred Resources + Energy Storage Redispatch}
- Ramping needs based on future flexible capacity needs will be explored in future planning cycles based on advancement of a number of issues associated with flexible ramping requirements

# Estimated Potential Peaking Generation Ramping Need to Prepare for the Second Contingency

| Local Area | 2025 LCR Need Based on Single-Element Contingency (MW) | 2025 LCR Need Based on Multiple-Element Contingency (MW) | Re-dispatch Capacity Need (MW) | Preferred Resources/Energy Storage Use for Re-dispatch (MW) | Potential Peaking Generator Re-dispatch Need (MW) |
|---|---|---|---|---|---|
| Western LA Basin | 5,236 | 5,514 | 278 | 278 | 0 / 278 |
| Eastern LA Basin | 2,132 | 2,805 | 673 | 0<br><br>(No procurement of additional resources for the Eastern LA Basin sub-area) | 673 |
| San Diego/Imperial Valley | 3,151 | 4,868 | 1,717 | 267 | 1,450 |

- Please refer to Table 3.3-4 of the ISO 2015-2016 draft Transmission Plan for further notes

# Overview of the Aliso Canyon Gas Leak Incident

- The gas leak was a massive and uncontrolled gas leak from a natural gas well within the Aliso Canyon underground storage facility located in the Santa Susana Mountains near Porter Ranch, Los Angeles.
- The Aliso Canyon underground gas storage facility has 115 wells connected to a reservoir that has a capacity of 86 billion cubic feet of natural gas. The field is the second largest underground gas storage in the U.S.
- The leak was first discovered on October 23, 2015, and was temporarily stopped on February 11, 2016. Works continue to permanently seal the affected well.
- More than 11,000 people from 2,800 households have been temporarily relocated by Southern Cal Gas; approximately more than 6,500 families have filed for help.

# Next Steps

- This incident highlights the complex interplay between gas transmission pipeline and storage capacity and the dependence on localized gas storage capacity in managing more rapidly varying withdrawals from the gas network for gas-fired generation in the area.
- The ISO has formed an internal Task Force to evaluate the potential near-term operational impact of the current gas storage conditions on summer 2016 electric reliability in southern California.
- Building on the findings of the operational related studies, the ISO intends to more fully explore these issues in the 2016-2017 transmission planning process and subsequent plans.

# A Bulk Energy Storage Resource Case Study with 40% RPS in 2024

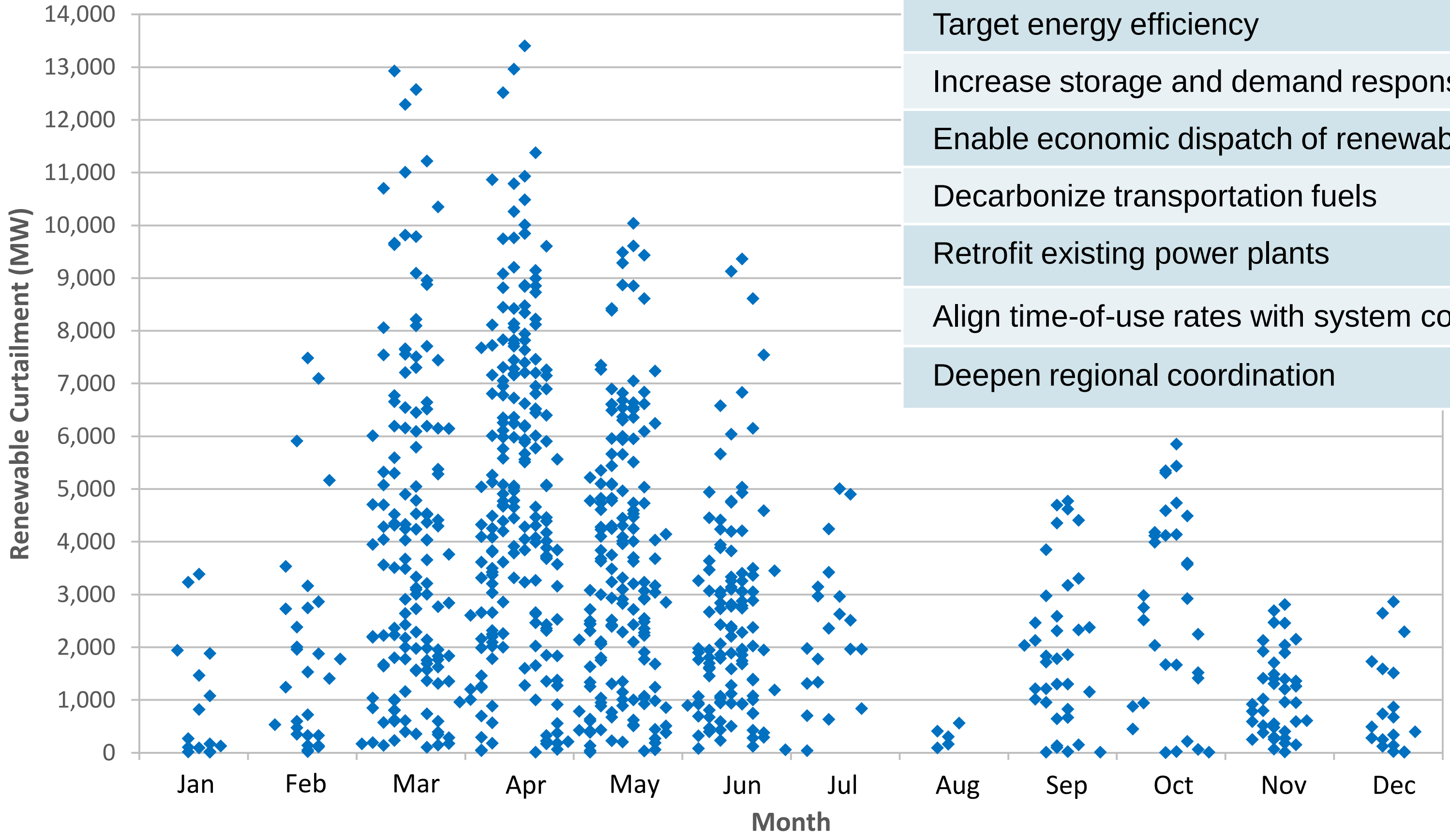
*Shucheng Liu*
*Principal, Market Development*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

