Agenda
Draft 2018-2019 Transmission Plan

Kristina Osborne
Lead Stakeholder Engagement and Policy Specialist

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

2018-2019 Transmission Planning Process Stakeholder Meeting Agenda

Topic	Presenter
Introduction	Kristina Osborne
Overview	Jeff Billinton
Reliability Projects for Approval	Binaya Shrestha
Frequency Response Study	Irina Green
Policy Assessment	Sushant Barave
Economic Assessment - Overview - Production Cost Modeling, Congestion Analysis and Economic Study Requests - LCR Area Gas Retirement Alternatives	 Neil Millar Yi Zhang Jeff Billinton and David Le
Interregional Transmission Coordination	Gary DeShazo
Pacific Northwest – California Transfer Increase Informational Special Study	Ebrahim Rahimi
System Capacity Requirements and Large Storage System Benefits – Special Study	Shucheng Liu
Next Steps	Kristina Osborne

Introduction and Overview
Draft 2018-2019 Transmission Plan and transmission project approval recommendations

Jeff Billinton
Manager, Regional Transmission - North

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

2018-2019 Transmission Planning Process

January 2018 | April 2018 | March 2019

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.

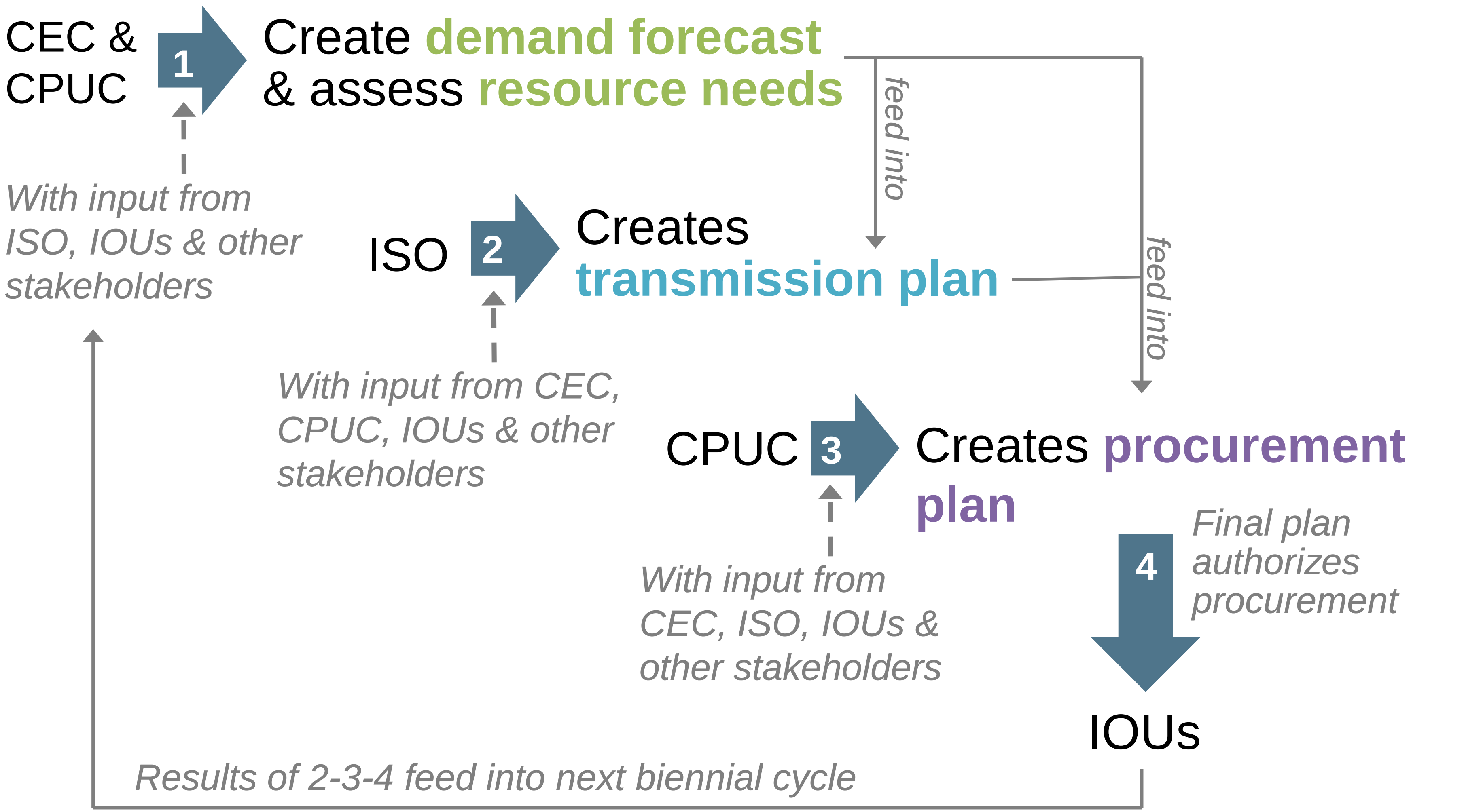
ISO Board for approval of transmission plan

California ISO

2018-2019 Transmission Plan Milestones

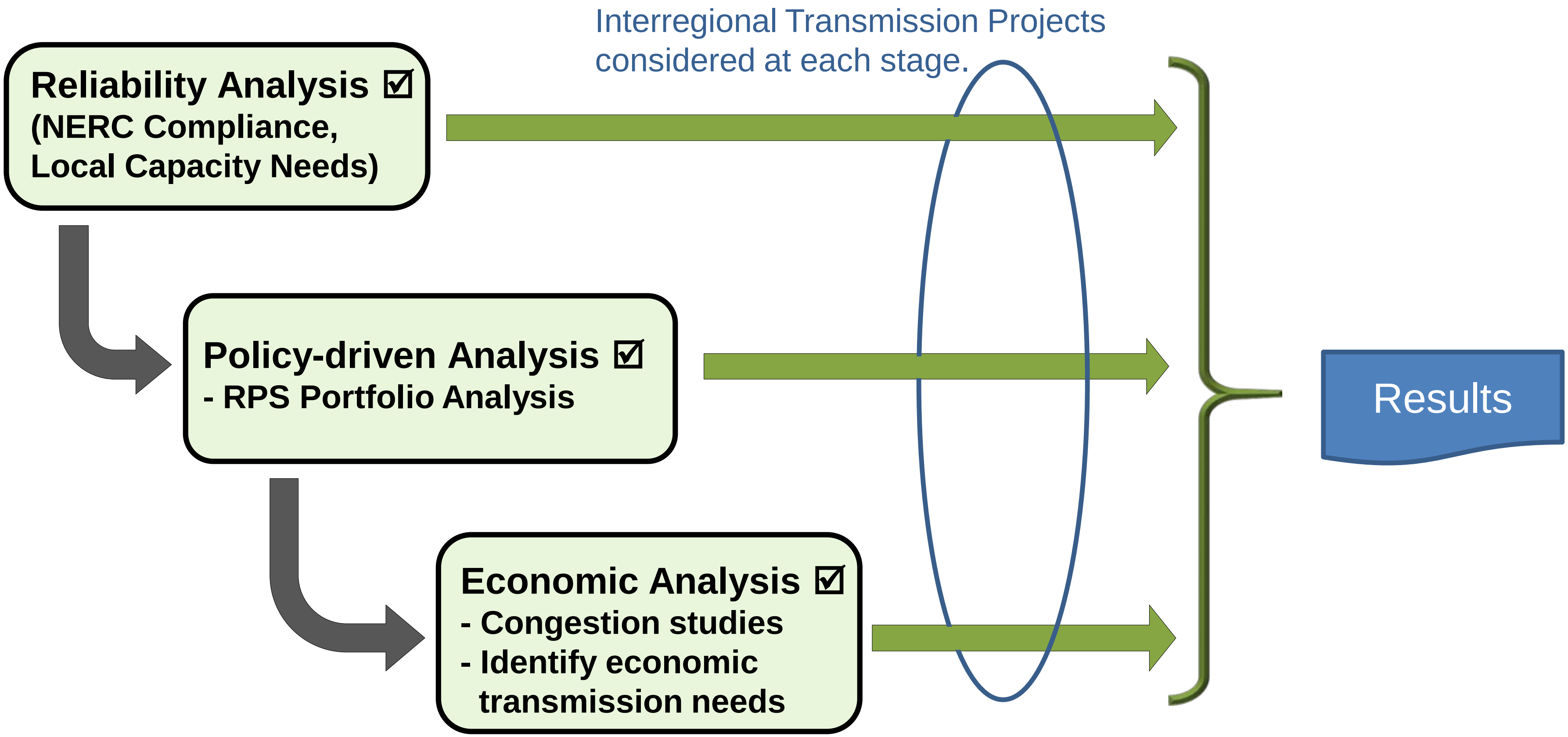
- Draft Study Plan posted on February 22
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 14
- Final Study Plan to be posted on March 31
- Preliminary reliability study results to be posted on August 15
- Stakeholder meeting on September 20 and 21
- Comments to be submitted by October 5
- Request window closes October 15
- Preliminary policy results and economic study update on November 16
- Comments to be submitted by November 30
- Draft transmission plan to be posted on February 4, 2019
- Today: Stakeholder meeting to review draft Transmission Plan
- Comments to be submitted by February 28, 2019
- Revised draft for approval at March Board of Governor meeting

Planning and procurement overview



California ISO

Following our sequential study process has been challenging – but critical to managing study requests:



Stakeholders have submitted proposals into multiple forums, *e.g.* as reliability projects, economic study requests, alternatives to reduce local capacity requirements, and interregional transmission projects

Emphasis in the transmission planning cycle:

- A modest capital program, as:
  - Reliability issues are largely in hand,
  - Policy work was informational as we await actionable renewable portfolio policy direction regarding moving beyond 50%
  - Very little economic–driven opportunity, largely due to status of IRP decision-making
- Final resolution of previously approved projects
- Significant interest in development community for transmission lines and storage (battery and pumped hydro) – <u>13</u> proposals for “major” facilities needing detailed economic analysis
- Special study efforts on local capacity areas and gas-fired generation requirements, and on improving transfer capabilities with northwest hydro resources

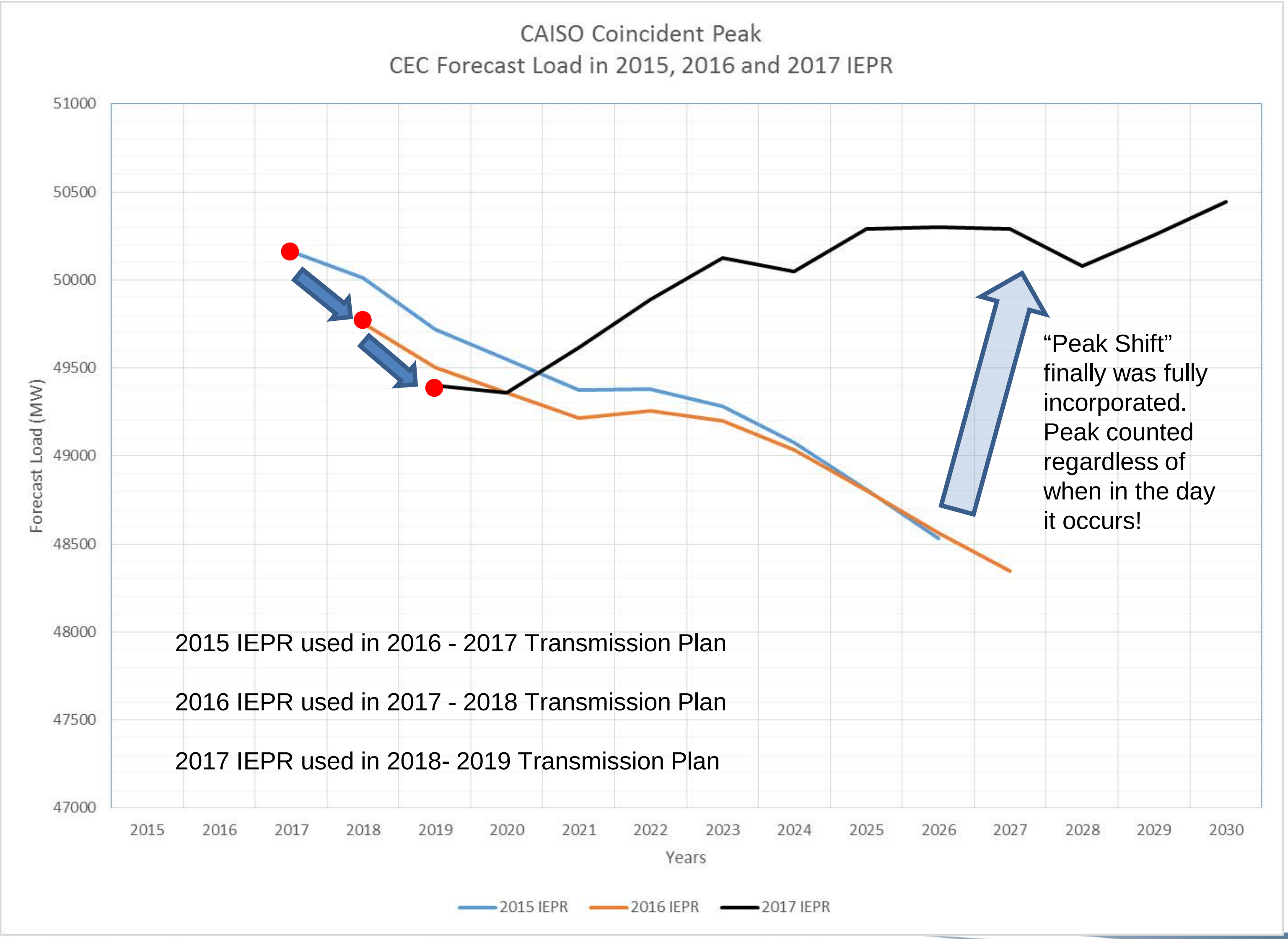
Consideration of the impacts of behind the meter photovoltaic generation on load shapes – and shifting the time of load peaks to later in the day – continues to evolve:

- In CED 2015 (2016-2026 Forecast), the CEC determined peak loads through downward adjustments to the traditional mid-day peak loads and acknowledged the issue of later-day peaks. In the 2016-2017 planning cycle the ISO conducted is own sensitivities.

- In CEDU 2016 (2017-2027), the CEC provided sensitivities of later day peaks. The ISO used those sensitivities in this 2017-2017 planning cycle to review previously-approved projects, but not as the basis for approving new projects.

- In CED 2017 (2018-2028), the CEC provided hourly load shapes.

CEC forecast includes peak shifts as part of hourly loads



New Projects Recommended for Approval (all in PG&E)

Projects	Project cost	Comment
Round Mountain 500 kV Dynamic Voltage Support	$160M-$190M	Reliability – Eligible for Competitive Solicitation
Gates 500 kV Dynamic Voltage Support	$210M-$250M	Reliability – Eligible for Competitive Solicitation
Lakeville 115 kV Bus Upgrade	$10M-$15M	Reliability
Tyler 60 kV Shunt Capacitor	$5.8-$7M	Reliability
Cottonwood 115 kV Bus Sectionalizing Breaker	$8.5M-$10.5M	Reliability
Gold Hill 230/115 kV Transformer Addition Project	$22M	Reliability
Jefferson 230 kV Bus Upgrade	$6M-$11M	Reliability
Christie-Sobrante 115 kV Line Reconductor	$10.5M	Reliability
Moraga-Sobrante 115 kV Line Reconductor	$12M-$18M	Reliability
Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	$0.1M-$0.2M	Reliability
Tesla 230 kV Bus Series Reactor project	$24M-$29M	Reliability
South of Mesa Upgrade	$45M	Reliability
Giffen Line Reconductoring Project	Less than $5M	Economic

Projects to be Canceled ($440-$550 million)

Projects	Planning Area
Atlantic-Placer 115 kV Line	Central Valley
Jefferson - Stanford #2 60 kV Line	Greater Bay Area
Morrow Bay 230/115 kV Transformer Project Table	Central Coast and Los Padres
Diablo Canyon Voltage Support Project	Central Coast and Los Padres
Gates-Gregg 230 kV Line	Fresno
Bridgeville – Garberville No. 2 115 kV Line	Humboldt

Projects remaining on hold

Projects	Planning Area
Midway-Andrew Project	Central Coast and Los Padres

Policy-driven analysis was not conducted for approval purposes – only as a sensitivity, as per CPUC direction:

- Per CPUC decision in integrated resource planning proceeding:
  - *50% RPS portfolio (IRP "default" scenario) provided for reliability and economic study purposes*
  - *42 MMT portfolio (IRP "reference" scenario) provided as a policy study "sensitivity", and specifically excluded providing a "policy base case" that would be necessary for any policy-driven transmission to be approved.*
  - *Full capacity deliverability status and energy-only amounts were specified*
- The expectation was that the "preferred" plan coming out of the 2018 IRP effort would form a "base case" for the 2019-2020 planning cycle.

Economic Study Issues:

- Large number of stakeholder proposals for transmission and storage – both pumped hydro and battery
- Proposals came in as:
  - proposed reliability projects,
  - economic study requests,
  - suggested alternatives to reduce local capacity requirements,
  - and/or interregional transmission project proposals

Special study efforts conducted in 2018:

- Risks of early economic retirement of gas fleet (also feeding into IRP process)
- Large scale storage system benefits – found significant production cost benefits, but capacity benefits needed in order to be viable

PLEXOS updates to prior years' efforts

- CPUC/CEC study request re transfers of non-GHG resources with Pacific Northwest
- In-depth study of local capacity resource requirement needs (e.g. profiles of "need") and development of conceptual mitigations for half of the areas and sub-areas (none were found to be economic).

Recommendations for New Reliability-Driven Project Approvals and Previously Approved Projects On-hold

Binaya Shrestha
Regional Transmission - North

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

Overview

- Review of on-hold projects.
- Review of new projects.
- Review of request Window submissions.

Review of Previously Approved Projects On-hold

Recommendations for Previously Approved Projects On-hold

Projects	Planning Area	Project Type	Cost ($ million)
Jefferson-Stanford #2 60 kV Line	Bay Area	Cancel (New Project)	30-40
Morro Bay 230 kV Transformer	Central Coast and Los Padres	Cancel	50-60
Diablo Canyon Voltage Support	Central Coast and Los Padres	Cancel	33
Atlantic-Placer 115 kV	Central Valley	Cancel (New Project)	80-90
Bridgerville-Garberville 115 kV Line	Humboldt	Cancel	55-65
Gates-Gregg 230 kV Line	Fresno	Cancel	200-250
Total (Cancelation)			448-538

Projects	Planning Area	Project Type	Cost ($ million)
North of Mesa Upgrade (formerly Midway-Andrew Project)	Central Coast and Los Padres	On-hold (Rescope and New Project)	170
Total (On Hold)			170

Jefferson-Stanford #2 60 kV Line (GBA)

Approved cycle:
- 2010-2011 TPP

Original scope:
- Build a new Jefferson- Stanford #2 60 kV line

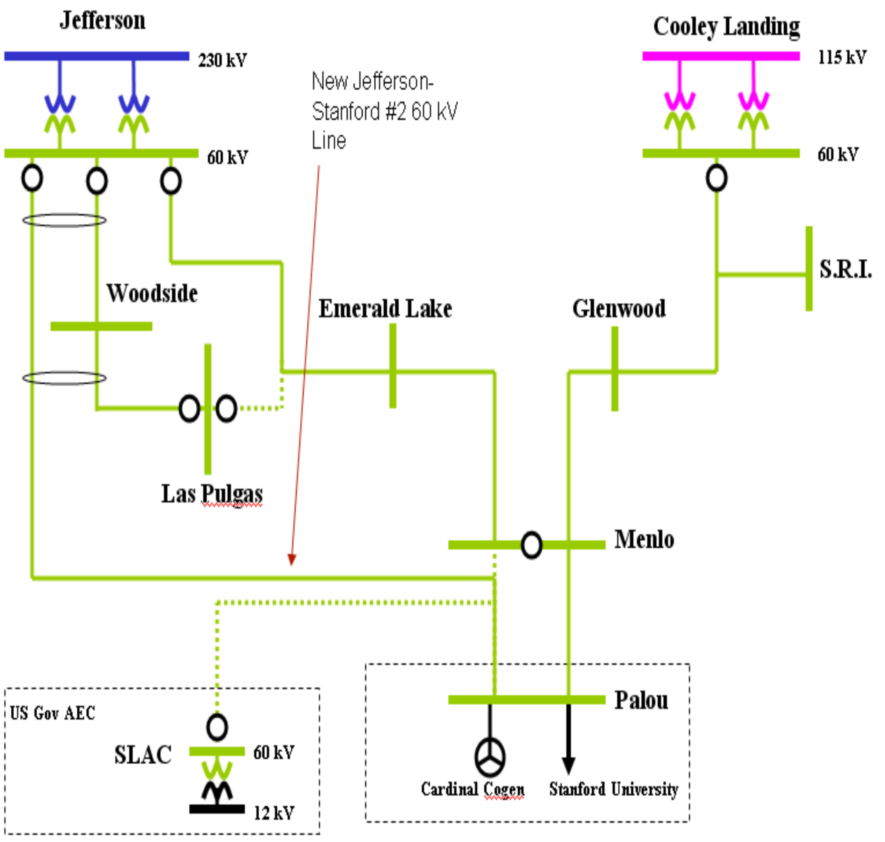
Project cost:
- Original cost: $25M-$35M
- Current estimated cost: $30M-$40M

Current In-service Date:
- On hold

Reliability Assessment Need:
- NERC Category P6 and P7 BES contingencies resulting in overloads on Peninsula 60 kV system.

Mitigation still required {or not}:
- Mitigation required for reliability

Recommendation:
- Cancel the Jefferson-Stanford #2 60 kV line project.
- Operating solution for P6.
- Jefferson 230 kV bus upgrade for P7 overloads on Hillsdale-San Mateo-Jefferson 60 kV lines.
    - 230 kV BAAH Bay #3 ($5M-$9M)
    - Protection upgrade ($1M-$2M)
- Cost of proposed alternative: $6M-$11M



Morro Bay 230/115 kV Transformer Project (CCLP)

Approved cycle:
- 2010-2011 TPP

Original scope:
- Build a new Morro Bay 230/115 kV transformer

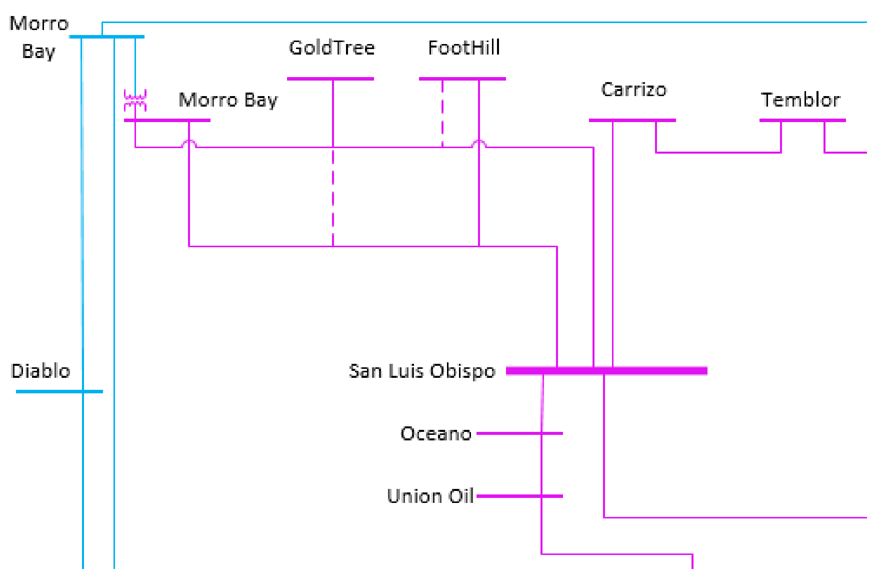
Project cost:
- Original cost: $8M-$10M
- Current estimated cost: $50M-$60M

Current In-service Date:
- On hold

Reliability Assessment Need:
- The reliability assessment identified no P0, P1, or P3 overloads in the area following the loss of the Morro Bay 230/115 kV transformer

Mitigation still required {or not}:
- None

Recommendation:
- Cancel the Morro Bay 230/115 kV transformer project.



Diablo Canyon Voltage Support Project (CCLP)

Approved cycle:

- 2012-2013 TPP

Original scope:

- Install a new static var compensator (SVC) or thyristor controlled switched capacitor bank rated at +150 MVAr at the Diablo Canyon 230 kV substation and construct the associated bus to provide voltage control and support for the Diablo Canyon Power Plant (DCPP)

Project cost:

- Original cost: $35M-$45M
- Current estimated cost: $33M

Current In-service Date:

- On hold

Reliability Assessment Need:

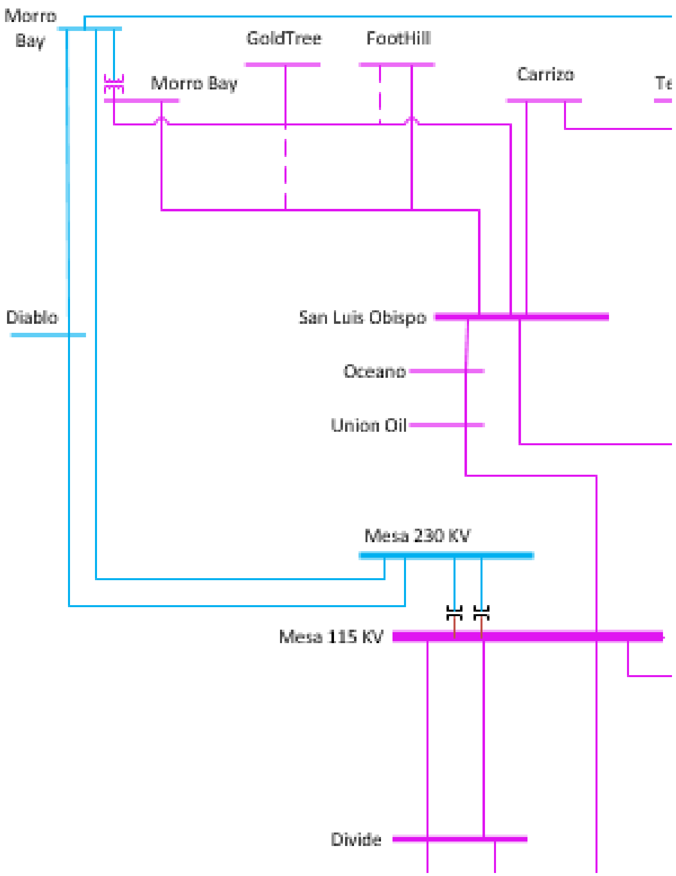
- None

Mitigation still required {or not}:

- Comply with Nuclear Power interface requirements, NUC-001-3.

Recommendation:

- Since there are no reliability concerns in the area ISO recommends Canceling the Diablo Canyon Voltage support project.
- To meet NUC-001-3 requirements utilize Local RAS (such as Divide or Mesa UVLS) for mitigation until Diablo retires in 2025



Midway – Andrew Project (CCLP)

Approved cycle:

- 2012-2013 TPP

Original scope:

- Build new 230/115 kV Andrew substation
- Convert existing Midway-Santa Maria 115 kV Line to a new Midway-Andrew 230 kV Line.
- Installs one 3-phase 420 MVA 230/115 kV Bank at the new Andrew Sub
- Loops Andrew 115 kV bus into Santa Maria-Sisquoc and Mesa-Sisquoc 115 kV Lines.
- Install a new 10-mile Andrew-Divide #1 115 kV Line.

Project cost:

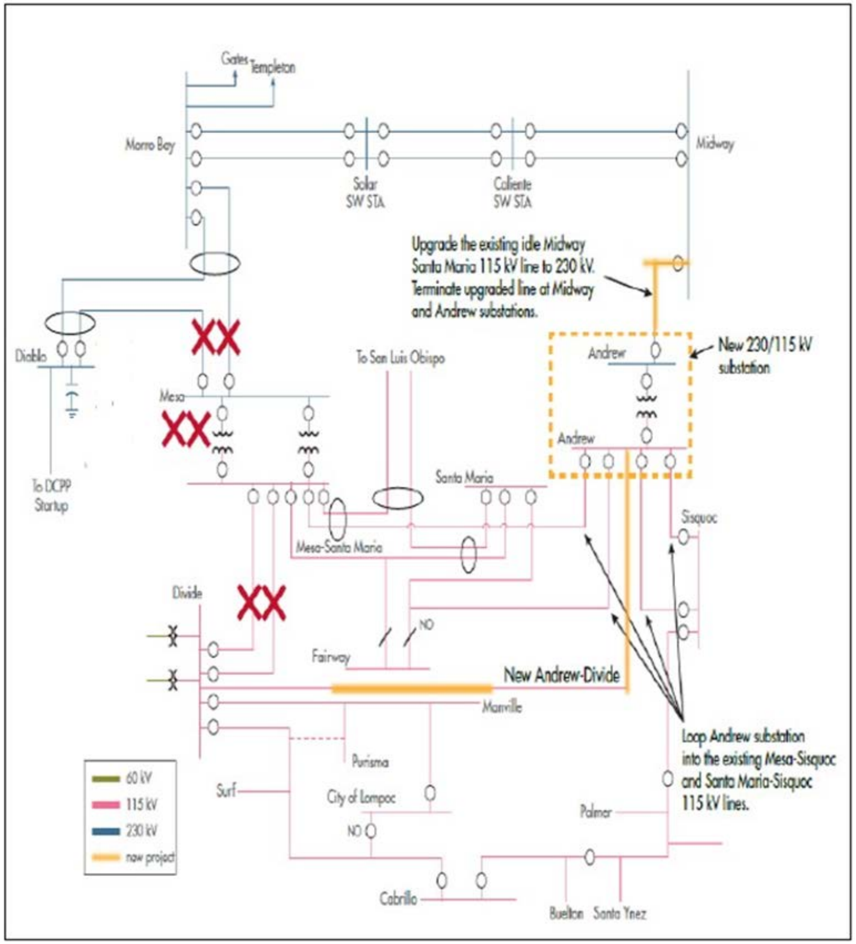
- Original cost: $120M-$150M
- Current estimated cost: $215M

Current In-service Date:

- On hold

Reliability Assessment Need:

- The reliability assessment identified severe thermal P2 and P6 overloads in the 115 kV system supplied from the Mesa substation.



Midway – Andrew Project (CCLP) North of Mesa

Proposed Scope for North of Mesa:

- Build Andrew 230/115 kV substation.
- Energize Diablo – Midway 500 kV line at 230 kV connect to Andrew substation.
- Loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations

Reliability Assessment Need:

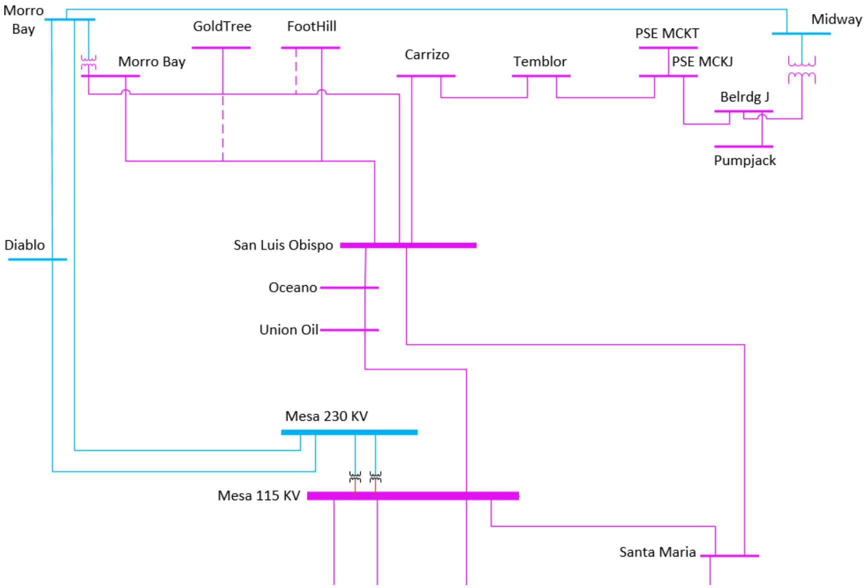
- The reliability assessment identified severe thermal P2 and P6 overloads in the 115 kV system supplied from the Mesa substation.
- No reasonable time to take outage for maintenance

Mitigation still required {or not}:

- Mitigation still required for reliability

Recommendation:

- Split Midway- Andrew into two Projects; North of Mesa Upgrades and South of Mesa Upgrades.
- Continuing further assessment of the conversion of one of the 500 kV lines from Midway to Diablo to 230 kV for North of Mesa.



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Midway – Andrew Project (CCLP) South of Mesa

Reliability Assessment Need:

- The reliability assessment identified severe thermal P6 overloads and voltage collapse in the 115 kV system south of Mesa substation.
- No reasonable time to take outage for maintenance

Project Scope

- Increase the Winter emergency rating of Sisquoc - Santa Ynez 115 kV line to 120 MVA
- Install 20 Mvar capacitor bank at Cabrillo
- Install SPS to shed load if P6 occurs under peak load

Project in service date

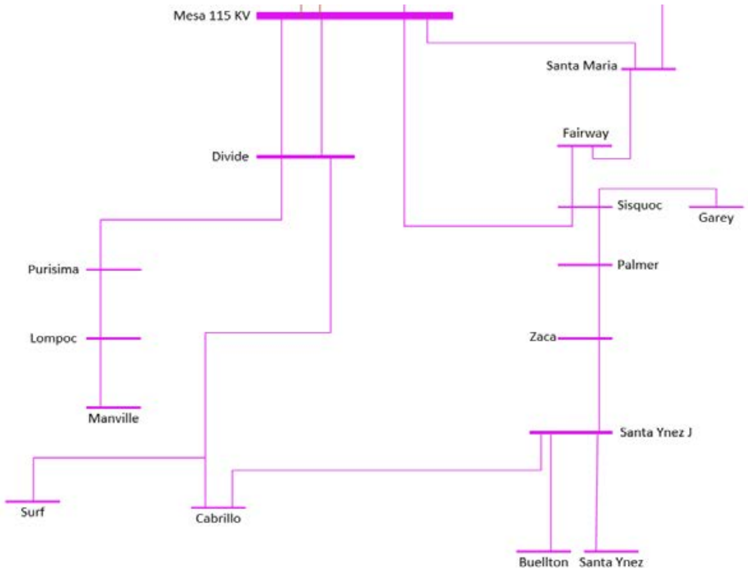
- 2023

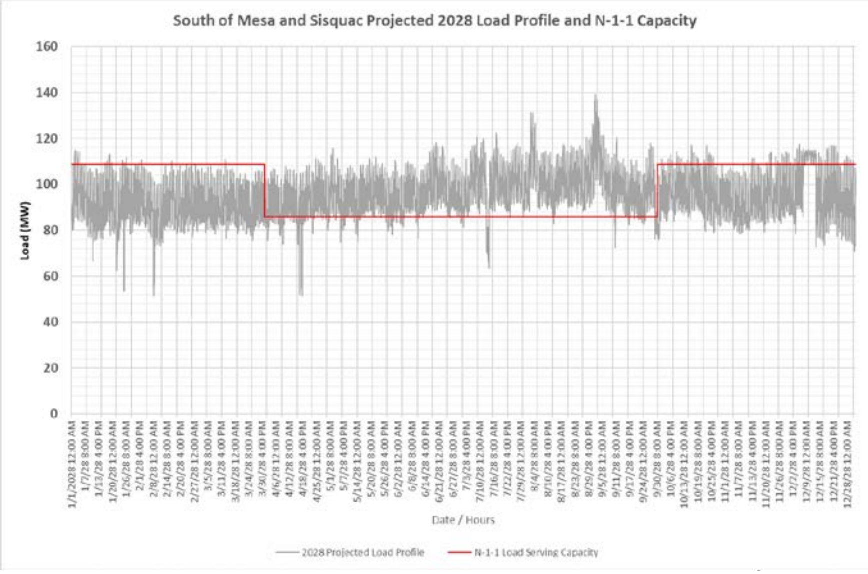
Project Costs

- $45M

Recommendation

- Approval





Atlantic – Placer 115 kV Line Project (CVLY)

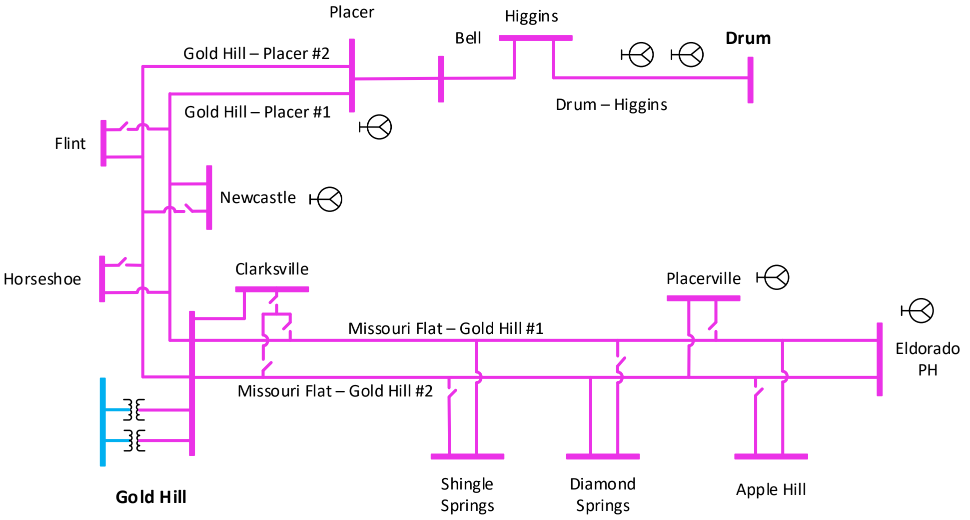
Approved cycle:
- 2012-2013 TPP

Original scope:
- Construct a new 115 kV line between existing Atlantic and Placer 115 kV substations (approximately 14 miles long, capable of 1,100 Amps under emergency conditions)
- Adding a second Placer 115/60 kV three phase transformer rated at 200 MVA and
- Installing an SPS for the loss of two Gold Hill 230/115 kV transformers.

- **Project cost:**
- Original cost: $55M-$85M
- Current estimated cost: $80M-90M

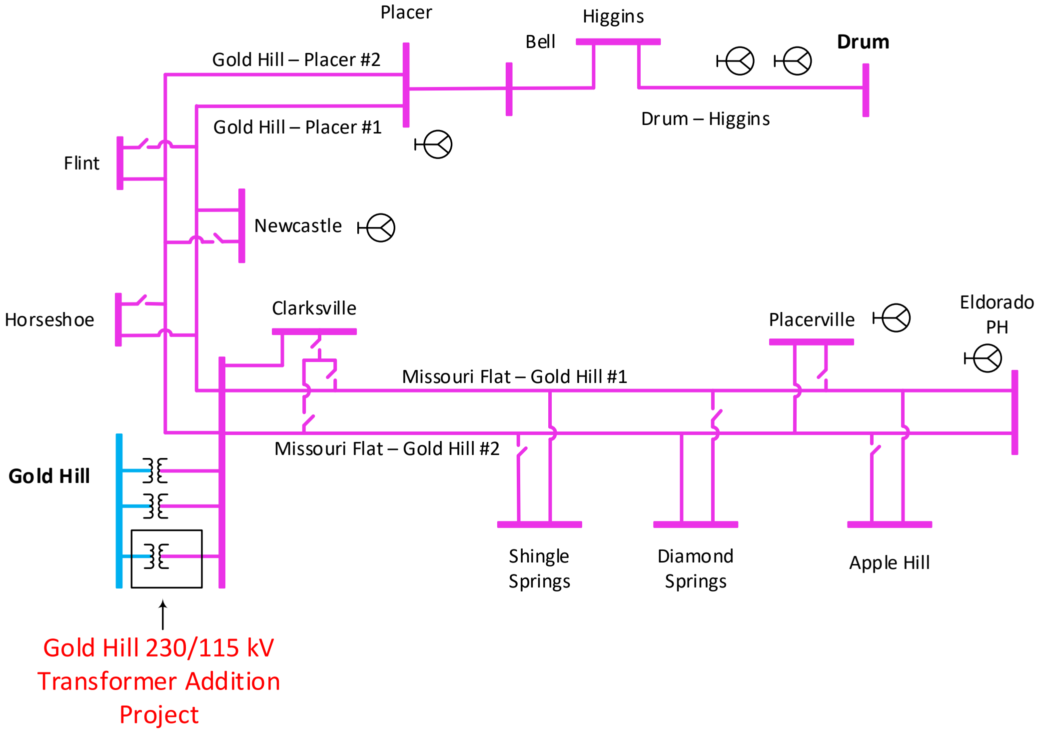
Current In-service Date:
- On hold

Reliability Assessment Need:
- There are no window available to take maintenance outage of Gold Hill 230/115 kV transformers
- Outage of two Gold Hill transformer causes voltage collapse in the area
- P2-1 on Gold Hill Missouri Flats 115 kV line causes overload in the long term

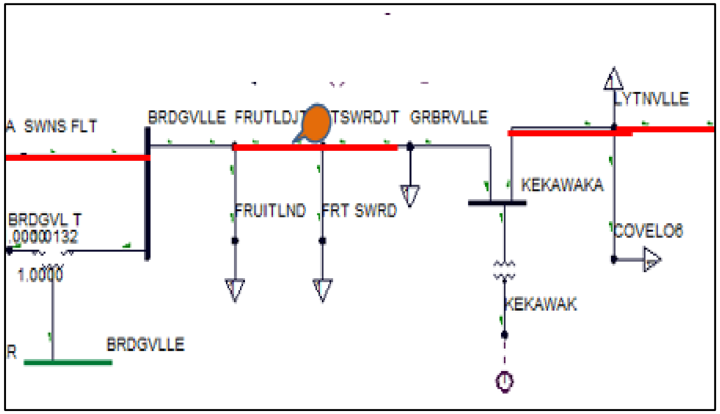


Gold Hill 230/115 kV Transformer Addition Project (Central Vallry Area)

- Reliability Assessment Need
  - No Maintenance window for Gold Hill 230/115 kV transformers due to thermal overload on Drum – Higgins 115 kV line.
- Project Scope
  - Add a third 230/115 kV Transformer bank at Gold Hill substation
- Project Cost
  - $22M
- Alternatives Considered
  - Upgrade Drum – Higgins 115 kV line
  - Bring another source to the Placerville/Shingle Spring area
- Recommendation
  - Approval



Bridgeville – Garberville No.2 115kV Line (Humboldt)



Approved cycle:

- 2011-2012 TPP

Original scope:

- Install new 36 mile long 115kV line between Bridgeville and Garberville substations as a double circuit tower with existing 60kV line.
- Will also require construction of new 115kV bus at Garberville substation and 115/60kV transformer.
- Reliability need, P1 and P2 thermal overloads

Project cost:

- Original cost: $55 - $65 million

Current In-service Date:

- January 2024

Reliability Assessment Need:

- No thermal overloads observed in the 2018-2019 TPP studies

Recommendation:

- Cancel the Bridgeville-Garberville 115kV Line
- Recommend new project to mitigate high voltages in the area

Gates-Gregg 230kV Line (Fresno)

Approved cycle:
- 2012-2013 TPP

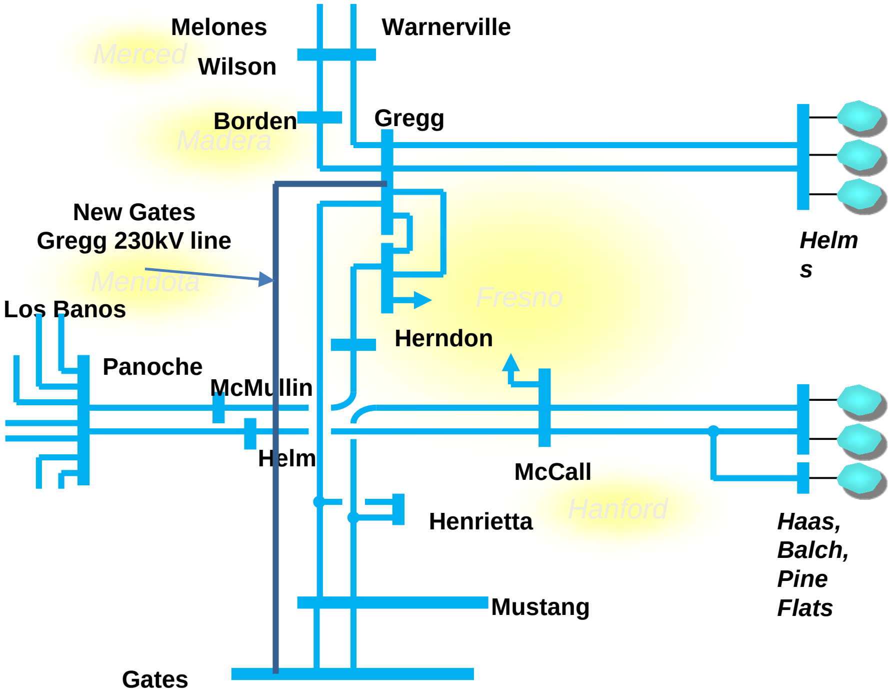
Original scope:
- Build a new Gates-Gregg 230kV line to address

Original Need:
- Project was approved as a Reliability-driven project with potential renewable integration benefits
  - Reliability needs identified to start in the 2023 to 2029 timeframe

Project cost:
- Original cost: $115M-$145M
- Current estimated cost: $200M-$250M
  - Current expenditures $29M