# About the ISO bulk energy storage case study

- The study follows the CPUC 2014 Long-Term Procurement Plan (LTPP) Planning Assumptions and Scenarios
- In 2014 LTPP, the ISO studied four scenarios and one sensitivity
  – Trajectory scenario
  – High Load scenario
  – Expanded Preferred Resources scenario
  – 40% RPS in 2024 scenario
  – Trajectory without Diablo Canyon sensitivity case

# The 2014 LTPP study identified large quantity of renewable curtailment in the 40% RPS scenario.




| Solutions |
|---|
| Target energy efficiency |
| Increase storage and demand response |
| Enable economic dispatch of renewables |
| Decarbonize transportation fuels |
| Retrofit existing power plants |
| Align time-of-use rates with system conditions |
| Deepen regional coordination |

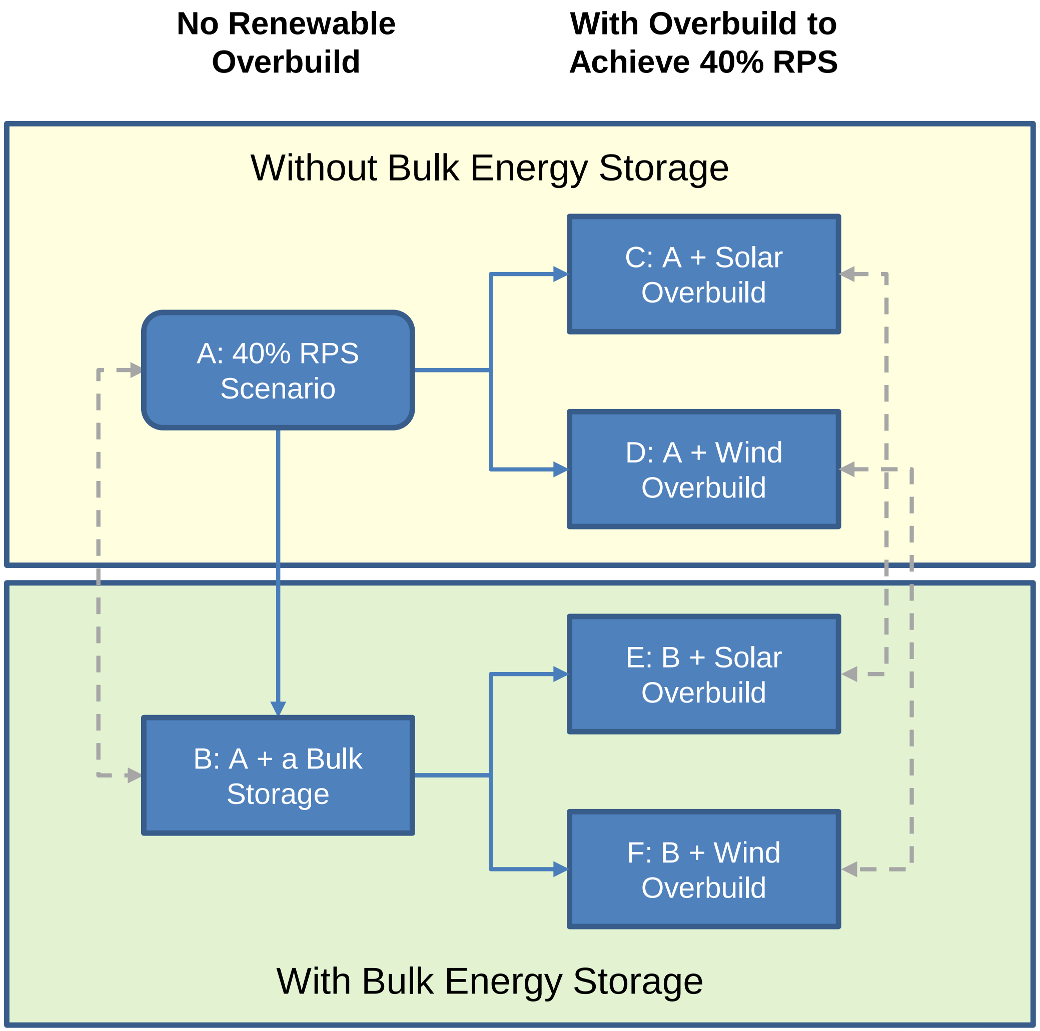
# Purpose of the ISO bulk energy storage case study