Current In-service Date:
- On hold

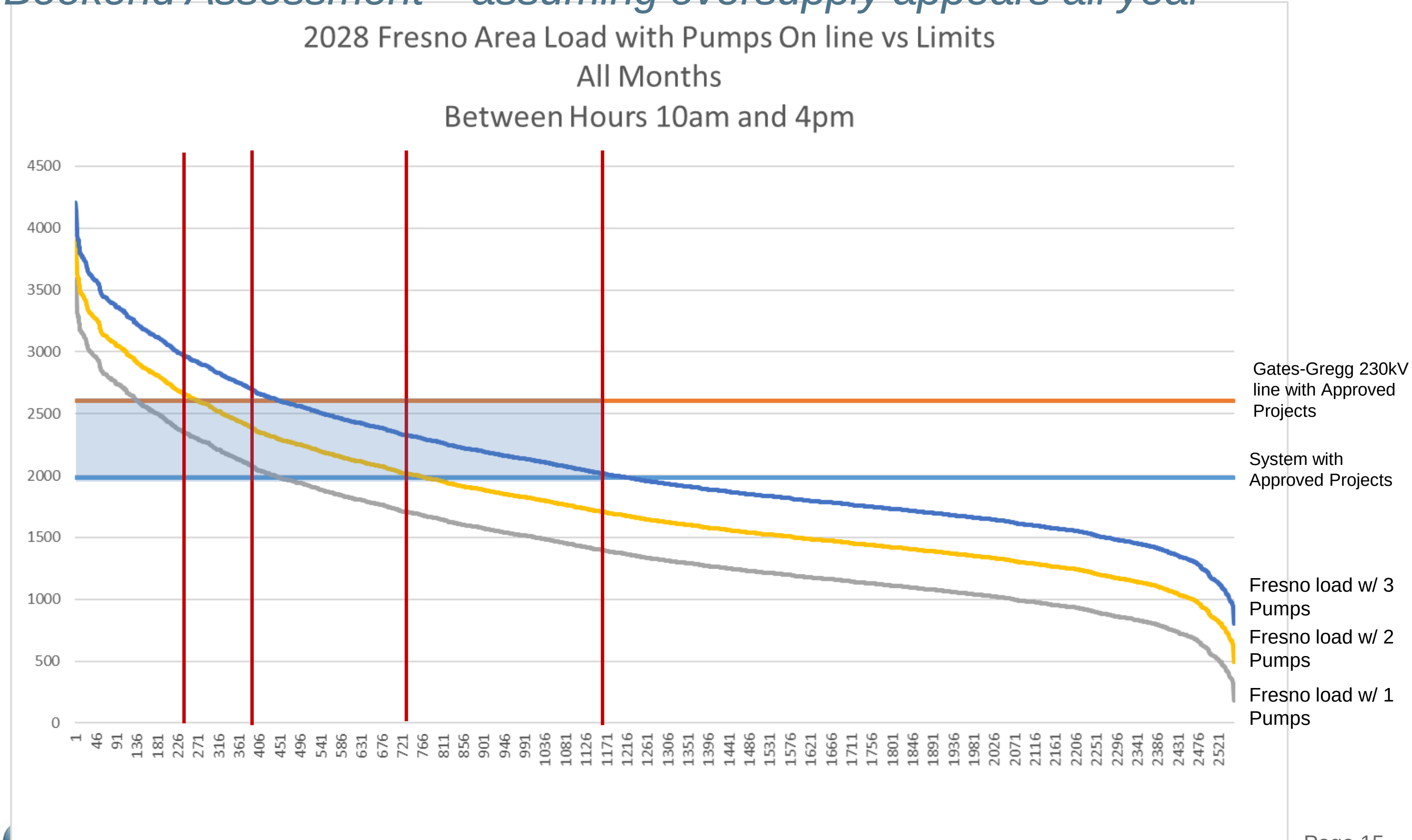
Reliability Assessment Need:
- None



Gates Gregg-230 kV Line (Fresno)

2028 Area Loads with Pumps versus Capability

Bookend Assessment – assuming oversupply appears all year



Gates-Gregg 230 kV Line (Fresno)
Value of Curtailment Economic Assessment

- There does not appear to be sufficient economic benefits to support the Gates-Gregg 230 kV Transmission Line Project
- With the current estimated cost of the project being $200-250 million dollars and the identified annual benefits result in BCR of 0.39 to 0.97
- The ISO is recommending to cancel the Gates-Gregg 230 kV Transmission Line Project in the ISO 2018-2019 transmission planning process

Gates-Gregg Project						
Avoided Curtailment Benefit						
Avoided Curtailment Benefits	Pumping Not Available Assuming Oversuppy for All Hours			Pumping Not Available with Expected Oversuppy Hours		
	At $40/MWh estimated cost of curtailment	At $66/MWh estimated cost of curtailment	At $100/MWh estimated cost of curtailment	At $40/MWh estimated cost of curtailment	At $66/MWh estimated cost of curtailment	At $100/MWh estimated cost of curtailment
Net Curtailment Saving ($million/year)	$18.24	$30.10	$45.60	$9.14	$15.10	$22.90
PV of Curtailment Savings ($million)	$251.73	$415.40	$629.31	$126.14	$208.39	$316.04
Capital Cost						
Capital Cost Estimate ($ million)	$250			$250		
Estimated “Total” Cost (screening) ($million)	$325			$325		
Benefit to Cost						
PV of Savings ($million)	$251.73	$415.40	$629.31	$126.14	$208.39	$316.04
Estimated “Total” Cost (screening) ($million)	$325.00			$325.00		
Benefit to Cost	0.77	1.28	1.94	0.39	0.64	0.97

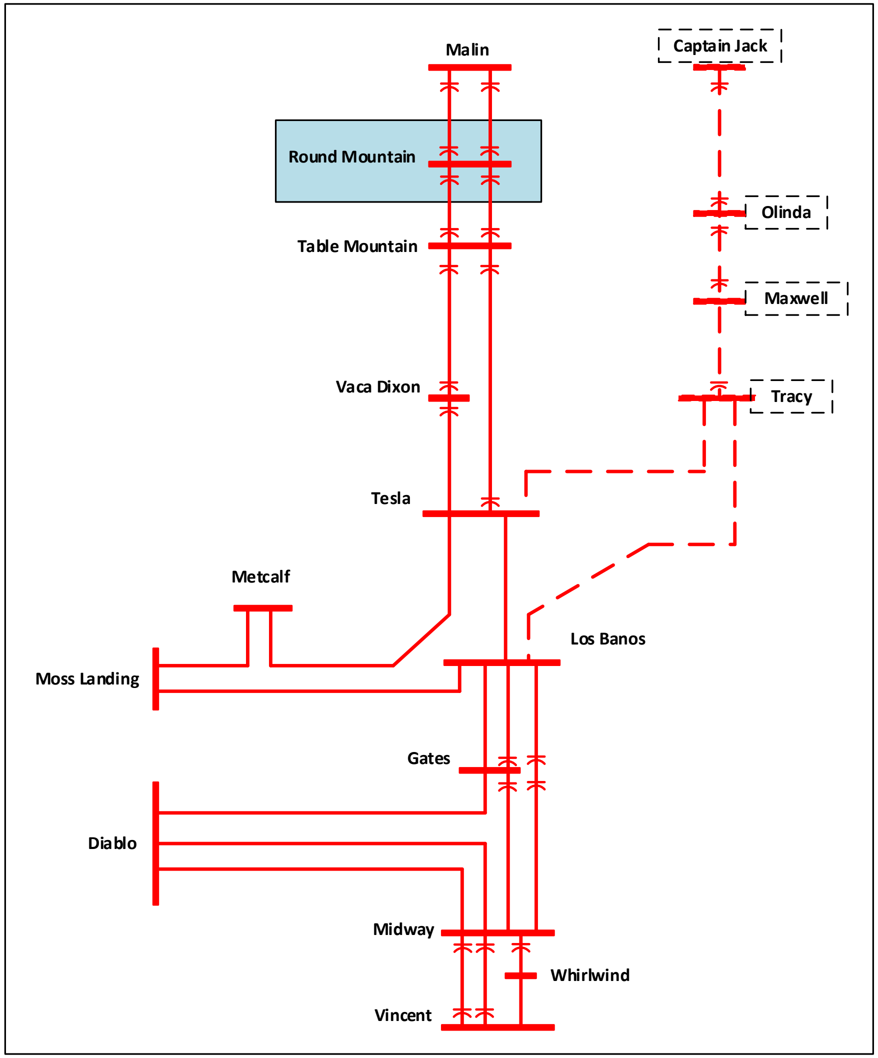
New Projects Recommended for Approval in 2018-2019 TPP

New Projects Recommended for Approval in 2018-2019 TPP

Projects	Planning Area	Project Type	Cost ($ million)
Round Mountain 500 kV Dynamic Reactive Support	Bulk	New	160-190
Gates 500 kV Dynamic Reactive Support	Bulk	New	210-250
Lakeville 115 kV Bus Upgrade	North Coast and North Bay	New	10-15
Tyler 60 kV Shunt Capacitor	North Valley	New	5.8-7
Cottonwood 115 kV Bus Sectionalizing Breaker	North Valley	New	8.5-10.5
Gold Hill 230/115 kV Transformer Addition	Central Valley	Substitute for on-hold project	22
Tesla 230 kV Bus Series Reactor	Central Valley	New	24-29
Jefferson 230 kV Bus Upgrade	Bay Area	Substitute for on-hold project	6-11
Christie-Sobrante 115 kV Line Reconductor	Bay Area	New	10.5
Moraga-Sobrante 115 kV Line Reconductor	Bay Area	New	12-18
Ravenswood 230/115 kV Transformer #1 Limiting Facility Upgrade	Bay Area	New	0.1-0.2
South of Mesa Upgrade	Central Coast and Los Padres	Substitute for on-hold project	45
Total			514-608

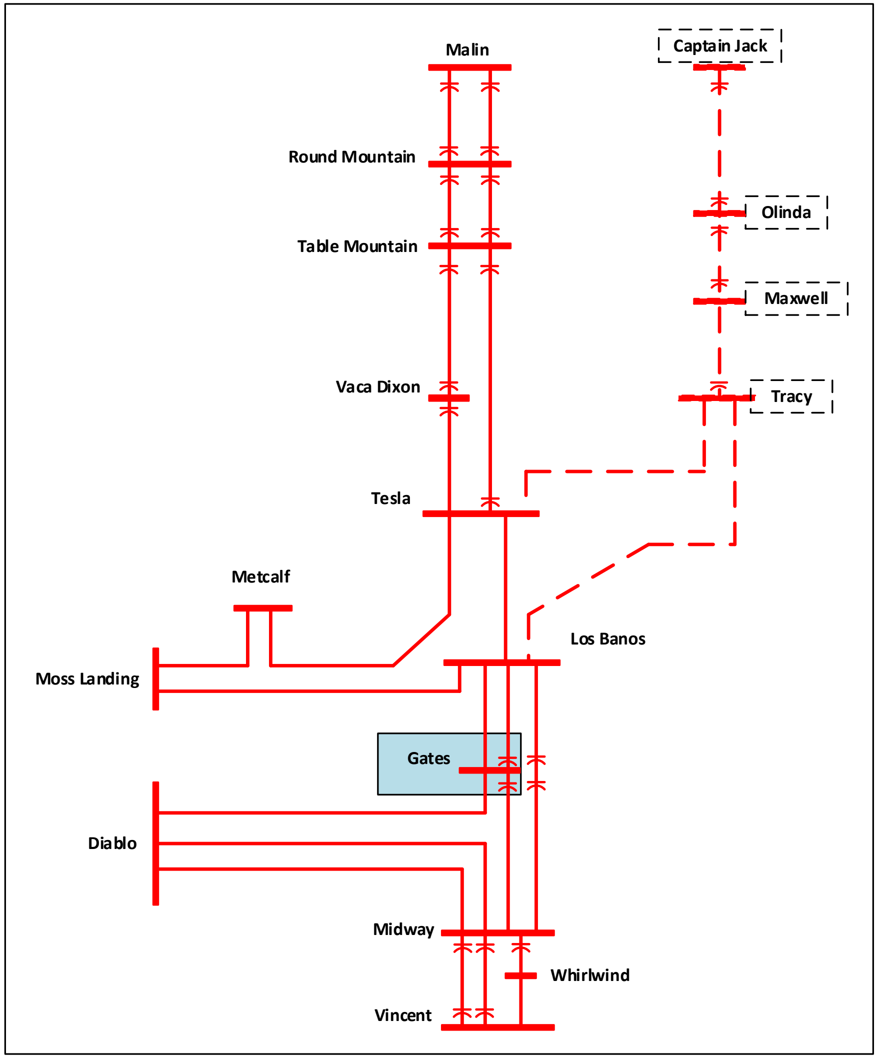
Round Mountain 500 kV Dynamic Reactive Support Project (Bulk System)

- Reliability Assessment Need
  - High voltage under P0, P1, and P6 contingencies, low voltage under PDCI outage, and significant daily voltage fluctuations.
- Project Scope
  - Add a ± 500 Mvar dynamic reactive support device at Round Mountain 500 kV substation.
- Project Cost
  - $160M - $190M
- Alternatives Considered
  - Shunt reactor/capacitor
  - Request Window submissions
- Recommendation
  - Approval
  - Eligible for competitive solicitation.



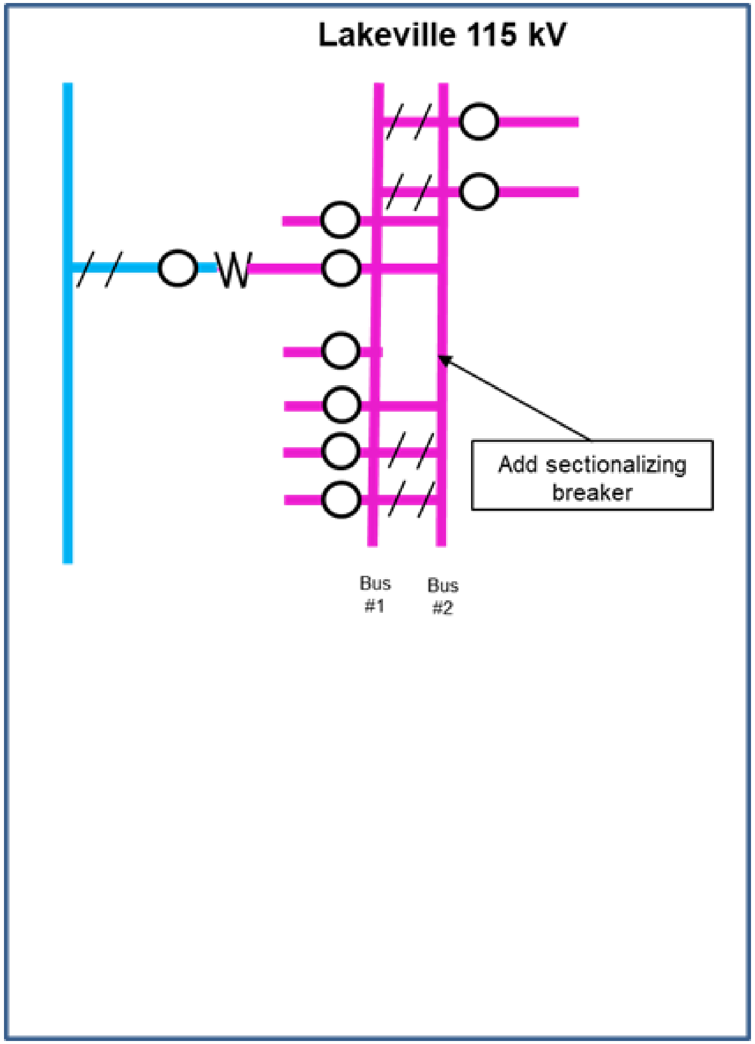
Gates 500 kV Dynamic Reactive Support Project (Bulk System)

- Reliability Assessment Need
  - After Diablo Canyon PP retirement, there will be high voltage under P0, P1, and P6 contingencies, delayed voltage recovery after fault which results in load shedding, and momentary cessation of PV plants.
- Project Scope
  - Add a ± 800 Mvar dynamic reactive support device at Gates 500 kV substation.
- Project Cost
  - $210M - $250M
- Alternatives Considered
  - Shunt reactor/capacitor
  - Request Window submissions
- Recommendation
  - Approval
  - Eligible for competitive solicitation



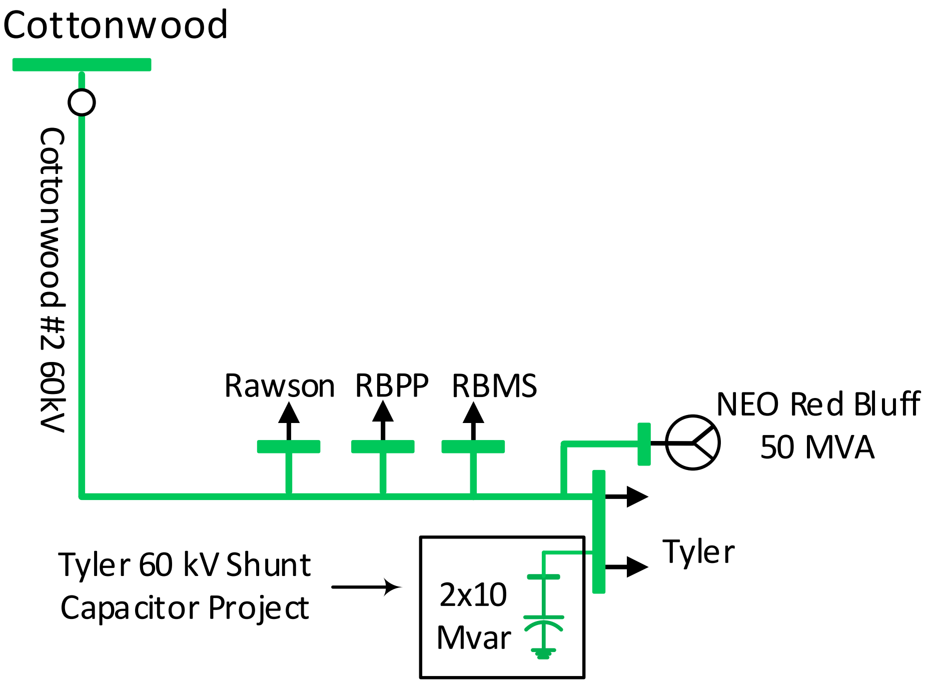
Lakeville 115 kV Bus Upgrade (North Coast North Bay Area)

- Reliability Assessment Need
  - NERC Categories P2 thermal overload starting 2020
- Project Scope
  - Add a sectionalizing breaker on the Lakeville 115 kV bus section “D”.
- Project Cost
  - $10M - $15M
- Alternatives Considered
  - None
- Recommendation
  - Approval



Tyler 60 kV Shunt Capacitor Project (North Vallry Area)

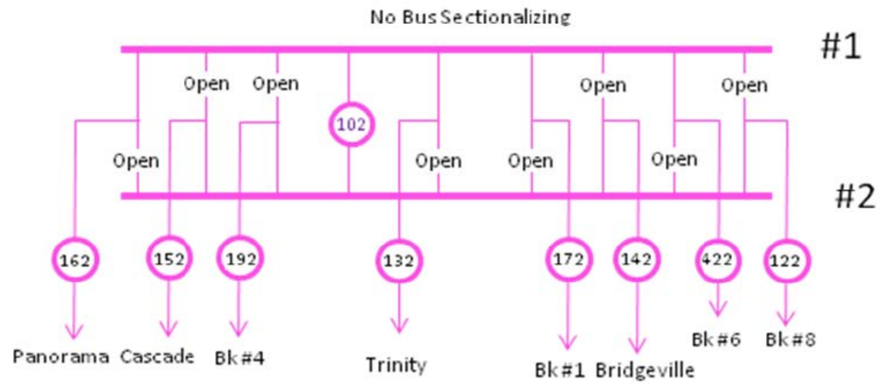
- Reliability Assessment Need
  - NERC Categories P1 voltage issues starting 2020 and thermal overloads in the long term.
- Project Scope
  - Add a 2 x 10 Mvar Capacitor bank at Tyler 60 kV substation
- Project Cost
  - $5.8M - $7M
- Alternatives Considered
  - Capacitor bank at Rawson substation
- Recommendation
  - Approval



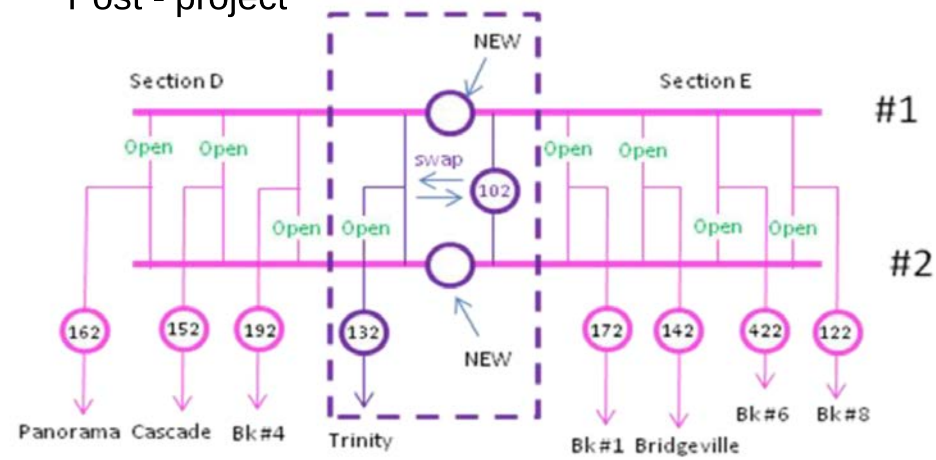
Cottonwood 115 kV Bus Sectionalizing Breaker Project (North Vallry Area)

- Reliability Assessment Need
  - NERC Categories P2-4 voltage collapse issue starting 2020.
- Project Scope
  - Swap the CB 132 (Cottonwood-Trinity) and CB 102 positions in the bus
  - Install sectionalizing breakers in the #1 and #2 operating busses between CB 102 and CB 132
- Project Cost
  - $8.5M - $10.5M
- Alternatives Considered
  - Adding a breaker in series with CB 102
- Recommendation
  - Approval

Existing system:



Post - project

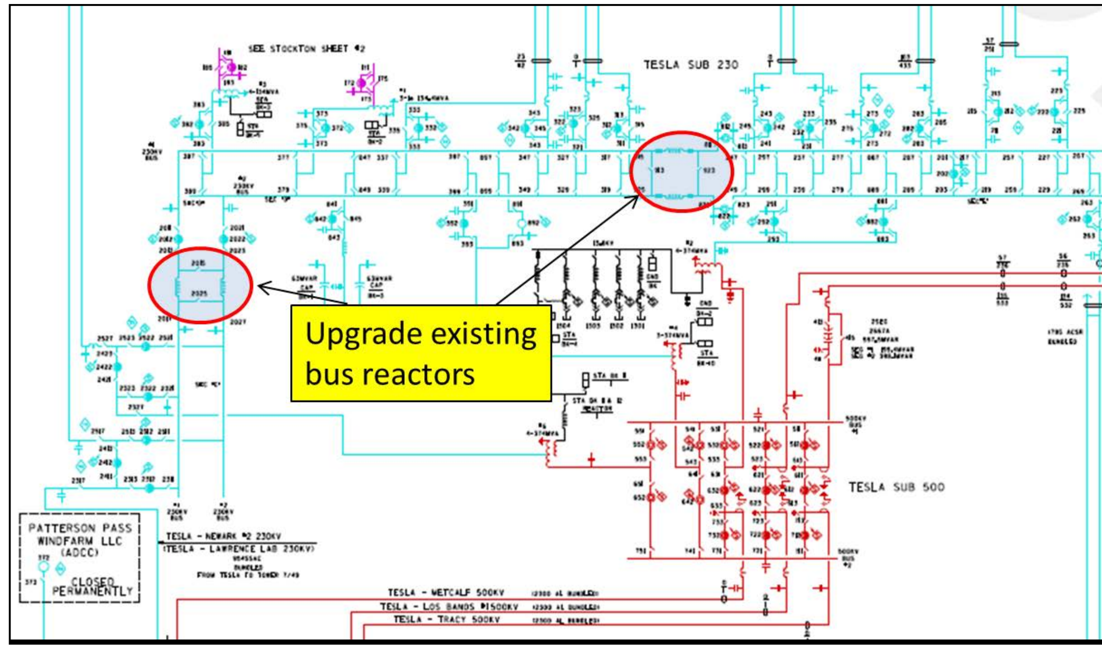


Source: PG&E Project Submission

California ISO

Tesla 230 kV Bus Series Reactor Project (Central Valley Area)

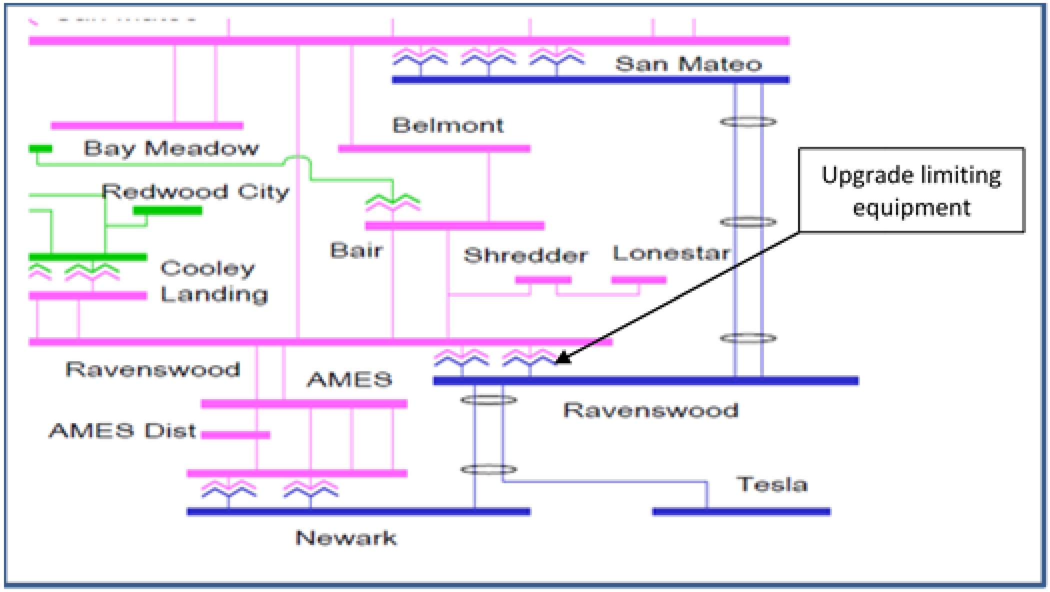
- Reliability Assessment Need
  - Fault current at Tesla 230 kV bus is higher than breaker capability
- Project Scope
  - Replace the existing equivalent 8 ohms and 4 ohms bus reactors between bus sections C-D and D-E respectfully, with 18 ohms equivalent reactors
- Project Cost
  - $24M - $29M
- Alternatives Considered
  - Replace all eleven 230 kV circuit breakers with 80 kA breaker and reinforce bus structure for higher fault current stresses.
- Recommendation
  - Approval



Source: PG&E Project Submission

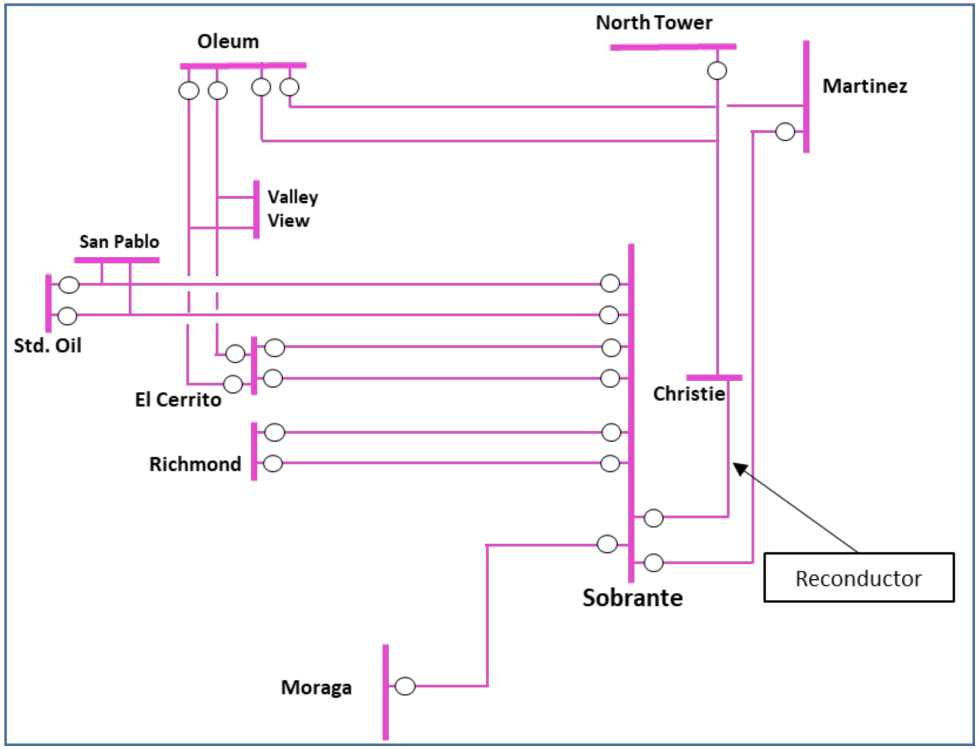
Ravenswood 230/115 kV Transformer #1 Limiting Facility Upgrade (Greater Bay Area)

- Reliability Assessment Need
  - NERC Categories P2 and P7 thermal overloads starting 2020.
  - P1 and P3 thermal overloads in sensitivity.
- Project Scope
  - Upgrade limiting equipment (disconnect switch)
- Project Cost
  - $100K - $200K
- Alternatives Considered
  - None
- Recommendation
  - Approval



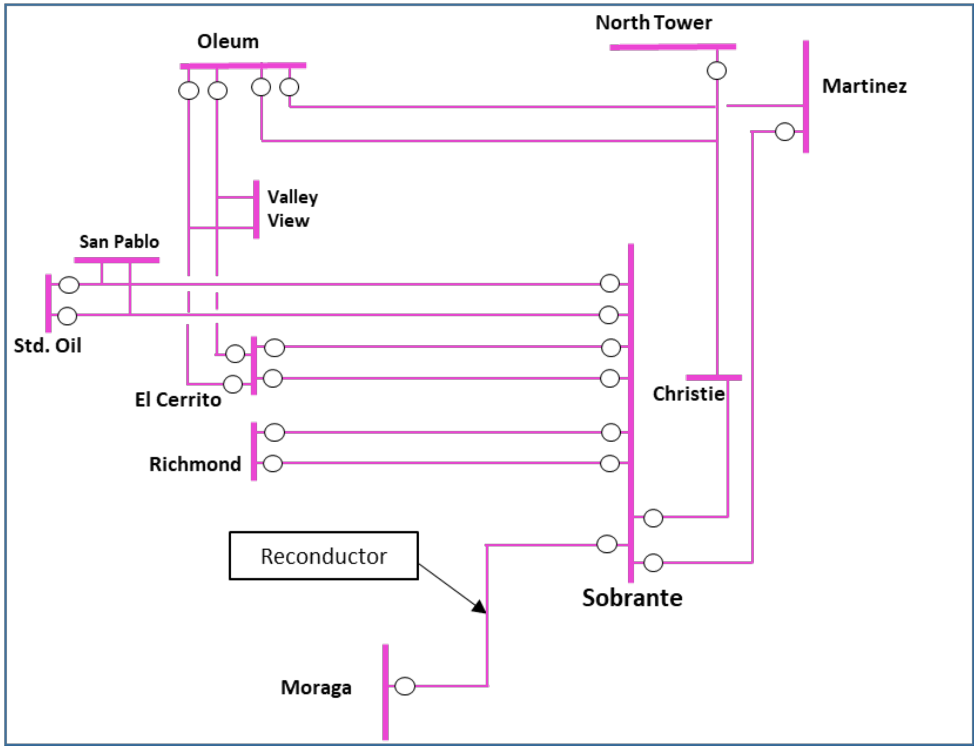
Christie-Sobrante 115 kV Line Reconductor (Greater Bay Area)

- Reliability Assessment Need
  - NERC Category P7 thermal overload starting 2020.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Scope
  - Reconductor Christie-Sobrante 115 kV line
- Project Cost
  - $10.5M
- Alternatives Considered
  - Rerate: Not sufficient
- Recommendation
  - Approval



Moraga-Sobrante 115 kV Line Reconductor (Greater Bay Area)

- Reliability Assessment Need
  - NERC Category P2 thermal overloads starting 2020.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Scope
  - Reconductor Moraga-Sobrante 115 kV line
- Project Cost
  - $12M-$18M
- Alternatives Considered
  - Rerate: Not feasible
- Recommendation
  - Approval



2018 Request Window Submissions – PG&E Area

Ref. #	Project Name	Submitted by	In-Service Date	Cost ($M)	ISO Recommendation
1	Tyler 60 kV Shunt Capacitor Project	PG&E	2022	$5.8-$7	Approve
2	Cottonwood 115kV Bus Sectionalizing Breakers Project	PG&E	2022	$8.5-$10.5	Approve
3	Tesla 230 kV Bus Series Reactor	PG&E	2023	$24-$29	Approve
4	Crazy Horse-Salinas 115 kV Lines	PG&E	2025	$35-$42	Need addressed by other project. SPS recommended for interim.
5	Kingsburg-Leemore Reconductoring	PG&E	2021	$12.2-$14.6	Additional information requested.
6	Round Mountain 500 kV Substation Voltage Support Project	PG&E	2024	$160-$190	Round Mountain 500 kV Dynamic Reactive Support recommended
7	Gates 500 kV Voltage Support Project	PG&E	2024	$240-$290	Gates 500 kV Dynamic Reactive Support recommended
8	Round Mountain Dynamic Reactive 500 kV Transmission System	NEET West	2024	$75	Round Mountain 500 kV Dynamic Reactive Support recommended
9	Gates or Diablo Dynamic Reactive 500 kV Transmission System	NEET West	2024	$65-$75	Gates 500 kV Dynamic Reactive Support recommended
10	Cayetano 230 kV Energy Storage 1A	NEET West	2023	$280	Continue to monitor load increases in the future load forecast
11	Cayetano 230 kV Energy Storage 2A	NEET West	2023	$320	Continue to monitor load increases in the future load forecast
12	Cayetano 230 kV Energy Storage 1B	NEET West	2023	$125	Continue to monitor load increases in the future load forecast
13	Cayetano 230 kV Energy Storage 2B	NEET West	2023	$165	Continue to monitor load increases in the future load forecast
14	Lopez to Divide 500/230 kV Transmission System Project	NEET West	2024	$85	Need addressed by other previously approved project.
15	Weber – Manteca 230 kV Project	NEET West	2024	$35	Mitigation solution under development. SPS recommended for interim.
16	Temettate Advanced CAES	Hydrostor	2024	$190-$320	Doesn't address all reliability issues identified. Project that mitigates all reliability issues recommended.
17	500 kV/230 kV Chorro Junction Substation	LS Power	2023		Gates 500 kV Dynamic Reactive Support recommended
18	500 kV Wells Place Substation	LS Power	2023		Round Mountain 500 kV Dynamic Reactive Support recommended
19	Southwest Intertie Project - North (SWIP - North)	LS Power	2022	$525	Reliability assessment did not identify any reliability need.
20	Delta Reliability Energy Storage	Tenaska	2021		LCR Sub-area not selected to assess alternatives to reduce or eliminate the LCR requirement.

2018 Request Window Submissions – SCE Area

Ref. #	Project Name	Submitted by	In-Service Date	Cost ($M)	ISO Recommendation
1	Mountainview RAS Modification	SCE	2021	$2-$5	Reliability assessment did not identify any reliability need.
2	Etiwanda-Vista23 kV_Clearance Upgrade	SCE	2021	$3-$6	Reliability assessment did not identify any reliability need.
3	Control-Silver Peak 55 kV_Mitigation-TLRR	SCE	2025	$60-$75	No concerns identified with the project. No ISO approval required.
4	Coolwater-Ivanpah Corridor_Mitigation-TLRR	SCE	2025	$8-$15	No concerns identified with the project. No ISO approval required.
5	Coolwater-Kramer Corridor_Mitigation-TLRR	SCE	2025	$35-$50	No concerns identified with the project. No ISO approval required.
6	Red Bluff-Mira Loma_Reliability Project	NEETWest	2024	$850	Reliability assessment did not identify any reliability need. Insufficient BCR.
7	California Transmission Project	CTPC	2027	$1.83B	Insufficient BCR.
8	Red Bluff-Victorville-Lugo 500 kV	NEER	2024	$1,011	Reliability assessment did not identify any reliability need.

2018 Request Window Submissions – SDG&E Area

Ref. #	Project Name	Submitted by	In-Service Date	Cost ($M)	ISO Recommendation
1	Border Sub Area LCR Reduction	SDG&E	2021	$6-$10	Reliability assessment did not identify any reliability need. Insufficient BCR.
2	El Cajon Sub Area LCR Reduction	SDG&E	2023	$28-$43	Reliability assessment did not identify any reliability need. Insufficient BCR.
3	ESCO Sub Area LCR Reduction	SDG&E	2023	$14-$20	Reliability assessment did not identify any reliability need. Insufficient BCR.
4	Pala Sub Area LCR Reduction	SDG&E	2021	$25-$37	Reliability assessment did not identify any reliability need. Insufficient BCR.
5	Southern California Regional LCR Reduction	SDG&E	2023	$100-$200	Reliability assessment did not identify any reliability need. Insufficient BCR.
6	TL649A Reconductor	SDG&E	2021	$4-$6	Reliability assessment did not identify any reliability need.
7	LEAPS	NHC	2025	$1,760-$2,040	Reliability assessment did not identify any reliability need. Insufficient BCR.
8	Suncrest Sycamore 230 kV_Reliability Project	NEETWest	2024	$100	Reliability assessment did not identify any reliability need.
9	Sycamore 230 kV_Storage-SATA_Proposal	NEETWest	2024	$200	Reliability assessment did not identify any reliability need. Insufficient BCR.
10	San Vicente Energy Storage Project	City of San Diego	2028	$1,500-$2,000	Reliability assessment did not identify any reliability need. Insufficient BCR.
11	Westside Canal Reliability Center	Sempra	2021	$304	Reliability assessment did not identify any reliability need. Insufficient BCR.
12	Sycamore Reliability Energy Storage	Tenaska	2021	$108-$178	Reliability assessment did not identify any reliability need. Insufficient BCR.

2018 Request Window Submissions – GridLiance/VEA Area

Ref. #	Project Name	Submitted by	In-Service Date	Cost ($M)	ISO Recommendation
1	Amargosa Valley Reliability Improvement	GridLiance	2022	$41	Found not needed. Doesn't address all reliability issues identified.
2	Pahrump Valley Loop-in	GridLiance	2022	$24	Found not needed. Lower cost alternative available.
3	Southwest Nevada Reliability Improvement	GridLiance	2023	$65	Found not needed. Adverse impact to the system reliability
4	Gamebird Charleston 230 kV Reliability Project	NEETWest	2024	$35	Found not needed. Lower cost alternative available.

Frequency Response Assessment and Data Requirements

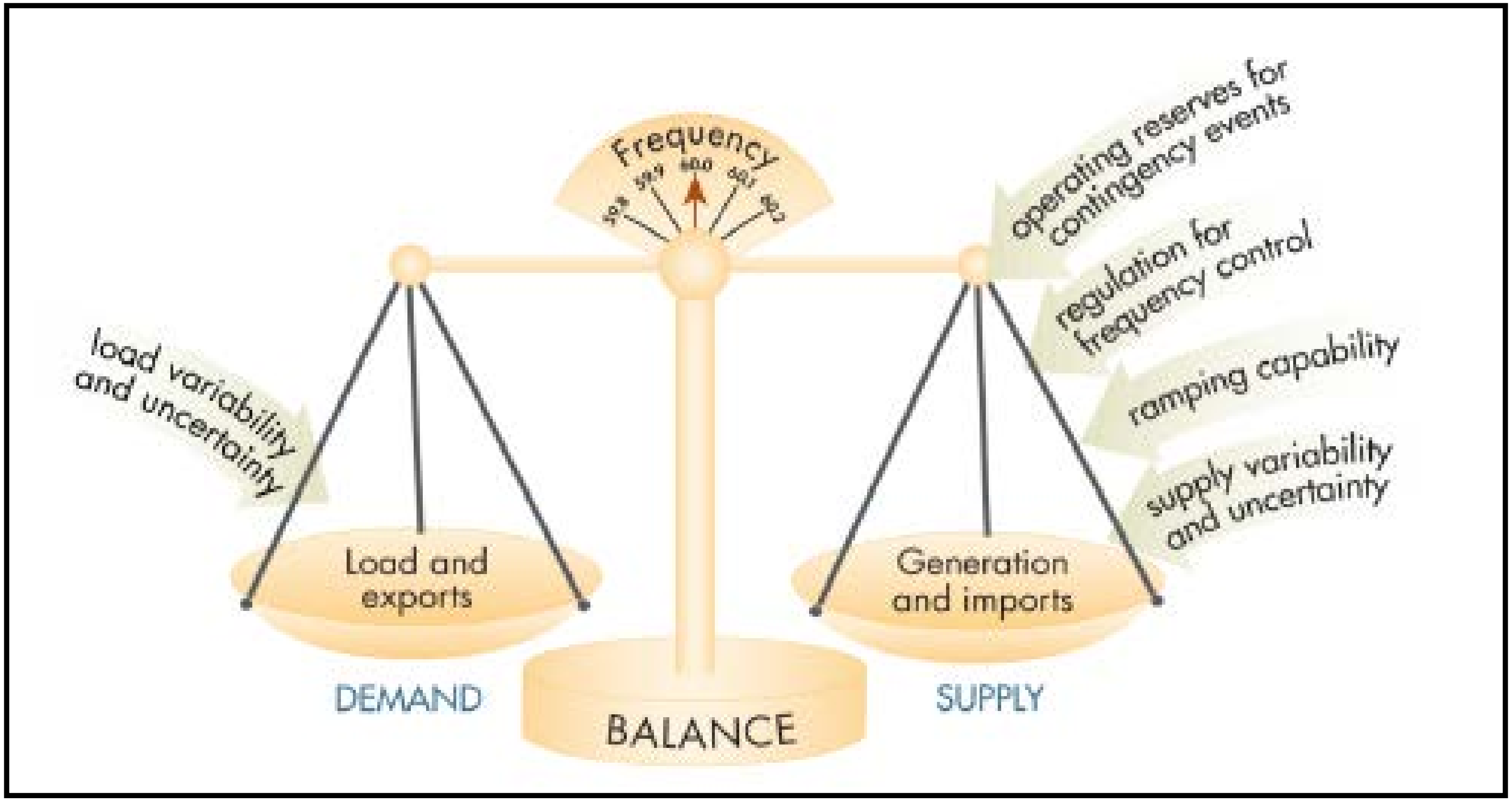
Irina Green
Regional Transmission - North

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

Presentation Overview

- Basics of frequency response
- ISO frequency response study results
- Data collection and improvement efforts

Continuous Supply and Demand Balance



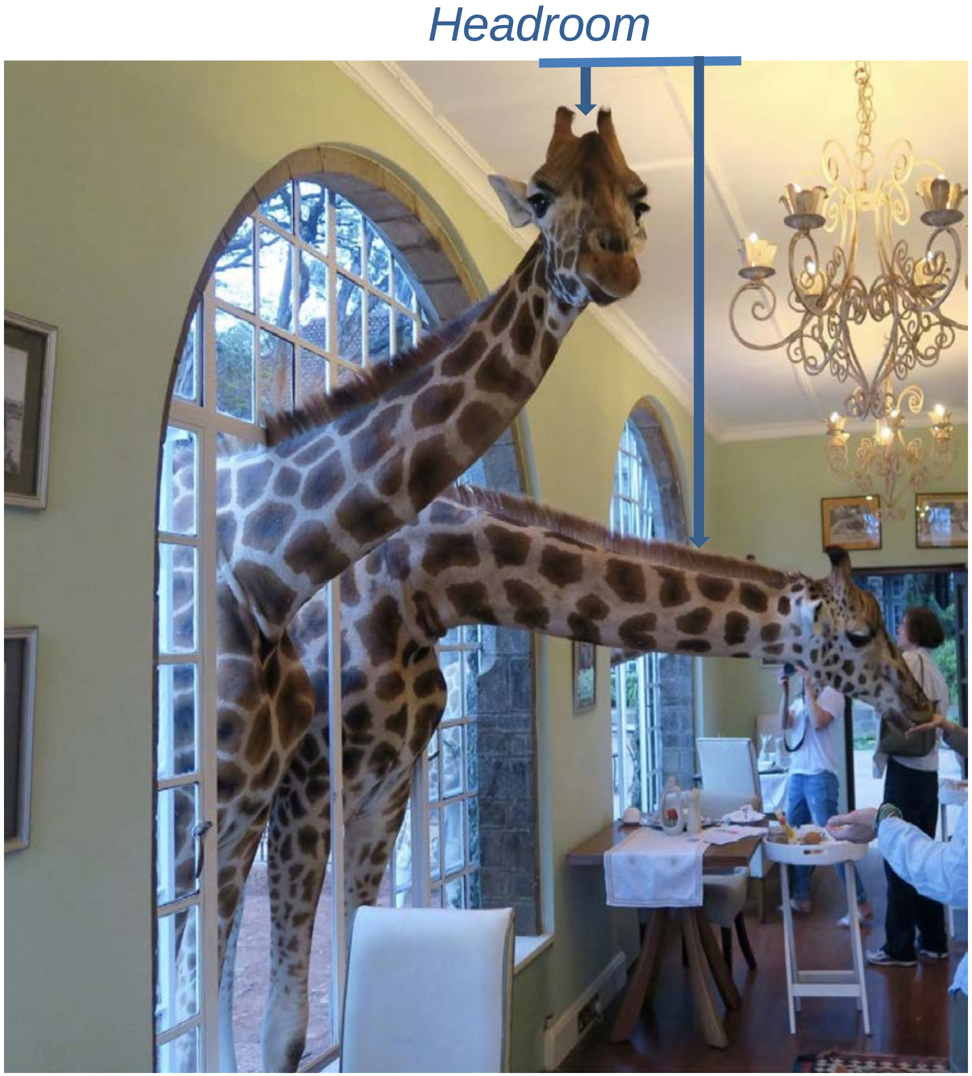
Governor Response

- Each generating unit contributes 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
- Governor response has significant impact on frequency regulation
- Poor system frequency regulation can lead to load shedding, generator trips and instability
- For studies of off-nominal frequency events, it is essential to properly characterize the response of each generator
- Governor response depends amount of generators with responsive governors and on the droop and headroom of each governor

Frequency Regulation –Governor Droop

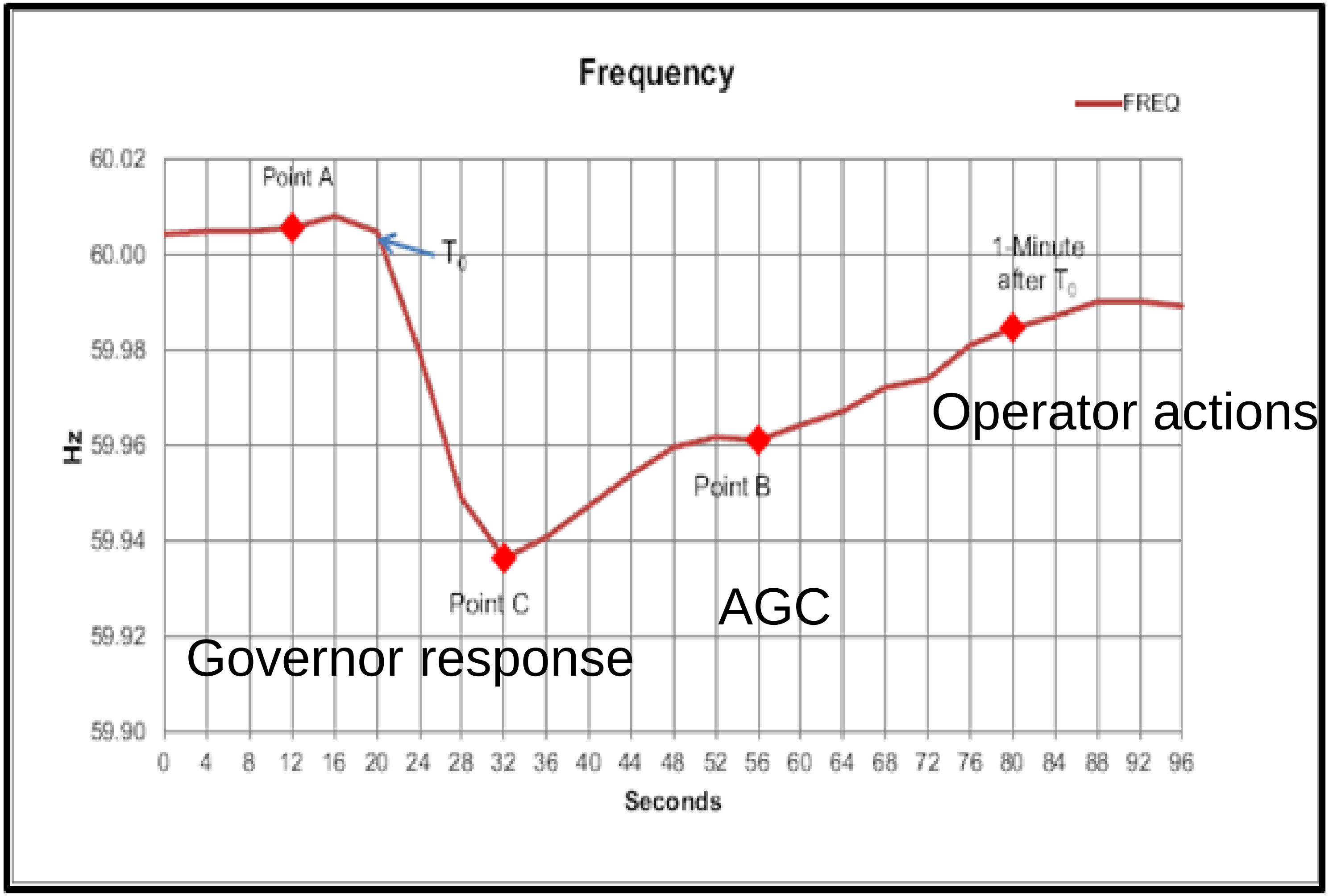
- Droop = Change in percent frequency per change in percent output, e.g.,
  - *Frequency drops to 59.9 Hz, with 5% droop setting, unit responds with ([60-59.9]/60)/0.05 = 3.33% of rated power*
  - *With 4% droop settings it responds ([60-59.9]/60)/0.04 =4.17%*
- The smaller is the droop, the higher is response, but generator may become unstable if it is too small

Frequency Regulation – Generator Headroom



- The headroom is the difference between the maximum capacity of the unit and the unit’s output.
- For a system to react most effectively to changes in frequency, enough total headroom must be available.
- Block loaded units and units that don’t respond to changes in frequency have no headroom.
- Kt is the ratio of power generation capability of units with governors to the MW capability of all generation units.

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 NERC BAL-003-1.1 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 (257.4 MW/0.1Hz)

ISO Frequency Response Studies

- Study goal – determine if the ISO can meet its FRO with the most severe credible contingency – outage of two Palo Verde units
- Previous study results (2014-2015 and 2015-2016 TPP):
  - Total frequency response from WECC was above the interconnection's FRO, but the ISO had insufficient frequency response when the amount of dispatched renewable generation was significant.
  - The results of the simulations did not match the actual measurements showing higher response to frequency deviations.
  - The study results appeared to be too optimistic, and the actual frequency response deficiency may be higher than the studies showed.
- These results were the reason to focus primarily on data collection and model validation in the 2016-2017 and 2017-2018 planning cycles

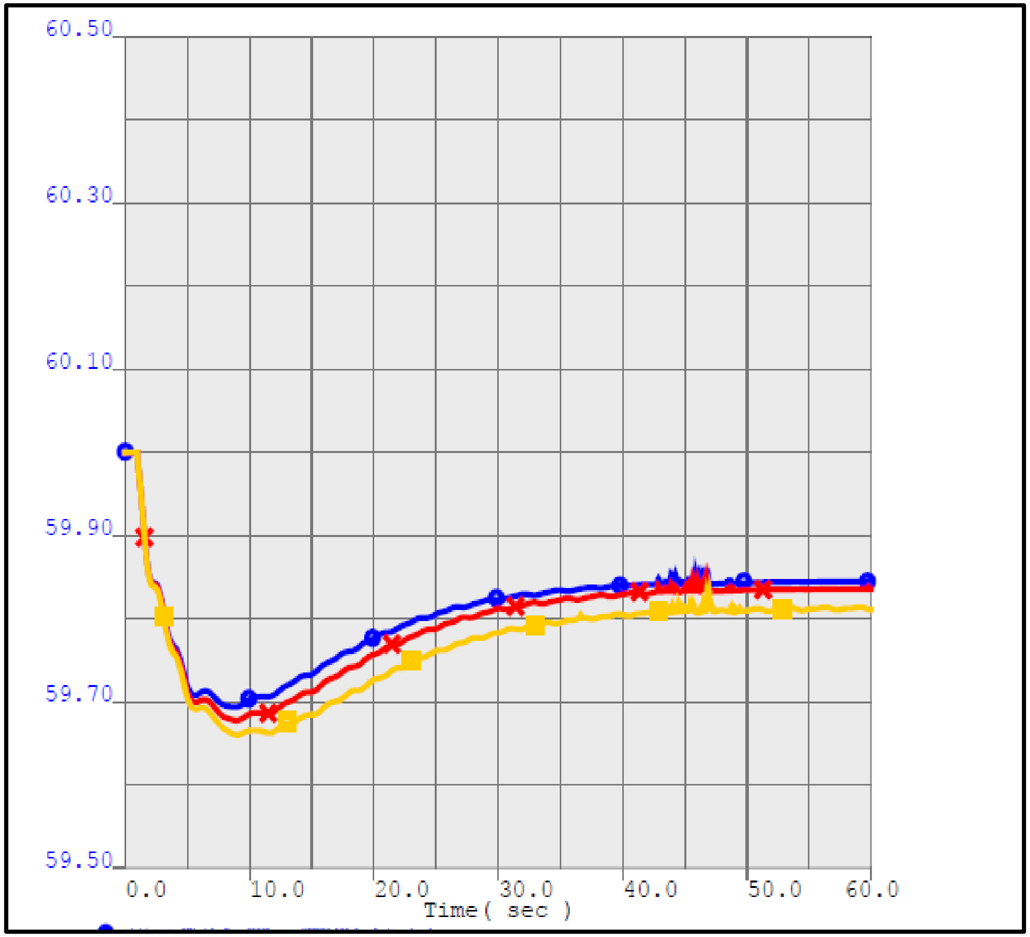
2018-2019 TPP Frequency Study Methodology

- Starting case: Spring off-peak 2023 sensitivity case with high renewable generation (Case 1)
- Updated dynamic stability models for generation based on the model updates received and updated load models (composite load model with single phase A/C stalling and DER)
- 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)
- Determine required headroom and ratio of generators with responsive governors to meet the ISO's FRO
- Other cases studied: Case 2 - turn off the "suspicious" units with unreasonable response, Case 3 – reduced headroom

Cases Studied

Case		2023 spring off-peak high renewables	Case 2 - high and negative response units off	Case 3 - reduced headroom
Load, including pumps and motors, MW	ISO, incl. MUNI	27,108	27,108	27,108
	Total WECC	92,609	92,609	92,609
Generation total dispatch , incl. DER, MW	ISO, incl. MUNI	29,483	29,531	29,531
	Total WECC	95,313	95,320	95,311
Generation with responsive governors, MW	ISO, incl. MUNI, dispatch	7,210	7,122	6,023
	ISO, incl. MUNI, capacity	9,515	9,108	7,851
	Total WECC, dispacth	30,974	31,009	27,519
	Total WECC, capacity	45,544	44,868	38,422
Renewable, non responsive, including DER, dispatch MW	ISO, incl. MUNI	11,615	11,615	11,615
	Total WECC	16,882	16,822	16,822
Conventional non responsive, MW	ISO, incl. MUNI	10,658	10,794	11,893
	Total WECC	47,457	47,489	50,970
Dispatch of responsive generation, % of capacity	ISO, incl. MUNI	75.8%	78.2%	76.7%
	Total WECC	68.0%	69.1%	71.6%
Kt – ratio of responsive generation to total, %	ISO, incl. MUNI	29.9%	28.9%	25.0%
	Total WECC	41.4%	41.1%	36.2%

Frequency on the Midway 500 kV bus with an outage of two Palo Verde units. 2023 Spring off-peak with high renewables



- Case 1 nadir – 59.675 Hz, settling frequency 59.844 Hz
- Case 2 nadir – 59.670 Hz, settling frequency 59.835 Hz
- Case 3 nadir – 59.650 Hz, settling frequency 59.812 Hz

Frequency Study Results. Outage of two Palo Verde units. 2023 Spring off-peak with high renewables

Case	Headroom, MW		Responsive units		Response, MW		Response, MW/0.1Hz		Nadir, Hz	Settling frequecy, Hz	Kt – ratio of responsive generation to total, %	
	ISO, incl. MUNI	Total WECC	ISO, incl. MUNI	Total WECC	ISO, incl. MUNI	Total WECC	ISO, incl. MUNI	Total WECC			ISO, incl. MUNI	Total WECC
2023 spring off-peak high renewables	2,310	14,580	147	656	450	2,476	288	1,587	59.675	59.844	29.9%	41.4%
Case 2 - high and negative response units off	1,990	13,870	142	629	442	2,446	268	1,482	59.670	59.835	28.9%	41.1%
Case 3 - reduced headroom	1,910	12,390	139	613	463	2,412	246	1,283	59.650	59.812	25.0%	36.2%

ISO response below FRO

Study Conclusions

- Starting case- acceptable frequency performance both within WECC and the ISO, with response above the obligation BAL-003-1.1.
- With lower commitment of the frequency-responsive units, frequency response from the ISO was below the FRO specified by NERC.
- The responsive generation capacity in the ISO should be no less than approximately 30% to meet FRO.
- In the future with more inverter-based renewable generation online, frequency response from the ISO will most likely become insufficient.
- Compared to the ISO’s actual system performance during disturbances, the study results seem optimistic. Therefore, a thorough validation of the models is needed.
- The issue that was observed in real system operation was withdrawal of the governor response that was not observed in the simulations.

Data Collection and Improvement – NERC Standards

- MOD-032: each Balancing Authority, Planning Authority and Planning Coordinator should establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system
- MOD-033-1 requirements include comparison of the performance of the Planning Coordinator’s portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other real-time data sources.
- This reliability standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. ISO developed such process in 2017.

California ISO

Data Collection and Improvement: 2018-2019 Progress

- The ISO added a section to the Tranmission Planning Process BPM regarding data collection
- Five categories of participating generators were developed based on size and interconnection voltage
- The ISO developed data templates for the generator owners to provide the data
- ISO is requesting validated modeling data from all generators
- The process is on-going and is implemented in several stages depending on the categories. It will start in May 2019 and its completion for all the units is planned for September of 2022.
- The data are submitted to the ISO based on the instructions in the BPM. The data requirements to each category of the generators are also described in the BPM.
- Sanctions have been introduced for not submitting the data

Next Steps

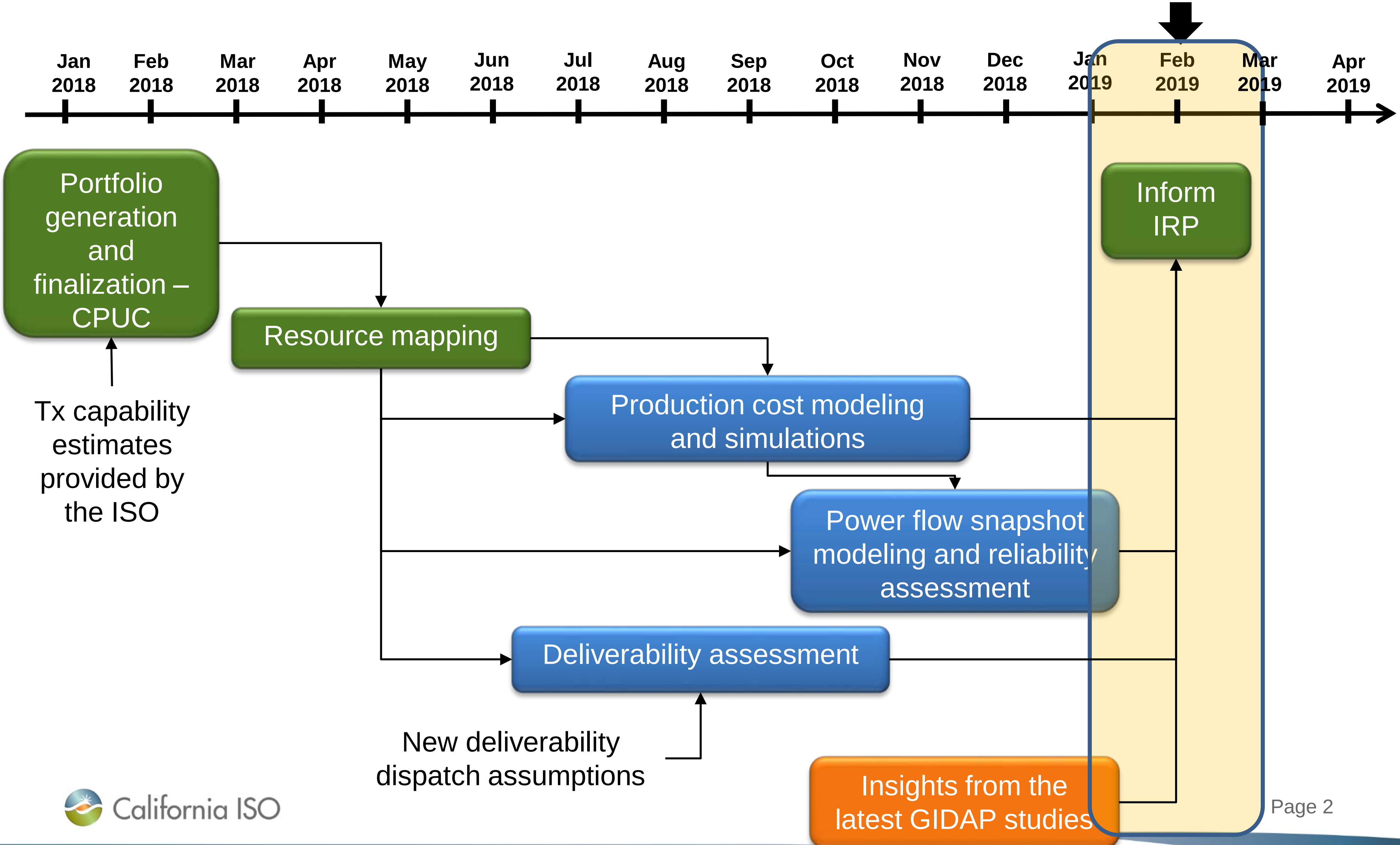
- Continue to collect modeling data
- Update the dynamic database after the data are received
- Perform dynamic stability simulations to ensure that the updated models demonstrate adequate dynamic stability performance.
- After the models are validated, they will be sent to WECC to update the WECC Dynamic Masterfile and the updated models will be used in the future.
- Future work will include validation of models based on real-time contingencies and studies with modeling of behind the meter generation.
- Further work will also investigate measures to improve the ISO frequency response post contingency. Other contingencies may also need to be studied, as well as other cases that may be critical for frequency response.

2018-2019 Transmission Plan Policy-driven Assessment

Sushant Barave
RTE Lead, Regional Transmission - South

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

2018-2019 policy-driven assessment results and the latest GIDAP studies are used to inform the CPUC IRP process



Agenda for today's policy-driven assessment discussion

- Recap of the key objectives and the renewable generation portfolio studied
- Updates regarding previously presented study components
  - Update on implementation of proposed revisions to the deliverability methodology
  - Updated curtailment results
- Snapshot analysis and summary (today's focus)
  - Powerflow snapshot assessment and potential mitigation options
  - Conclusion
  - Next steps

Recap of the key objectives of 2018-2019 policy-driven assessment

- Study the transmission impacts of the sensitivity portfolio transmitted to the ISO by CPUC
- Evaluate transmission solutions (only Category 2 in this planning cycle)
- Test the transmission capability estimates used in CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation
- Test deliverability of FCDS resources in the portfolio using new renewable output assumptions that take into account the new qualifying capacity calculations for solar and wind

The sensitivity portfolio studied in 2018-2019 TPP is a combination of FCDS and EODS resources

Renewable Zones	Solar (MW)		Wind (MW)		Geothermal (MW)	
	FCDS	**EODS**	**FCDS**	**EODS**	**FCDS**	**EODS**
Northern CA	-	-	-	-	-	210
Solano	-	-	-	643	-	-
Central Valley / Los Banos	-	-	146	-	-	-
Greater Carrizo	-	-	-	160	-	-
Tehachapi	1,013	-	153	-	-	-
Kramer & Inyokern	978	-	-	-	-	-
El Dorado, Mountain Pass, Southern NV	802	2,204	-	-	-	-
Riverside East & Palm Springs	2,791	1,084	42	-	-	-
TOTAL	**5,584**	**3,288**	**341**	**803**	**-**	**210**

Updates regarding (i) implementation of the proposed deliverability approach and (ii) PCM results

Implementation of the proposed revisions to the deliverability methodology has been delayed to Q1 of 2020

- The ISO proposed to test deliverability under multiple system conditions – (i) the highest system need scenario and (ii) the secondary system need scenarios
- The proposal attempted to better align generation output assumptions in deliverability assessments with the time of day of those system needs
- In response to stakeholder comments, the ISO has delayed the implementation of the revisions to the generation deliverability assessment methodology from Q1 2019 to Q1 2020

Modeling change in PCM simulations for Kramer-Inyokern and Southern NV resources

- The ISO tested resources in Kramer-Inyokern and Southern NV by modeling these at Lugo 500 kV and Eldorado 500 kV to avoid the local transmission constraints observed in the draft PCM results
- Nested constraints could not be accommodated in the CPUC's portfolio development tool
- Not an indication of preferred point of interconnection
- This was done in order to avoid masking any issues due to curtailment of these resources

Intra-ISO transmission-related renewables curtailment was approximately 4.24 TWh, or roughly a quarter of the total renewable curtailment

	42 MMT w/ 2000 MW ISO Net Export Limit	42 MMT w/ No Export Limit
Total wind and solar generation (TWh)	82.92	96.50
Total wind and solar curtailment (TWh)	17.82	**4.24**
Energy from other renewable resources (Geo, Bio, and Small Hydro) (TWh)	21.38	22.37
Load in front of the meter (same as in CEC forecast) (TWh)	203.99	203.99
Estimated %RPS (All transmission connected renewable energy/Load in front of the meter)	51.1%	58.3%

Snapshot analysis of the 42 MMT portfolio

Severe snapshots were selected with the objective of studying a reasonable upper bound on stressed system conditions

GridView Simulations

8760 Hours of production cost simulation results

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

Within this subset, selected hours with reasonably **stressed major path flows and/or study area load**

Prior study experience and engineering judgement

Special considerations e.g. high conventional generation levels in Solano area

Scenario	Northern CA	Southern CA
42 MMT portfolio	**August 17, 2028 Hr 21**	**April 25, 2028 Hr 13**

Northern CA snapshot assessment – Resource and dispatch assumptions

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
Northern CA	-	-	210
Greater Carrizo	-	160	-
Central Valley / Los Banos	-	146	-
Solano	-	643	-

- Portfolio resources in Solano were dispatched to ~90 percent of the nameplate capacity
- Conventional generation dispatch was at ~100 percent of the nameplate capacity

Northern CA snapshot assessment – No area-wide transmission issue that would limit renewable generation

Limiting Element	Contingency	Type	Overload (%)	Impacted Zones
North Dublin – Cayetano 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	103.7%	Solano
Newark – Las Positas 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	111.5%	
Cayetano – Lone Tree 230 kV Line	Contra Costa 230 kV – Section 2F and 1F	P2-4	109.5%	
Newark – Las Positas 230 kV Line	Contra Costa – Moraga No. 1 and 2 230 kV lines	P7-1	103.5%	

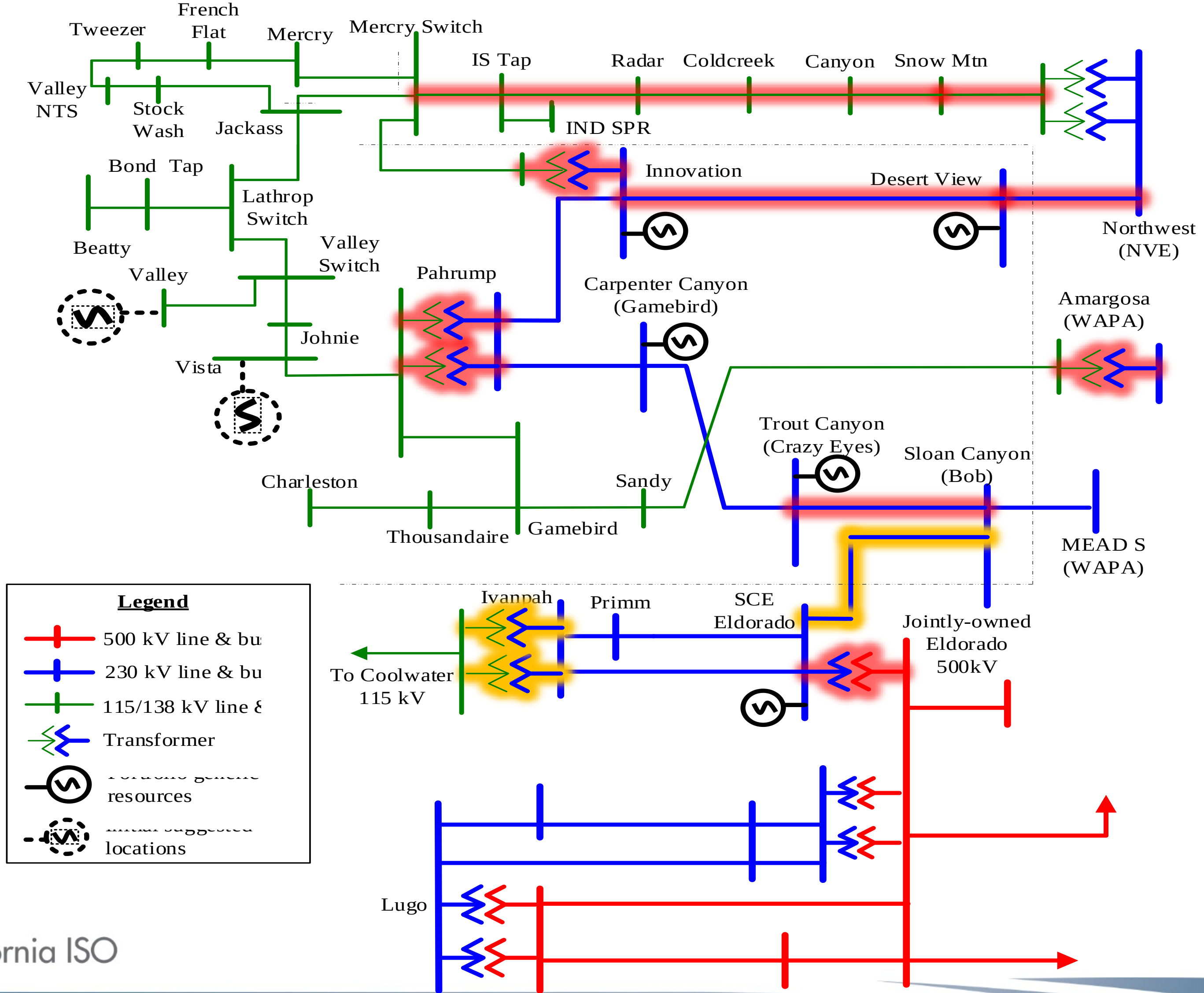
- Potential mitigations for these issues include (i) pre-contingency generation curtailment and (ii) remedial action schemes (RAS) to trip generation as result of a contingency.
- Either mitigation options are unlikely to result in renewable curtailment because curtailment of convention generation in this area was found to be adequate to mitigate the overloads

Southern CA snapshot assessment – Resource and dispatch assumptions in Eldorado, Mountain Pass and Southern NV

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
El Dorado, Mountain Pass, Southern NV	3,006	-	-

- Portfolio resources were dispatched to ~98 percent of the nameplate capacity

Several base case (N-0) and contingency (N-1 and N-2) transmission constraints in Southern NV zone



Transmission constraints observed in Southern NV, Eldorado and Mountain Pass zones

Limiting Element	Contingency	Type	Overload (%)	Impacted Zones
Indian Springs Tap – Mercury Switch (VEA to NV Energy's Northwest 138 kV path)	Base case (N-0)	P0	305.00%	Southern NV

Mitigation options:

- A phase shifting transformer limiting the flow towards NV Energy's Indian Springs substation

OR

- Pre-contingency renewable curtailment (~1,300 MW)

Transmission constraints observed in Southern NV, Eldorado and Mountain Pass zones

Limiting Element	Contingency	Type	Overload (%)	Impacted Zones
Amargosa 230/138 kV Transformer	Base case (N-0)	P0	248.33%	Southern NV
Amargosa 230/138 kV Transformer	Pahrump – Innovation 230 kV	P1	283.43%	Southern NV

Mitigation options:

- Upgrade the existing transformer or add a new 230/138 kV transformer at Amargosa

  OR

- Renewable curtailment (~1,200 MW)

A 230/138 kV Gamebird transformer could partially mitigate this issue

Transmission constraints observed in Southern NV, Eldorado and Mountain Pass zones

Limiting Element	Contingency	Type	Overload (%)	Impacted Zones
Innovation – Desert View 230 kV	Base case (N-0)	P0	347.48%	Southern NV
Trout Canyon (Crazy Eyes) – Sloan Canyon (Bob) 230 kV	Base case (N-0)	P0	279.32%	Southern NV
Northwest – Desert View 230 kV	Base case (N-0)	P0	232.39%	Southern NV
Pahrump 230/138 kV Transformer No. 1	Base case (N-0)	P0	113.86%	Southern NV
Pahrump 230/138 kV Transformer No. 2	Base case (N-0)	P0	108.13%	Southern NV
Innovation 230/138 kV Transformer	Base case (N-0)	P0	108.07%	Southern NV
Divergence	Desert View – Northwest 230 kV	P1	N/A	Southern NV
Divergence	Innovation – Desert View 230 kV	P1	N/A	Southern NV
Divergence	Pahrump – Innovation 230kV & Vista – Johnnie 138kV	P7-1	N/A	Southern NV

Mitigation options:

- A combination of 230 kV upgrades on the GridLiance system
- Pre-contingency curtailment (~1,200 to ~1,500 MW) and RAS (only for contingency issues)

Transmission constraints observed in Southern NV, Eldorado and Mountain Pass zones

Limiting Element	Contingency	Type	Overload (%)	Impacted Zones
Northwest – Westside 230 kV	Northwest – Beltway 230 kV No. 2	P1	112.85%	Southern NV
Ivanpah 230/115 kV Transformer Bank No. 1 or No. 2	Ivanpah 230/115 kV Transformer Bank No. 2 or No. 1	P1	116.06%	Southern NV, Eldorado and Mountain Pass
Eldorado 500/230 5AA Transformer	Base case (N-0)	P0	107.14%	Southern NV, Eldorado and Mountain Pass
Eldorado – Bob 230 kV	Eldorado 500/230 5AA Transformer	P1	123.02%	Southern NV, Eldorado and Mountain Pass

Mitigation options:

- Pre-contingency curtailment
  AND
- RAS to trip generation (existing, proposed or future RAS)

Upgrade options to mitigate transmission constraints for resources mapped in the Southern NV zone

- The need to curtail large amounts of generation to mitigate reliability issues indicated that major upgrades would be required if renewable curtailment is to be avoided.
- Elimination of all the transmission constraints was not the objective, so upgrades with scope additions were incrementally tested with the suggested resource mapping
- Tested upgrade options only in power flow snapshots in order to get directional insights by comparing mitigation effectiveness with scope and costs
- PCM studies were not performed on the upgrade options

Southern NV Upgrade option I – scope and mitigation effectiveness

Option	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
I	• Phase shifting transformer at Mercury Switching Station to prevent overloads on NV Energy's 138 kV lines connected to Northwest 230/138 kV substation • Rebuild existing Pahrump – Sloan Canyon (Bob) 230 kV line to 926/1195 MVA normal/emergency rating and connect to Carpenter Canyon (Gamebird) and Trout Canyon (Crazy Eyes). • Rebuild existing Innovation – Desert View 230 kV line to 926/1195 MVA normal/emergency rating and add a 2nd circuit with the same rating. • Add 2nd 230 kV circuit Desert View – Northwest at 926/1195 MVA normal/emergency rating.	~$150 M	- Not all base case overloads can be eliminated - Some contingency overloads cannot be managed using RAS and pre-contingency curtailment - If Southern NV renewable capacity was reduced to ~2,000 MW from 3,000 MW, then very little transmission-driven curtailment is expected - With Southern NV dispatch reduced to 2,000 MW, Amargosa 230/138 kV bank overload still observed for a large number of contingency scenarios

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Southern NV Upgrade option II

Option	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
II	In addition to Option I • Upgrade existing Desert View - Northwest 230 to 926/1195 MVA normal/emergency rating • Upgrade existing Pahrump - Innovation 230 kV to 926/1195 MVA normal/emergency rating	~$180 M	- Marginal improvement over Option I - With Southern NV capacity reduced to 2,000 MW, the number of contingencies causing Amargosa 230/138 kV bank to overload is almost cut into half

Southern NV Upgrade option III

Option	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
III	In addition to Option I • A new 230 kV substation at Vista • A new Vista - Charleston 230 kV line (926/1195 MVA normal/emergency rating) • Rebuild Vista - Pahrump 230 kV line to 926/1195 MVA normal/emergency rating	~$190 M	- Marginal improvement over option I - With Southern NV capacity reduced to 2,000 MW, Amargosa 230/138 kV bank overloads increased under this option with a large number of contingency scenarios resulting in an overload

Southern NV Upgrade option IV

Option	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
IV	In addition to Option II, • A 2nd Pahrump - Sloan Canyon 230 kV line (926/1195 MVA normal/emergency) • 500 kV loop-in station at Sloan Canyon connecting to Harry Allen – Eldorado 500 kV line	~$300 M	- All base case overloads except Amargosa 230/138 kV bank overload can be eliminated. - Most contingency overloads are eliminated and the rest can be managed with a RAS - If Southern NV renewable capacity was reduced to ~2,000 MW from 3,000 MW, then very little transmission-driven curtailment is expected.

Evaluation of upgrade options indicates that 230 kV system enhancements in Southern NV can significantly reduce transmission-driven curtailment

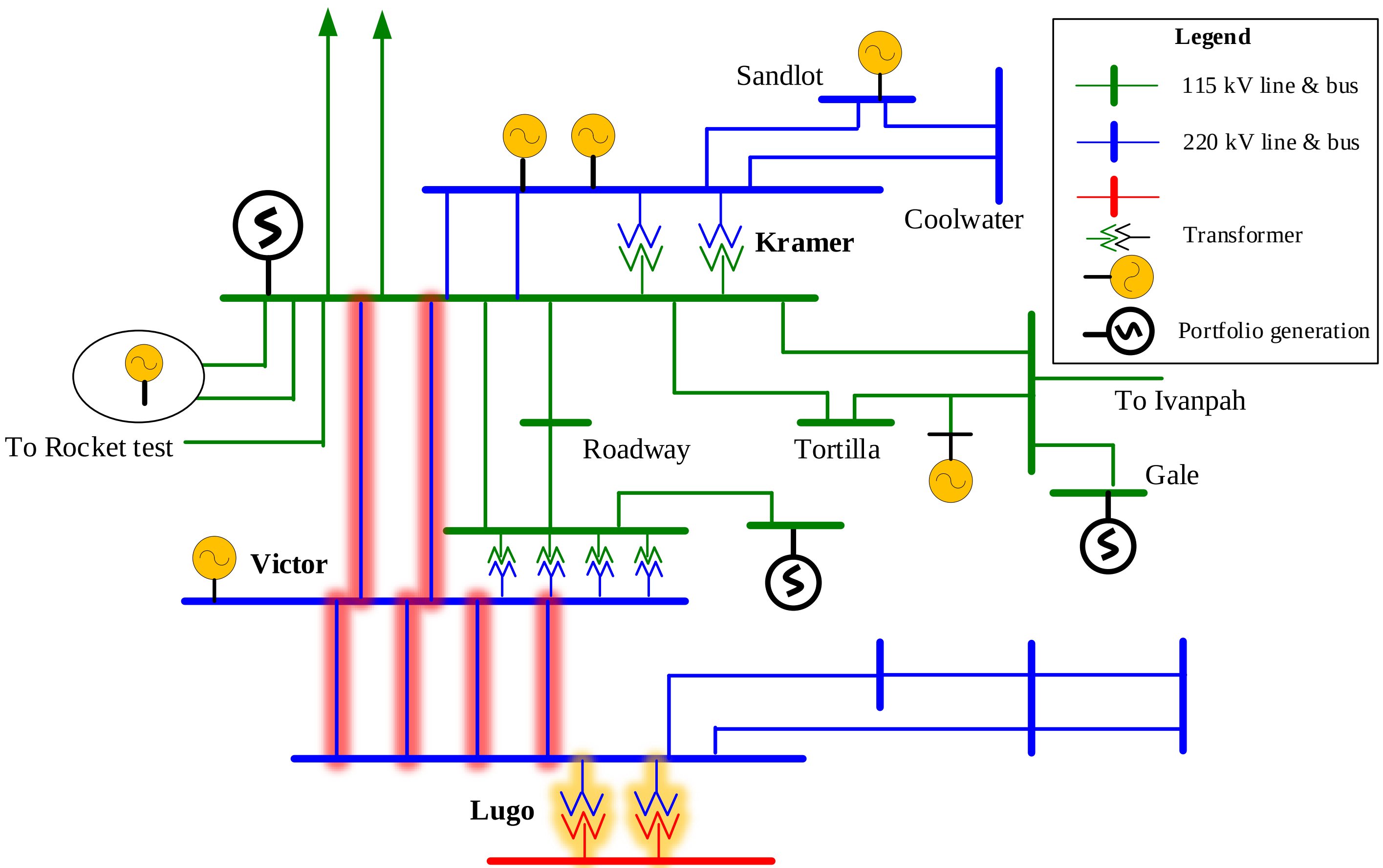
- Option IV seemed to eliminate most of the reliability issues observed under ~3,000 MW renewables output
- Option I seemed to eliminate several base case overloads and reduced the severity of the remaining overloads under ~3,000 MW renewable output
- Options II and III showed marginal improvements over Option I
- When tested with a reduced capacity of ~2,000 MW in Southern NV, Option I eliminated all reliability issues except for the Amargosa 230/138 kV bank overloads
  - A reliability-driven project identified in this TPP cycle for further evaluation to add a Gamebird 230/138 kV transformer could mitigate the Amargosa 230/138 kV bank overloads

Southern CA snapshot assessment – Resource and dispatch assumptions in Kramer-Inyokern zone

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
Kramer and Inyokern	978	-	-

- Portfolio resources were dispatched to ~98 percent of the nameplate capacity

Several base case (N-0) and contingency (N-1 and N-2) transmission constraints in Kramer-Inyokern zone



More than 950 MW of behind-the-meter (BTM) solar generation in this zone dispatched for an Hour 13 snapshot had a significant impact on the results

Transmission constraints observed in Kramer and Inyokern zone

Limiting Element	Contingency	Type	Overload (%)
Kramer – Victor 220 kV No. 1 and No. 2	Base case (N-0)	P0	142.02%
Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	Base case (N-0)	P0	103.53%
Divergence	Kramer – Victor 220 kV No. 1 and No. 2	P7	N/A

Mitigation options:

- Coolwater – Calcite – Lugo 230 kV line

  OR

- Pre-contingency renewable curtailment (~200 to ~400 MW)

Transmission constraints observed in Kramer and Inyokern zone

Limiting Element	Contingency	Type	Overload (%)
Kramer – Victor 220 kV No. 1 or No. 2	Kramer – Victor 230 kV No. 2 or No. 1	P1	184.64%
Any three of the Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	Any of the Lugo – Victor 220 kV No. 1, No. 2, No. 3 and No. 4	P1	102.87%
Lugo 500/220 kV Transformer No. 1 or No. 2	Lugo 500/220 kV Transformer No. 2 or No. 1	P1	151.82%
Kramer – Victor 220 kV No. 1 and No. 2	Kramer – Victor 220 kV No. 1 and Kramer – Roadway 115 kV No. 1	P7	128.95%
Lugo – Victor 220 kV line No. 1 and No. 2	Lugo – Victor 220 kV line No. 3 and No. 4	P7	154.35%

Mitigation options:

- Add portfolio generation to an existing RAS or a future RAS

The upgrade option considered for Kramer-Inyokern zone provided a modest increase in capability out of this zone compared to the status quo

Upgrade	Conceptual Scope	Cost Estimate	Mitigation Effectiveness
Coolwater – Calcite – Lugo 220 kV upgrade	• Build a new 220 kV Coolwater – Calcite transmission line • Rebuild transmission structures and transmission conductor along the existing Calcite - Lugo 220 kV Transmission Line	~$480 M	- Victor – Lugo 220 kV base case overloads are mitigated - Kramer – Victor 220 kV base case overloads are reduced to 105%, so can be managed with modest amounts of curtailment - All the contingency overloads can be mitigated by relying on RAS to drop generation - The upgrade provided a modest increase of 400 MW of FCDS capability estimate out of this zone

Southern CA snapshot assessment – Resource and dispatch assumptions in Riverside East and Palm Springs zone

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
Riverside East and Palm Springs	3,875	42	-

- Portfolio resources were dispatched to ~98 percent of the nameplate capacity for the solar and ~82% of the nameplate capacity of the wind

Transmission constraints observed in Riverside East and Palm Springs zone

Limiting Element	Contingency	Type	Overload (%)
Devers – Red Bluff 500 kV No. 1 or No. 2	Devers – Red Bluff 500 kV No. 2 or No. 1	P1	119.88%
Devers 500/230 kV Transformer	Devers – Valley 500 kV No. 1 and No. 2	P1	101.91%
Divergence	Devers – Red Bluff 500 kV No. 1 and No. 2	P7	N/A

Mitigation options:

- RAS to drop generation (~1,150 MW for N-1 and ~1,400 for N-2 contingencies)

OR

- Pre-contingency renewable curtailment

Southern CA snapshot assessment – Resource and dispatch assumptions in Tehachapi zone

Renewable Zones	Solar (MW)	Wind (MW)	Geothermal (MW)
Tehachapi	1,013	153	-

- Portfolio resources were dispatched to ~98 percent of the nameplate capacity for the solar and ~82% of the nameplate capacity of the wind

Transmission constraints observed in Tehachapi zone

Limiting Element	Contingency	Type	Overload (%)
Midway – Whirlwind 500 kV No. 3	Base case (N-0)	P0	120.42%
Windhub 500/230 kV Transformer Bank No. 1 or 2	Windhub 500/230 kV Transformer Bank No. 2 or 1	P1	155.11%
Windhub 500/230 kV Transformer Bank No. 3 or 4	Windhub 500/230 kV Transformer Bank No. 4 or 3	P1	109.74%
Midway – Whirlwind 500 kV No. 3	Midway – Vincent 500 kV No. 1 or 2	P1	105.07%

Mitigation options:

- Generation curtailment for P0 (~1,000 MW curtailment – some of this can come from conventional generation)
- RAS to drop generation or reconfiguration at Windhub 500 kV (to mitigate Windhub transformer bank overloads)
- RAS to trip generation (to mitigate contingency overload on Midway – Whirlwind 500 kV No. 3)

Conclusions and next steps

The proposed deliverability assessment approach found no new transmission needs

- The proposal attempted to better align generation output assumptions in deliverability assessment with the time of day and time of year of severe system needs

- In response to stakeholder comments, the ISO has delayed the implementation of the revisions to the generation deliverability assessment methodology from Q1 2019 to Q1 2020

42 MMT portfolio with the suggested mapping resulted in significant renewable curtailment in Southern CA

- Primarily attributed to the incremental renewable resources identified in Southern CA, specifically in the Kramer-Inyokern zone and the Southern NV zone in the 42 MMT portfolio

- The ISO net export limit exhibited an inverse relationship with the energy being delivered out of Southern CA renewable zones

Powerflow snapshot assessment showed no issues for Northern CA portfolio resources but showed severe overloads in Southern CA

- Portfolio resources in Northern CA (primarily Solano) are unlikely to be curtailed due to transmission limitations
- Severe transmission constraints in Southern NV, Eldorado, Kramer and Inyokern zones drive significant renewable curtailment
- Conceptual upgrades primarily consisting of 230 kV system enhancements to the GridLiance system could effectively reduce the expected curtailment and could accommodate ~2,000 MW resources without triggering a large amount of renewable curtailment
- Coolwater-Calcite-Lugo 230 kV conceptual upgrade is likely to avoid ~400 MW of renewable curtailment during hours when severe curtailment is expected in Kramer-Inyokern zone

The ISO did not identify Category 1 or Category 2 policy-driven upgrades

- With the 42 MMT portfolio being a sensitivity portfolio, the ISO did not identify any Category 1 policy-driven upgrade
- The ISO did not identify any Category 2 policy-driven upgrades after considering
  - the preliminary nature of the sensitivity portfolio
  - the wide range of potential solutions available
  - significant changes observed in the draft recommended portfolios recommended for 2019-2020 TPP cycle as part of the IRP proceeding

Next steps

- Provide the updated transmission capability estimates to the CPUC and assist with incorporating these into the RESOLVE model
  - The ISO is currently working with the CPUC to ensure that nested constraints are considered

- Inform the IRP proceeding with insights regarding renewable curtailment and conceptual upgrades tested in 2018-2019 policy-driven assessment

- Incorporate key findings from this study in coordinating with the CEC staff for mapping portfolio resources in zones with high likelihood of severe local transmission constraints

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

Overview and Key Issues
Economic Assessment

Neil Millar
Executive Director, Infrastructure Development

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

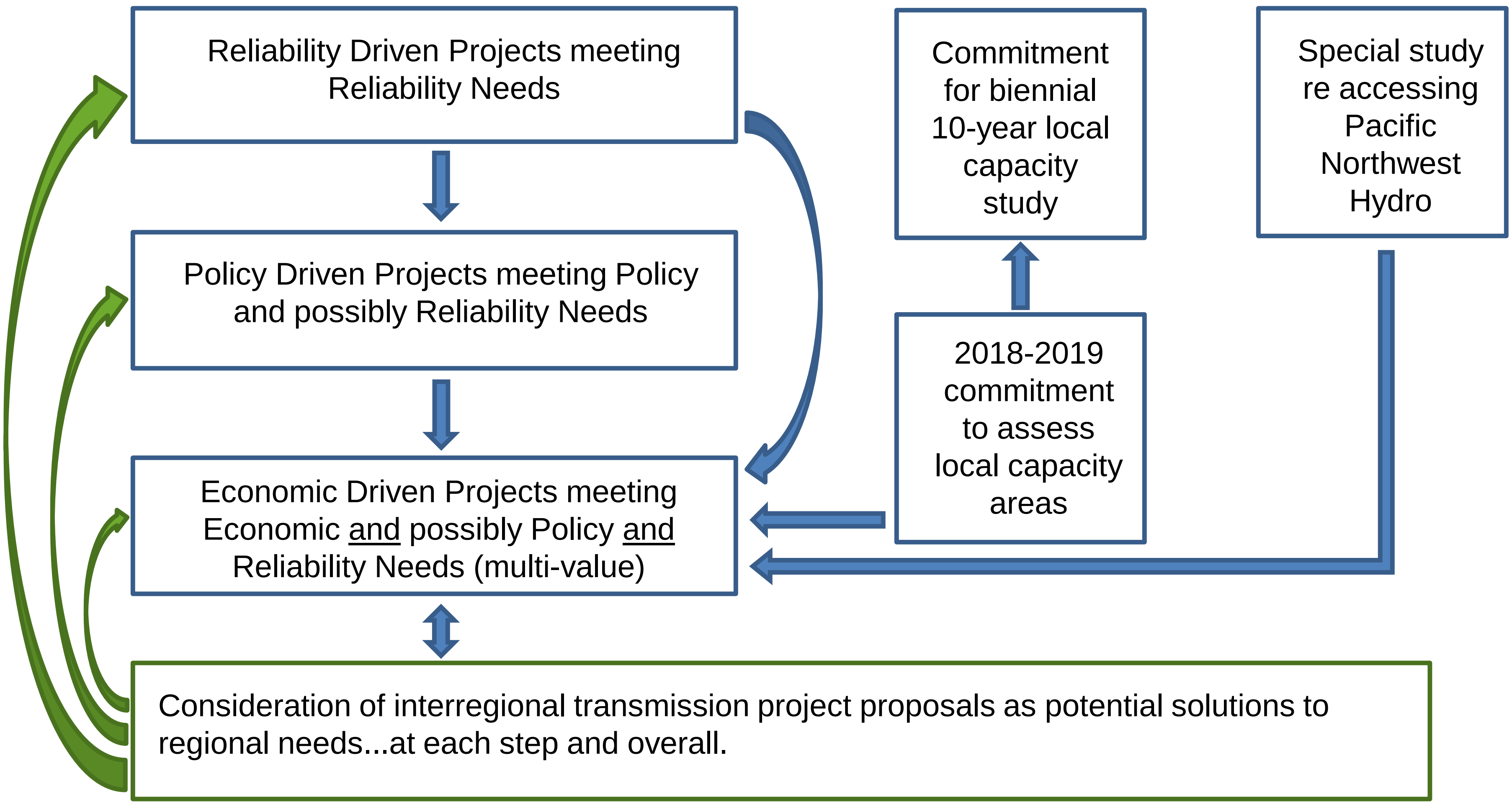
Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analysis or to meet local capacity deficiencies
  - An "economic driven" transmission project may be upsizing a previously identified reliability solution, or replacing that solution with a different project…
- Opportunities were explored to reduce the cost of local capacity requirements – considering capacity costs in particular.
- Interregional transmission projects needed to be considered as potential alternatives to regional solutions to regional needs.