- To explore solutions to curtailment of large quantity of renewable generation
- To assess a bulk storage resource's ability to reduce
  - production cost
  - renewable curtailment
  - CO2 emission
  - renewable overbuild to achieve the 40% RPS target
- To analyze the economic feasibility of the bulk storage resource

# Study approach

- Based on the 2014 LTPP 40% RPS in 2024 Scenario with renewable curtailment remaining unlimited
- Analyses compare two renewable build baselines, with and without the new bulk storage resource:
  - No overbuild of renewable resources
  - Overbuild renewables to achieve the 40% RPS target
- Overbuild of renewable with solar or wind
  - Demonstrate the benefits of more diversified RPS portfolios

# Definition of the study cases and expected takeaways




This study quantifies

- reduction of production cost, renewable curtailment and CO2 emission,
- quantity and cost of renewable overbuild
- cost and market revenue of the bulk storage resource

It does not quantify

- transmission impact

# Assumptions of the new pumped storage resource

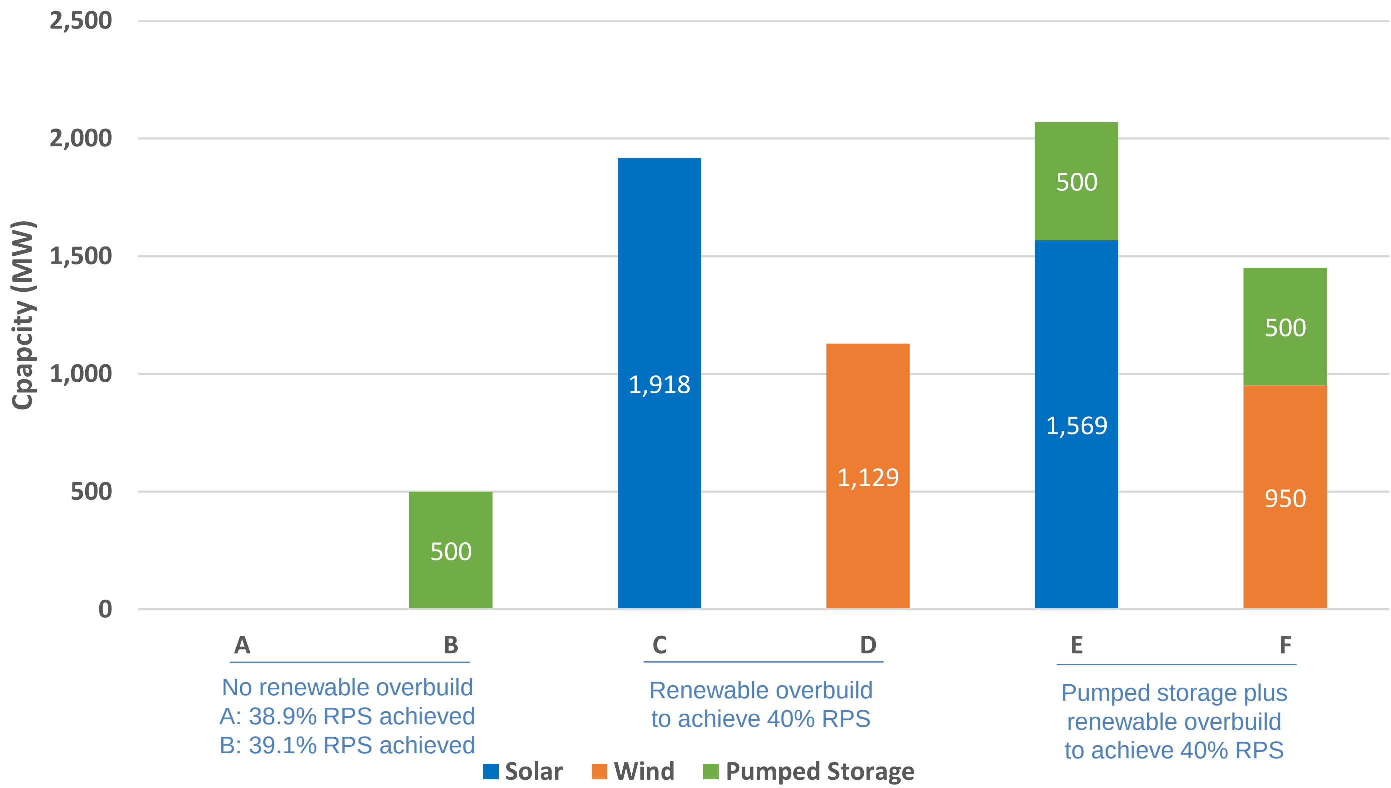
| Item | Value |
|---|---|
| **Number of units** | **2** |
| **Max pumping capacity per unit (MW)** | **300** |
| Minimum pumping capacity per unit (MW) | 75 |
| **Maximum generation capacity per unit (MW)** | **250** |
| Minimum generation capacity per unit (MW) | 5 |
| **Pumping ramp rate (MW/min)** | **50** |
| **Generation ramp rate (MW/min)** | **250** |
| **Round-trip efficiency** | **83%** |
| **VOM Cost ($/MWh)** | **3** |
| Maintenance rate | 8.65% |
| Forced outage rate | 6.10% |
| Upper reservoir maximum capacity (GWh) | 8 |
| Upper reservoir minimum capacity (GWh) | 2 |
| Interval to restore upper reservoir water level | Monthly |
| **Pump technology** | **Variable speed** |
| **Reserves can provide in generation and pumping modes** | **Regulation, spinning and load following** |
| **Reserves can provide in off modes** | **Non-spinning** |
| Location | Southern California |

# Assumptions of revenue requirements and RA revenue of the new resources

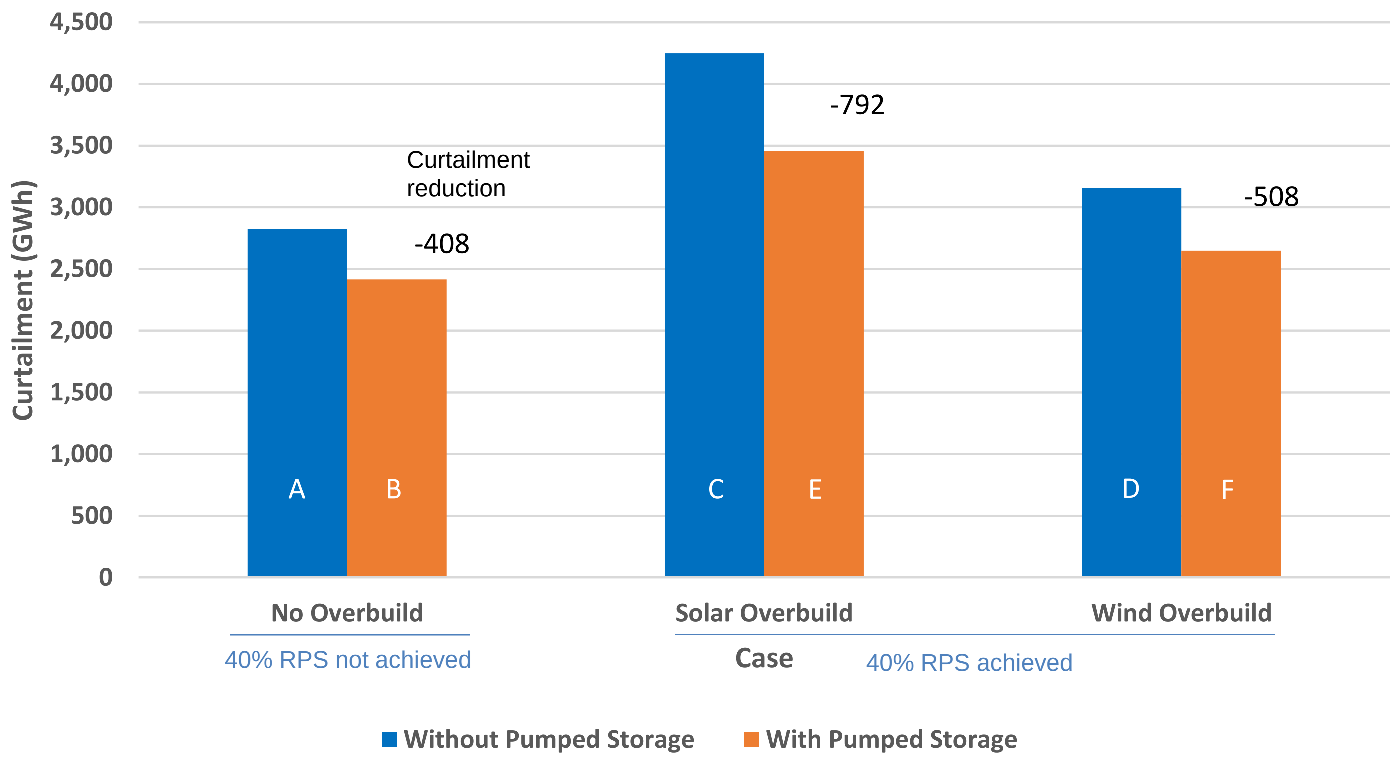
| Item | Revenue Requirement ($/kW-year) | | NQC Peak Factor [1] | RA Revenue ($/kW-year) [2] |
|---|---|---|---|---|
| | Generation Resource [3] | Transmission Upgrade [4] | | |
| Large Solar In-State | 327.12 | 22.00 | 47% | 16.13 |
| Large Solar Out-State | 306.26 | 22.00 | 47% | 16.13 |
| Small Solar In-State | 376.99 | 11.00 | 47% | 16.13 |
| Solar Thermal In-State | 601.71 | 22.00 | 90% | 30.89 |
| Wind In-State | 286.62 | 16.50 | 17% | 5.83 |
| Wind Out-State | 261.13 | 72.00 | 45% | 15.44 |
| Pumped Storage In-State | 383.62 | 16.50 | 100% | 34.32 |

[1] References https://www.caiso.com/Documents/2012TACAreaSolar-WindFactors.xls and https://www.wecc.biz/Reliability/2024-Common-Case.zip
[2] Reference http://www.cpuc.ca.gov/NR/rdonlyres/2AF422A2-BFE8-4F4F-8C19-827ED4BA8E03/0/2013_14ResourceAdequacyReport.pdf
[3] References https://www.wecc.biz/Reliability/2014_TEPPC_GenCapCostCalculator.xlsm and https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf
[4] Reference http://www.transwestexpress.net/scoping/docs/TWE-what.pdf and the CAISO assumptions.