The existing study framework has proven to be sufficiently robust, providing flexibility where needed:

- Selection of preferred solutions at “reliability” and “policy” stages were initially based on more conventional cost comparisons to meet reliability needs, e.g. capital and operating costs, transmission line loss savings, etc.
- Consideration of more comprehensive benefits, e.g. broader application of the TEAM, were conducted at the economic study stage, and could have led to replacing or upscaling a solution initially identified at the reliability or policy stage.
- The relationship between ISO transmission planning, and CPUC-led resource procurement was respected.

The 2018-2019 economic analysis is therefore heavily coordinated with other study activities:



The scope of the local capacity requirement reduction study was to:

- Provide profiles to help develop characteristic of potential preferred resources alternatives.
- Identify potential alternatives - conventional transmission upgrades and preferred resources - to reduce requirements in at least <u>half</u> of the existing areas and sub-areas:
  - prioritized areas and sub-areas based on the attributes of the gas-fired generation to provide other system benefits and on the gas-fired generation being located in disadvantaged communities
- Some of those alternatives were carried into the “economic-driven” transmission study phase for detailed analysis.

Issues in considering alternatives to eliminate or reduce local capacity requirements:

- Given the current planning assumptions over the ISO planning horizon regarding gas-fired generation, there was generally not a reliability requirement or policy requirement in the planning horizon that needed to be addressed.
- The studies therefore focused on economic analysis.
- The in-depth local capacity study was expected to be largely informational, providing detailed need analysis and consideration of alternatives.
- There were some alternatives with sufficient support for moving forward as economic-driven projects, or were alternatives to other projects than needed consideration – and we needed to consider how to value the benefits they provided.

In considering economic benefits to reduce local capacity reductions in this cycle:

- Conservative assumptions were employed at this time for potential transmission project approvals, while awaiting clearer direction in future CPUC IRP cycles on SB 100-related gas-fired generation reduction plans
- These alternatives could include conventional transmission, hybrid solutions, and preferred resources including storage
    - Resource substitution decisions fall exclusively to the CPUC
- System capacity benefits – a consideration for preferred resources including storage, or storage as transmission assets – were identified, but valuing system capacity benefits was deferred pending increased coordination with the CPUC IRP process:
    - Local capacity requirement reduction benefits were valued at the difference between local resource adequacy capacity costs (or reliability must-run costs if applicable) and system capacity costs.

Regarding the SATA initiative and FERC's policy statement on storage :

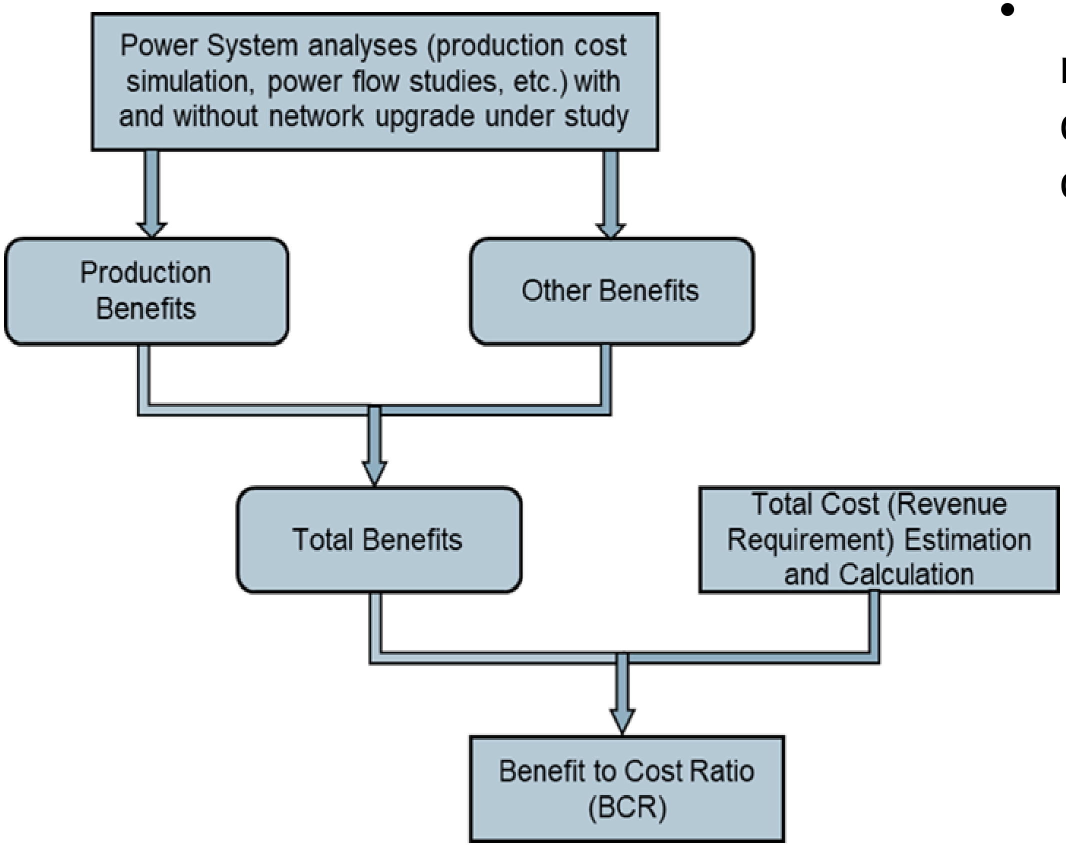
- The SATA initiative has been placed on hold, recognizing the need to address certain market issues for storage more holistically before the SATA initiative could move forward.
- Storage projects were nonetheless assessed considering ratepayer benefits including potential net revenues (profits) assuming these benefits could be returned to ratepayers through properly structured resource procurement contracts.
  - Total production cost benefits were also calculated, but for information only – not the basis for ISO decision-making.
- The ISO also assessed the benefits being provided to see if the benefits were due to the storage functioning as a transmission facility, *i.e.* providing a transmission function, using the guidance previously discussed.

Economic Assessment

Yi Zhang
Lead Engineer, Regional Transmission - North

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

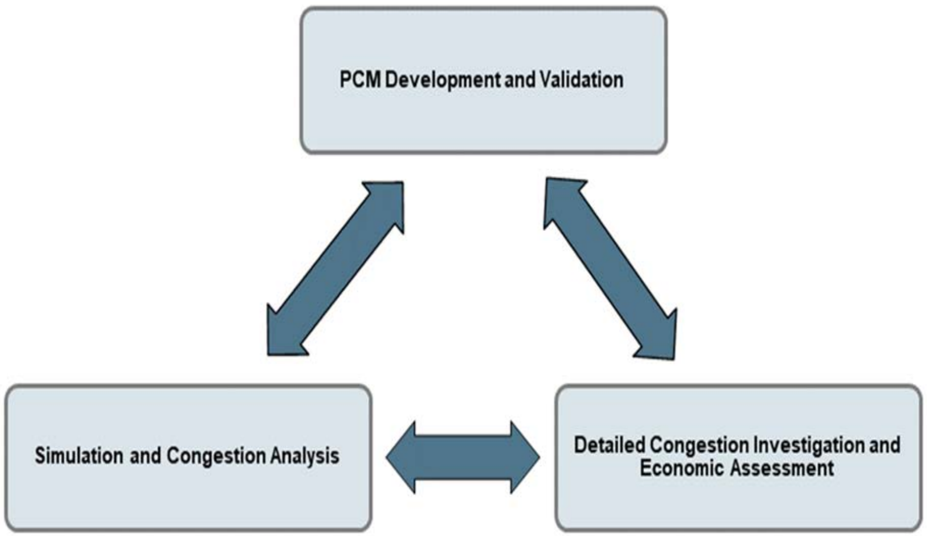
Technical approach of economic planning study



- The CC-to-RR multiplier for revenue requirement estimation changed from previous planning cycles
  - The multiplier is used for estimating the present value of the revenue requirement of transmission project
  - Updated from 1.45 to 1.3 (i.e. RR=1.3*Capital Cost)
  - The update reflects changes in federal income tax rates and more current rate of return inputs
  - This multiplier is used for screening purposes

Production cost model (PCM) development and validation

- Network model (transmission topology, generator location, and load distribution)
- Transmission operation model, such as transmission constraints, nomograms, phase shifters, etc.
- Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, renewable profiles.
- Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers such as DG, DR, and EE.
- Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission, etc.



- Production cost simulation software review and enhancement, in coordination with vendors, regions, and WECC work groups, are conducted regularly through the PCM development process

Production cost simulation tool for transmission congestion and production cost assessment

Program name	Version	Functionality
ABB GridView™	10.2.46	The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year (8784 hours for leap year)

- ABB GridView version 10.2.46 was used to conduct production cost simulations for the draft transmission plan in 2018-2019 planning cycle
- For reference, the preliminary results presented in November 16, 2018 stakeholder meeting were produced using GridView version 10.2.38

Summary of key database development steps since November stakeholder session

- Changes identified in coordination with the ADS PCM validation process
  - APS load modified based on the updated APS load forecast data
  - BPA load shape modified with the consistent BPA load shape and pumping load profiles
    - Total energy and peak remained the same
  - NW wheeling model modified based on BPA's recommendation with consideration of firm transmission right among NW areas
    - In general, hurdles reduced among NW areas, and between NW and California areas
  - BC Hydro hydro-generator data error fixed, available energy reduced
  - Regions coal generator retirement and replacement, mainly with renewable generators, as recommended by regions

Summary of key database development steps (cont.)

- Ancillary service requirements were updated based on the new renewable and load data, consistent with the assumptions in the ISO's renewable integration study
- Wind profiles were updated for wind generators within ISO footprint
  - New profiles were calibrated to better match capacity factors in historical data
  - ADS PCM has adopted the ISO's wind profiles
- PDCI south to north path rating was modeled as1050 MW based on LADWP's operation limit
- Some SPS models were modified with tripping future renewable generators under contingencies, which helped to reduce congestion and curtailment in the corresponding areas
- Allowed renewable to provide downward load following in the model
  - Helped to reduce renewable curtailment

Summary of key database development steps (cont.)

- Generic generators in CPUC's portfolios in SCE's NOL area and in Southern NV area were relocated to Lugo 500 kV bus, and Eldorado 230 kV bus or 500 kV buses, respectively, because of the obvious transmission constraints identified in the preliminary results

	Lugo 500 kV bus (MW)	Eldorado 500 kV bus (MW)	Eldorado 230 kV bus (MW)
Default portfolio	978	1134	0
42 MMT portfolio	978	2676	330

Future modeling enhancements

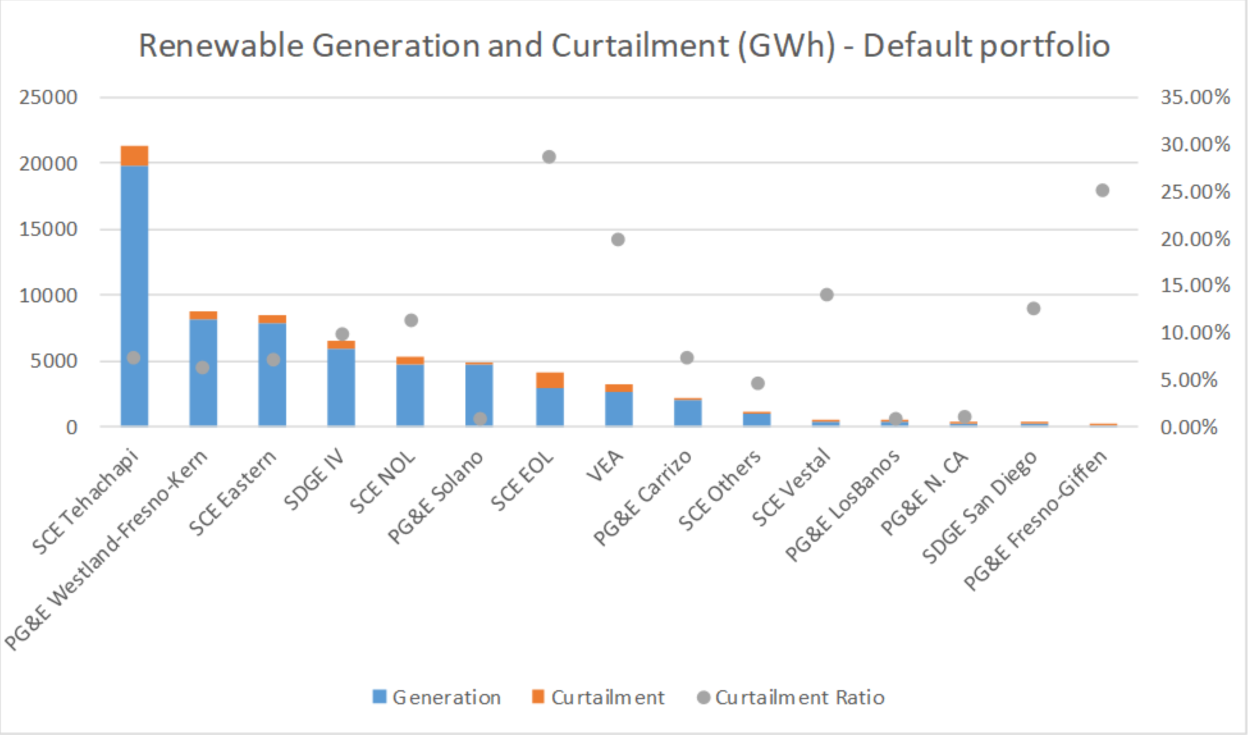
- Some potential enhancements discussed in Nov. meeting were not implemented in this planning cycle, mainly
  - Inter-tie derate due to imported A/S
    - Requires major enhancement and redesign of the model and the software
    - Will coordinate with vendors, regions, and WECC work groups in a larger framework for market model enhancement in PCM
  - Hydro generation dispatch to response to the intermittency of renewable
    - Will coordinate with vendors, regions, and WECC work groups for hydro modeling enhancement
- Will provide update of the implementations and applications to stakeholders in the future

Production cost simulation results (congestion and curtailment)

Summary of congestions – Default Portfolio

No	Aggregated congestion	2028	
		Costs (M$)	Duration (Hr)
1	VEA	28.51	1,580
2	Path 26	25.00	1,029
3	Path 45	6.01	1,494
4	COI Corridor	5.06	165
5	PG&E Quinto - Los Banos	3.71	118
6	PG&E/TID Exchequer	3.66	1,368
7	PG&E Fresno Panoche-Excelsior	2.75	641
8	PG&E POE-RIO OSO	2.15	87
9	Path 15/CC	1.85	42
10	SCE NOL-Kramer-Inyokern-Control	1.64	1,442
11	SDGE Sanlusry-S.Onofre 230 kV	1.33	161
12	SCE LCIENEGA-LA FRESA 230 kV line	1.24	48
13	SDGE Silvergate-Bay Blvd 230 kV line	1.17	61
14	SCE J.HINDS-MIRAGE 230 kV line	1.10	178
15	PG&E Fresno Giffen	0.87	1,483
16	Path 46 WOR	0.80	26
17	PDCI	0.50	76
18	PG&E Solano	0.49	9
19	SDGE IV-SD Import	0.47	19
20	Path 61/Lugo - Victorville	0.37	119
21	PG&E Delevn-Cortina 230 kV	0.22	12
22	PG&E Fresno	0.20	33
23	SCE Sylmar - Pardee 230 kV	0.20	25
24	PG&E GBA	0.16	11
25	SDGE-CFE OTAYMESA-TJI 230 kV line	0.10	23
26	PG&E Table Mt.-Palermo 230 kV line	0.08	1
27	SCE Delaney-ColoradoRiver 500 kV	0.03	2
28	SDGE-CFE IV-ROA 230 kV line and IV PFC	0.01	1
29	SDGE N.Gila-Imperial Valley 500 kV line	0.00	1
30	SCE Devers 230/115 kV transformer	0.00	1
31	PG&E Humboldt	0.00	1

Summary of Curtailment – Default Portfolio



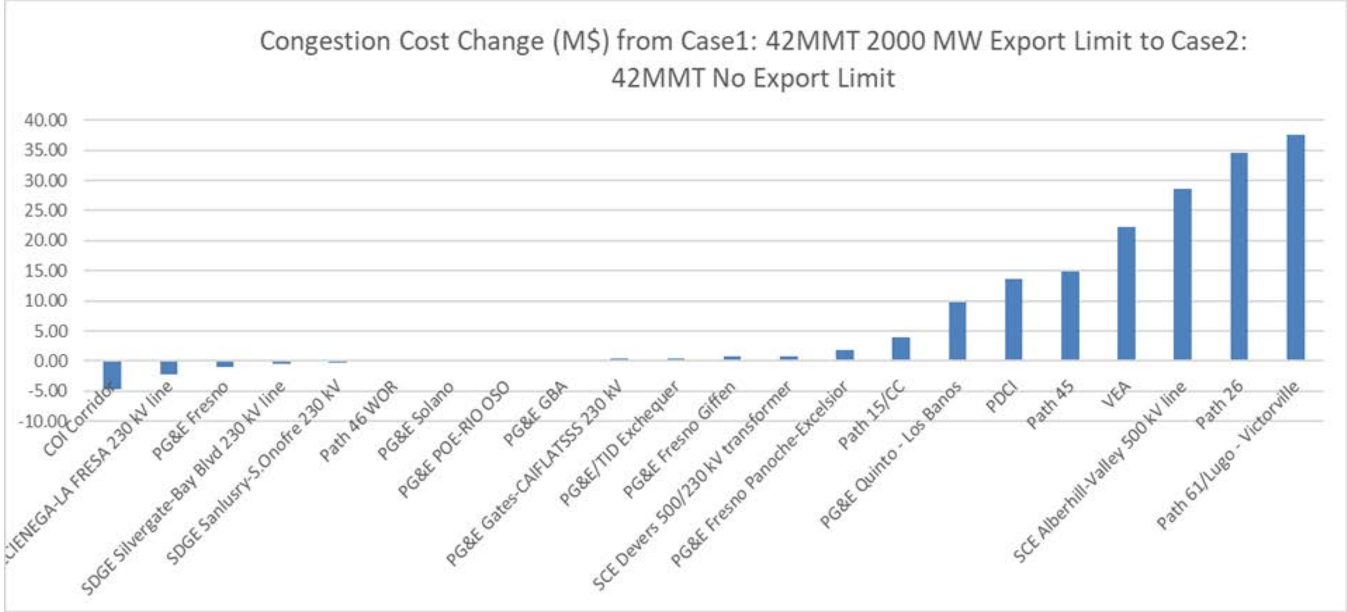
The total wind and solar curtailment in ISO's system in the study year (2028) in the default portfolio was about 7.47 TWh, which is about 9.2% of the total potential wind and solar energy.

California ISO

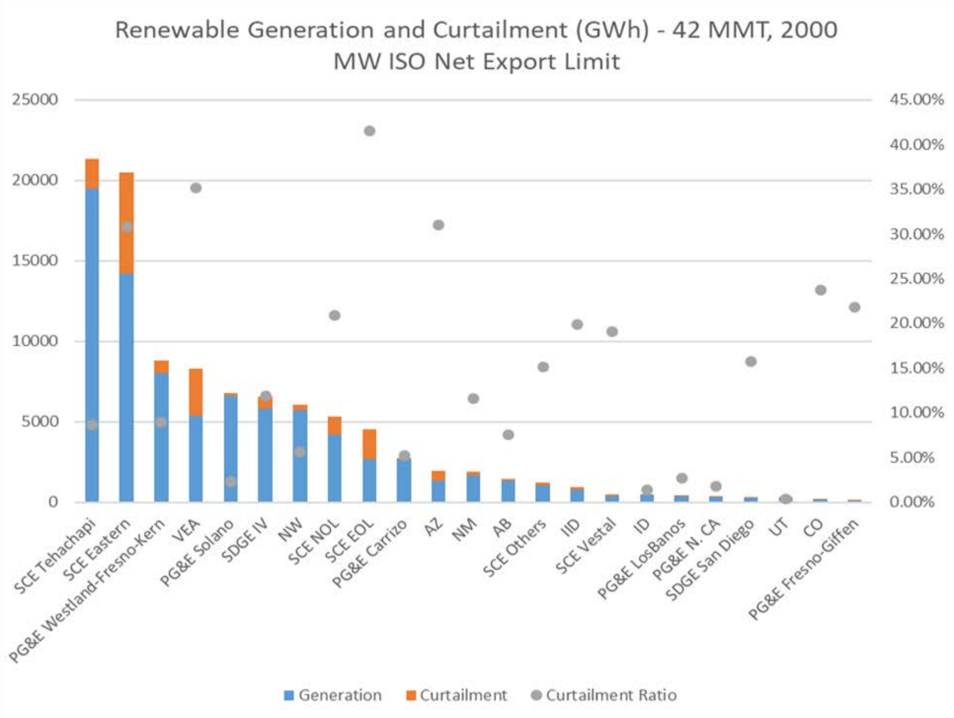
Summary of congestions – 42 MMT Portfolio, 2000 MW ISO net export limit enforced

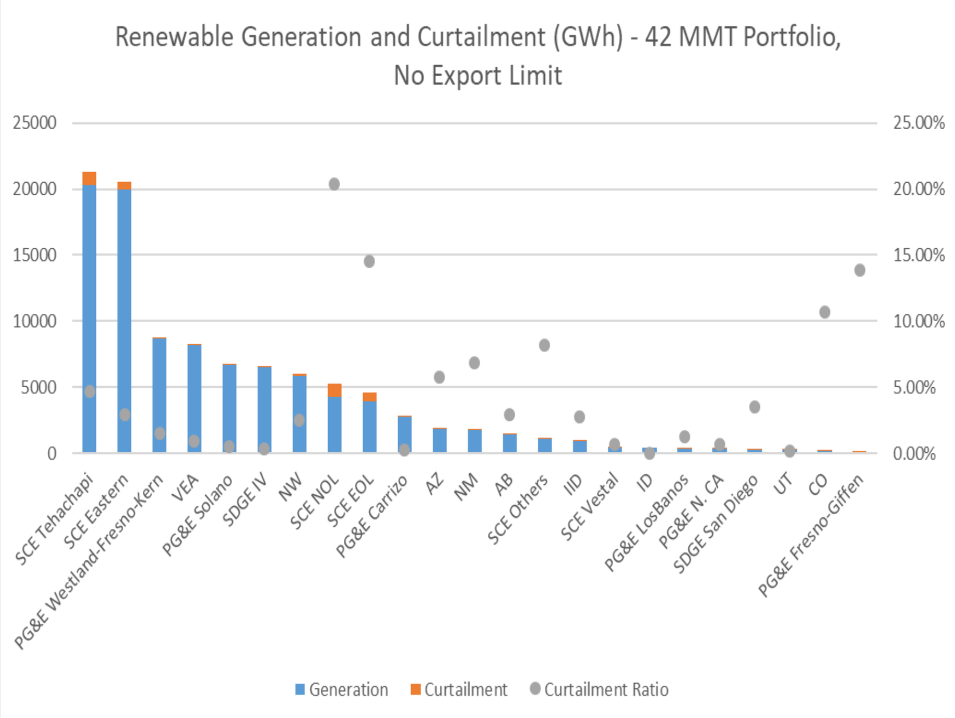
Aggregated Congestion	Congestion Cost ($M)	Congestion Duration (Hr)
Path 26	61.46	1,609
PG&E Fresno Giffen	0.49	1,597
Path 45	5.68	1,567
SCE NOL-Kramer-Inyokern-Control	1.44	1,130
PG&E/TID Exchequer	2.93	1,102
VEA	5.93	813
PG&E Fresno Panoche-Excelsior	1.27	650
PDCI	3.06	317
SCE Alberhill-Valley 500 kV line	26.89	279
SCE J.HINDS-MIRAGE 230 kV line	1.02	170
COI Corridor	9.51	154
SDGE Sanlusry-S.Onofre 230 kV	1.03	146
Path 61/Lugo - Victorville	0.26	133
SCE LCIENEGA-LA FRESA 230 kV line	4.89	101
PG&E Quinto - Los Banos	2.59	99
PG&E POE-RIO OSO	1.83	85
PG&E Fresno	1.11	73
Path 15/CC	3.47	55
SCE Devers 500/230 kV transformer	1.45	52
SDGE Silvergate-Bay Blvd 230 kV line	1.19	50
SCE Sylmar - Pardee 230 kV	0.19	26
SDGE IV-SD Import	0.32	18
Path 46 WOR	0.44	17
PG&E Solano	0.63	12
PG&E Delevn-Cortina 230 kV	0.15	11
PG&E GBA	0.16	10
SDGE-CFE OTAYMESA-TJI 230 kV line	0.04	8
PG&E Gates-CAIFLATSSS 230 kV	0.02	7
PG&E Humboldt	0.00	4
SCE Delaney-ColoradoRiver 500 kV	0.02	2
PG&E Table Mt.-Palermo 230 kV line	0.02	1
SDGE-CFE IV-ROA 230 kV line and IV PFC	0.00	1
SDGE N.Gila-Imperial Valley 500 kV line	0.00	1
SDGE Hoodoo Wash - N.Gila 500 kV line	0.00	1
Path 25	0.09	1
PG&E Summit-Drum 115 kV	0.08	1
Path 24	0.05	1

Summary of congestions – 42 MMT Portfolio, comparison between 2000 MW net export limit and No export limit



Summary of Curtailment - 42 MMT Portfolio

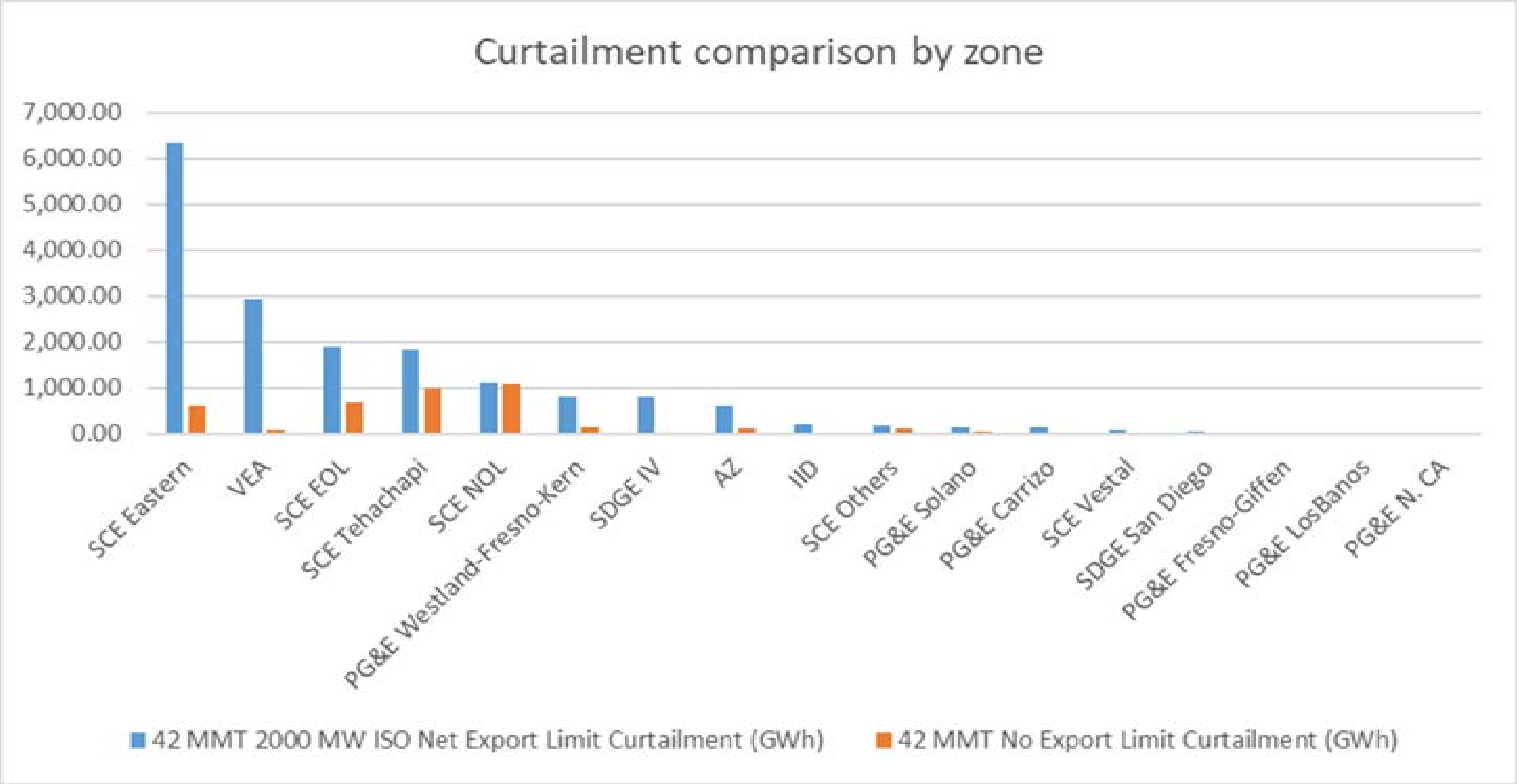




Scenario	42 MMT 2000 MW ISO Net Export Limit	42 MMT No Export Limit
Total Wind and Solar Generation (TWh)	82.92	96.50
Total Curtailment (TWh)	17.82	4.24

California ISO

Summary of Curtailment – 42 MMT Portfolio, comparison by zone between 2000 MW Export Limit and No Export Limit scenarios



Congestion analysis and production benefit economic assessment (based on the Default portfolio)

Analysis and discussion for congestions with relatively large cost or duration but not selected for detailed investigation

- Congestions with large cost or duration that were driven by local renewable generators
  - Congestions in these areas were subject to change with further clarity of the interconnection plans of the future resources
  - Therefore, the congestions in these areas or zones were not selected for detailed analysis in this planning cycle, particularly, in VEA and SCE EOL area, SCE NOL area, PG&E Fresno area, and PG&E Los Banos area
- Path 15 congestion was monitored in Path 26 study
  - Congestion was observed in south to north direction, in which Path 15 is the downstream of Path 26

Congestion selected for detailed investigation and economic assessment

Aggregated congestion	Cost (M$)	Duration (Hours)	Reason for selection
Path 26	25.00	1,029	Path 26 south to north congestion increased from previous planning cycles, and was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio.
COI corridor	5.06	165	A continuation of work on COI congestion investigation. COI congestion increased from previous planning.
PG&E Fresno Giffen	0.87	1483	Giffen congestion is an existing issue.
San Diego congestions	2.97	241	Includes Sanlusry-S.Onofre 230 kV, Silvergate-Bay Blvd 230 kV, and IV-SD import corridor congestions. These congestions were studied in detail as an effort to investigate potential LCR reduction in local areas.
SCE J.Hinds-Mirage	1.10	178	A continuation of work on this recurring congestion.

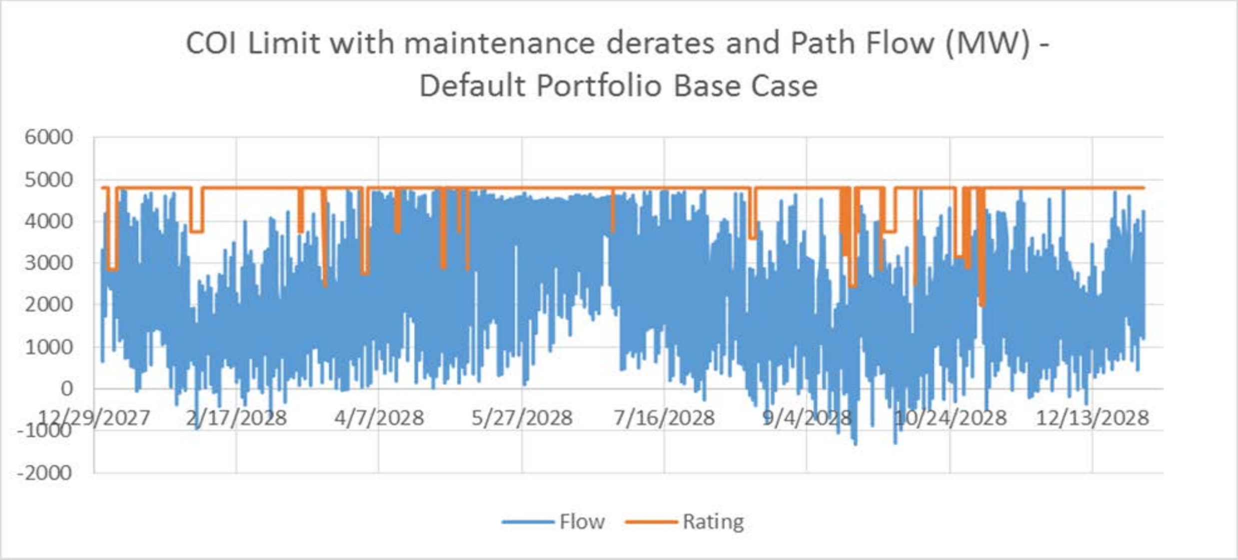
COI congestion mitigation assessment

- The production cost simulations in this planning cycle showed an increase in COI congestion from previous planning cycles
- The analysis in this study continues to focus on incremental gains in physical capacity – either by rating increases on the existing facilities or by system reinforcements
- Two alternatives were studied
  - Alternative 1: Model COI path rating at 5100 MW assuming the N-2 contingency of the two 500 kV lines between Malin and Round Mountain is conditional credible and with necessary revisions to existing SPS.
  - Alternative 2: SWIP - North project (an economic study request)

COI assessment – Alternative 1: COI 5100 MW path rating

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,466	-9
ISO owned generation profits	2,526	2,525	-1
ISO owned transmission revenue	199	202	3
ISO Net payment	5,387	5,389	-7
WECC Production cost	16,875	16,876	-1

- Majority of COI congestion occurred in the simulation when COI rating was derated due to scheduled maintenance. These derates were not impacted by the path rating increase



COI assessment – Alternative 1: COI 5100 MW path rating - Conclusion

- Simply increasing the COI path rating did not bring net benefits to ISO's ratepayers
- The study results do not support pursuing capital expenditures to achieve a path rating increase at this time
- The issue of the path rating criteria will be monitored, and a path rating increase will be pursued if it can be achieved in the future without requiring capital expenditures (as set out in Chapter 7 in the draft transmission plan)

COI assessment – Other factors that may impact COI flow and congestion, and potential benefits of upgrades

- Ability to access additional capacity from the Northwest that has been stored during energy surplus periods in California due to high solar output
- Resource and transmission assumptions in NW areas
  - COI congestion and potential benefits of increasing the COI path rating were also investigated in the Pacific Northwest – California Transfer Increase Study, using different hydro conditions

COI assessment – Alternative 2: SWIP North project – production benefit assessment

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,495	-38
ISO owned generation profits	2,526	2,529	-3
ISO owned transmission revenue	199	213	14
ISO Net payment	5,387	5,408	-21
WECC Production cost	16,875	16,869	6

- SWIP-North line lowered the production cost over the entire WECC foot print
- SWIP-North line may not provide incremental import from Northwest regions when there is no energy surplus depending on resource and transmission assumptions
- SWIP-North may allow more exports from California to other regions when there are renewable energy surplus within California
- Lower priced imports can result in increased profits to out-of-state generation and reduced profits to ISO owned generation in the ISO footprint

COI assessment – Alternative 2: SWIP North project - Summary

- The SWIP-North project, on a standalone basis and without support from other areas that may benefit from the project, was not supported by the findings in the 2018-2019 transmission planning studies
- The project was also submitted in the 2018 Request Window for reliability-driven and as an interregional transmission project
- The ISO expects that dialogue will continue with neighboring planning regions as their own plans evolve, and as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement

PG&E Fresno Giffen area assessment

- A net generation pocket with total 39 MW of existing grid-connected solar PV generation
- Giffen Junction to Giffen 70 kV line is the radial connection of the area to the rest of the system
- This line can be congested depending on the seasonal rating of the line
- Reconductoring the line can mitigate its congestion
- Baseline and sensitivity studies
  - Baseline study assumed the multi-tiered renewable curtailment price
  - Sensitivity study assumed -$25 curtailment price

PG&E Fresno Giffen area assessment

- Baseline study (multi-tiered curtailment price)

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,443	14
ISO owned generation profits	2,526	2,520	-6
ISO owned transmission revenue	199	198	-1
ISO Net payment	5,387	5,376	7
WECC Production cost	16,875	16,880	-5

- Sensitivity study (-$25 curtailment price)

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,564	8,544	20
ISO owned generation profits	2,596	2,595	-1
ISO owned transmission revenue	213	210	-3
ISO Net payment	5,756	5,740	16
WECC Production cost	16,908	16,903	5

PG&E Fresno Giffen area assessment – cost and production benefit and assessment

- Cost assessment
  - The estimated capital cost is $5 million, the present value of revenue requirement is $6.5 million using the 1.3 CC-to-RR screening ratio
- Benefit assessment
  - $7 million annual benefit, which is the lower one between the baseline and sensitivity studies
  - 40 years economic life and 7% discount rate
  - Present value of the benefit is $49 million
- BCR is about 7.5
- The ISO recommends proceeding with the Giffen line reconductoring project as an economic-driven project

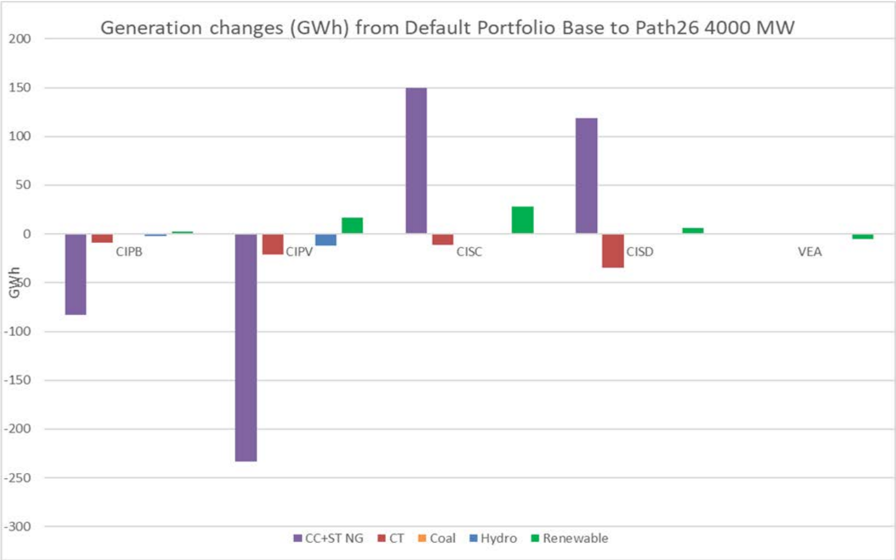
Path 26 congestion

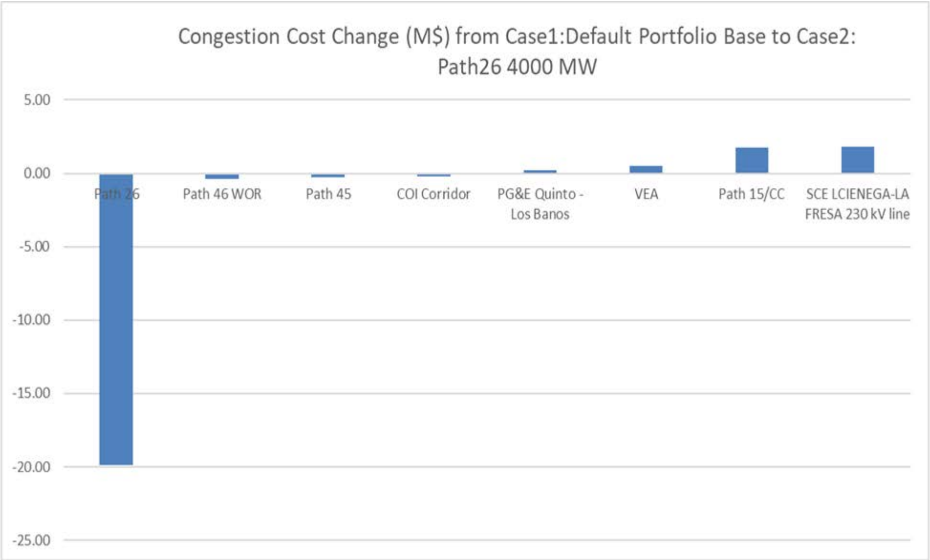
Constraints	Duration_T (Hrs)
P26 Northern-Southern California	718
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	287
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	21
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #1 500kV	3

- All congestions are in the direction from south to north mainly because of renewable in Southern California areas
- Two alternatives were studied:
  - Alternative 1: increase the Path 26 south to north rating 4000 MW; upgrade Midway to Wirlwind line rating and bypass its series capacitor
  - Alternative 2: CTP three-terminal DC project (Diablo-Ormond Beach-Redondo Beach)

Path 26 assessment – Alternative 1 Path 26 south to north rating 4000 MW

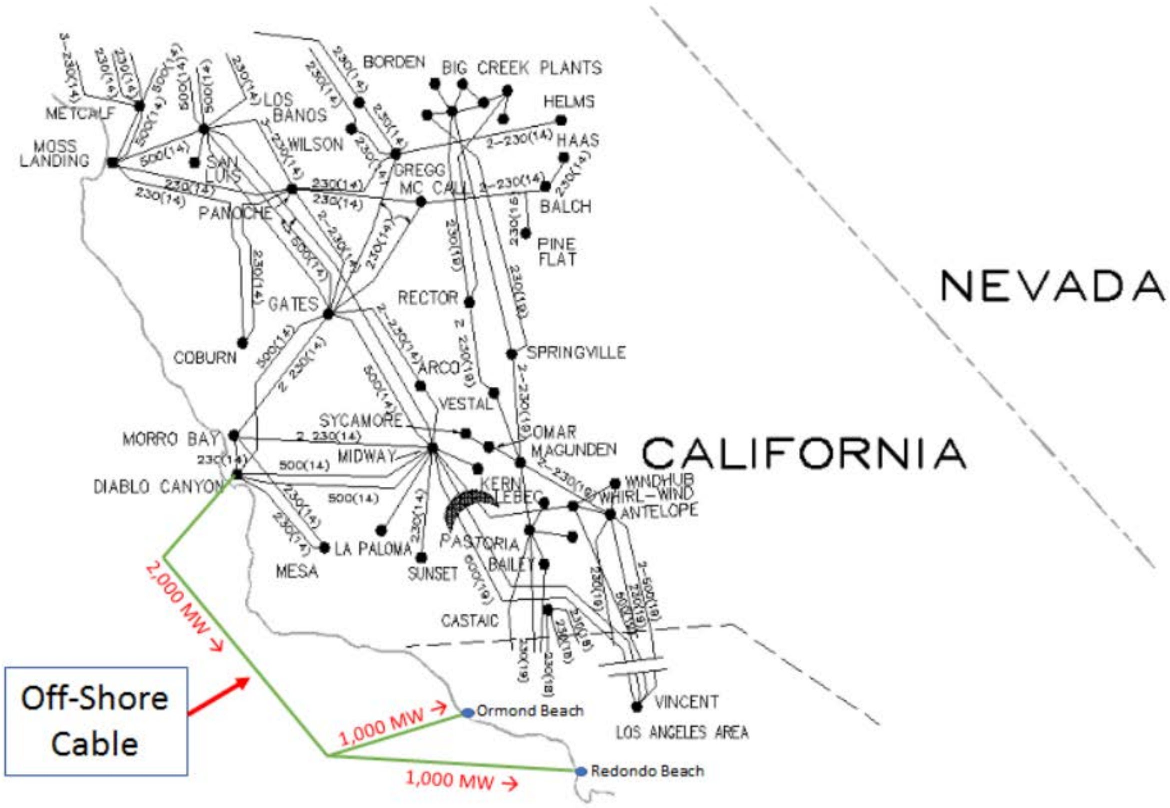
	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,445	12
ISO owned generation profits	2,526	2,532	6
ISO owned transmission revenue	199	181	-18
ISO Net payment	5,733	5,733	0
WECC Production cost	16,875	16,877	-2





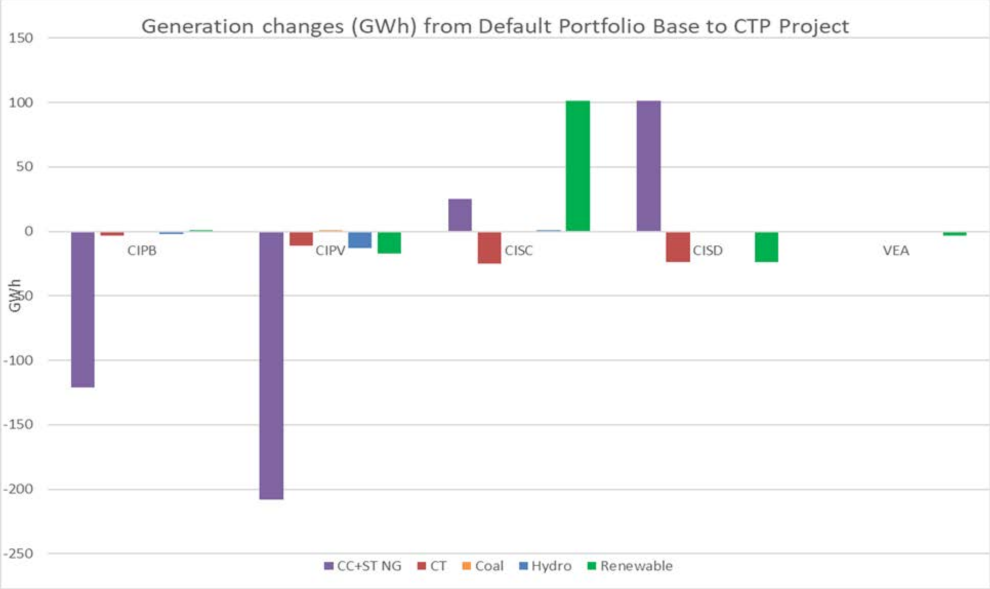
The study results do not support pursuing a path rating increase at this time. This will be further monitored and investigated in the future planning cycles