# Capacity of renewable overbuild to achieve the 40% RPS target

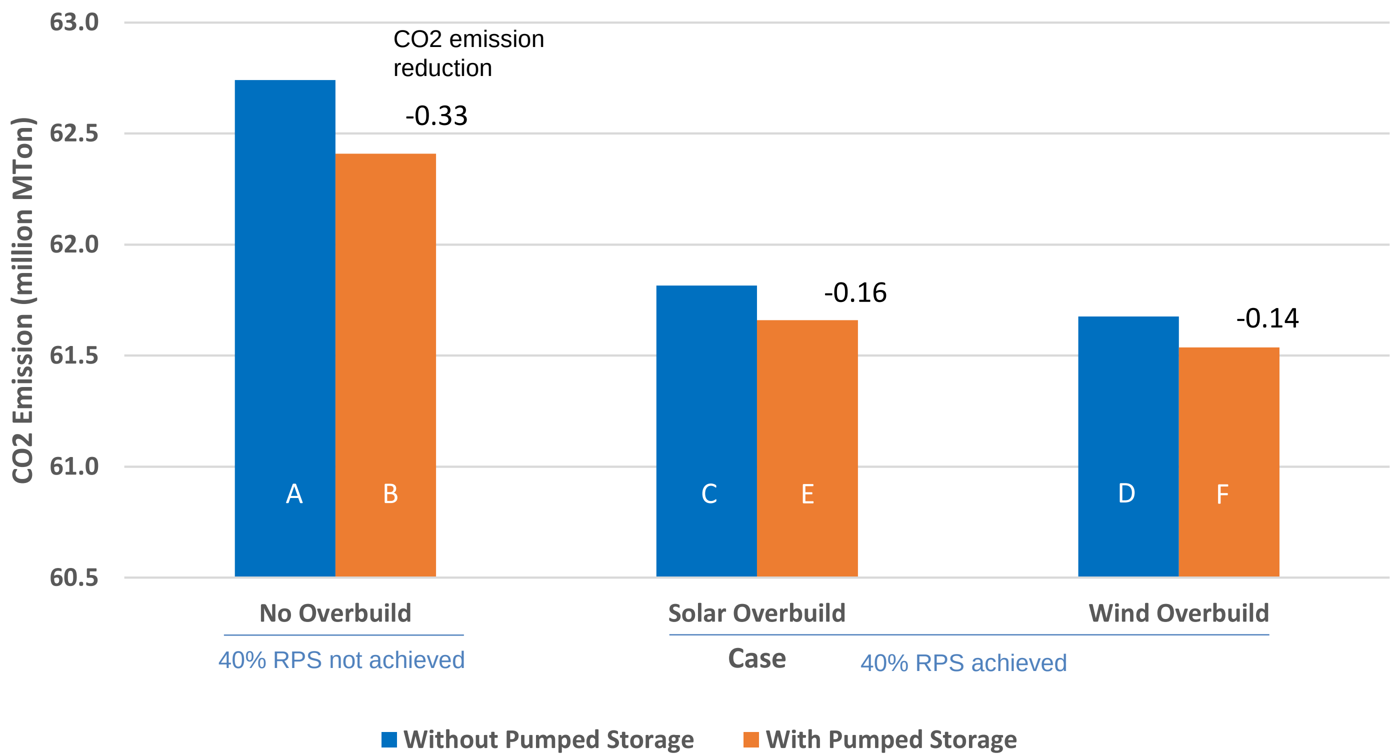


# California renewable generation curtailment



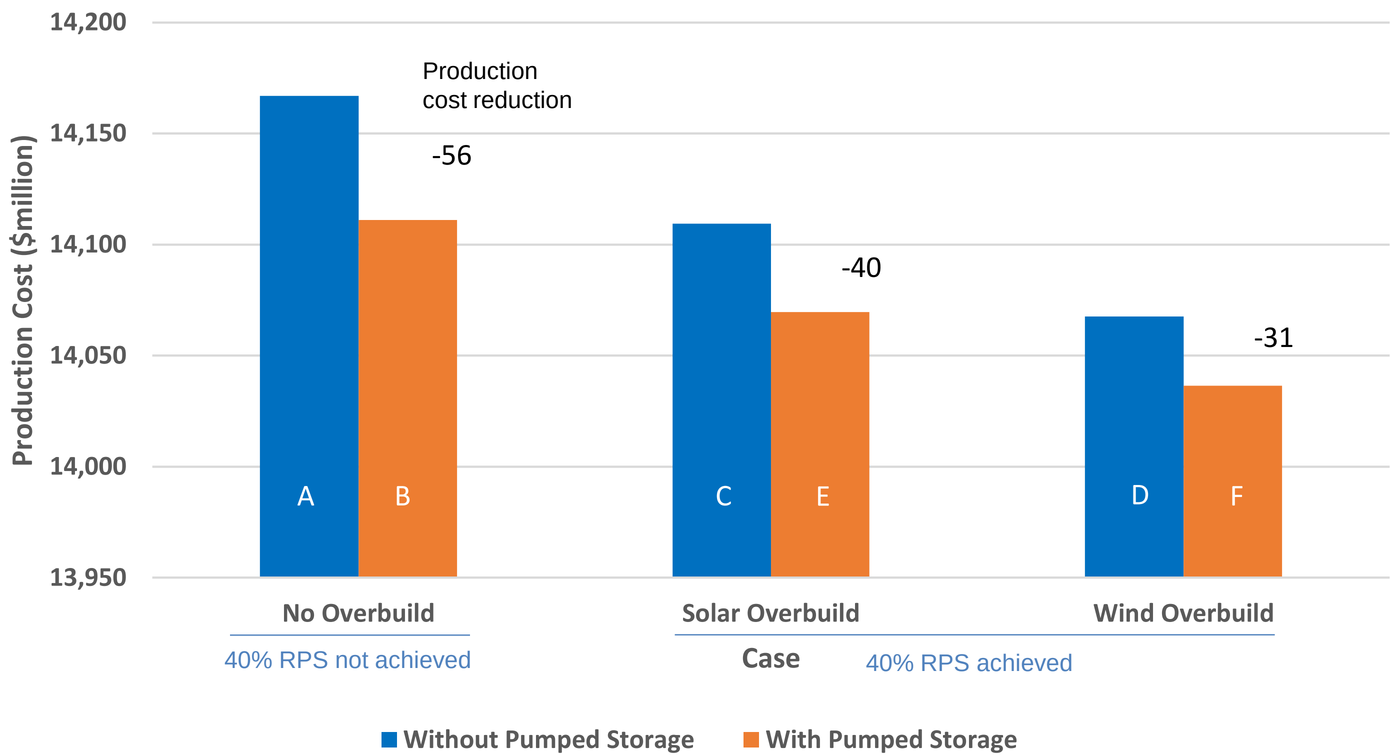

* Renewable generation is curtailed at -$300/MWh market clearing price (MCP).