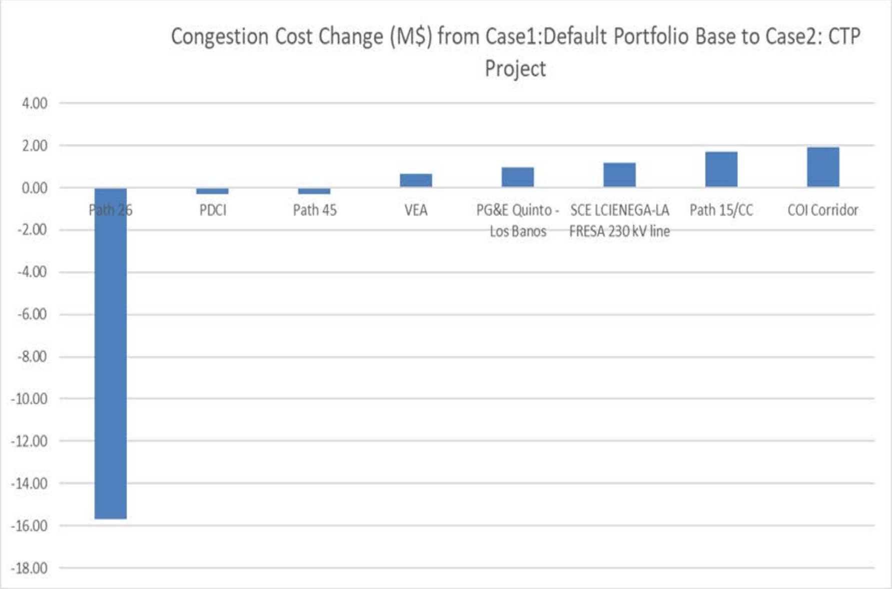
Path 26 assessment – Alternative 2: California Transmission Project



Path 26 assessment – Alternative 2: CTP Project

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,457	8,468	-11
ISO owned generation profits	2,526	2,551	25
ISO owned transmission revenue	199	188	-11
ISO Net payment	5,733	5,730	3
WECC Production cost	16,875	16,876	-1

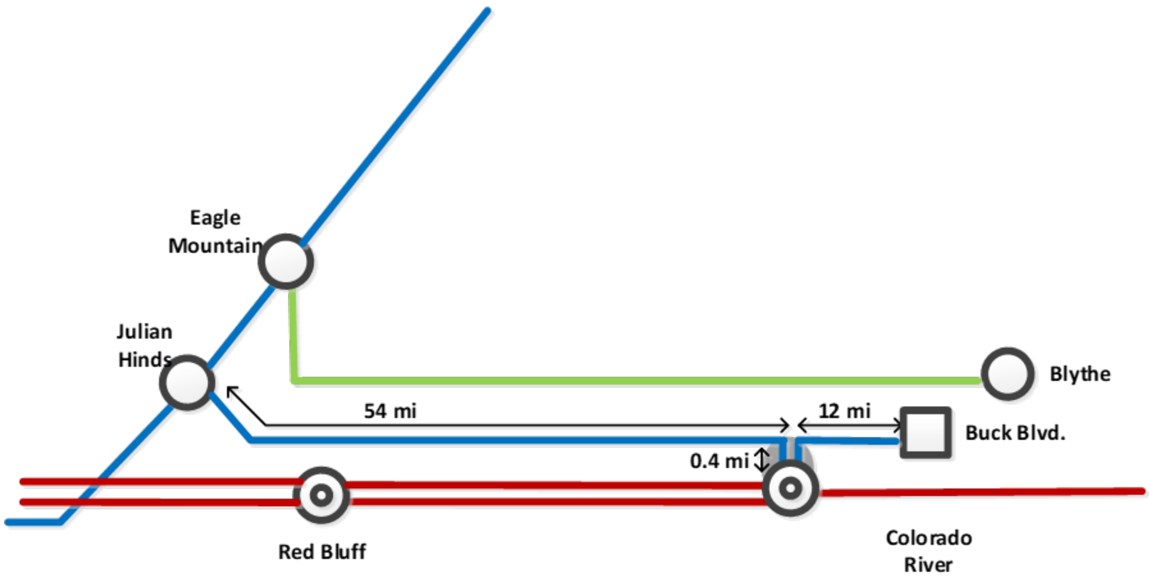




LCR reduction benefit was assessed in LCR reduction section

Julian Hinds-Mirage congestion assessment – Colorado River-Julian Hinds 230 kV project

- Option 1: Re-terminating Buck Blvd substation to Colorado River 230 kV bus, deenergizing Colorado River to Julian Hinds portion
- Option 2: Looping in the Buck Blvd-Julian Hinds line into Colorado River
- Option 3: Same as Option 2, but Buck Blvd substation disconnected
- Option 3 was to assesse the risk to ISO ratepayers if the gas-fired generator at Buck Blvd retired



- The total cost estimate provided by AltaGas is $76 million for Option 2. The line termination upgrades at Colorado River 230 kV bus were estimated to be $25 million

California ISO

Julian Hinds-Mirage congestion assessment – Colorado River-Julian Hinds 230 kV project-Production Benefit

	Pre project upgrade ($M)	Option 1		Option 2		Pre project upgrade ($M)	Option 3	
		Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)		Post project upgrade ($M)	Savings ($M)
ISO load payment	8564	8554	10	8554	11	8606	8614	-8
ISO generator net revenue benefitting ratepayers*	2596	2598	2	2585	-11	2611	2612	1
ISO owned transmission revenue	213	210	-3	210	-3	210	213	3
ISO Net payment	5756	5746	9	5759	-3	5785	5789	-5
WECC Production cost	16908	16905	3	16904	4	16908	16909	-1

Colorado River-Julian Hinds 230 kV project- benefit to cost ratio

	Option 1	Option 2	Option 3
Production Benefits			
Ratepayer Benefits ($million/year)	$9	-$3	-$8
Net Market Revenue ($million/year)	$0	$0	$0
Total PCM Benefits ($million/year)	$9	-$3	-$8
PV of Prod Cost Savings ($million)	$121.93	-$44	-$111
Capital Cost Estimate ($million)	$25	$76	$76
Estimated “Total” Cost (screening) ($million)	$33	$99	$99
Benefit to Cost			
PV of Savings ($million)	$121.93	-$44	-$111
Estimated “Total” Cost (screening) ($million)	$32.50	$99	$99
Benefit to Cost	3.75	-0.45	-1.12

Colorado River-Julian Hinds 230 kV project - Conclusions

- Option 1 provides the most benefit to ISO ratepayers from both a gross benefit and benefit to cost ratio perspective
  - Assumed no regulated cost of service cost recovery for the line, and the Blythe Energy Center remaining in service into the future
- Option 2 and Option 3 was not supported by the production cost results
- These results will have to be reviewed once the ISO has finalized any changes to its parameters used in its deliverability methodology and assesses the deliverability impact of the proposed project taking the new deliverability methodology into account

Local Capacity Area

Congestion analysis and production benefit economic assessment

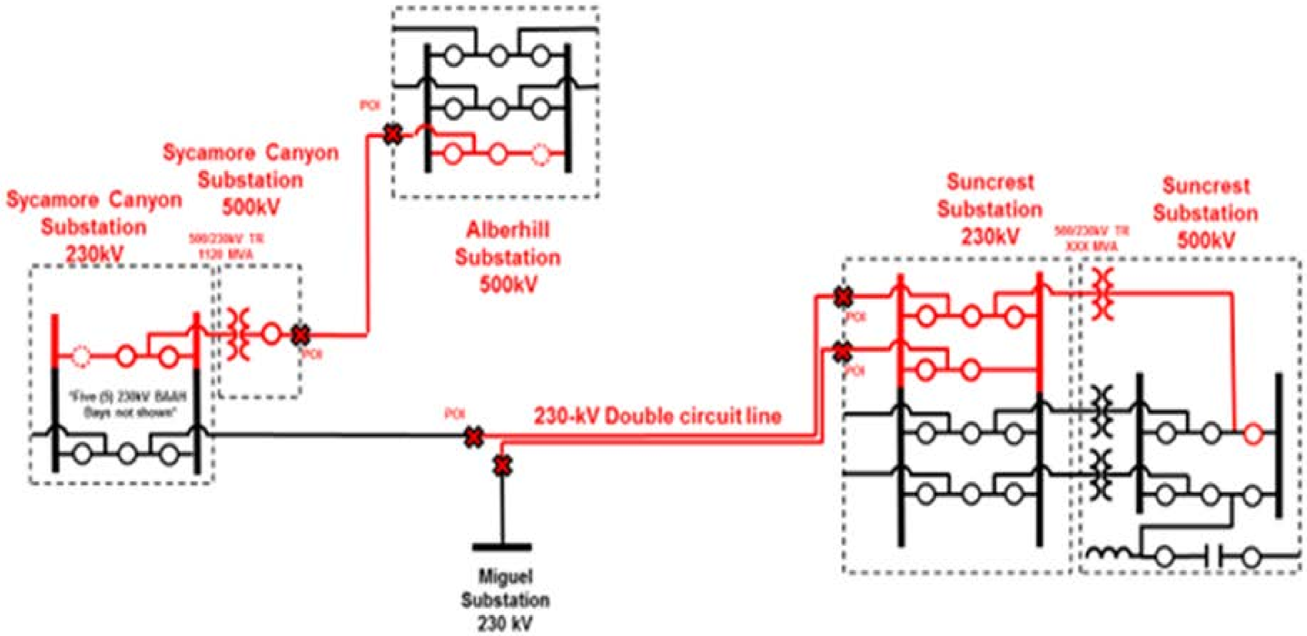
LCR reduction benefits will be presented separately

San Diego Congestions

Constraints	Duration_T (Hrs)
SDGE Silvergate-Bay Blvd 230 kV line	61
SDGE IV-SD Import	19
SDGE Sanlusry-S.Onofre 230 kV	161

- 3200 MW of existing and future solar or wind generators are modeled in Imperial Valley area and AZ in the PCM, 105 MW in other areas in SDGE territory
- Several projects in the economic study requests may help to reduce San Diego congestions
  - Alberhill-Sycamore
  - S. Cal LCR reduction project (Mission to S. Onofre upgrade)
  - Energy storage projects

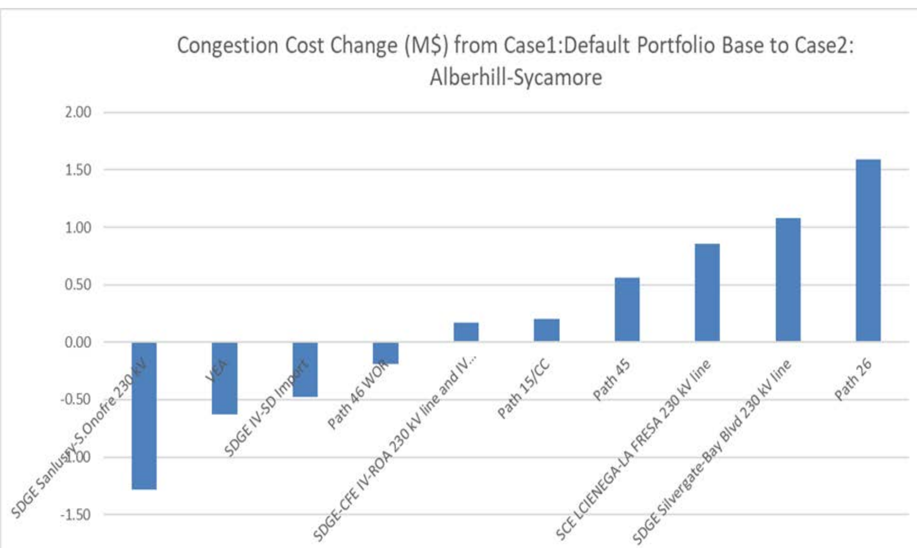
Alberhill-Sycamore Project

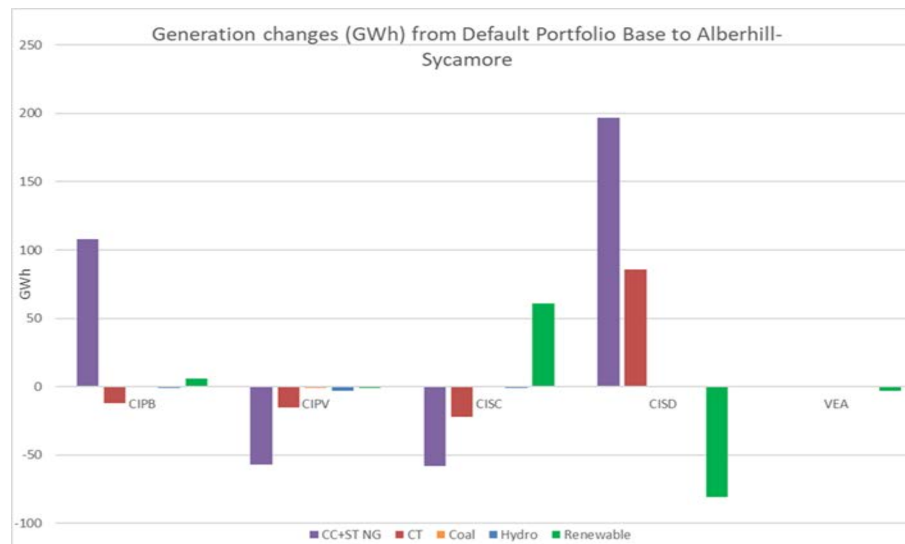


Alberhill-Sycamore Project – production benefit and congestion assessment

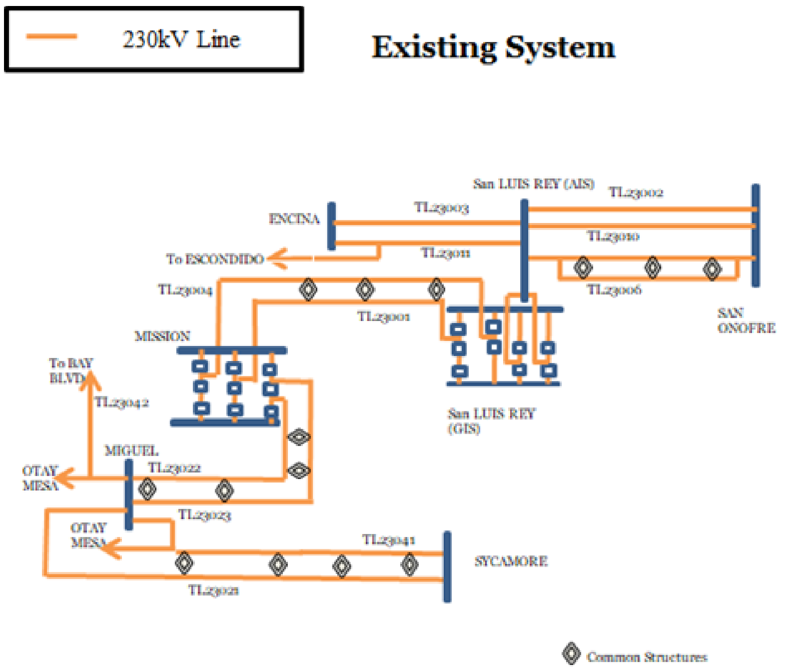
	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8448	9
ISO generator net revenue benefitting ratepayers	2526	2519	-7
ISO owned transmission revenue	199	199	1
ISO Net payment	5733	5730	**3**
WECC Production cost	16875	16881	**-6**

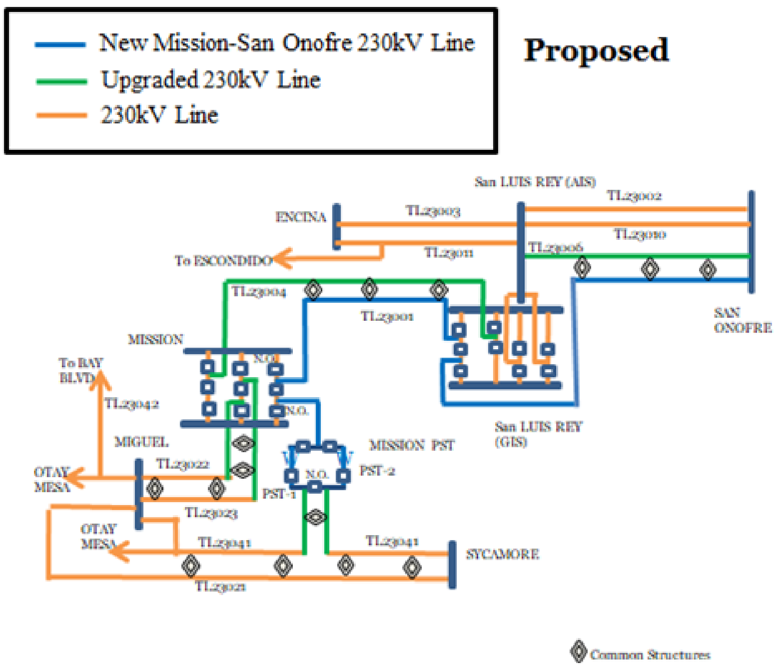
The estimated capital cost is $500 million





S.Cal Regional LCR Reduction Project

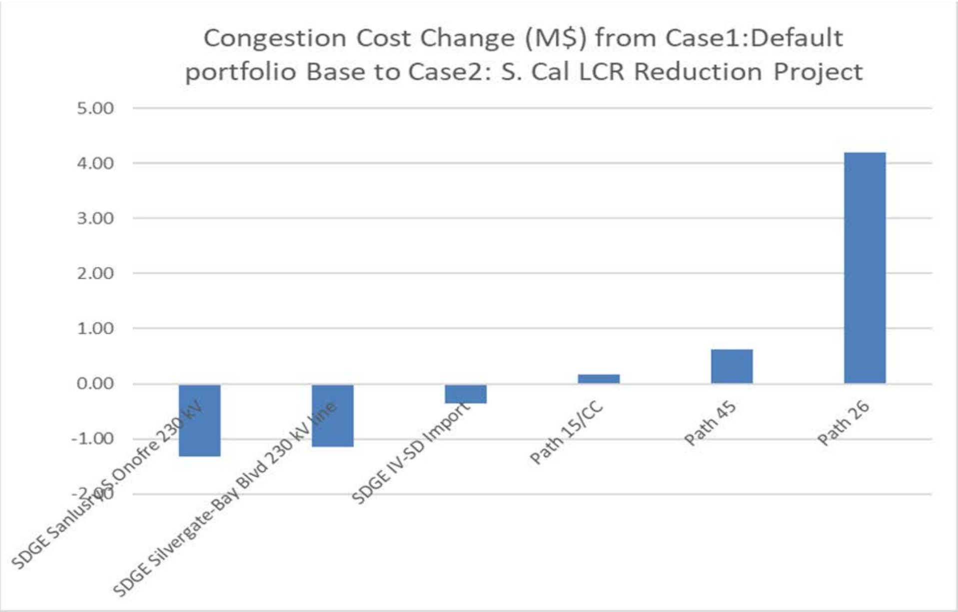


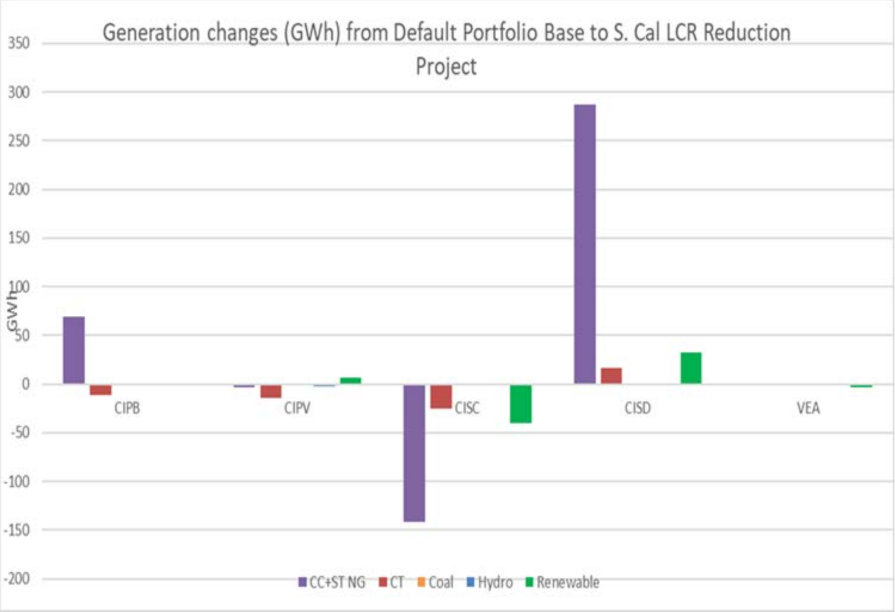


S.Cal Regional LCR Reduction Project – production benefit and congestion assessment

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8465	-8
ISO generator net revenue benefitting ratepayers	2526	2525	-1
ISO owned transmission revenue	199	201	2
ISO Net payment	5733	5740	**-7**
WECC Production cost	16875	16878	**-3**

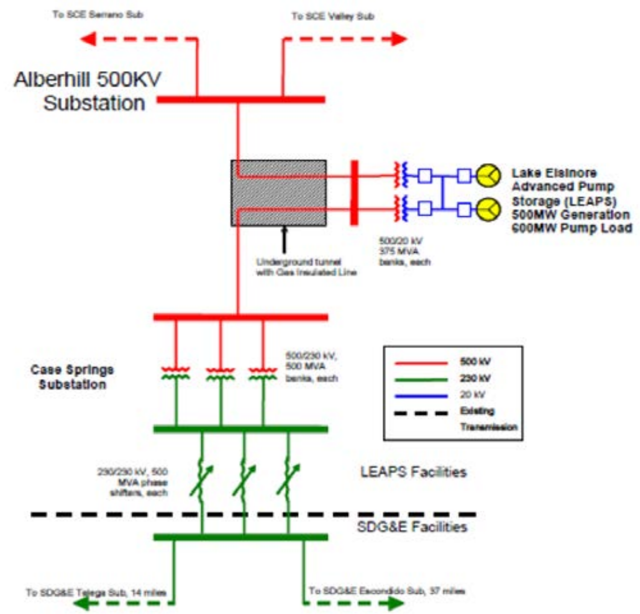
The estimated capital cost is between $100 to $200 million

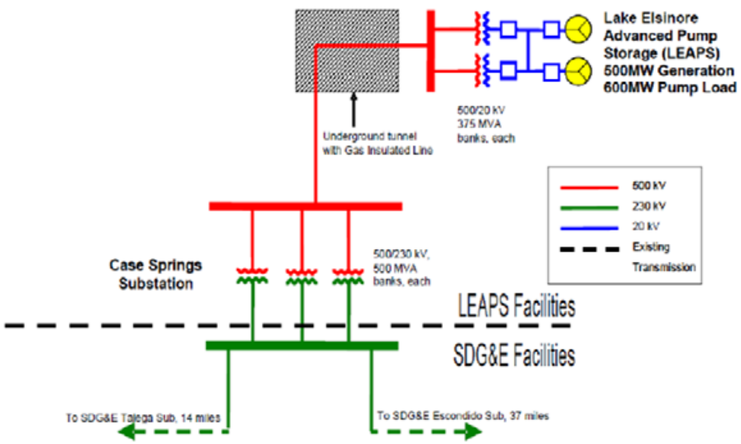




Energy storage projects-LEAPS

- Option 1: Connection to both SCE and SDG&E, approximate Project Cost = $2.04 billion
  - Option 1a – the transmission development without the hydro pumped storage; and,
  - Option 1b – the complete proposal, reflecting the addition of the hydro pumped storage facility to the transmission development
- Option 2: Connection to SDG& only, approximate Project Cost $1.76 billion





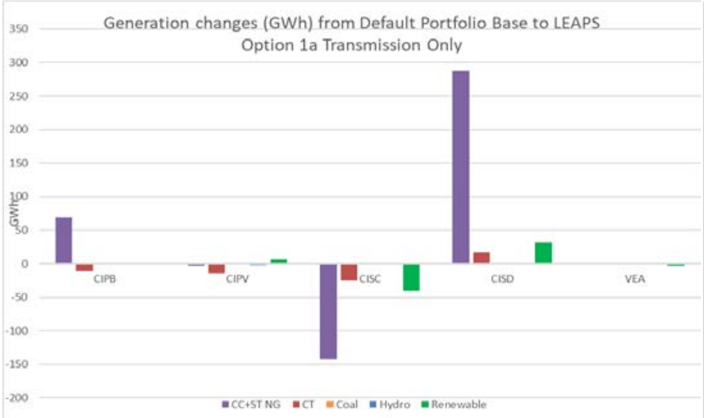
California ISO

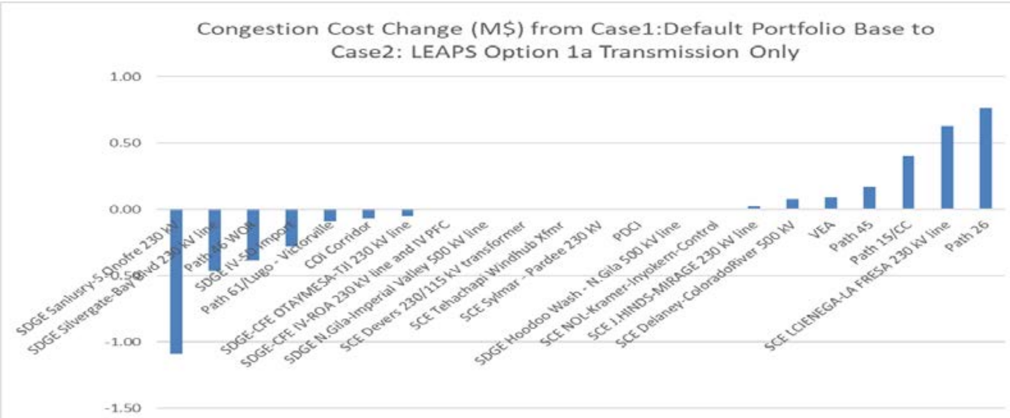
LEAPS production benefit – multi-tiered curtailment price

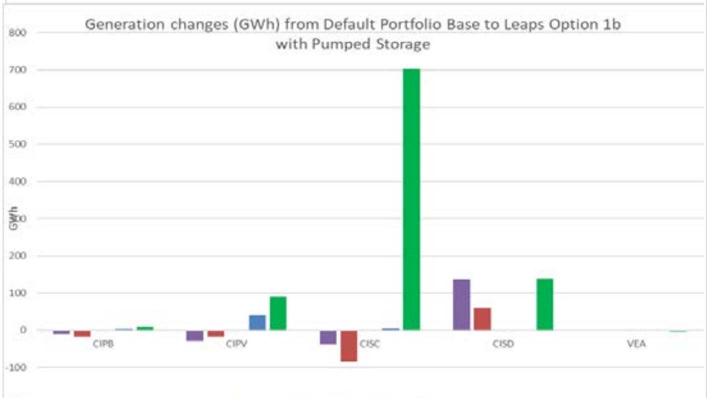
	Pre project upgrade ($M)	Option 1a		Option 1b		Option 2		Lugo Connection (sensitivity)	
		Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8456	1	8594	-137	8589	-132	8591	-134
ISO generator net revenue benefitting ratepayers*	2526	2529	3	2631	105	2624	99	2630	105
ISO owned transmission revenue	199	198	-1	199	0	198	-1	197	-1
ISO Net payment	5733	5729	4	5764	-31	5767	-34	5764	-31
WECC Production cost	16875	16878	-3	16838	37	16825	50	16842	33
Storage net revenue			NA		73		73		75
ISO Net payment including storage revenue					42		39		44

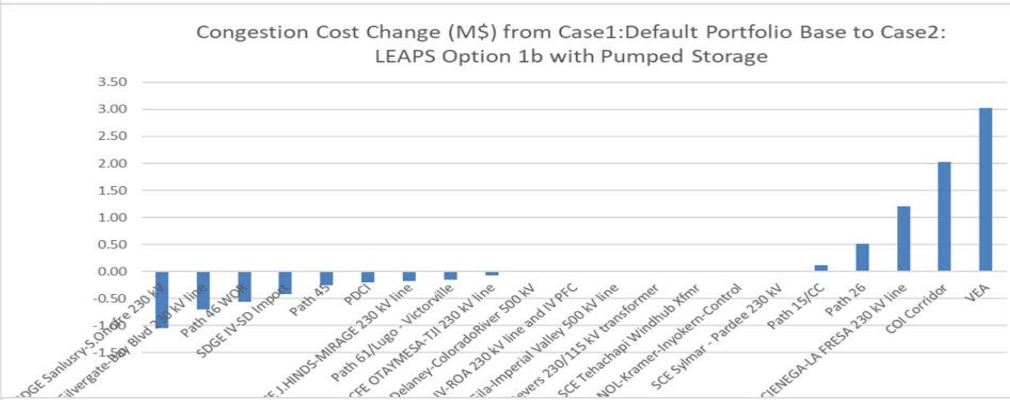
Lugo connection sensitivity was chosen as Lugo bus is a relatively unconstrained location in southern California. This sensitivity was used to evaluate the locational impacts on energy storage study results

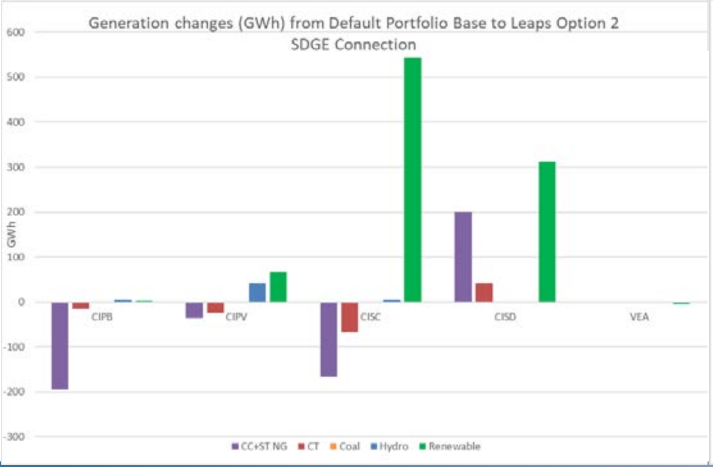
LEAPS- Generation and congestion changes

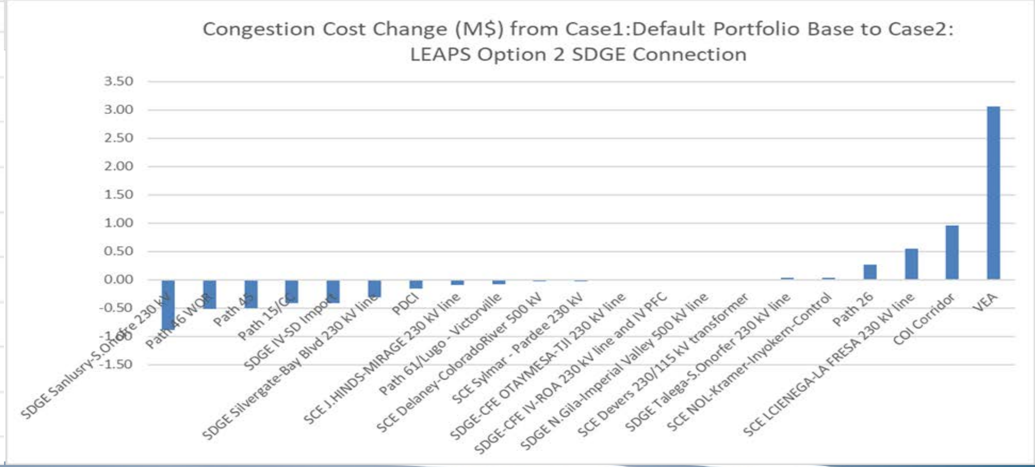




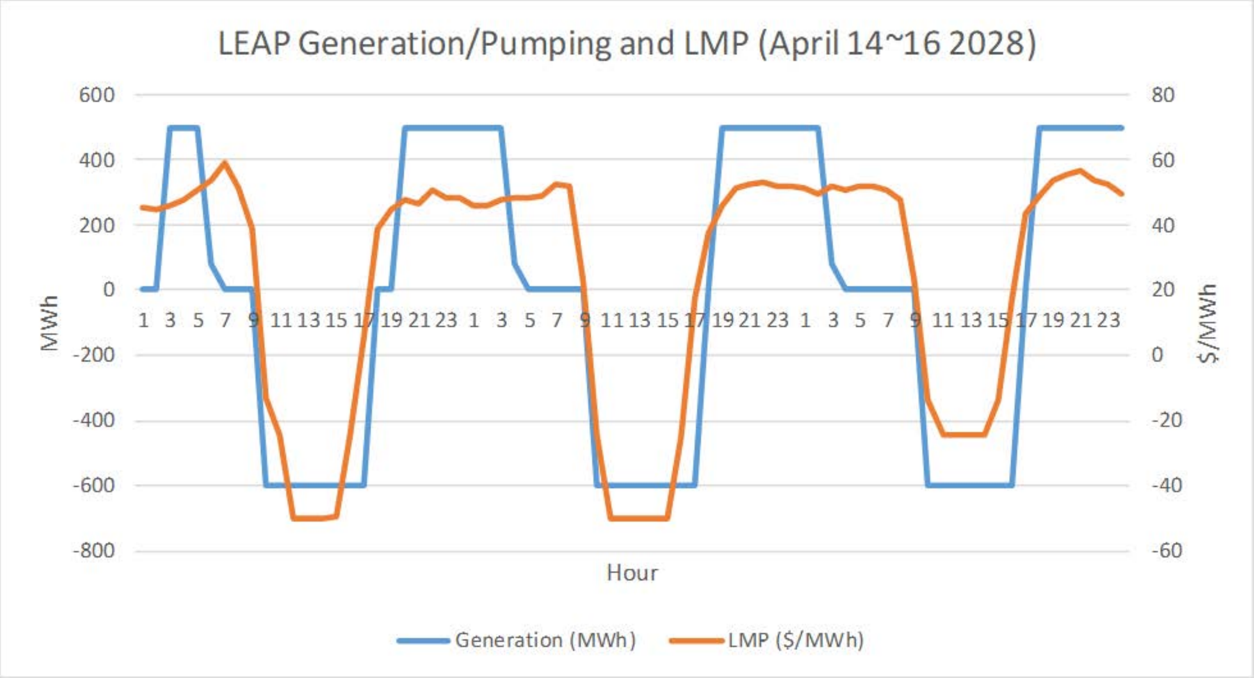








LEAPS-Pumped storage dispatch



LEAPS production benefit – Negative $25/MWh curtailment price

	Option 1b		Option 2		Lugo Connection (sensitivity)	
	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8,659	-94	8,657	-92	8,656	-91
ISO generator net revenue benefitting ratepayers	2,677	81	2,667	72	2,674	78
ISO owned transmission revenue	206	-7	209	-5	208	-5
ISO Net payment	5,775	-20	5,781	-25	5,774	-18
Storage net revenue		68		67		70
ISO Net payment including storage revenue		48		42		52
WECC Production cost	16,852	55	16,856	52	16,855	53

LEAPS-Observations

- All three options (Option 1a, Option 1b, and Option 2) can help to reduce San Diego congestions
- Pumped storage (Option 1b and Option 2) help to reduce renewable curtailment
- Pumped storage had positive net revenue, primarily due to arbitraging wholesale energy market prices
- Lugo connection sensitivity analysis showed that LEAPS essentially functions as an energy or capacity resource in the ISO market
  - The benefit analysis does not support the pumped storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources"
- Curtailment price assumption does impact the observations

Other energy storage projects – Production benefit assessment

		San Vicente (Sycamore 500 MW PS)		SRES (Sycamore 381 MW Battery)		NEET (Sycamore 210 MW Battery)		Westside Canal (IV 268 MW Battery)	
	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8557	-100	8528	-71	8494	-37	8504	-47
ISO generator net revenue benefitting ratepayers *	2526	2602	77	2590	65	2561	35	2578	52
ISO owned transmission revenue	199	199	0	200	1	198	-1	198	0
ISO Net payment	5733	5756	-23	5738	-5	5736	-3	5728	5
WECC Production cost	16875	16838	37	16853	22	16865	10	16857	18
Energy Storage Net Benefit			54		35		20		25

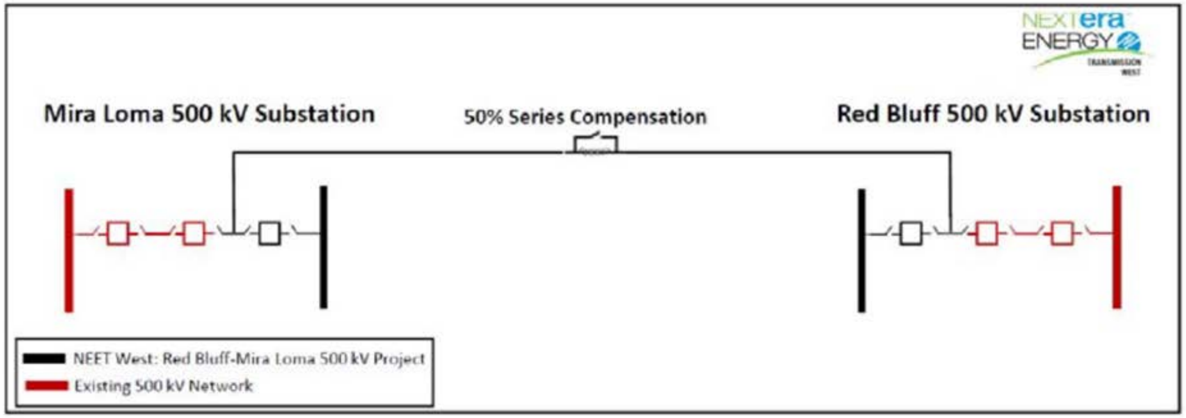
Other energy storage projects – observations

- These energy storage projects in San Diego and IV areas have similar impact on production cost and ISO ratepayer's benefit, magnitude may be different depending on the size of the projects
- The impacts on the pattern of generation and congestion changes are also similar
- A sensitivity to model the Sycamore 381 MW battery project at Lugo was conducted
  - This analysis led to the conclusion that the project functions as an energy or capacity resource in the ISO market. The benefit analysis does not support the pumped storage facilities being considered as providing a transmission function to "improve access to cost-efficient resources"
  - Same conclusion can be made for the other energy storage projects in this study

Congestion analysis and production benefit assessment for other economic study requests

- These study requests were not selected as high priority studies
  - Red Bluff – Mira Loma
  - N.Gila – Imperial Valley #2
  - HVDC Conversion
- But, they were studied in this planning cycle as LCR reduction alternatives
  - Production benefit were assessed in order to capture all potential benefit in TEAM analysis

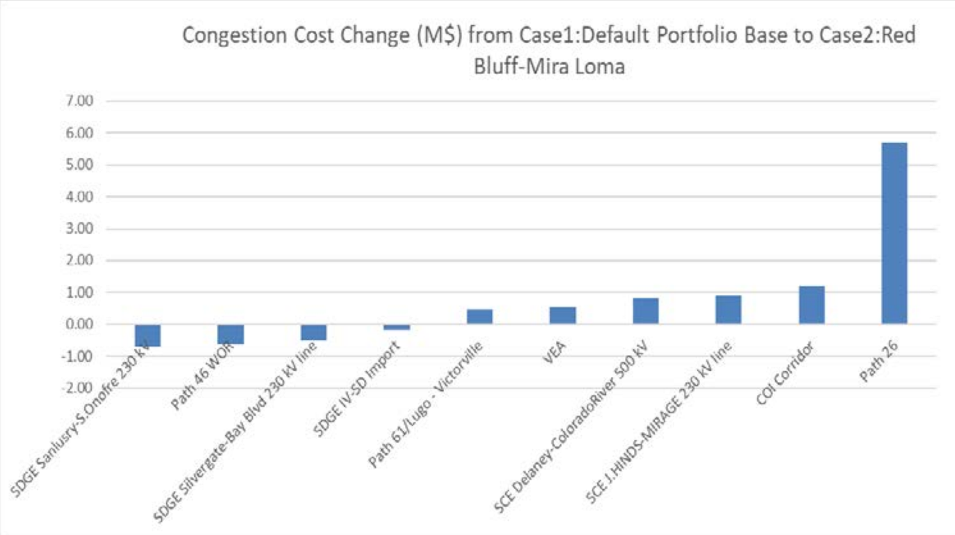
Red Bluff – Mira Loma 500 kV Project

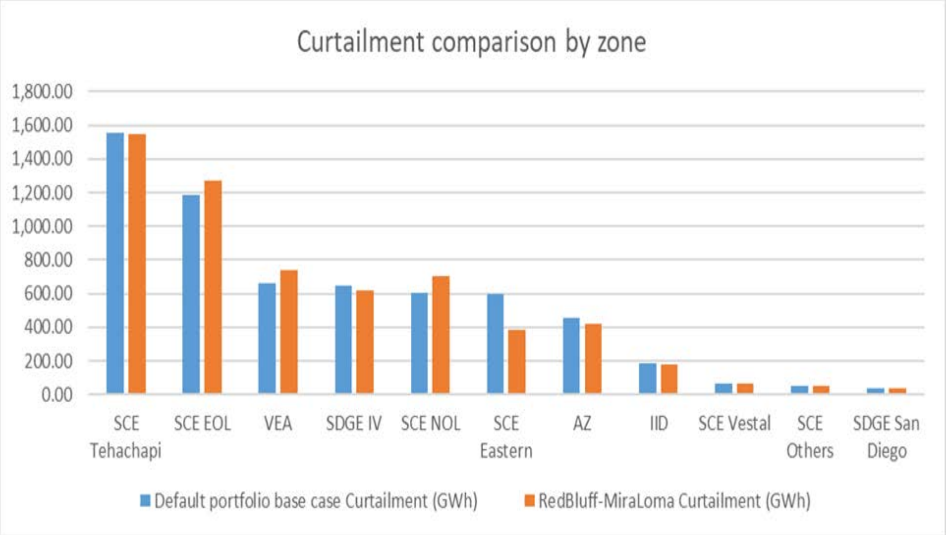


Red Bluff – Mira Loma 500 kV Project – Production benefit and curtailment assessment

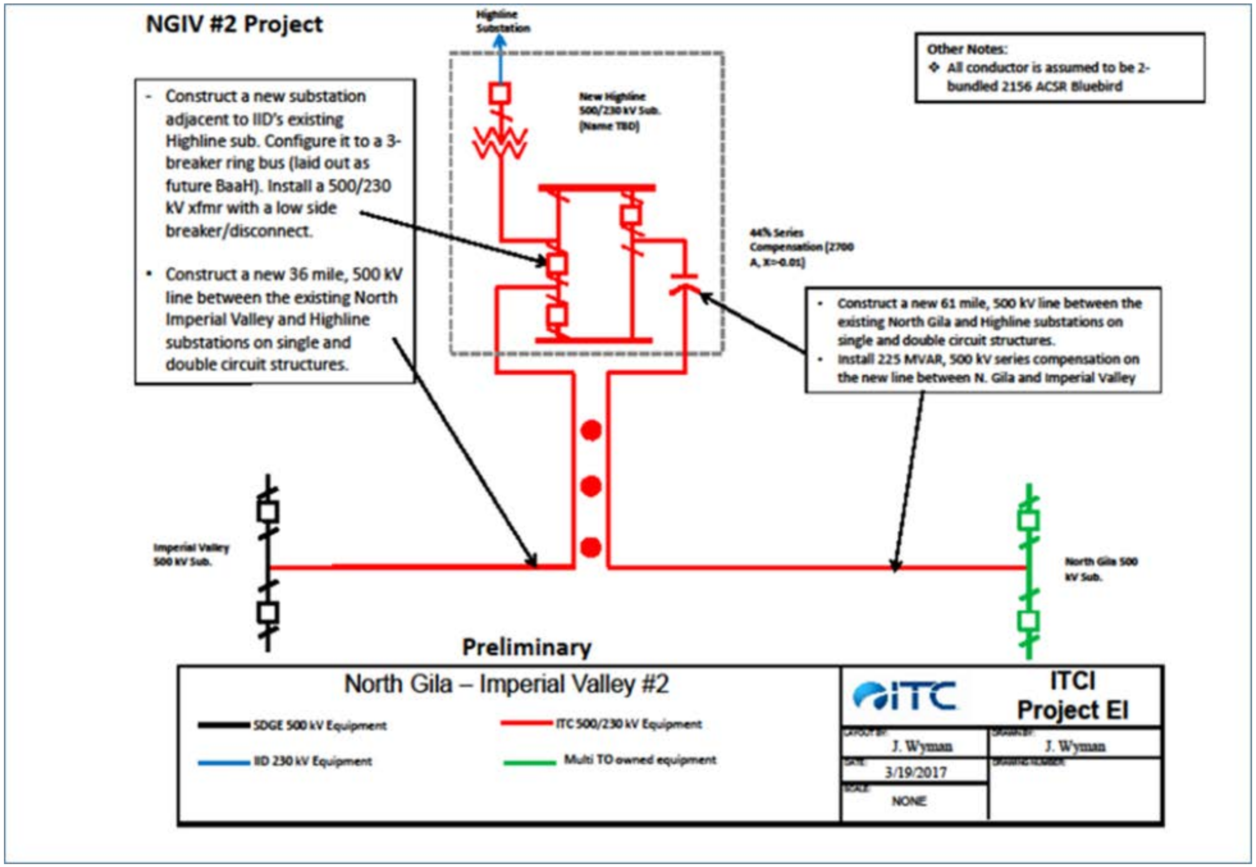
	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8442	15
ISO generator net revenue benefitting ratepayers	2526	2525	0
ISO owned transmission revenue	199	206	8
ISO Net payment	5733	5710	23
WECC Production cost	16875	16866	9

- The project's estimated capital cost is $850 million
- This project can also help to reduce San Diego congestion





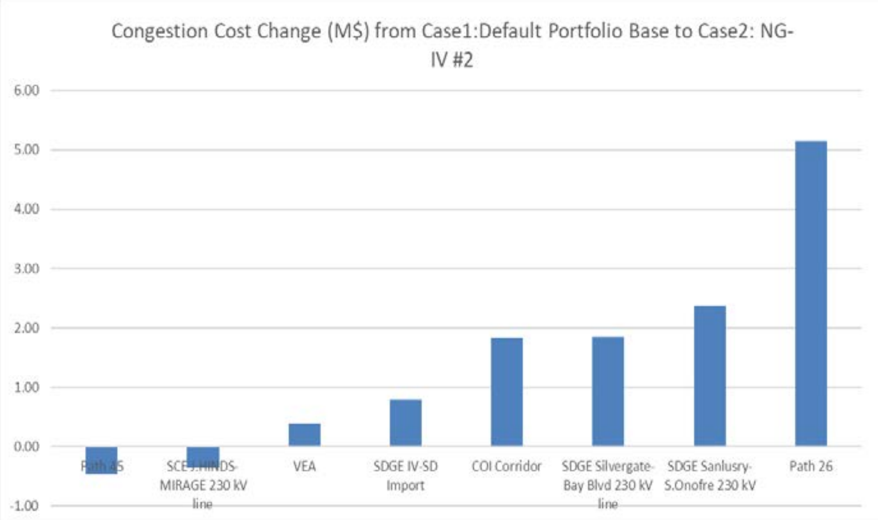
North Gila – Imperial Valley #2 500 kV Project

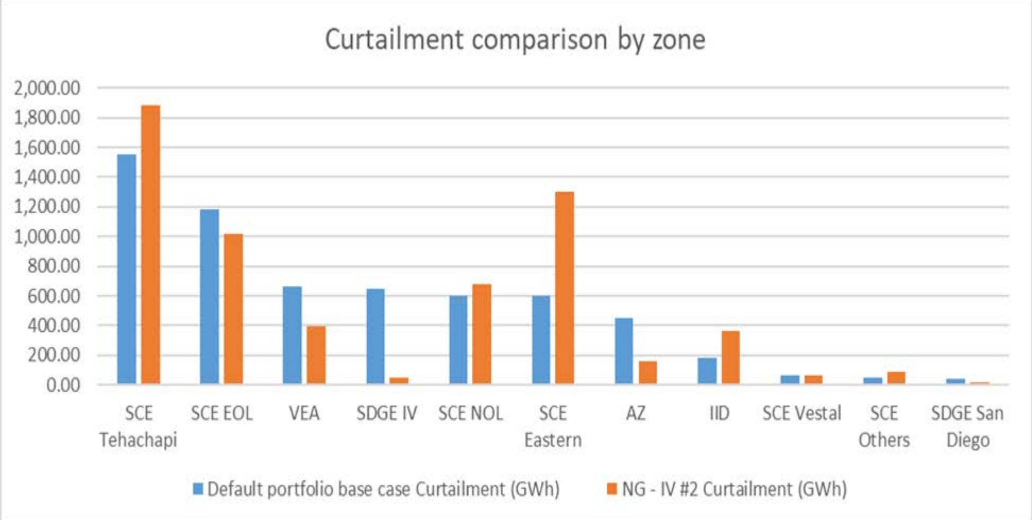


North Gila – Imperial Valley #2 – Production benefit, congestion and curtailment assessment

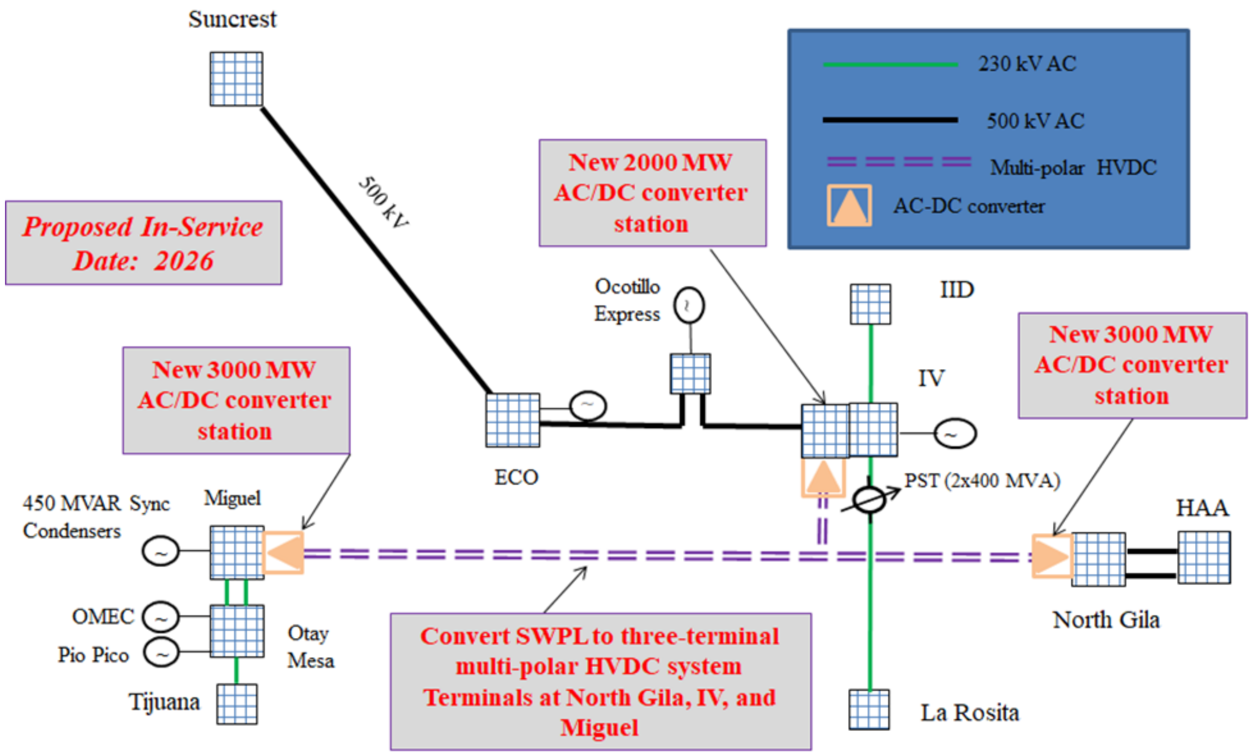
	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8485	-27
ISO generator net revenue benefitting ratepayers	2526	2545	19
ISO owned transmission revenue	199	213	14
ISO Net payment	5733	5727	6
WECC Production cost	16875	16886	-11

- The project's estimated capital cost for a single circuit line is $291 million, including loop-in to IID
- With this project modeled, San Diego congestions increased





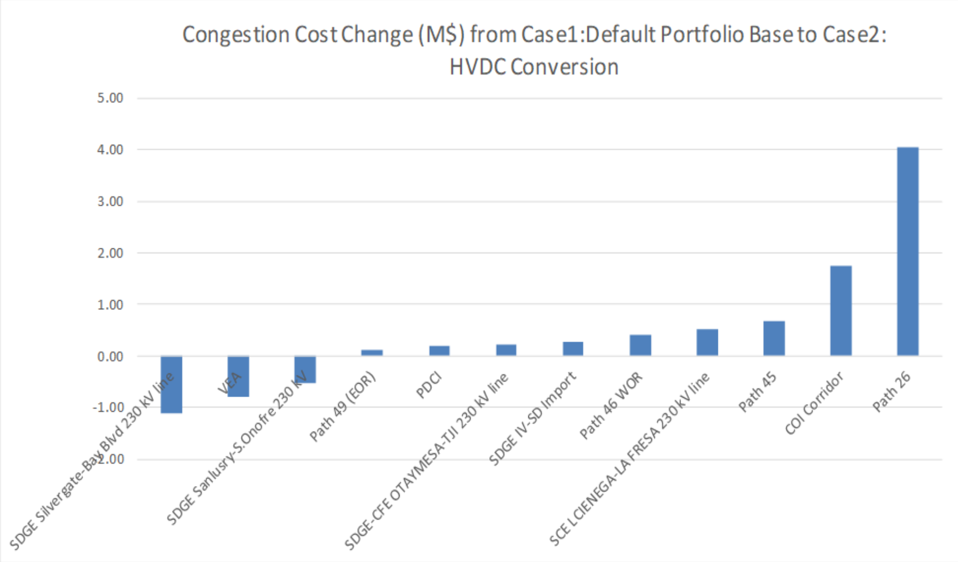
HVDC Conversion Project

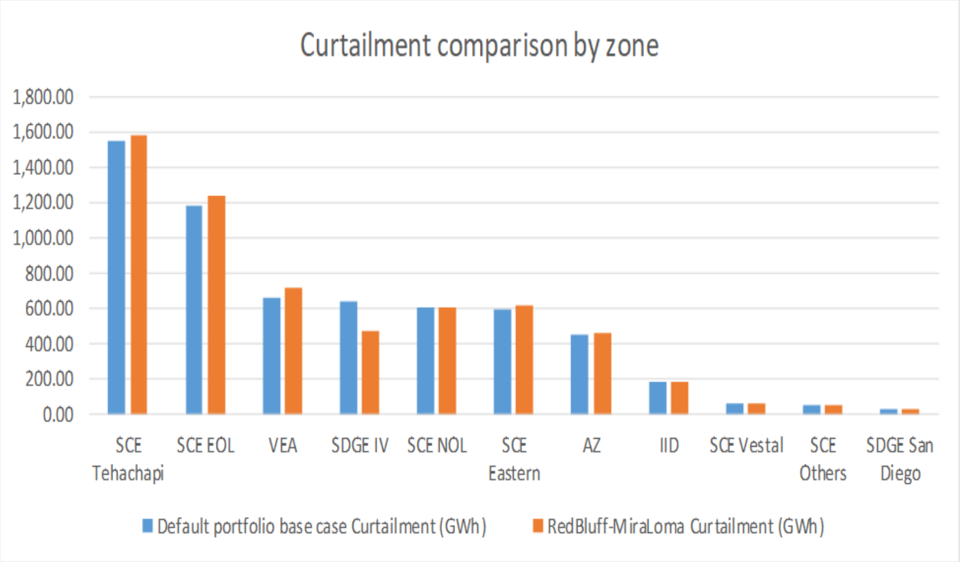


HVDC Conversion – Production benefit, congestion and curtailment assessment

	Pre project upgrade ($M)	Post project upgrade ($M)	Savings ($M)
ISO load payment	8457	8,464	-7
ISO generator net revenue benefitting ratepayers	2526	2,515	-11
ISO owned transmission revenue	199	204	5
ISO Net payment	5733	5,746	-13
WECC Production cost	16875	16903	-28

- The project’s estimated capital cost is $700 to $900 million





Economic Benefit Assessment Alternatives to Gas Generation in Local Capacity Areas

Jeff Billinton
Manager, Regional Transmission – North

David Le
Sr. Advisor, Regional Transmission - South

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

Selection of Areas and Sub-areas for Examination of Alternatives and for Detailed Economic Analysis

Areas and sub-areas selected for examination of potential alternatives – "more than half" of the areas and sub-areas.		Areas and sub-areas selected for detailed economic analysis in section 4.9
1	Sierra Area	
2	- *Pease*	*Selected for detailed economic analysis*
3	- South of Rio Oso	
	Bay Area (overall studied only if required)	
4	- Llagas	
5	- San Jose	
6	- South Bay-Moss Landing	
7	- Ames/Pittsburg/Oakland	
	Fresno (overall studied only if required)	
8	- *Hanford*	*Selected for detailed economic analysis*
9	- Herndon	
10	- Reedley (special case)	
11	Kern	
12	- Westpark	
13	- *Kern Oil*	*Selected for detailed economic analysis*
14	*LA Basin (combined with San Diego/Imperial Valley)*	*Selected for detailed economic analysis – See 17 and 18*
15	- *Eastern*	*Selected for detailed economic analysis*
	Big Creek/Ventura (overall studied only if required)	
16	- *Santa Clara*	*Selected for detailed economic analysis*
17	*San Diego/Imperial Valley (combined with LA Basin)*	*Selected for detailed economic analysis – see 14 and 18*
18	- *San Diego*	*Selected for detailed economic analysis – see 14 and 17*
19	- *El Cajon*	*Selected for detailed economic analysis*
20	- *Pala*	
21	- *Border*	*Selected for detailed economic analysis*
22	- *Esco*	

Valuing Local Capacity Area Requirement Reductions

- It cannot be assumed that gas-fired generation no longer required for local capacity purposes will not continue to be needed for system or flexible capacity reasons, albeit through competition with other system resources.

- The basis for the local price may depend on the circumstances within the local capacity area, with several scenarios set out below

Scenario	Methodology (for this cycle)
If the local capacity area has a surplus of resources in the area and there is a reasonable level of competition in selling local RA capacity	The price differential between system and local capacity.
If there is only one (newer) generator in the area, and essentially no competition (or if all the units are needed and the oldest is still relatively new)	The price differential between system capacity and the full cost of service of the least expensive resource(s) may be the appropriate metric.
If there is only one older unit in the area that is heavily depreciated (or all the units are needed and if the newest is still relatively old)	Consider price the differential between the CPM soft offer cap and system capacity.*

Differential between system and local capacity

- In this planning cycle, the ISO applied the differential between the local capacity price and system capacity price to assess the economic benefits of reducing the need for gas-fired generation when considering both transmission and other alternatives.

Net capacity value for the Greater Bay and Other PG&E areas versus system or north of Path 26 resources

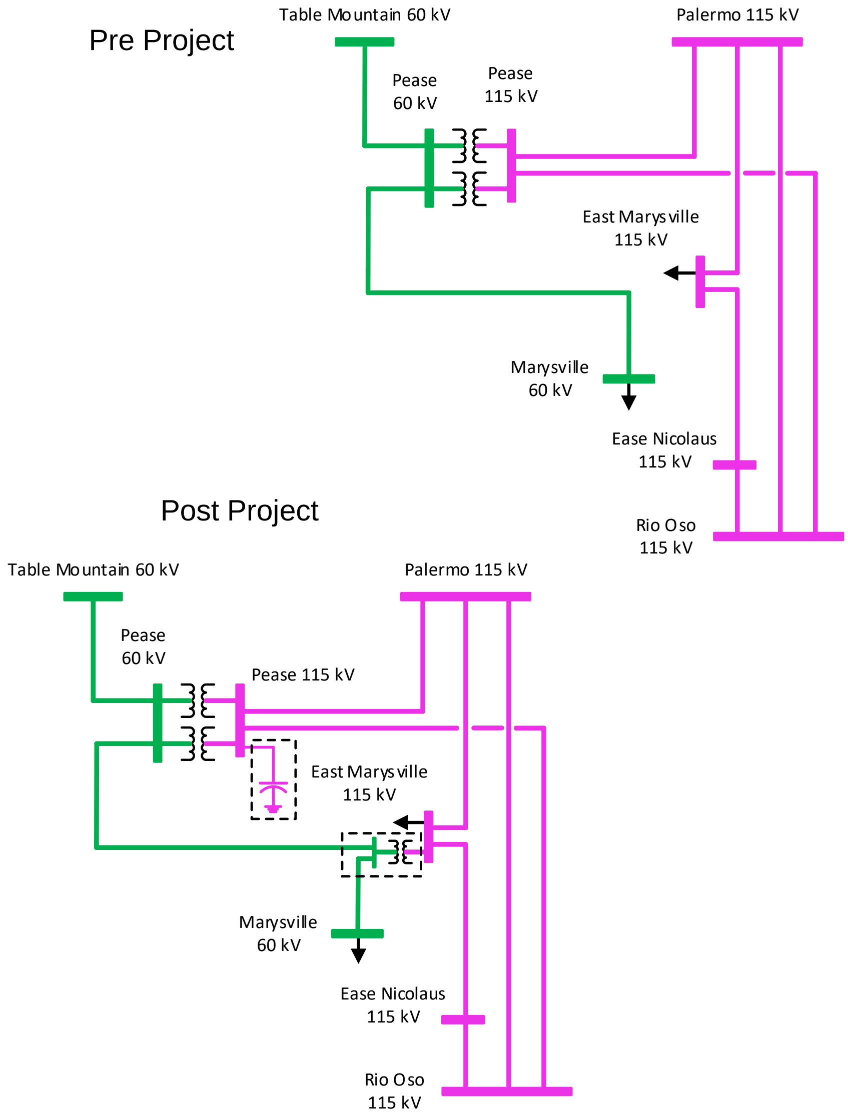
	Net capacity values (local – system)	Net capacity values (local – NP 26 system resources)
Greater Bay Area	$1,560/MW-year	$840/MW-year
Other PG&E Areas	$2,160/MW-year	$1,440/MW-year

Net capacity value for the LA Basin and San Diego areas versus system or South of Path 26 resources

	Net capacity values (local – system)	Net capacity values (local – SP 26 system resources)
LA Basin	$16,680/MW-year	$22,680/MW-year
San Diego	$13,080/MW-year	$19,080/MW-year

Northern System
Local Capacity Area Assessments

Pease Sub-area (Sierra Area) Alternative



Alternative:

- Loop in Pease – Marysville 60 kV line into E. Marysville 115 kV substation and install a 115/60 kV transformer at E. Marysville substation plus 25 Mvar voltage support at Pease 115 kV.
- Estimated Cost: $26 to 52 million
- Reduction of gas-fired generation to meet the local capacity requirement: 92 MW

Pease Sub-area (Sierra Area)
Economic Assessment of Alternative

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation			
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	RMR Cost versus System Capacity
LCR reduction benefit (Pease Sub-area) (MW)	92		
Capacity value (per MW-year)	$2,160	$1,440	$52,950
LCR Reduction Benefit ($million)	$0.2	$0.1	$4.9

- Differential of local versus system or North of Path 26 do not support alternative
- Use of RMR cost results in almost a BCR of 1.0
- Further consideration will be given in future planning cycles once cost estimate are better refined

Looping in of Pease-Marysville 60 kV line into East Marysville 115 kV substation			
Local Capacity Benefits			
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	RMR Cost
Net LCR Saving ($million/year)	$0.2	$0.1	$4.9
PV of LCR Savings ($million)	$2.74	$1.83	$67.23
Capitall Cost			
Capital Cost Estimate ($ million)	$52		
Estimated "Total" Cost (screening) ($million)	$68		
Benefit to Cost			
PV of Savings ($million)	$2.74	$1.83	$67.23
Estimated "Total" Cost (screening) ($million)	$67.60		
Benefit to Cost	0.04	0.03	0.99

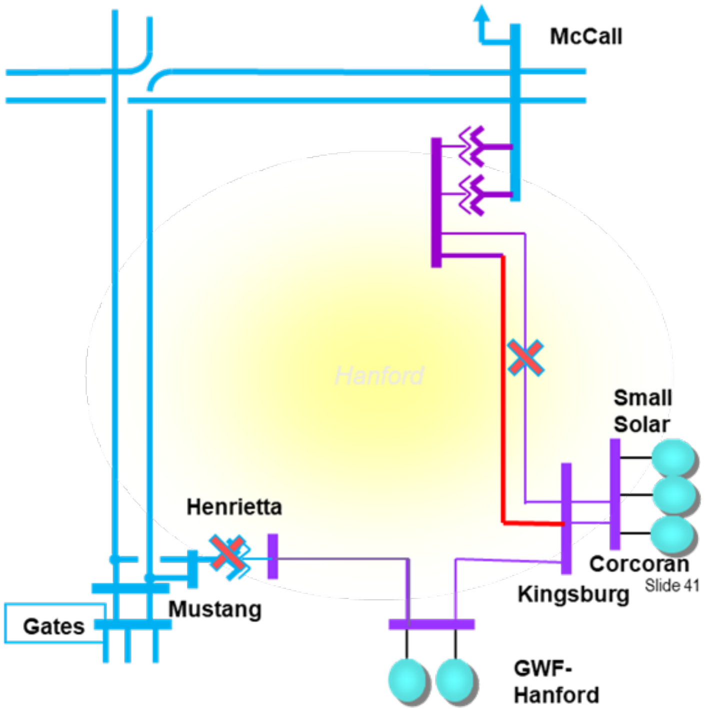
Hanford Sub-area (Fresno Area) Alternatives

Alternative 1:

- Reconductoring of the McCall-Kingsburg #1 115 kV line
- Estimated Cost: <u>$9 million</u>
- Reduction of gas-fired generation to meet the local capacity requirement: <u>39 MW</u>

Alternative 2:

- Reconductoring of both the McCall-Kingsburg #1 and #2 115 kV lines
- Estimated Cost: <u>$23.5 million</u>
- Reduction of gas-fired generation to meet the local capacity requirement: <u>125 MW</u>



Hanford Sub-area (Fresno Area) Economic Assessment of Alternatives

	Reconductor McCall-Kingsburg #1 115kV line		Reconductor McCall-Kingsburg #1 and #2 115kV lines	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Hanford Sub-area) (MW)	39		125	
Capacity value (per MW-year)	$2,160	$1,440	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.1	$0.1	$0.3	$0.2

- Differential of local versus system or North of Path 26 do not support alternative
- Further consideration will be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the Hanford sub-area for system reasons is achieved

	Reconductor McCall-Kingsburg #1 115kV line		Reconductor McCall-Kingsburg #1 and #2 115kV lines	
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.1	$0.1	$0.3	$0.2
PV of LCR Savings ($million)	$1.16	$0.78	$3.73	$2.48
Capital Cost				
Capital Cost Estimate ($ million)	$9		$24	
Estimated “Total” Cost (screening) ($million)	$12		$30.55	
Benefit to Cost				
PV of Savings ($million)	$1.16	$0.78	$3.73	$2.48
Estimated “Total” Cost (screening) ($million)	$11.70		$30.55	
Benefit to Cost	0.10	0.07	0.12	0.08

California ISO

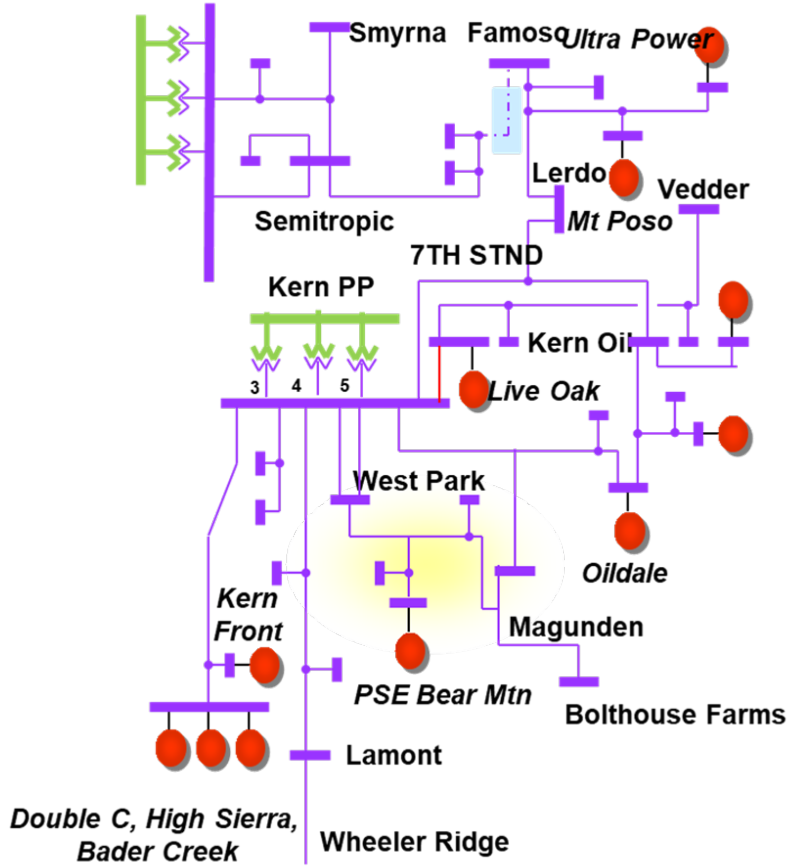
Kern Oil Sub-area (Kern Area) Economic Assessment of Alternative

Alternative:

- Reconductor sections of line between Kern Oil and Kern Oil Junction and increase the scope of the Kern Power-Kern Oil Junction upgrades as a part of the previously approved Kern 115 kV Reinforcement project from rerating to reconductoring.

- Estimated Cost: $15 million

- Reduction of gas-fired generation to meet the local capacity requirement: 21 MW



California ISO

Kern Oil Sub-area (Kern Area) Economic Assessment of Alternative

Reconductor sections of line between Kern Oil and Kern oil Junction and increase the scope of the Kern Power-Kern Oil Junction from rerate to reconductor		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit Kern Oil Sub-area) (MW)	21	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.05	$0.03

- Differential of local versus system or North of Path 26 do not support alternative
- Further consideration will be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the Hanford sub-area for system reasons is achieved

Reconductor sections of line between Kern Oil and Kern oil Junction and increase the scope of the Kern Power-Kern Oil Junction from rerate to reconductor		
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.05	$0.03
PV of LCR Savings ($million)	$0.63	$0.42
Capital Cost		
Capital Cost Estimate ($ million)	$15	
Estimated "Total" Cost (screening) ($million)	$20	
Benefit to Cost		
PV of Savings ($million)	$0.63	$0.42
Estimated "Total" Cost (screening) ($million)	$19.50	
Benefit to Cost	0.03	0.02

Note: Tables for Kern Oil Sub-area assessment will be updated in the Revised Draft

Southern System

Local Capacity Area Assessments

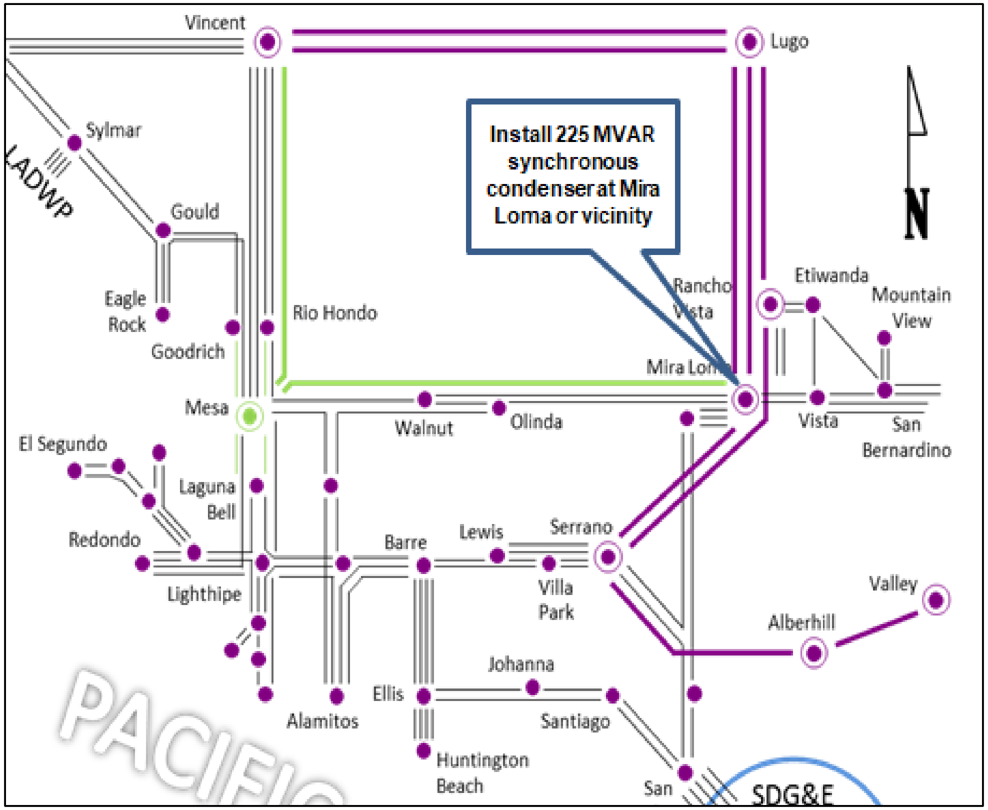
Eastern Sub-area (LA Basin Area) Economic Assessment of Mira Loma Dynamic Reactive Support Alternative

Alternative:

- Install approximately 225 Mvar of dynamic reactive support (i.e., synchronous condenser) at Mira Loma Substation (the optimal location would be evaluated further if there is further consideration for this option).

- Estimated Cost: <u>$30 million to $80 million</u>

- Reduction of gas-fired generation to meet the local capacity requirement: <u>350 MW</u>



Eastern Sub-area (LA Basin Area) Economic Assessment of Mira Loma Dynamic Reactive Support Alternative

Mira Loma Dynamic Reactive Support		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Eastern LA Basin) (MW)	350	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.8	$7.9
LCR increase (Western LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$5.8	$7.9

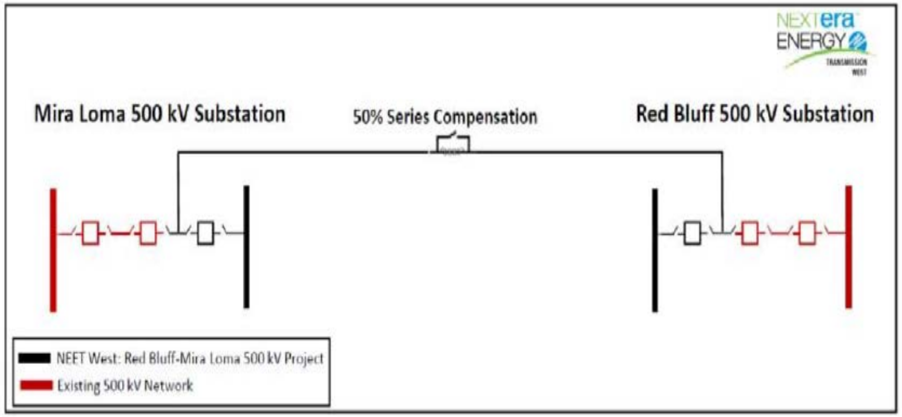
- Differential of local versus system do not support alternative; however, differential of local versus South of Path 26 support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the Eastern sub-area for system reasons is achieved

Mira Loma Dynamic Reactive Support		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$5.8	$7.9
PV of LCR Savings ($million)	$80.57	$109.55
Capital Cost		
Capital Cost Estimate ($ million)	$80	
Estimated “Total” Cost (screening) ($million)	$104	
Benefit to Cost		
PV of Savings ($million)	$80.57	$109.55
Estimated “Total” Cost (screening) ($million)	$104.00	
Benefit to Cost	0.77	1.05

Eastern Sub-area (LA Basin Area) Economic Assessment of Red Bluff-Mira Loma 500kV Transmission Alternative

<u>Alternative:</u>

- Construct a new 500-kV transmission line (~139 mile) between the Red Bluff substation and the Mira Loma substation with 50% compensation, with line ratings of 3,421 MVA normal and 3,880 MVA emergency.
- Install 50% series compensation with the optimal location in the line yet to be determined from more detailed studies. The line series compensation would have a normal rating of 3,291 MVA and an emergency rating of 3,949 MVA.
- Estimated Cost: <u>$850 million</u>
- Reduction of gas-fired generation to meet the local capacity requirement: <u>91 MW</u>
- Adverse impact to Western LA Basin LCR: <u>30 MW</u>



Eastern Sub-area (LA Basin Area) Economic Assessment of Red Bluff-Mira Loma 500kV Transmission Alternative

Mira Loma - Red Bluff 500 kV Line		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Eastern LA Basin) (MW)	91	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$1.5	$2.1
LCR increase (Western LA Basin) (MW)	30	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.5	$0.7
Net LCR Saving ($million/year)	$1.0	$1.4

- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the Eastern sub-area for system reasons is achieved

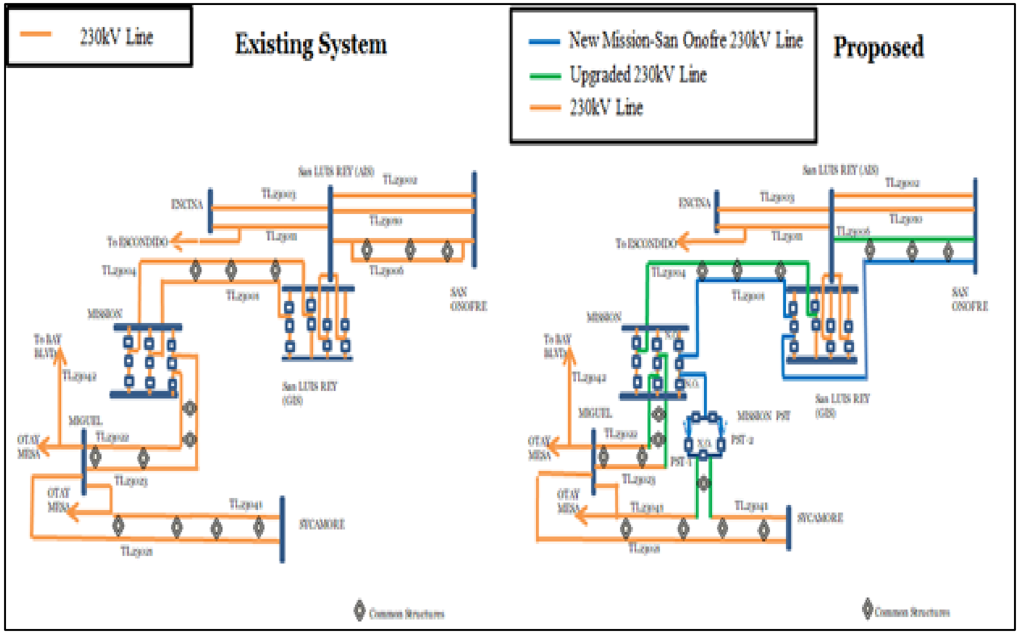
Red Bluff – Mira Loma 500 kV Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$23	
ML-RB Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$23	
PV of Prod Cost Savings ($million)	$317.42	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$1.0	$1.4
PV of LCR Savings ($million)	$14.04	$19.09
Capital Cost		
Capital Cost Estimate ($ million)	$850	
Estimated “Total” Cost (screening) ($million)	$1,105	
Benefit to Cost		
PV of Savings ($million)	$331.46	$336.51
Estimated “Total” Cost (screening) ($million)	$1,105.00	
Benefit to Cost	0.30	0.30

California ISO

Western Sub-area (LA Basin Area) Economic Assessment of Southern California Regional LCR Reduction Transmission Alternative

Alternative:

- Construct a new 230 kV line (2-1033ACSR), Mission-San Luis Rey- San Onofre, by utilizing the existing 230 kV facilities.
- Convert half of the existing 138kV Mission switchyard (Bay 5 to Bay 9) to a 230 kV Phase Shifter Station (2–600MW PSTs).
- Upgrade TL23004 (Mission-San Luis Rey), TL23006 (San Onofre-San Luis Rey), TL23022 (Miguel-Mission), and TL23023 (Miguel – Mission) with bundled 1033ACSR.
- Estimated Cost: $100 million - $200 million
- Reduction of gas-fired generation to meet the local capacity requirement: 83 MW



Western Sub-area (LA Basin Area) Economic Assessment of Southern California Regional LCR Reduction Transmission Alternative

Southern California Region LCR Reduction Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Western LA Basin) (MW)	83	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$1.4	$1.9
LCR increase (San Diego – IV) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$1.4	$1.9

- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the Western sub-area for system reasons is achieved

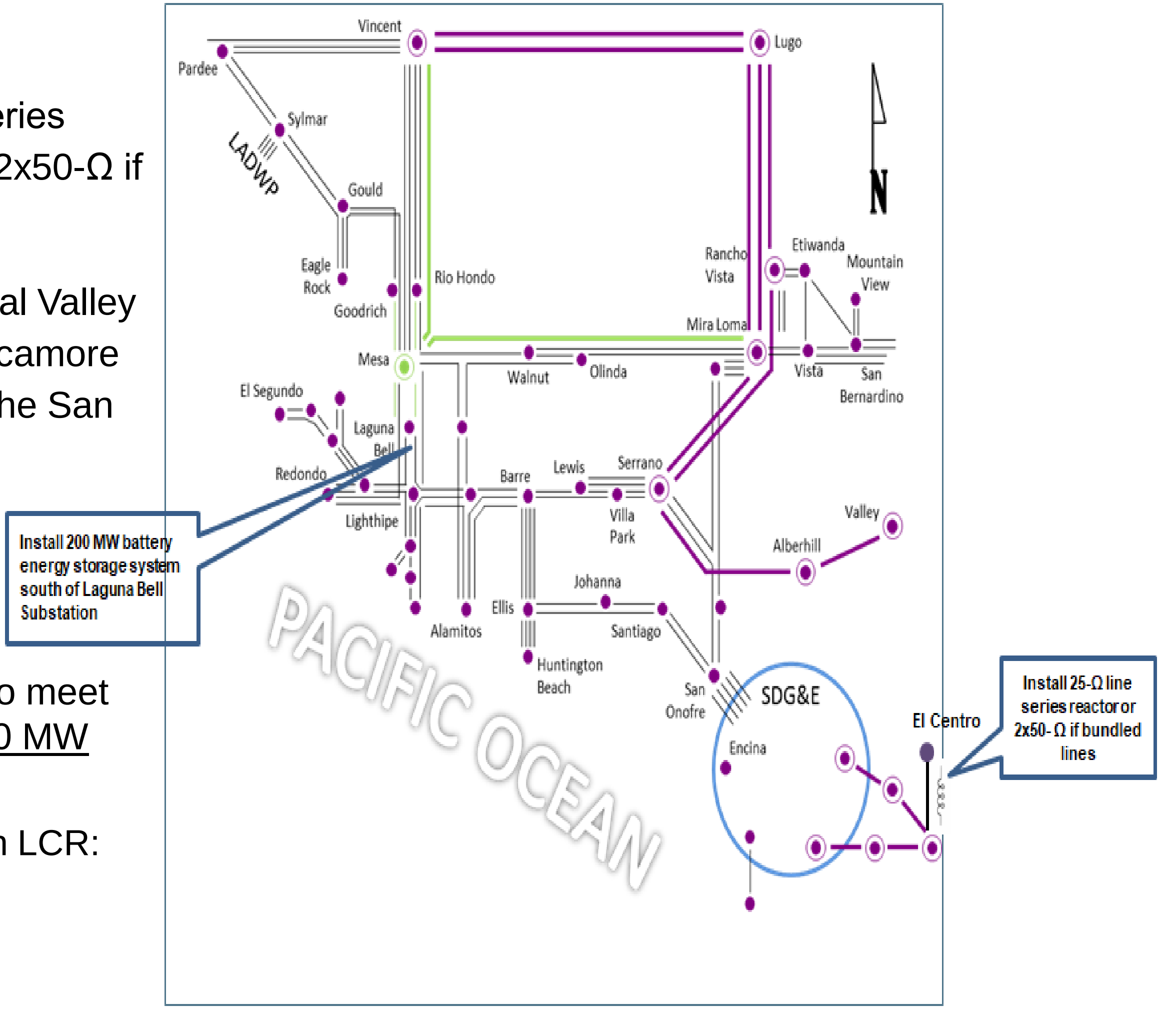
Southern California Region LCR Reduction Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$7	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	-$7	
PV of Prod Cost Savings ($million)	-$96	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$1.4	$1.9
PV of LCR Savings ($million)	$18.5	$25.1
Capital Cost		
Capital Cost Estimate ($ million)	$200	
Estimated "Total" Cost (screening) ($million)	$260	
Benefit to Cost		
PV of Savings ($million)	-$77.2	-$70.6
Estimated "Total" Cost (screening) ($million)	$260.00	
Benefit to Cost	-0.30	-0.27

California ISO

San Diego-Imperial Valley Area Economic Assessment of S-Line Reactor Transmission Alternative

Alternative:

- Install an equivalent of 25-Ω line series reactor on the upgraded S-line (or 2x50-Ω if there are 2 lines in parallel); and
- Utilize the existing RAS and Imperial Valley phase shifters for mitigating the Sycamore Canyon – Suncrest 230 kV line in the San Diego bulk transmission sub-area.
- Estimated Cost: $30 million
- Reduction of gas-fired generation to meet the local capacity requirement: 600 MW
- Adverse impact to Western LA Basin LCR: 200 MW



California ISO

San Diego-Imperial Valley Area Economic Assessment of S-Line Reactor Transmission Alternative

S-Line Series Reactor Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	600	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$7.8	$11.4
LCR increase (Western LA Basin) (MW)	200	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$3.3	$4.5
Net LCR Saving ($million/year)	$4.5	$6.9

- The benefit to cost ratio of this project is encouraging notwithstanding the conservative value assigned to local capacity requirement reductions.
- The project will be considered in future planning cycles, once the design and configuration of the IID-owned S-Line upgrade is finalized.

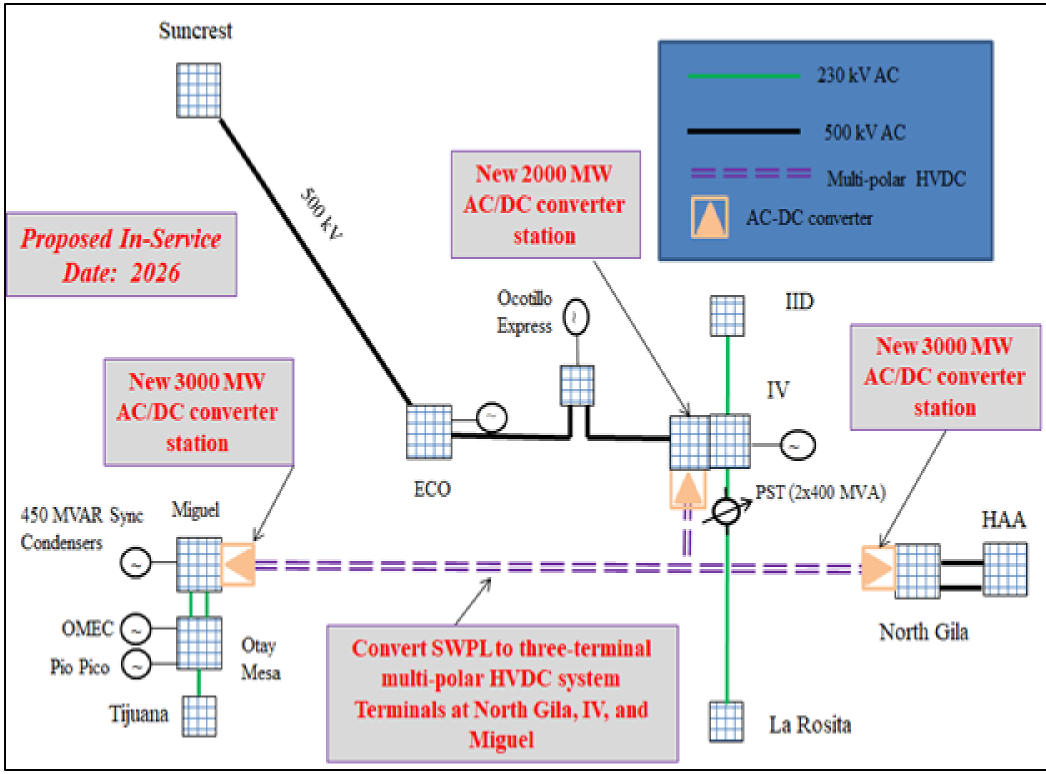
S-Line Series Reactor Project		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$4.5	$6.9
PV of LCR Savings ($million)	$60.15	$92.15
Capital Cost		
Capital Cost Estimate ($ million)	$30	
Estimated “Total” Cost (screening) ($million)	$39	
Benefit to Cost		
PV of Savings ($million)	$60.15	$92.15
Estimated “Total” Cost (screening) ($million)	$39.00	
Benefit to Cost	1.54	2.36

California ISO

San Diego-Imperial Valley Area Economic Assessment of HVDC Conversion Transmission Alternative

Alternative:

- Convert a portion of the 500 kV Southwest Powerlink (SWPL) to a three-terminal HVDC system with two fully independent poles.
- Install terminals at or adjacent to North Gila, Imperial Valley, and Miguel Substations. Each pole will be capable of fully independent operation at its maximum rated capacity.
- The proposed capacity of the proposed HVDC system is 2x1500 MW, bi-directional, for a total transfer capacity of 3000 MW.
- Replace existing loop-in of Southwest Powerlink at ECO with Sunrise Powerlink to replace AC connectivity.
- Estimated Cost: $700 million - $900 million
- Reduction of gas-fired generation to meet the local capacity requirement: 690 MW
- Adverse impact to Western LA Basin LCR: 40 MW



San Diego-Imperial Valley Area Economic Assessment of HVDC Conversion Transmission Alternative

	HVDC Conversion Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	690	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$9.0	$13.2
LCR increase (Western LA Basin) (MW)	40	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.7	$0.9
Net LCR Saving ($million/year)	$8.4	$12.3

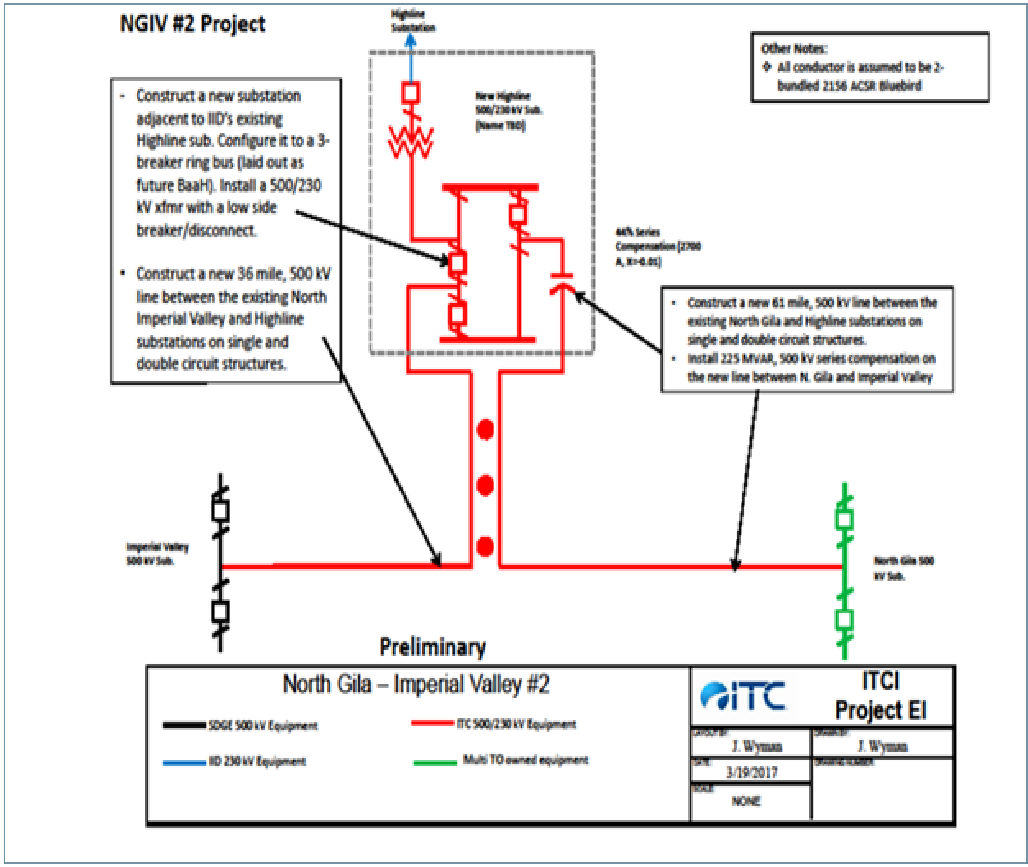
- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

HVDC Conversion Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$13	
N.Gila-IV #2 500kV Line Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	-$13	
PV of Prod Cost Savings ($million)	($179.41)	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$8.4	$12.3
PV of LCR Savings ($million)	$115.4	$169.2
Capital Cost		
Capital Cost Estimate ($ million)	$900	
Estimated “Total” Cost (screening) ($million)	$1,170	
Benefit to Cost		
PV of Savings ($million)	-$64	-$10
Estimated “Total” Cost (screening) ($million)	$1,170	
Benefit to Cost	-0.05	-0.01

San Diego-Imperial Valley Area Economic Assessment of North Gila-Imperial Valley #2 500kV Line Transmission Alternative