# California $CO_2$ emission



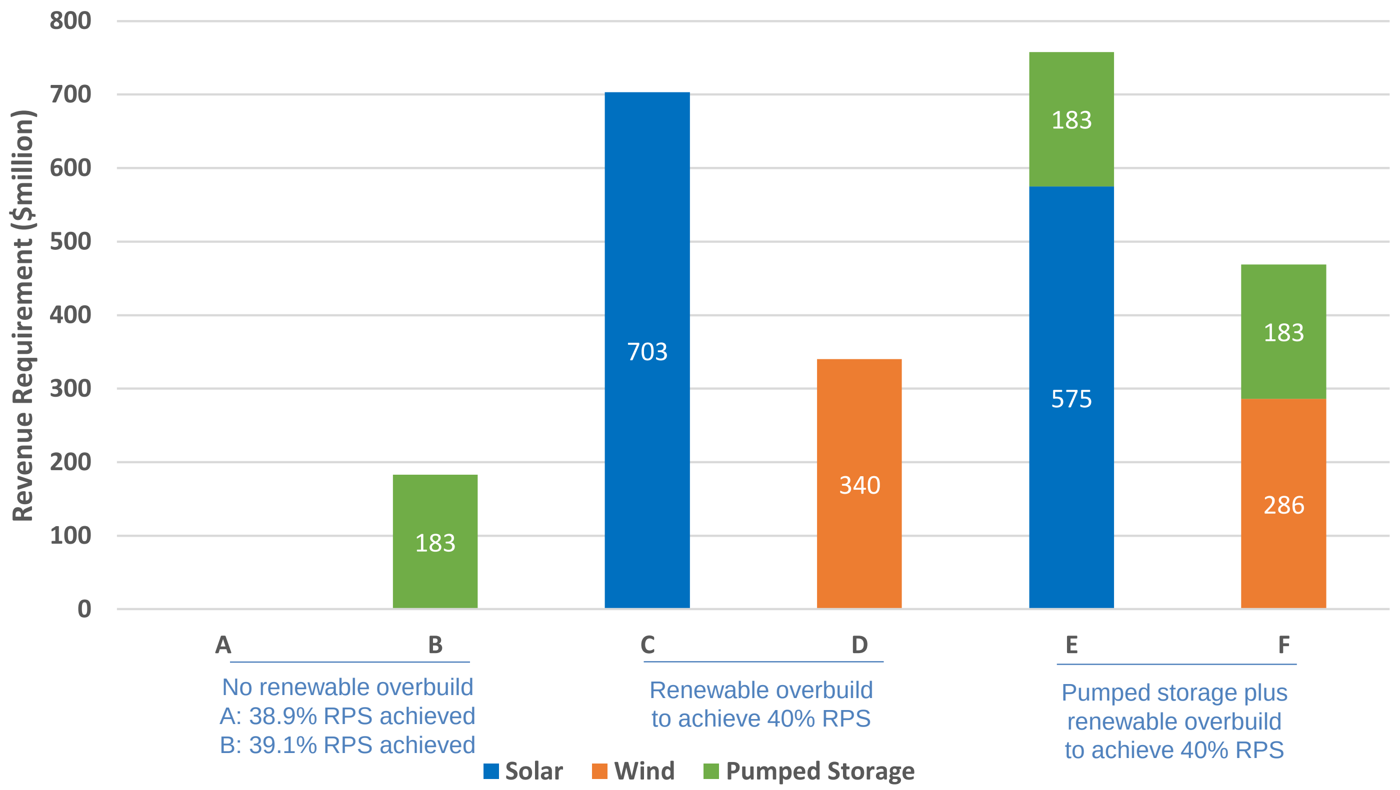

** California $CO_2$ emission includes the emission from energy net import.

# WECC annual production cost

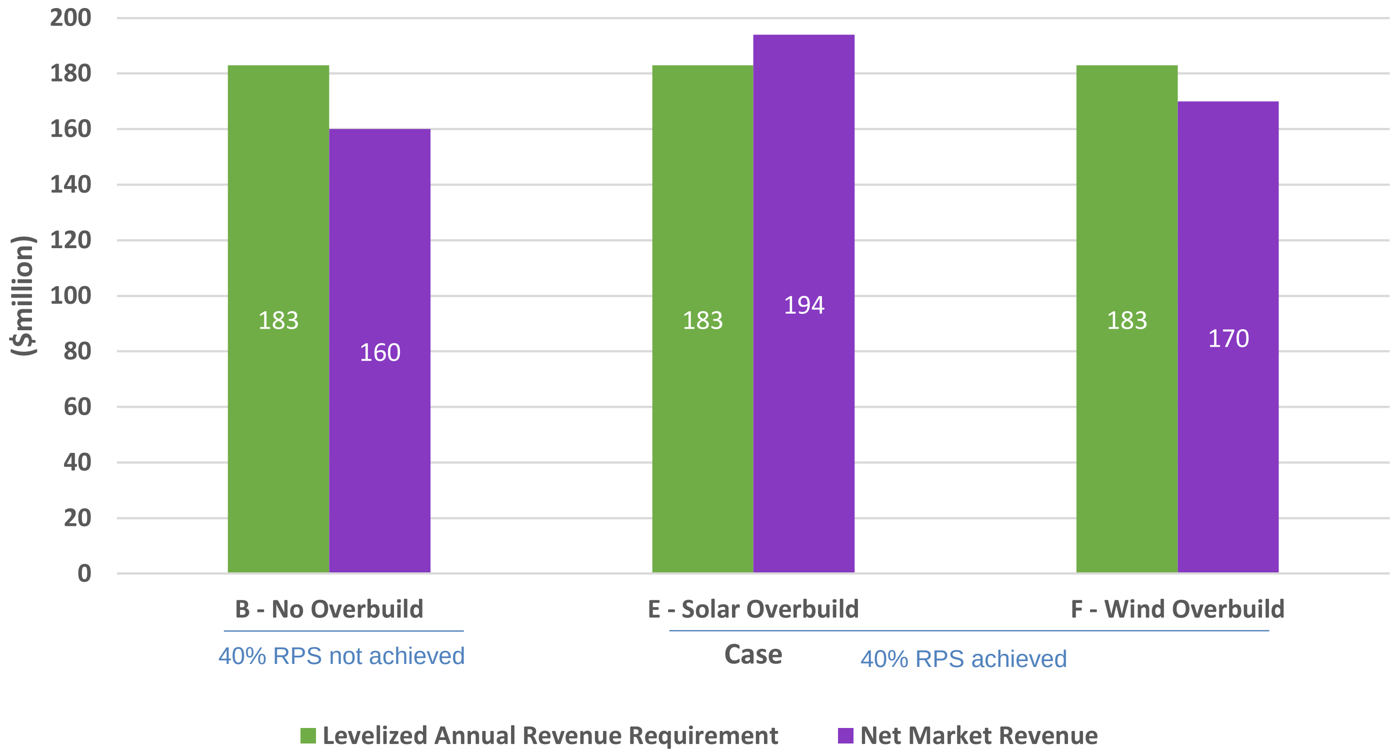



**** Production cost includes start-up, fuel and VOM cost, not CO2 cost.

# Renewable overbuild and pumped storage levelized annual revenue requirements



# Pumped storage levelized annual revenue requirement and net market revenue of 2024




***** Net revenue is revenue from generation, reserves and load following minus cost of operation and energy consumed.

# Some observations

- Original 40% RPS portfolio is solar-dominant (53% in capacity)
- Wind overbuild increases diversity of the RPS portfolio and shows more benefits than solar overbuild
  - Requires less overbuild than solar due to less incremental curtailment from the overbuild
  - Has lower CO2 emission and production costs than solar due to less steep ramping

# Some observations (cont.)

- Bulk storage brings benefits in all cases
  - Reduced curtailment, $CO_2$ emission, production costs and overbuild of renewables to achieve the 40% RPS target
- Bulk storage is better utilized with solar-dominant RPS portfolio than more diversified
  - Capturing more renewable curtailment in midday
  - Moving more energy to the evening and morning
  - Reducing more production cost and $CO_2$ emission

# Some observations (cont.)

- Bulk storage benefit to cost ratios dependent on
  - Storage costs
  - Mix of renewable resources
  - Renewable curtailment price
  - Other assumptions