Alternative:

- Construct the North Gila-Imperial Valley #2 500 kV transmission line (95-mile) single circuit 500 kV AC transmission project between southwest Arizona and southern California.
- Estimated Cost: $291 million
- Reduction of gas-fired generation to meet the local capacity requirement: 865 MW
- Adverse impact to Western LA Basin LCR: 100 MW



San Diego-Imperial Valley Area Economic Assessment of North Gila-Imperial Valley #2 500kV Line Transmission Alternative

N.Gila-Imperial Valley 500 kV Line #2 Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	865	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$11.3	$16.5
LCR increase (Western LA Basin) (MW)	100	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$1.7	$2.3
Net LCR Saving ($million/year)	$9.6	$14.2

- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

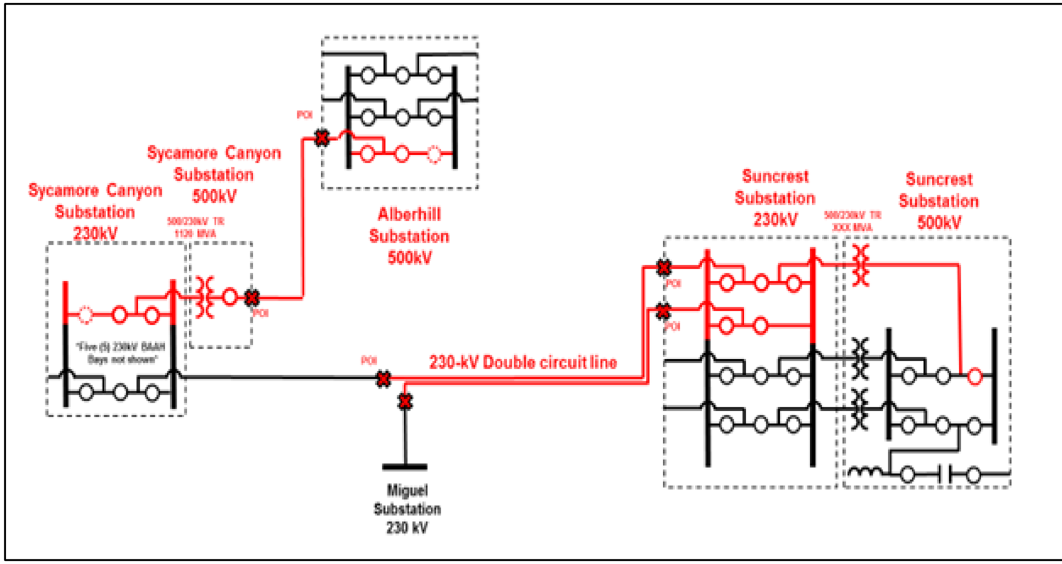
NG-IV #2 500 kV Line		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$6	
NG-IV #2 500 kV Line Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$6	
PV of Prod Cost Savings ($million)	$82.80	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.6	$14.2
PV of LCR Savings ($million)	$133.12	$196.47
Capital Cost		
Capital Cost Estimate ($ million)	$291	
Estimated “Total” Cost (screening) ($million)	$378	
Benefit to Cost		
PV of Savings ($million)	$215.9	$279.3
Estimated “Total” Cost (screening) ($million)	$378	
Benefit to Cost	0.57	0.74

California ISO

San Diego-Imperial Valley Area Economic Assessment of Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Transmission Alternative

<u>Alternative:</u>

- Construct a new 500-kV transmission line from the proposed Alberhill substation to a new 500-kV Sycamore Canyon substation with a new 500/230-kV transformer at Sycamore Canyon substation. The CPUC denied the permit application for Alberhill substation project without prejudice in its environmental permitting process. Since the Alberhill Substation Project was denied by the CPUC, PG&E and TransCanyon would need to modify the Request Window submittal to include the cost for a new switching station in lieu of the Alberhill substation.
- Install a third 500/230-kV transformer at Suncrest Substation and a new double circuit 230 kV transmission line that will loop the existing Miguel – Sycamore Canyon 230 kV transmission line to Suncrest substation.Estimated
- Cost: <u>$500 million</u>
- Reduction of gas-fired generation to meet the local capacity requirement: <u>942 MW</u>
- Adverse impact to Western LA Basin LCR: <u>170 MW</u>



San Diego-Imperial Valley Area Economic Assessment of Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Transmission Alternative

Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	942	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$12.3	$18.0
LCR increase (Western LA Basin) (MW)	170	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$2.8	$3.9
Net LCR Saving ($million/year)	$9.5	$14.1

- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

Alberhill-Sycamore 500 kV line plus Miguel to Sycamore loop into Suncrest 230 kV		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/ year)	$3	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$3	
PV of Prod Cost Savings ($million)	$41.40	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.5	$14.1
PV of LCR Savings ($million)	$130.91	$194.84
Capital Cost		
Capital Cost Estimate ($ million)	$500	
Estimated “Total” Cost (screening) ($million)	$650	
Benefit to Cost		
PV of Savings ($million)	$172.31	$236.24
Estimated “Total” Cost (screening) ($million)	$650	
Benefit to Cost	0.26	0.36

San Diego-Imperial Valley Area Economic Assessment of Lake Elsinore Advanced Pumped Storage Alternative

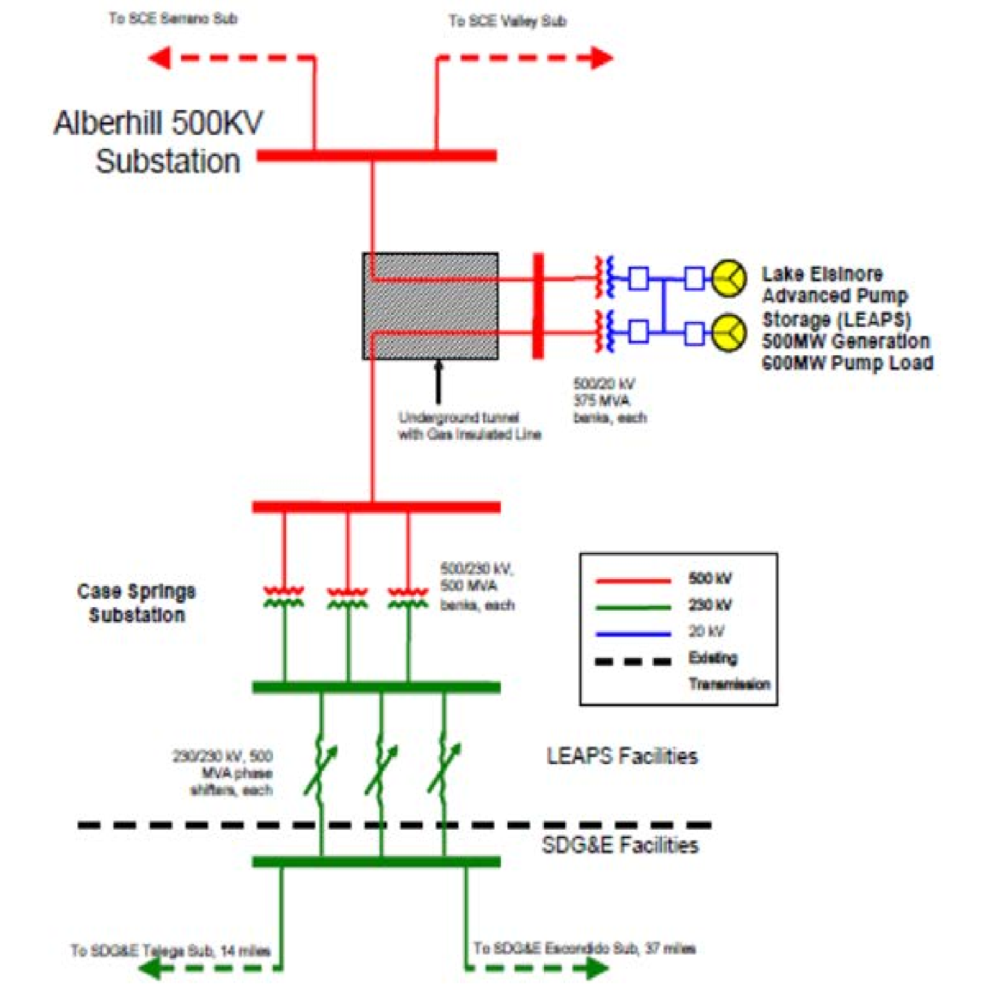
Alternative:

Option 1a:

- This option interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill 500 kV substation (if approved by the CPUC) and (ii) to SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation. If Alberhill is not approved, the connection point will be roughly one mile to the north-west at the proposed Lake Switchyard location. This option does not have the pumped storage.
- Cost: $829 million
- Reduction of gas-fired generation to meet the local capacity requirement: 443 MW
- Adverse impact to Western LA Basin LCR: 150 MW

Option 1b:

- Same as Option 1a but with the addition of the 500 MW pumped storage
- Cost: $2.04 billion
- Reduction of gas-fired generation to meet the local capacity requirement: 514 MW
- Adverse impact to Western LA Basin LCR: 0 MW



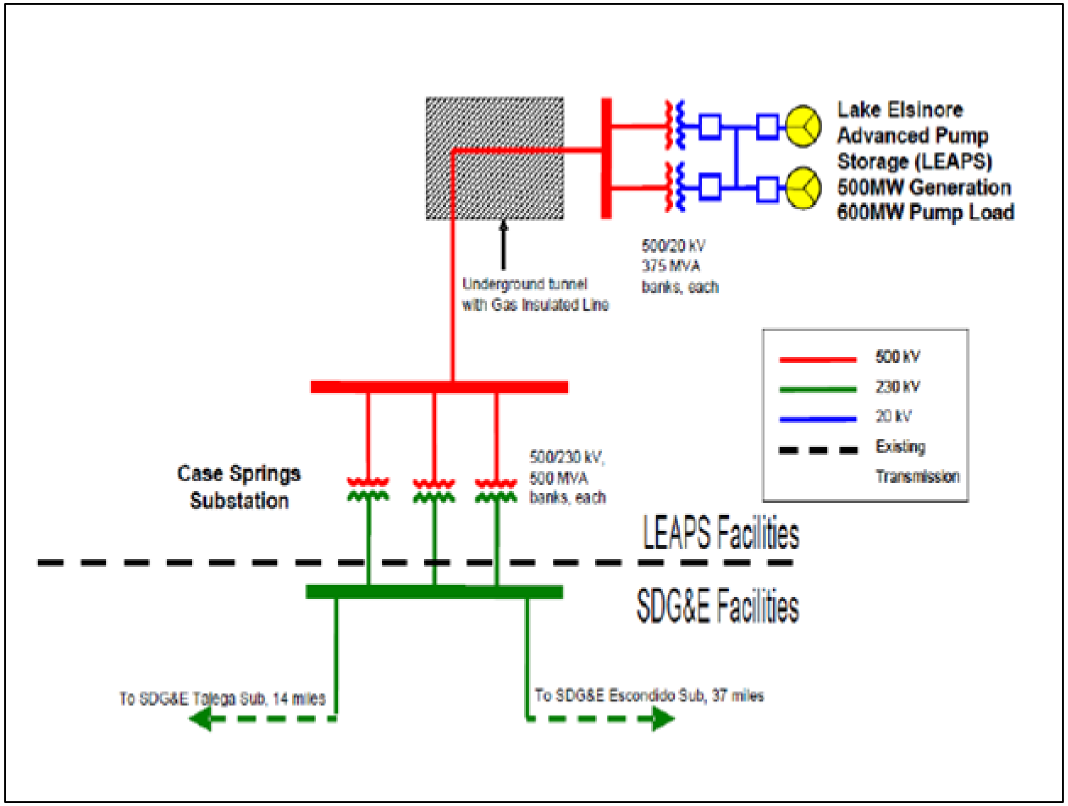
San Diego-Imperial Valley Area Economic Assessment of Lake Elsinore Advanced Pumped Storage Alternative

Alternative:

Option 2:

- This option interconnects the project to SDG&E only: by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation.
- This option has the 500 MW pumped storage
- Cost: $1.76 billion
- Reduction of gas-fired generation to meet the local capacity requirement: 533 MW
- Adverse impact to Western LA Basin LCR:

  0 MW



San Diego-Imperial Valley Area Economic Assessment of Lake Elsinore Advanced Pumped Storage Alternative

	Option 1a		Option 1b		Option 2	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego) (MW)	443		514		533	
Capacity value (per MW-year)	$13,080	$19,080	$13,080	$19,080	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.8	$8.5	$6.7	$9.8	$7.0	$10.2
LCR increase (LA Basin) (MW)	150		0		0	
Capacity value (per MW-year)	$16,680	$22,680	N/A	N/A	N/A	N/A
LCR increase cost ($million)	$2.5	$3.4	0	0	0	0
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2

	Option 1a		Option 1b		Option 2	
Production Cost Modeling Benefits						
Ratepayer Benefits ($million/year)	$4		-$31		-$34	
LEAPS Net Market Revenue ($million/ year)	$0		$73		$73	
Total PCM Benefits ($million/year)	$4		$42		$39	
PV of Prod Cost Savings ($million)	$55.20		$579.63		$538.23	
Local Capacity Benefits						
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$3.3	$5.1	$6.7	$9.8	$7.0	$10.2
PV of LCR Savings ($million)	$45.44	$69.70	$92.78	$135.35	$96.21	$140.35
Capital Cost						
Capital Cost Estimate ($ million)	$829		$2,040		$1,765	
Estimated “Total” Cost (screening) ($million)	$995		$2,448		$2,118	
Benefit to Cost						
PV of Savings ($million)	$100.64	$124.90	$672.42	$714.98	$634.44	$678.58
Estimated “Total” Cost (screening) ($million)	$994.80		$2,448		$2,118	
Benefit to Cost	0.10	0.13	0.27	0.29	0.30	0.32

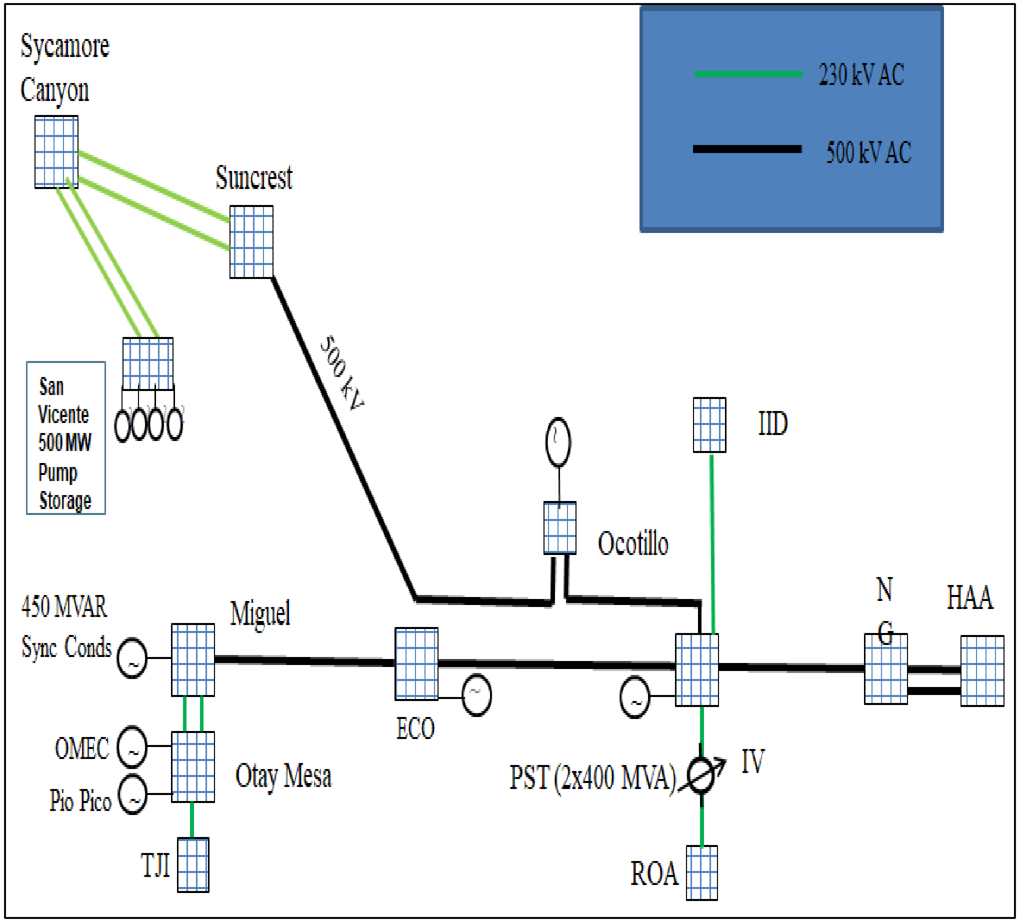
- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

San Diego-Imperial Valley Area Economic Assessment of San Vicente Storage Project Alternative

Alternative:

- The energy storage plant is configured with four individual generating units with a total generating capacity of 500 MW.
- Construct two 230 kV generation tie line circuits extend from the project switchyard to the proposed point of interconnection at Sycamore Canyon 230 kV substation.
- Cost: $1.5 billion to $2 billion
- Reduction of gas-fired generation to meet the local capacity requirement: 690 MW
- Adverse impact to Western LA Basin LCR:

  0 MW



San Diego-Imperial Valley Area Economic Assessment of San Vicente Storage Project Alternative

San Vicente Energy Storage Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	690	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$9.0	$13.2
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$9.0	$13.2

- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

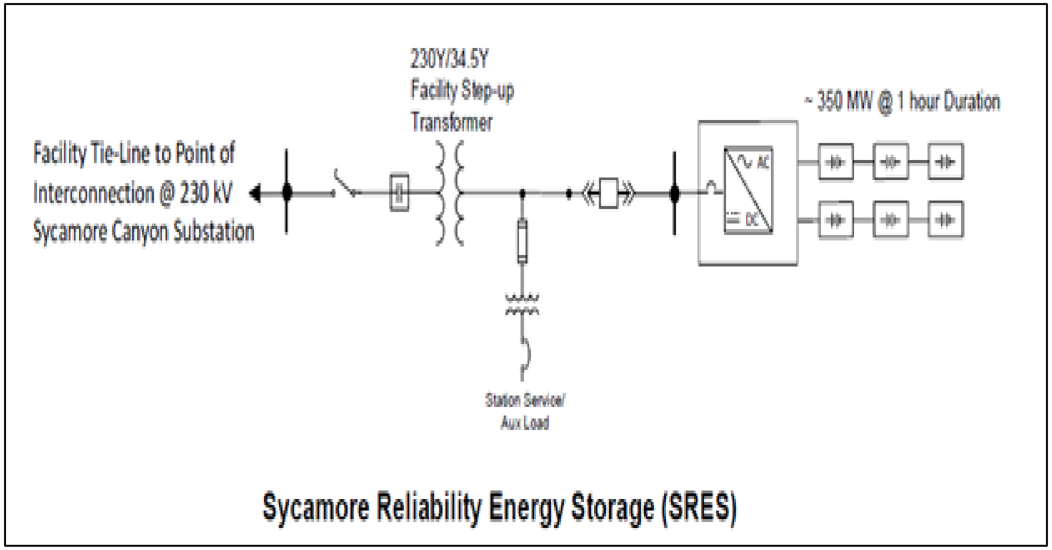
San Vicente Energy Storage Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	-$23	
San Vicente Net Market Revenue ($million/ year)	$54	
Total PCM Benefits ($million/year)	$31	
PV of Prod Cost Savings ($million)	$427.82	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.0	$13.2
PV of LCR Savings ($million)	$124.55	$181.69
Capital Cost		
Capital Cost Estimate ($ million)	$2,000	
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost		
PV of Savings ($million)	$552.38	$609.51
Estimated “Total” Cost (screening) ($million)	$2,600	
Benefit to Cost	0.21	0.23

San Diego-Imperial Valley Area Economic Assessment of Sycamore Reliability Energy Storage Project Alternative

<u>Alternative:</u>

- Construct a 381 MW battery energy storage system (BESS) with one-hour discharge duration. It is noted that for local Resource Adequacy consideration, the resource would need to be available for at least 4 hours.
- Cost: <u>$108 million to $178 million</u> (for 1-hour duration); $548 million (estimated for 4-hour duration)
- Reduction of gas-fired generation to meet the local capacity requirement: <u>391 MW</u>
- Adverse impact to Western LA Basin LCR:

  <u>0 MW</u>



* Tenaska provided 381 MW power flow model

San Diego-Imperial Valley Area Economic Assessment of Sycamore Reliability Energy Storage Project Alternative

	Sycamore Reliability Energy Storage Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	391	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.1	$7.5
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$5.1	$7.5

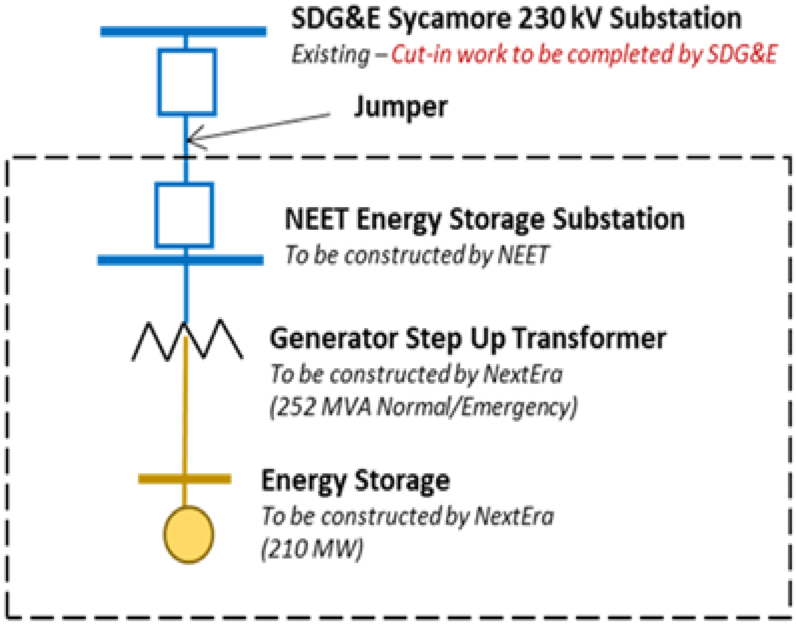
- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

Sycamore Reliability Energy Storage Project				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	-$5			
Sycamore RES Net Market Revenue ($million/ year)	$35			
Total PCM Benefits ($million/ year)	$30			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$5.1		$7.5	
Capital Cost				
Capacity (MW)	381			
Cost Estimate Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$548		$548
Capital Cost $/kW	$1,660	$1,438	$1,660	$1,438
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$130	$150	$130
Benefit to Cost				
Savings ($million/year)	$35	$35	$38	$38
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$150	$130	$150	$130
Benefit to Cost	0.23	0.27	0.25	0.29

San Diego-Imperial Valley Area Economic Assessment of Sycamore 230kV Energy Storage Project Alternative

Alternative:

- Construct a new 230 kV bus outside the existing SDG&E Sycamore 230 kV substation.
- Install a 210 MW energy storage and connect it to the new 230 kV bus outside the SDG&E Sycamore substation.
- Cut in and connect to 230 kV jumper line dead end structures outside of the Sycamore substation.
- Cost: $230 million
- Reduction of gas-fired generation to meet the local capacity requirement: 230 MW
- Adverse impact to Western LA Basin LCR: 0 MW



California ISO

San Diego-Imperial Valley Area Economic Assessment of Sycamore 230kV Energy Storage Project Alternative

	NEET Sycamore 230 kV Energy Storage Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	230	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$3.0	$4.4
LCR increase (LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$3.0	$4.4

NEET Sycamore 230 kV Energy Storage Project				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	-$3			
NEET Sycamore 230 kV Energy Storage Net Market Revenue ($million/ year)	$20			
Total PCM Benefits ($million/ year)	$17			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	210			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$200		$200.0
Capital Cost $/kW	$1,660	$952	$1,660	$952
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost				
Savings ($million/year)	$20	$20	$21	$21
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$83	$47	$83	$47
Benefit to Cost	0.24	0.42	0.26	0.45

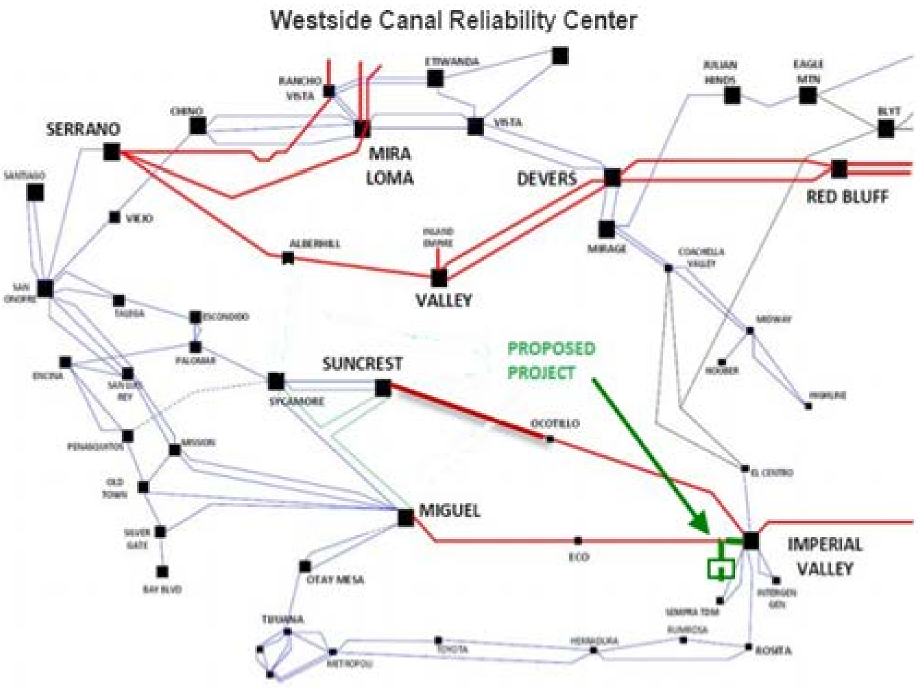
- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

San Diego-Imperial Valley Area Economic Assessment of Westside Canal Reliability Center Project Alternative

Alternative:

- Construct a 268 MW battery energy storage system with 4-hour discharge capability with interconnection to the 230 kV Imperial Valley substation.
- The point of interconnection for the proposed project would be at the 230 kV bus at the Imperial Valley Substation.
- Cost: <u>$304 million</u>
- Reduction of gas-fired generation to meet the local capacity requirement: <u>430 MW</u>
- Adverse impact to Western LA Basin LCR:

  <u>100 MW</u>



San Diego-Imperial Valley Area Economic Assessment of Westside Canal Reliability Center Project Alternative

Westside Canal Reliability Center Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	430	
Capacity value (per MW-year)	$13,080	$19,080
LCR Reduction Benefit ($million)	$5.6	$8.2
LCR increase (LA Basin) (MW)	100	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$1.7	$2.3
Net LCR Saving ($million/year)	$4.0	$5.9

- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the San Diego-Imperial Valley for system reasons is achieved

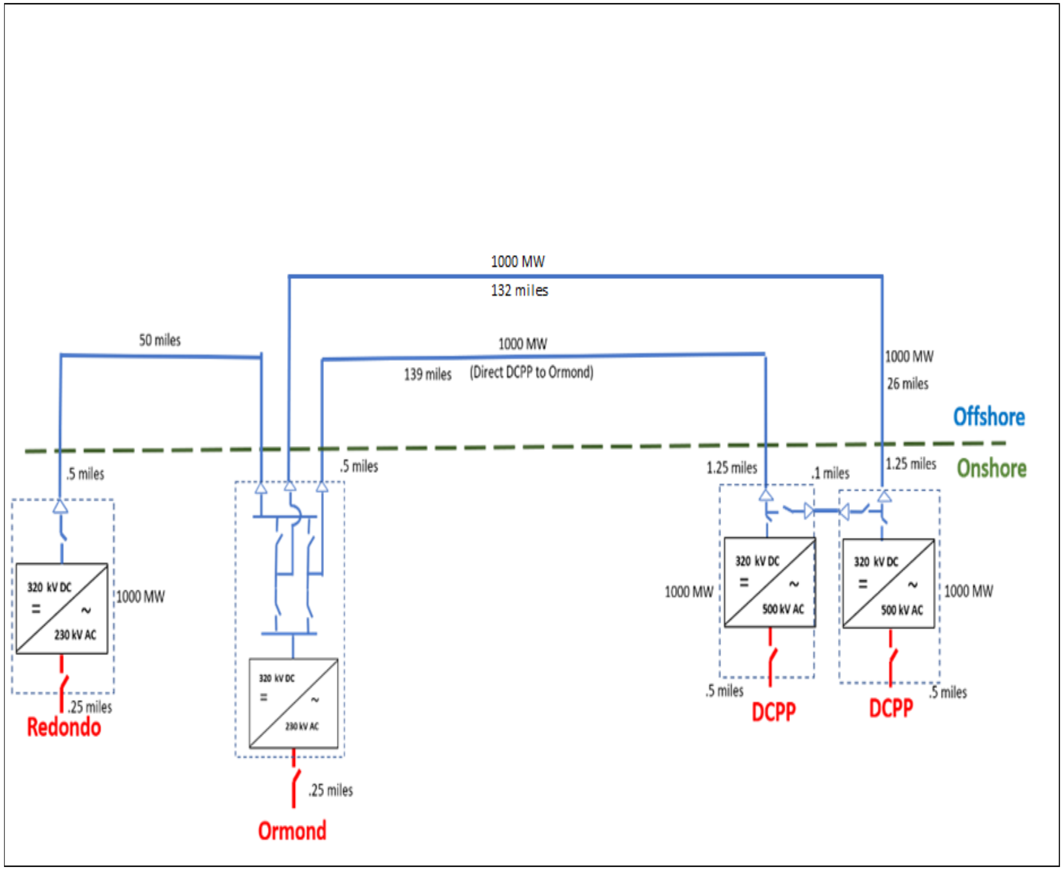
ConEd Renewables Westside Canal Reliability Center				
Production Cost Modeling Benefits				
Ratepayer Benefits ($million/ year)	$5			
Westside Canal Net Market Revenue ($million/ year)	$24			
Total PCM Benefits ($million/ year)	$29			
Local Capacity Benefits				
Basis for capacity benefit calculation	Local versus System Capacity		Local versus SP 26	
Net LCR Saving ($million/year)	$3		$4	
Capital Cost				
Capacity (MW)	268			
Capital Cost Source	Lazard [Note 1]	Proponent Provided [Note 2]	Lazard	Proponent Provided
Capital Cost ($ million)		$304		$304.0
Capital Cost $/kW	$1,660	$1,134	$1,660	$1,134
Levelized Fixed Cost ($/kW-year)	$394		$394	
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost				
Savings ($million/year)	$32	$32	$33	$33
Estimated Levelized Fixed Cost (screening) ($million/year) Note 3	$106	$72	$106	$72
Benefit to Cost	0.30	0.44	0.32	0.46

California ISO

Western LA Basin Sub-area (LA Basin Area) Economic Assessment of California Transmission Project Alternative

<u>Alternative:</u>

- This project is also known as Diablo Canyon to Ormond Beach and Redondo Beach
- The converters include Voltage Source Converters at Diablo Canyon, Ormond Beach and Redondo Beach
- The submarine cable system will consist of two 320kV HVDC segments (1000 MW each) between Diablo Canyon and Ormond Beach and one 1000 MW segment between Ormond Beach and Redondo Beach
- Cost: <u>$1.83 billion</u>
- Assumed potential reduction of gas-fired generation to meet the local capacity requirement in the LA Basin: <u>1000 MW</u> (preliminary estimates)
- There is also a potential 300 MW gas fired LCR reduction in the Big Creek/Ventura area.
- Western LA Basin sub-area and Big Creek/Ventura area were not selected for examining alternatives for LCR reduction in this planning cycle; the LA Basin area was studied in conjunction with the CPUC LTPP proceedings in previous planning cycles. The BC/Ventura area only relies on about 300 MW of gas generation.



Western LA Basin Sub-area (LA Basin Area) Economic Assessment of California Transmission Project Alternative

	California Transmission Project	
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Western LA Basin) (MW)	1000	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$16.7	$22.7
LCR increase (San Diego – IV) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	$16.7	$22.7

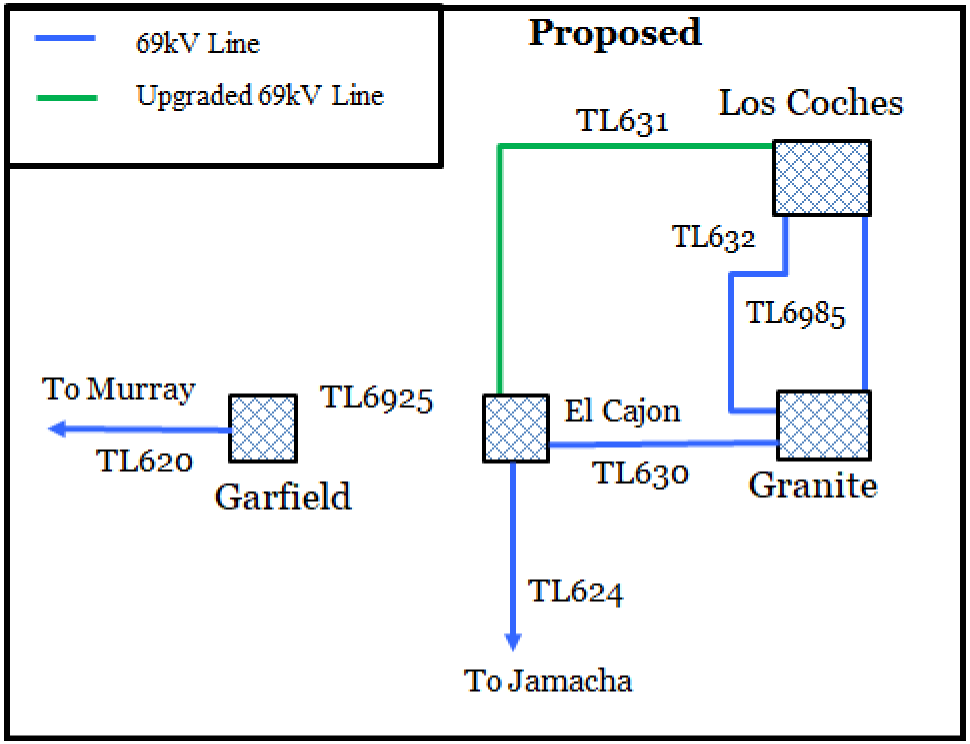
- Production cost benefits plus differential of local versus system or local versus South of Path 26 do not support alternative
- Further consideration may be given in future planning cycles once greater clarity on the need to retain gas-fired generation in the Western LA Basin sub-area for system reasons is achieved

California Transmission Project		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/year)	$3	
Proposed Project Net Market Revenue ($million/year)	$0	
Total PCM Benefits ($million/year)	$3	
PV of Prod Cost Savings ($million)	$39	
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$16.7	$22.7
PV of LCR Savings ($million)	$230.2	$313.0
Capital Cost		
Capital Cost Estimate ($ million)	$1,830	
Estimated “Total” Cost (screening) ($million)	$2,379	
Benefit to Cost		
PV of Savings ($million)	$269.6	$352.4
Estimated “Total” Cost (screening) ($million)	$2,379	
Benefit to Cost	0.11	0.15

San Diego Non-Bulk Area Economic Assessment of El Cajon Sub-area LCR Reduction Alternative

Alternative:

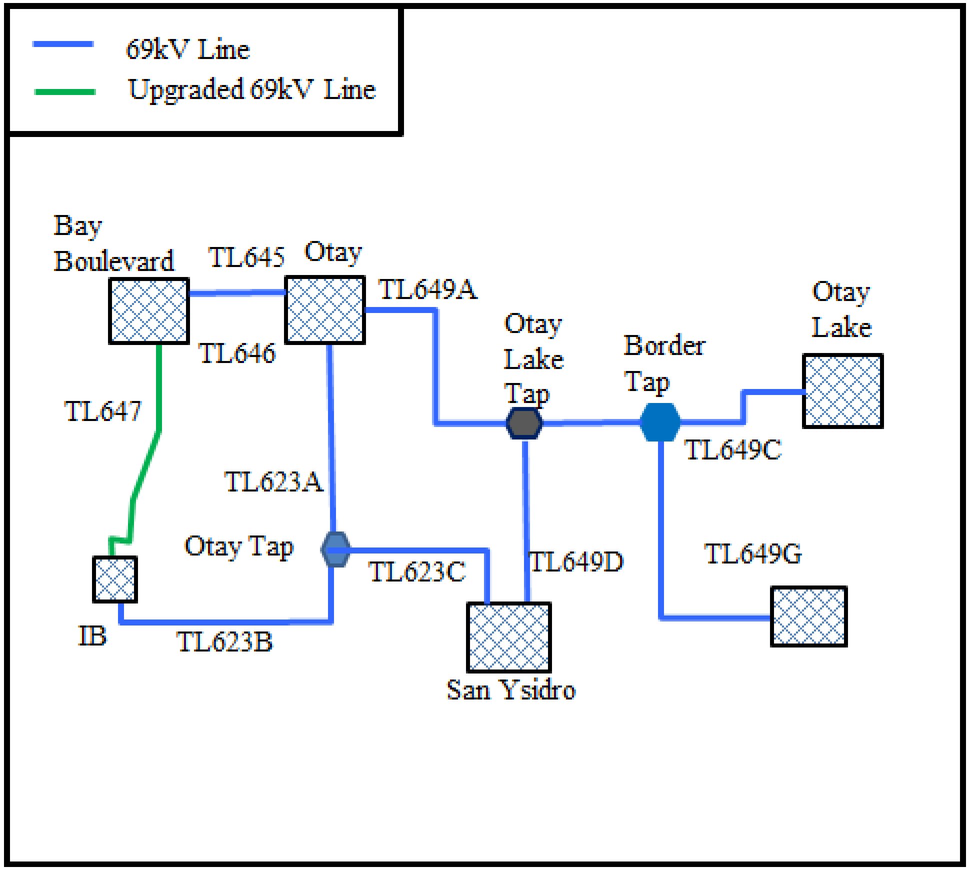
- Upgrade TL631 to a minimum continuous rating of 77 MVA
- Cost: $28 million - $43 million
- Potential reduction of gas-fired generation to meet the local capacity requirement: 76 MW
- Since the El Cajon sub-area is within the overall San Diego-Imperial Valley LCR area, reducing LCR need in the sub-area will also trigger the need to reduce the overall LCR need.
- Adding the lowest cost of reducing LCR need for overall area (i.e., S-line series reactor) to the cost of El Cajon LCR reduction alternative would exceed the estimated benefits for LCR reduction for the overall area.
- Without a broader strategy to reduce local capacity requirements in the Imperial Valley/San Diego area, it is not economic to proceed unilaterally on the proposed project.



San Diego Non-Bulk Area Economic Assessment of Border Sub-area LCR Reduction Alternative

Alternative:

- Upgrade TL647 to a minimum continuous rating of 110 MVAA
- Cost: $6 million - $10 million
- Potential reduction of gas-fired generation to meet the local capacity requirement: 52 MW
- Since the Border sub-area is within the overall San Diego-Imperial Valley LCR area, reducing LCR need in the sub-area will also trigger the need to reduce the overall LCR need.
- Adding the lowest cost of reducing LCR need for overall area (i.e., S-line series reactor) to the cost of El Cajon LCR reduction alternative would exceed the estimated benefits for LCR reduction for the overall area.
- Without a broader strategy to reduce local capacity requirements in the Imperial Valley/San Diego area, it is not economic to proceed unilaterally on the proposed project.



Summary of Economic Assessments of Proposed Alternatives for Gas-Fired LCR Reduction in the Southern Area

Congestion or study area	Benefits Consideration	Economic Justification
California Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Mira Loma Dynamic Reactive Support	Local capacity benefits not sufficient	No
Red Bluff – Mira Loma 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Southern California Regional LCR Reduction Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
S-Line Series Reactor	Production cost benefits sufficient, needs further assessment when S-Line Upgrade configuration is finalized	No
HVDC Conversion	Production cost ratepayer benefits and local capacity benefits not sufficient	No
North Gila – Imperial Valley #2 500 kV Transmission Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Alberhill to Sycamore 500 kV plus Miguel to Sycamore loop into Suncrest 230 kV Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Lake Elsinore Advanced Pumped Storage (LEAPS) Project (2 options)	Production cost ratepayer benefits and local capacity benefits not sufficient	No
San Vicente Energy Storage Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore Reliability Energy Storage (SRES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Sycamore 230 kV Energy Storage (SES) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
Westside Canal Reliability Center (Westside) Project	Production cost ratepayer benefits and local capacity benefits not sufficient	No
El Cajon Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No
Border Sub-area Local Capacity Requirement Reduction Project	Local capacity benefits not sufficient – broader San Diego sub-area plan required	No

Interregional Transmission Coordination

Gary DeShazo
Director Regional Coordination, Infrastructure Development

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

From last year's plan to this year's plan a final alignment with the ISO's Order 1000 tariff is in place

- Previous plans included "special studies" which considered Interregional Transmission Projects in a context beyond what the ISO's tariff requires
- The results of those studies were finalized in last year's plan and provided useful information for California's RPS initiatives
- In this year's plan the ISO has considered and documented its assessment of the proposed ITPs as per the defined processes specified in the ISO tariff
- Chapter 5 has been added to provide transparency on how the ISO considers ITPs in its planning process

Order 1000 requirements are embodied in the WPR’s common tariff for interregional coordination (IC)

- ***Establish a process***
  - Interregional Coordination and ITP Evaluation Schedule
  - ITP Project Submittal Information
- ***Develop a formal procedure***
  - Biennial “open window” for ITP submittals
  - Relevant Planning Regions develop ITP Coordination Plans
- ***An agreement***
  - Annual IC stakeholder meeting is held to share regional transmission plans and seek stakeholder input
- ***A website or e-mail list***
  - Each WPR developed its own website to provide stakeholder access to and share IC information
  - WPRs coordinate information that is “shared” on their websites

All WPRs are consistent in how they address ITPs within their Order 1000 regional processes

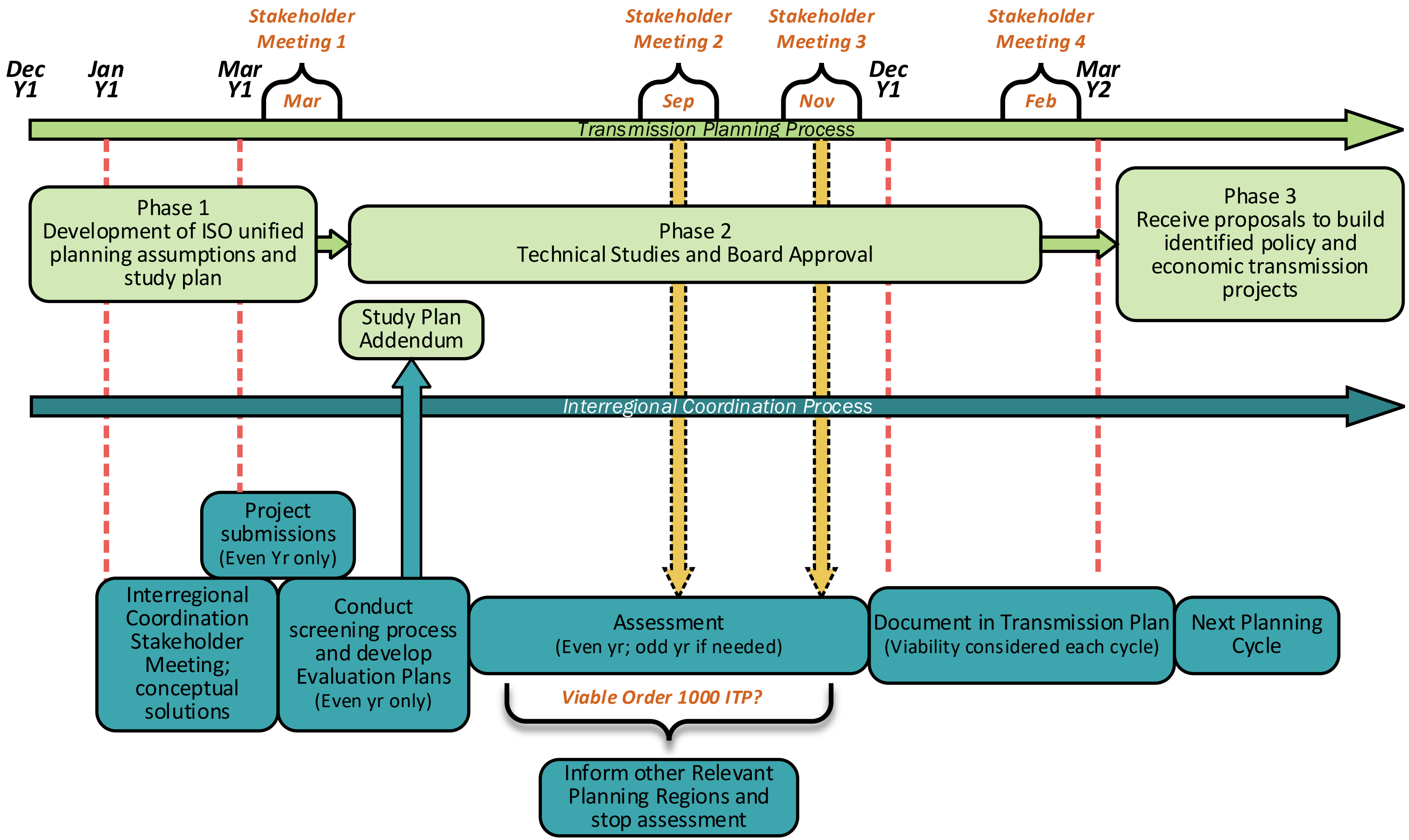
- The ITP must electrically interconnect at least two Order 1000 planning regions
- While an ITP may connect two Order 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO’s transmission planning process
- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region
- Without regard to a request for cost allocation, when a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess the ITP

Cost allocation is not necessary for one or more planning regions to consider an ITP within it regional process

- The assessment of an ITP in a WPR's regional process continues until a conclusion on regional need is reached
- If a regional need is not found, no further assessment of the ITP by that Relevant Planning Region is required
- Consideration by at least two Relevant Planning Regions is required for an ITP to be considered for interregional cost allocation purposes
- Otherwise, the ITP will no longer be considered within the context of interregional cost allocation
- One or more planning regions may consider an ITP within its regional process even though it is not on the path of cost allocation
  - Planning region(s) will continue some level of continued cooperation with other planning regions and with WECC
  - Applicable WECC processes will be followed to ensure all regional impacts are considered