# Summary of study results

| | Without Pumped Storage | | | With Pumped Storage | | |
|---|---|---|---|---|---|---|
| Case | A | C | D | B | E | F |
| Renewable Curtailment (GWh)* | 2,825 | 4,249 | 3,157 | 2,417 | 3,457 | 2,649 |
| CA CO2 Emission (Million Ton)** | 62.74 | 61.82 | 61.68 | 62.41 | 61.66 | 61.54 |
| CA CO2 Emission ($ mil)*** | 1,460 | 1,438 | 1,435 | 1,452 | 1,435 | 1,432 |
| Production Cost ($ mil)**** | | | | | | |
| WECC | 14,167 | 14,109 | 14,068 | 14,111 | 14,070 | 14,037 |
| CA | 3,866 | 3,826 | 3,795 | 3,803 | 3,779 | 3,751 |
| Renewable Overbuild and Pumped Storage Capacity (MW) | | | | | | |
| Solar | | 1,918 | | | 1,569 | |
| Wind | | | 1,129 | | | 950 |
| Pumped Storage | | | | 500 | 500 | 500 |
| Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($ mil) | | | | | | |
| Solar | | 703 | | | 575 | |
| Wind | | | 340 | | | 286 |
| Pumped Storage | | | | 183 | 183 | 183 |
| Pumped Storage Net Market Revenue ($ mil) ***** | | | | 160 | 194 | 170 |

* Renewable generation is curtailed at -$300/MWh market clearing price (MCP)
** Includes the CO2 emission from net import.
*** Calculated using $23.27/m-ton price.
**** Includes start-up, fuel and VOM cost, not CO2 cost.
***** Net revenue is revenue of energy, reserves and load following minus cost of energy and operation.

# Thank you.

Shucheng Liu
sliu@caiso.com

California ISO

# Economic Planning Study Final Recommendations

*Yi Zhang*
*Regional Transmission Engineer Lead*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

# 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 contingencies identified in reliability and policy studies
- Updated contingencies with SPS as identified in operating procedures and in reliability and policy studies
- Modeled Panoche-Oro Loma 115 kV upgrade

# Congestions

| No | Aggregated congestion | 2020 | | 2025 | |
|---|---|---|---|---|---|
| | | Costs (k$) | Duration (hr) | Costs (k$) | Duration (hr) |
| 1 | Path 26 | 6,885 | 564 | 3,421 | 226 |
| 2 | POE-RIO OSO | 1,329 | 85 | 1,429 | 75 |
| 3 | Exchequer | 946 | 631 | 1,113 | 599 |
| 4 | Path 45 | 616 | 366 | 1,022 | 245 |
| 5 | Delevan-Cortina | 1,723 | 111 | 510 | 36 |
| 6 | Path 15/CC (Central California) | 141 | 21 | 376 | 20 |
| 7 | COI | 736 | 286 | 255 | 97 |
| 8 | PG&E LCR (aggregated) | 354 | 43 | 128 | 38 |
| 9 | Inyo-Control | 17 | 16 | 21 | 19 |
| 10 | Lugo - Victorville | 0 | 0 | 14 | 1 |
| 11 | Path 24 | 0 | 0 | 5 | 5 |
| 12 | Path 25 | 5 | 9 | 3 | 4 |
| 13 | SCE LCR (aggregated) | 3,565 | 75 | 0 | 0 |
| 14 | Vincent bank | 24 | 1 | 0 | 0 |
| 15 | WARNERVL - WILSON | 141 | 40 | 0 | 0 |
| 16 | West of Devers | 27,321 | 621 | 0 | 0 |

# Evaluating economic planning study requests

- Nine 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

# High priority studies

| Selected study | Reasons for selection |
| --- | --- |
| Path 26 | Recurring congestion with relatively high cost |
| Exchequer | High congestion cost |
| POE-RIO OSO | High congestion cost |
| Path 15/Central California | Recurring congestion with relatively high cost |
| COI | Recurring congestion with increasing congestion cost |

# Path 26 and Path 15/CC studies

- Evaluation
  - These two congestions were identified in the previous planning cycles
  - No economic justifications were seen for network upgrades before
  - No significant changes in the system models in these two congestion areas
- Conclusion
  - No detailed production simulation and economic assessment
  - Will monitor and assess in the future cycles

# Exchequer and POE-RIO OSO

- These two congestions are in hydro-rich areas
- Evaluation
  - Modeled generic projects that were assumed to increase the ratings to mitigate the congestions
  - Production cost simulations and economic assessments
- Conclusion
  - No economic benefits to ISO ratepayers based on the current production cost model
  - Will continuously monitor and assess these congestions in the future planning cycles

# COI

- Evaluation
  - Congestion cost increased from the last planning cycle, but not material comparing with the cost of any potential upgrade
  - SWIP-North, a study request, was evaluated since it provides a parallel path to COI
- Conclusion
  - SWIP-North project does not bring sufficient benefit to the ISO's ratepayer
  - COI congestion will be re-evaluated in the future planning cycles

# Summary

- No economic upgrade recommended for approval in the 2015~2016 planning cycle
- Several paths and related projects will be monitored in future planning cycles to take into account
  - Improved hydro modeling
  - Further consideration of suggested changes to ISO economic modeling
  - Further clarity on 50% renewable energy goal

# Next Steps

*Kim Perez*
*Stakeholder Engagement and Policy Specialist*

*2015-2016 Transmission Planning Process Stakeholder Meeting*
*February 18, 2016*

# Next Steps

| Date | Milestone |
|---|---|
| March 3 | Stakeholder comments to be submitted to regionaltransmission@caiso.com |
| No later than March 17 | Post Revised Draft 2015-2016 Transmission Plan |
| March 24-25 | Present Revised Draft Plan to ISO Board of Governors |
| No later than March 28 | Post Final 2015-2016 Transmission Plan |