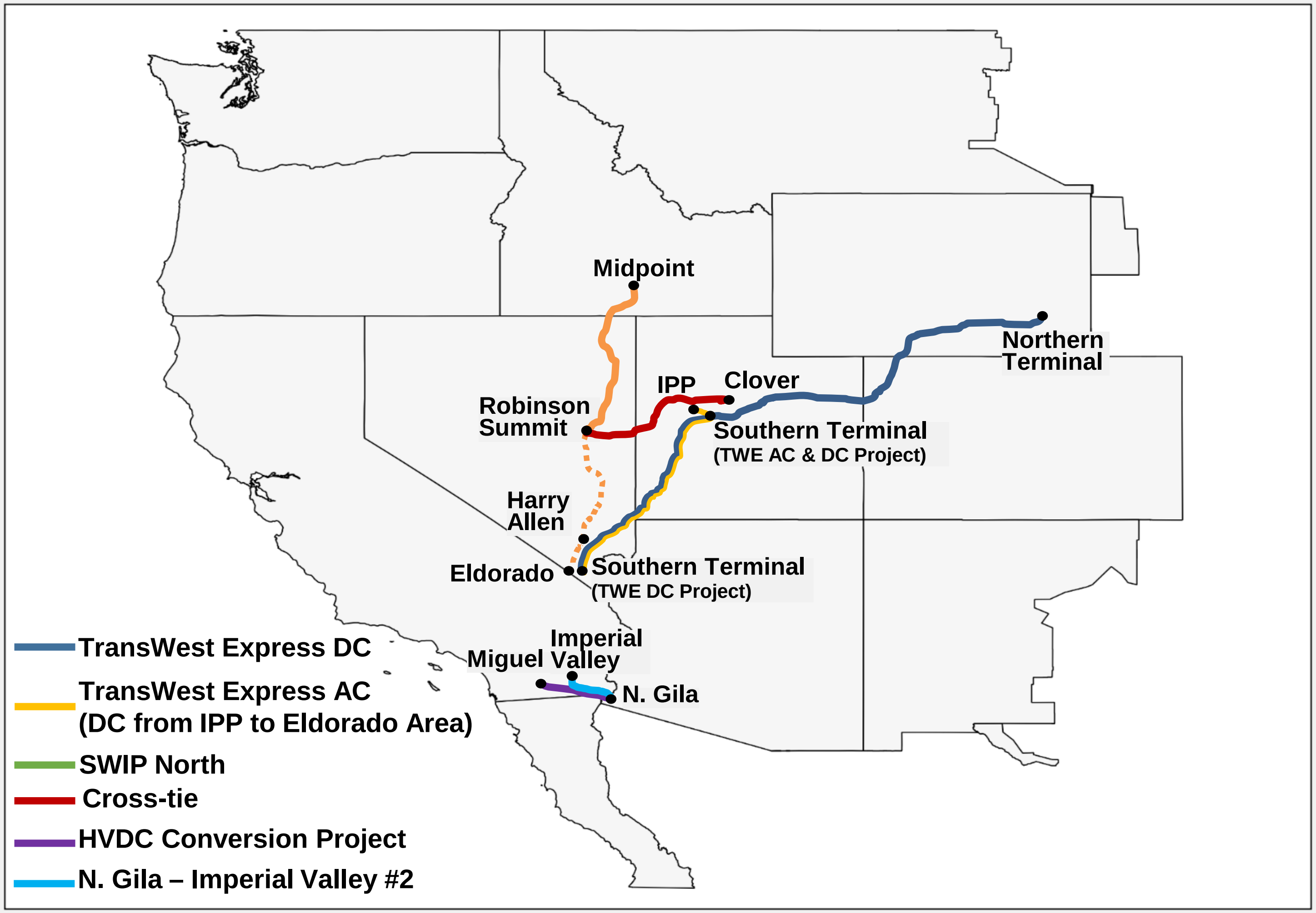
The ISO considers an ITP through its transmission planning process, taking up to 2 years to complete

A general representation of the ISO's Order 1000 process



California ISO

Proposed Interregional Transmission Projects
2018-2019 Interregional Coordination Cycle



Summary of the ISO's consideration of the 2018-2019 ITP submittals

Proposed ITP	Sponsor Identified Need	Cost Allocation	ISO Identified Need in this Planning Cycle
HVDC Conversion	Improve/remove existing reliability limitation; decrease San Diego and greater IV/San Diego LCR requirement	Not Requested	Reliability: None Economic: None - BCR less than 1.0
NG-IV#2	Decrease San Diego and greater IV/San Diego LCR requirement	ISO, WestConnect	Reliability: None Economic: None - BCR less than 1.0
SWIP - North	Economic, policy, reliability, reduce congestion on COI, facilitate access to renewables in PacifiCorp	ISO, NTTG, WestConnect	Reliability: None Economic: None - BCR less than 1.0
Cross-Tie	Strengthen interconnection between PacifiCorp and Nevada; facilitate California's RPS and GHG needs	ISO, NTTG, WestConnect	None: Based on 2018-2019 plan assumptions
TransWest Express AC/DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions
TransWest Express DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions

California ISO

Pacific Northwest – California Transfer Increase Informational Special Study

Ebrahim Rahimi
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2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

Background, Objective, Scope :

- CEC and CPUC issued a letter to CAISO* requesting evaluation of options to increase transfer of low carbon electricity between the Pacific Northwest and California

- Study scope:

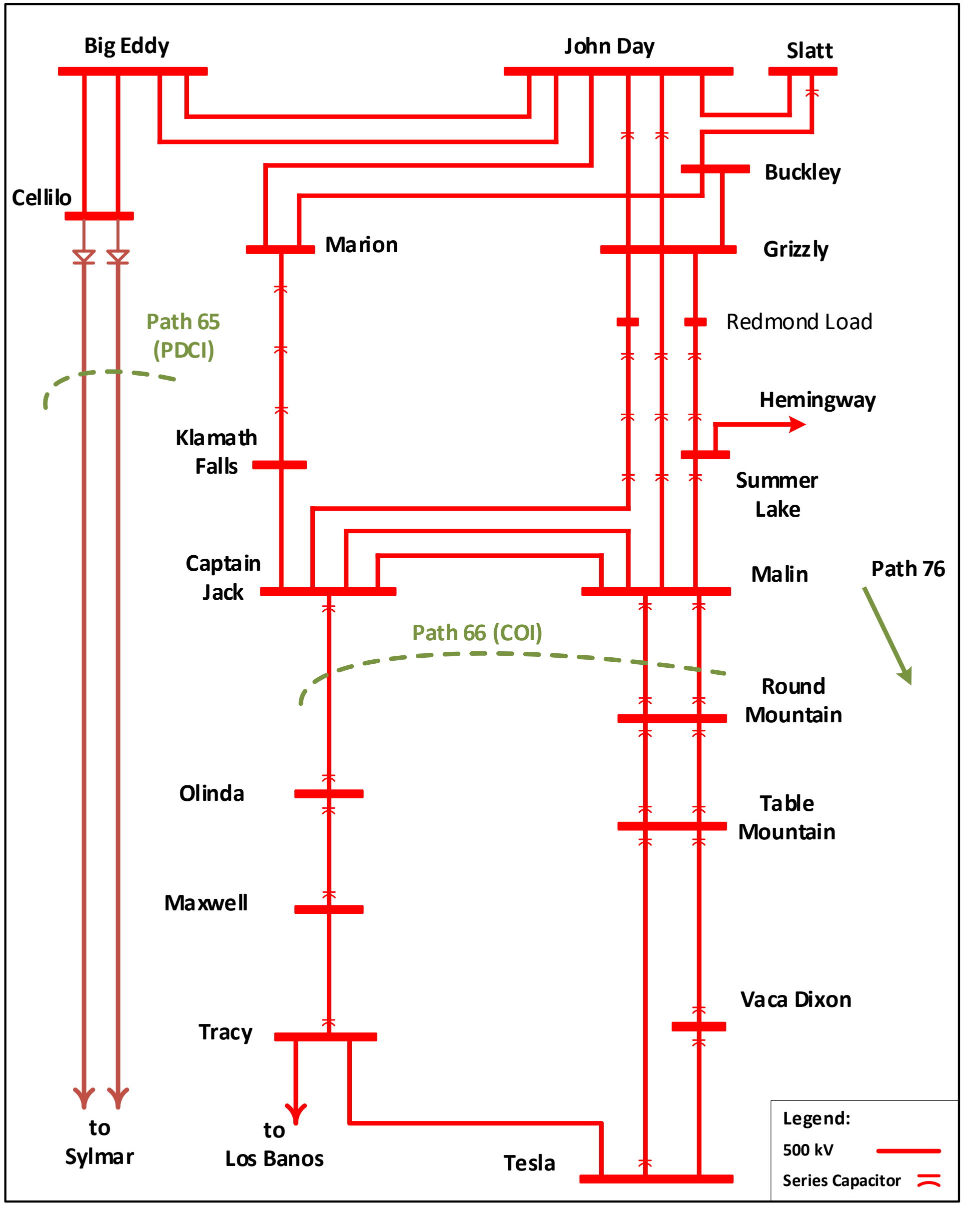
  1. Increase transfer capacity of AC and DC interties
  2. Increase dynamic transfer limit (DTC) on COI
  3. Implementing sub-hourly scheduling on PDCI
  4. Assigning RA value to firm zero-carbon imports or transfers

* http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf

1. Increase transfer capacity of AC and DC interties

AC and DC Interties

WECC Path	WECC Path Rating	Operational Limits
PDCI (Path 65)	3,220 MW north to south and 3,100 MW south to north direction	3,210 MW north to south and 1,000 MW south to north direction
COI (Path 66) (California-Oregon Intertie)	4,800 MW north to south and 3,675 MW south to north direction	COI nomogram in the north to south and 3,675 MW in the south to north direction



California ISO

Study Scenarios

Flow Direction	Transfer Objective	Near-term (2023)			Long-term (2028)
		Scenario Description	COI Flow (MW)	PDCI Flow (MW)	Study objective
North to South	Energy Transfer	Late afternoon in the Summer with load almost at peak. Import from PNW to serve load in California.	5,100	3,210	Performed production cost simulation using the WECC ADS case and the updated PNW hydro model received from NWPCC to estimate COI and PDCI congestions under high, medium, and low hydro condition.
	Resource Shaping	Late afternoon in the Spring with load around 60% of peak. Import from PNW to help with the evening ramp in California.	5,100	3,210	
South to North	Resource Shaping	Mid-day in the Spring. Export surplus solar in California to the PNW in anticipation of importing from PNW to help with the evening ramp	3,625	1,500 [1]	
	Energy Transfer	Late afternoon in the Fall. Export solar in Californian to serve load in PNW	2,500-3,600	1000-1500	

[1] PDCI is operationally limited to 1,000 MW in the south to north direction.

COI North to South Path Rating

- Current Path Rating is 4800 MW
- Limiting contingency is N-2 of two 500 kV line of adjacent circuits not on a common tower
  - WECC Regional Criteria used to treat adjacent 500 kV lines (250 feet separation or less) as P7 contingency
  - WECC Path Rating process currently treats as P7
  - NERC TPL-001-4 considers it as an Extreme Event

- Assessment considered treatment as P7 contingency as well as P6 contingency to assess potential COI capability
  - ISO Operations treating the contingency as a conditionally credible contingency

Study Conclusions (1/2)

- With contingency of adjacent 500 kV circuits as always credible, COI limit will remain 4,800 MW

- With conditionally credible contingencies, COI limit could increase to 5,100 MW.

- WECC path rating process is currently considers adjacent circuits as always credible contingency. The WECC process is currently under review.

- PDCI could be dispatched at 1,500 MW or higher in the south to north direction under certain scenarios.
  - Limiting conditions is the simultaneous trip of Adelanto-Toluca and Victorville-Rinaldi 500 kV lines overloading Rinaldi 500/230 kV transformer.
  - Real time data shows that the PDCI south to north flow are becoming more common and recently are hitting the maximum operation limit of 1,000 MW.

Study Conclusions (2/2)

- Long-term production cost simulation results identified COI congestion in all hydro scenarios.

- By increasing COI rating to 5,100 MW, the congested hours decrease by 106 hours in the medium hydro scenario and reduces the congestion cost by $1.9M.

- With PDCI at WECC path rating, no congestion was identified on PDCI even without enforcing the ISO export limit.

- With PDCI limited to 1,000 MW in the south to north direction there would be 82 hours with congestion on PDCI. This also increases the Path 26 congestion by 31 hours.
  - If the ISO net export limit is not enforced, PDCI congested hours will increase from 82 hours to 388 hours.

Next steps

- The potential to increase the current WECC Path Rating of the COI from 4800 MW to 5100 MW without any material transmission upgrades has been identified as a potential option. The increase in path rating could be achieved through changes to the criteria that was used to establish the current Path Rating. With this, initiate a WECC path rating process to increase COI rating to 5,100 MW upon completion of the WECC Path Rating Process review and if the revised process recognizes the concept of conditionally credible contingency.

- Recommend updates to WECC Anchor Data Set (ADS) to update the hydro generation profiles.

- LADWP is performing an engineering and planning study to identify the system upgrades required to increase the PDCI transfer capability from 3,220 MW to 3,800 MW. The study is expected to be completed by the end of Q3, 2019.

2. Increase dynamic transfer limit (DTC) on COI

Increase Dynamic Transfer Capability (DTC) on COI

- DTC is a 5-minute scheduling added to normal 15-minute scheduling on COI. DTC limit is currently at 600 MW. Voltage stability, manual RAS arming, and excessive voltage fluctuations were potential limiting factors.

- Voltage stability issue is resolved as of 12/1/2018. With automation of RAS arming targeted for 2020, excessive voltage fluctuation will be the limiting factor to increase DTC beyond 600 MW.

- BPA's DTC Roadmap* details studies and mitigation measures to address voltage fluctuation issues.
  - Employ Real-time Allocation of DTC,
  - Apply DTC Limit to Actuals (instead of schedules)
  - Use DTC Nomogram Instead of a Fixed Limit.
  - Real-Time Voltage Assessment Tools
  - Coordinated Voltage Controls (CVC)
  - Control State Awareness and Analytics

* http://www.caiso.com/Documents/AppendixH-Draft2018-2019TransmissionPlan.pdf (Attachment 1)

3. Implementing sub-hourly scheduling on PDCI

Sub-hourly Scheduling on PDCI

- Currently there are no sub-hourly scheduling on PDCI

- BPA performed initial system impact studies of PDCI dynamic transfers on the Pacific Northwest system. The studies indicated increased switching of power factor correction capacitors at BPA and LADWP substations.

- A joint BPA/LADWP project was initiated in January 2019 and the current target is to implement the sub-hourly scheduling on PDCI by the end of 2020 timeframe.

- BPA/LADWP will perform the required studies including system impact assessment of simultaneous COI and PDCI 5-minute scheduling, to facilitate the implementation of the project.

4. Assigning RA value to firm zero-carbon imports

RA procurement process

- As part of Maximum Import Capability (MIC) process, the ISO calculates MIC on all branch groups (BG) based on the historical hour-ahead scheduled import on the BGs.

- The MIC calculation is done annually, using the historical data on hour-ahead scheduled import during peak load over the two prior years.

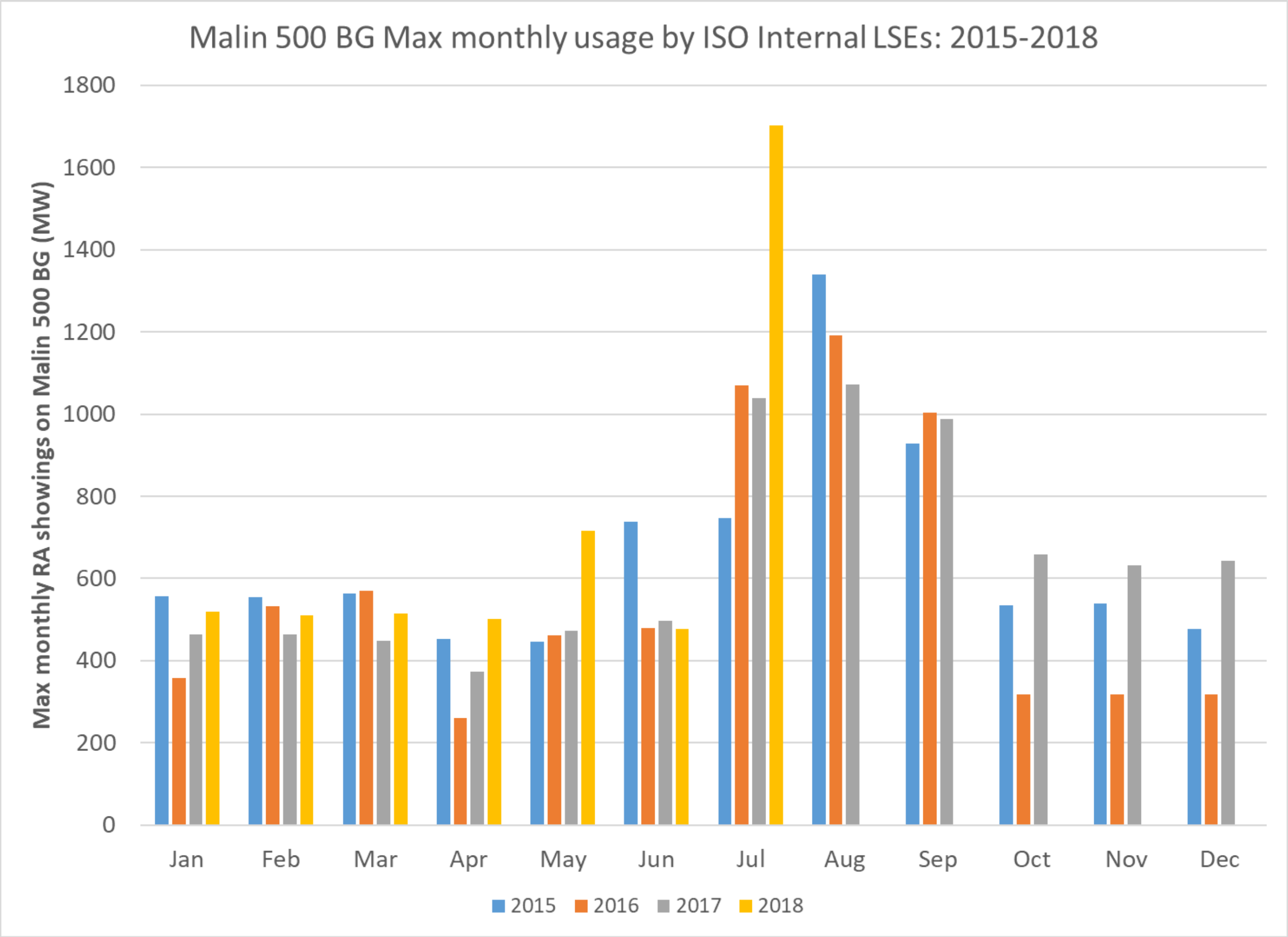
- It is possible that some of the allocated MIC to a BG should be reserved for entities outside the ISO through Existing Transmission Contracts (ETCs) and Transmission Ownership Rights (TORs).

- The remaining capacity will be available to internal ISO Load Serving Entities (LSEs) to procure RA resources:

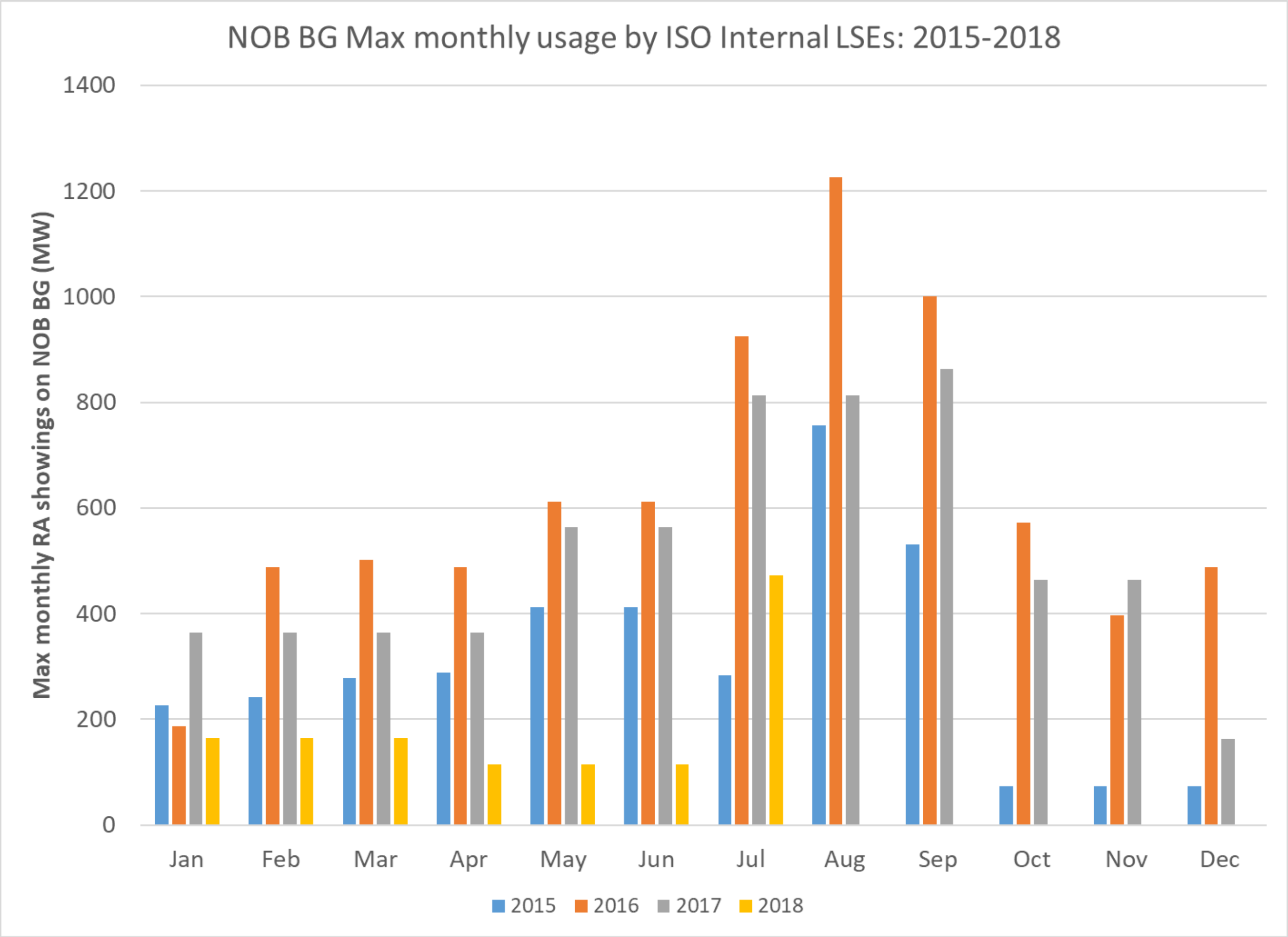
  Available Capacity for RA = MIC – TOR – ETC

- Average available capacity on Malin 500 (2/3 of COI) and Nevada-Oregon Border (NOB) (PDCI) branch groups in recent years are around 2,000 MW and 1,400 MW respectively.

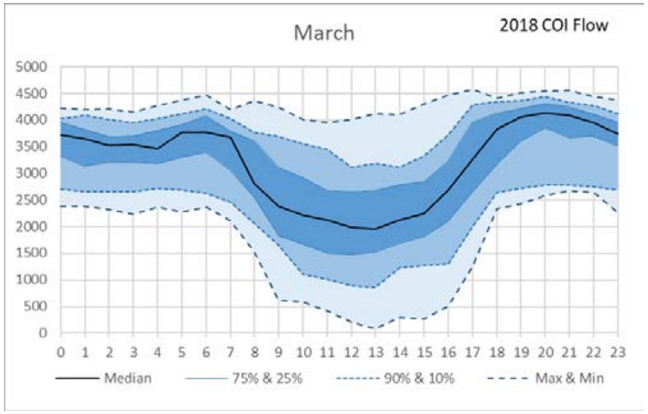
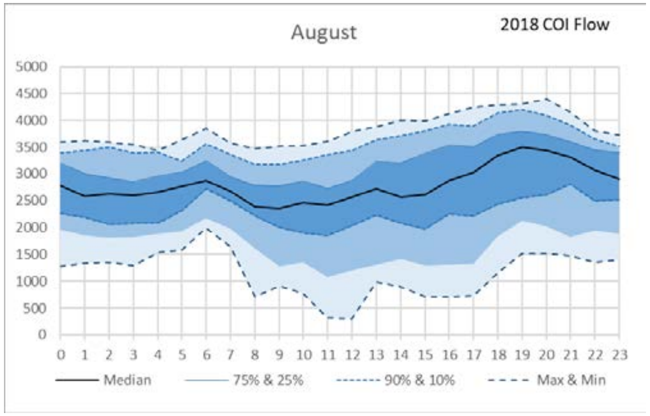
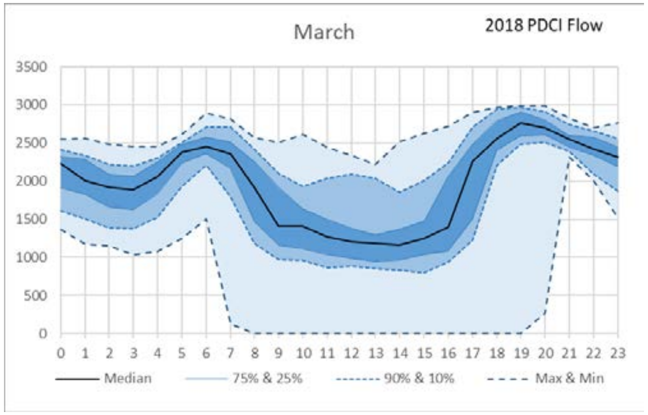
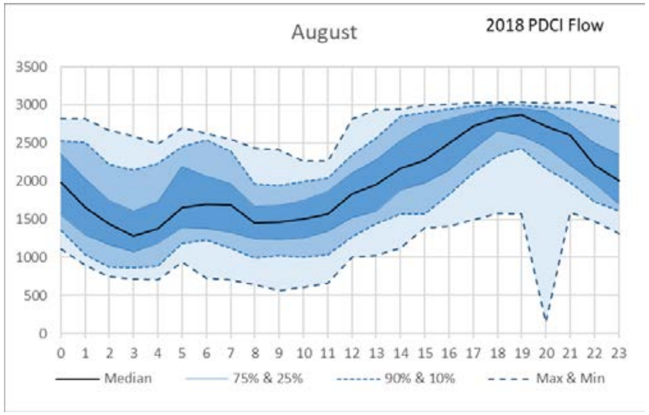
Historical RA showings on Malin 500 BG (COI)



Historical RA showings on NOB BG (PDCI)



COI and PDCI Flows – March and August 2018

	March	August
COI		
PDCI		

RA Assessment Summary

- Historically, except for summer months, the RA showings are less than capacity

- Historical Real Time flows on COI and PDCI indicate high flows close to capacity even if the RA showings are low.

- Due to the potential early retirement of coal units, load growth or a shift to more renewable integration in the Pacific Northwest, there are uncertainty on the amount of available capacity and energy, increasing or decreasing, in the NW which can be exported to California in the longer term.

- The ISO's resource adequacy enhancement stakeholder initiative or the CPUC's integrated resource plan and resource adequacy proceedings may address some of the uncertainties of the Pacific Northwest resources to supply load in California in the long term.

Overall Summary and Conclusions

- The ISO will continue to monitor and participate in the WECC path rating process review.
- If the updated WECC path rating process includes the concept of using the conditionally credible contingency of the adjacent 500 kV lines in the same right-of-way on separate towers, the ISO will work with the owners of the COI facilities to initiate a WECC path rating process to increase the rating of COI to 5,100 MW.
- The ISO will also continue to monitor the progress of LADWP on the identified further study work of PDCI and BPA on the dynamic transfer capability and implementing sub-hourly scheduling on PDCI.
- Through participation in the WECC ADS process, the ISO will work with other members to ensure latest hydro models are utilized in the production cost simulation model.
- To ensure availability of Pacific Northwest resources to supply load in California in the long term, some market or policy initiatives and regulations may be required. Details of such market structures, policies or regulations were beyond the scope of this study.
- Stakeholders are encouraged to participate in the ISO's RA enhancement initiative that includes a review of the MIC process and the CPUC's ongoing RA and IRP proceedings.

System Capacity Requirements and Large Storage System Benefits – Special Studies

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2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

About the two special studies

- System-wide capacity requirements:
  - Examines the need for capacity to maintain the reliability of the ISO system
  - Focuses on the retirement of thermal resources
- System-wide benefits by large energy storage projects
  - Provide useful insights in to the benefits provided by large storage on a system basis
- Plexos modeling supplements the transmission planning studies and provide a broader perspective to stakeholders

Modeling Approaches and Common Assumptions of the Special Studies

Modeling approaches of the special studies

- Using both deterministic and stochastic production cost modeling for the assessment
  - Deterministic simulations produce detail results for deep-diving analyses
  - Stochastic simulations examine a wide variety of system conditions and report the likelihood of capacity shortages

Modeling approaches of the special studies (cont.)

- Model simulations
  - Chronological simulations in hourly interval for the whole year of 2030
  - Deterministic model simulation for one iteration
  - Stochastic model simulations for 500 iterations

Reliability metrics for stochastic simulations

- Use the same metrics as defined in the IRP ALJ ruling*
  - A loss of load (LOL) event: a day with insufficient capacity to meet the sum of load and requirements for regulation, frequency response, and spinning reserve for at least one hour
  - Loss of load expectation (LOLE) criterion: the average of LOL events of all iterations of full-year simulations should be no higher than 0.1 (day/year)
  - For 500 iterations (500 years), up to 50 LOL events are allowed to meet the LOLE criterion

* Administrative Law Judge Ruling Directing Production Cost Modeling Requirements, September 23, 2016 (http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451199)

Common assumptions of the special studies

- Key inputs of the models
  - Energy Commission (CEC) Integrated Energy Policy Report (IEPR) Mid Demand case load forecast
  - Resources in CAISO from the CPUC Integrated Resource Plan (IRP) Hybrid Conforming Portfolio (HCP)
  - WECC ADS PCM dataset for non-CAISO regions

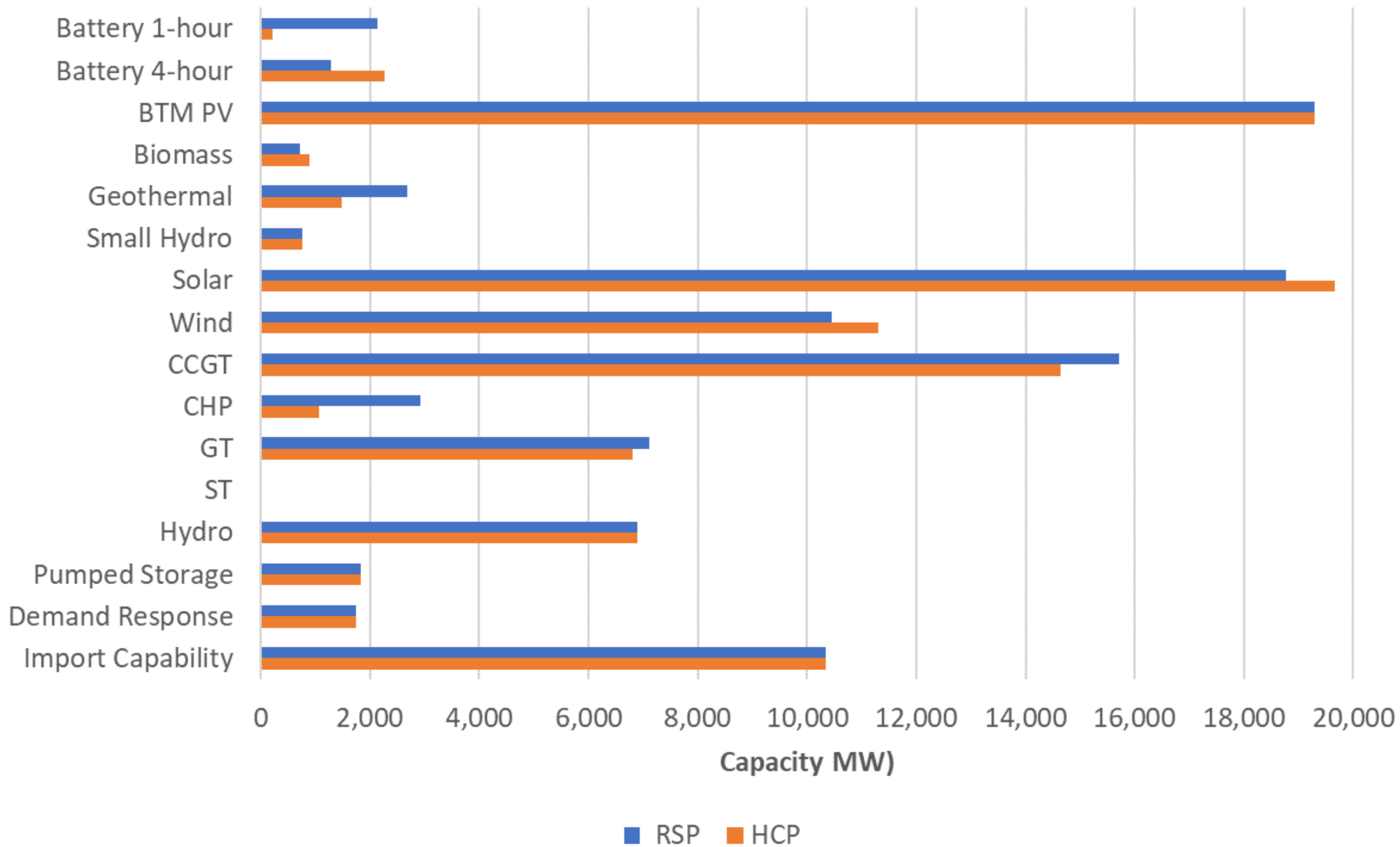
Changes of resource portfolio from Reference System Plan (RSP) to HCP

	RESOLVE	CAISO Plexos Model		
Capacity (MW)	**RSP**	**RSP**	**HCP**	**Change**
Battery	**3,429**	**3,429**	**2,480**	**-949**
1-hour	2,144	2,144	217	-1,927
4-hour	1,285	1,285	2,263	978
BTM PV	**19,992**	**19,295**	**19,295**	**0**
Renewable	**33,084**	**33,381**	**34,094**	**714**
Biomass	725	725	888	163
Geothermal	2,683	2,683	1,487	-1,197
Small Hydro	466	763	763	0
Solar	18,767	18,767	19,658	891
Wind	10,443	10,443	11,299	856
Thermal	**27,562**	**25,770**	**22,543**	**-3,227**
CCGT		15,720	14,642	-1,078
CHP	1,685	2,932	1,078	-1,854
GT		7,108	6,813	-295
ST		10	10	0
Gas	25,877			
Hydro	**7,844**	**6,890**	**6,890**	**0**
Pumped Storage	**1,832**	**1,831**	**1,831**	**0**
Demand Response	**1,752**	**1,752**	**1,752**	**0**
Net Import Limit	**10,068**	**10,341**	**10,341**	**0**

Notes:

- HCP battery has longer duration, but less capacity than RSP
- BTM PV capacity difference from RESOLVE is due to the shapes used to develop the profiles
- HCP has 714 MW more renewable capacity, but 5,649 GWh less renewable energy than RSP
- Geothermal capacity has 100% base load capacity factor
- Plexos thermal is based on Rated Capacity instead of Installed Capacity
- Thermal is after the retirement of all OTC and nuclear resources
- Demand Response availability varies over time

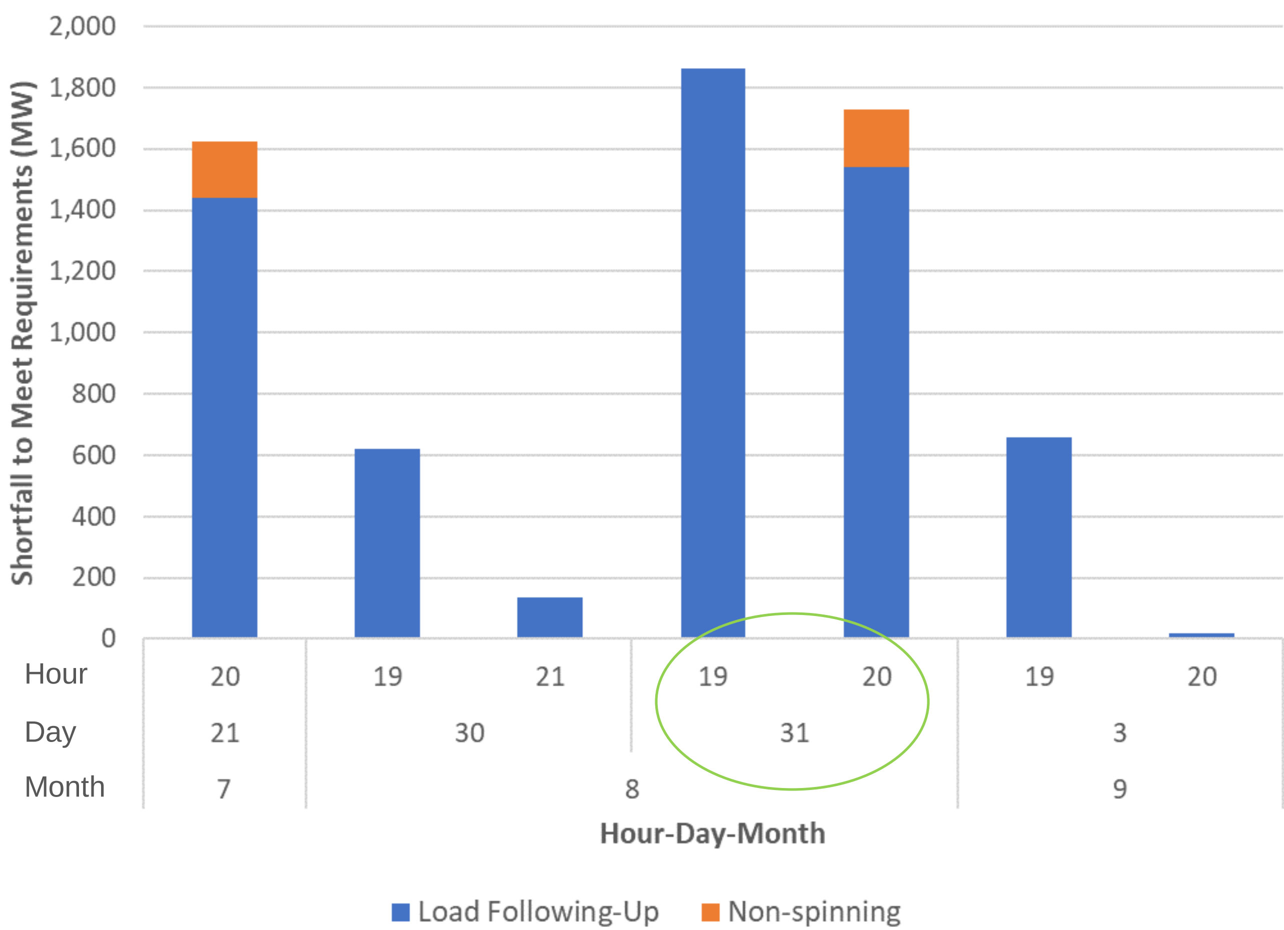
Comparison of resource portfolios of Reference System Plan (RSP) and HCP



California ISO

System-wide Capacity Requirement Study

CAISO supply is insufficient in the HCP case.



Capacity Changes (MW)	
Battery	**-949**
1-hour	-1,927
4-hour	978
BTM PV	**0**
Renewable	**714**
Biomass	163
Geothermal	-1,197
Small Hydro	0
Solar	891
Wind	856
Thermal	**-3,227**
CCGT	-1,078
CHP	-1,854
GT	-295

CAISO hourly load and generation balance of the HCP case on August 31, 2030

Hour	Load (MW)	Generation (MW)											Net Import (MW)	Reserve Shortfall	
		Total Generation	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage		Load Following-Up	NonSpin Reserve
1	32,447	22,227	0	6,683	616	0	335	6,894	84	5,252	0	2,363	10,221	0	0
2	30,705	20,510	0	6,096	590	0	335	6,894	0	5,231	0	1,363	10,195	0	0
3	29,396	19,055	0	6,027	590	0	335	6,894	0	5,205	0	4	10,341	0	0
4	28,802	19,006	0	6,055	573	0	335	6,894	0	5,149	0	0	9,796	0	0
5	28,843	18,830	0	6,125	573	0	335	6,894	0	4,903	0	0	10,013	0	0
6	28,891	19,283	71	6,197	580	0	332	6,894	0	4,483	0	726	9,608	0	0
7	31,436	26,035	2,822	5,370	543	0	252	6,161	0	10,886	0	0	5,402	0	0
8	32,316	28,820	6,722	5,471	516	0	252	1,041	0	14,819	0	0	3,496	0	0
9	37,093	35,585	10,446	5,471	523	0	252	2,039	0	16,853	0	0	1,508	0	0
10	41,783	40,473	13,504	5,507	516	0	252	2,125	0	18,571	0	0	1,310	0	0
11	43,973	42,656	15,255	5,585	516	0	252	1,245	0	19,804	0	0	1,317	0	0
12	46,472	45,079	15,763	5,720	523	0	252	2,834	0	19,987	0	0	1,393	0	0
13	48,735	47,412	15,953	6,014	523	0	252	4,037	0	20,632	0	0	1,323	0	0
14	48,994	47,732	14,578	6,310	533	0	252	5,587	0	20,472	0	0	1,262	0	0
15	49,024	47,812	12,815	6,881	554	0	252	6,891	0	20,419	0	0	1,212	0	0
16	48,525	45,948	9,867	9,187	628	0	332	6,889	199	18,846	0	0	2,577	0	0
17	47,619	42,847	6,400	10,878	719	0	1,312	6,889	813	15,835	0	0	4,772	0	0
18	45,953	39,100	2,524	12,667	1,078	0	3,456	6,890	1,831	10,644	10	0	6,853	0	0
19	44,635	35,729	65	13,493	1,078	1,168	3,811	6,890	1,831	5,523	10	1,858	8,907	1,862	0
20	45,811	36,167	0	13,609	1,078	1,168	3,866	6,890	1,831	5,504	10	2,210	9,644	1,538	189
21	43,689	33,348	0	13,393	1,071	0	3,772	6,890	1,831	5,827	10	554	10,341	0	0
22	40,204	30,019	0	12,537	747	0	2,189	6,890	1,831	5,821	4	0	10,185	0	0
23	36,718	27,724	0	11,198	734	0	1,949	6,891	1,340	5,609	4	0	8,995	0	0
24	33,472	24,919	0	10,034	695	0	1,061	6,891	581	5,657	0	0	8,552	0	0

- Renewable and BTM PV generation drops quickly in early evening
- Net import in hour 19 and 20 is below the CAISO net import limit
- Supply is insufficient to meet load-following up and non-spinning reserve requirements in hour 19 and 20

Load forecast and modifiers during peak net load hours on August 31, 2030

CAISO Load Forecast and Load Modifiers (MW)

Hour	Load Forecast	AAEE	Pump Load	EV	TOU	Load with Modifiers
16	51,565	4,596	1,158	681	-282	48,525
17	50,532	4,532	1,160	759	-299	47,619
18	48,486	4,194	1,159	795	-292	45,953
19	46,750	3,892	1,274	794	-292	44,635
20	45,791	3,714	1,394	2,630	-289	45,811
21	42,970	3,468	1,424	2,636	127	43,689

- August 31, 2030 is a Saturday. Compared to weekdays of the same week
  - AAEE is about 2,000 MW lower;
  - Pump load is about doubled
  - EV charging load is higher
  - TOU is in the same range

California ISO

Breakdown of renewable generation on August 31, 2030 (MW)

Hour	Biogas	Biomass	Geothermal	Small Hydro	Solar PV	Solar Thermal	Wind	Total
1	187	690	1,329	227	0	0	2,819	5,252
2	187	690	1,329	222	0	0	2,803	5,231
3	187	690	1,329	198	0	0	2,801	5,205
4	187	690	1,329	200	0	0	2,743	5,149
5	187	690	1,329	219	0	0	2,478	4,903
6	187	690	1,329	253	99	22	1,902	4,483
7	187	690	1,329	282	6,800	279	1,319	10,886
8	187	690	1,329	359	11,091	628	534	14,819
9	187	690	1,329	384	13,029	1,022	212	16,853
10	187	690	1,329	401	14,504	1,319	141	18,571
11	187	690	1,329	415	15,511	1,498	173	19,804
12	187	690	1,329	399	15,465	1,633	284	19,987
13	187	690	1,329	431	15,704	1,586	704	20,632
14	187	690	1,329	441	15,179	1,393	1,252	20,472
15	187	690	1,329	444	15,010	1,230	1,529	20,419
16	187	690	1,329	454	13,274	943	1,967	18,846
17	187	690	1,329	440	10,613	566	2,009	15,835
18	187	690	1,329	453	5,976	164	1,844	10,644
19	187	690	1,329	456	4	0	2,857	5,523
20	187	690	1,329	457	0	0	2,841	5,504
21	187	690	1,329	443	0	0	3,177	5,827
22	187	690	1,329	388	0	0	3,227	5,821
23	187	690	1,329	312	0	0	3,091	5,609
24	187	690	1,329	211	0	0	3,239	5,657

Generation capacity usage during peak net load hours on August 31, 2030

Generation and Import (MW)

Hour	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage	Net Import
16	9,867	9,187	628	0	332	6,889	199	18,846	0	0	2,577
17	6,400	10,878	719	0	1,312	6,889	813	15,835	0	0	4,772
18	2,524	12,667	1,078	0	3,456	6,890	1,831	10,644	10	0	6,853
19	65	13,493	1,078	1,168	3,811	6,890	1,831	5,523	10	1,858	8,907
20	0	13,609	1,078	1,168	3,866	6,890	1,831	5,504	10	2,210	9,644
21	0	13,393	1,071	0	3,772	6,890	1,831	5,827	10	554	10,341

Provision of Upward Load-following and Reserves (MW)

Hour	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage	Net Import
16	0	3,063	0	0	1,462	0	300	0	0	1,642	0
17	0	1,459	0	0	1,882	0	900	0	0	2,481	0
18	0	1,358	0	0	3,058	0	0	0	0	2,481	0
19	0	533	0	0	2,667	0	0	0	0	623	0
20	0	416	0	0	2,624	0	0	0	0	272	0
21	0	633	0	0	2,718	0	0	0	0	1,927	0

Outages (MW)

Hour	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage	Net Import
16	0	28	0	0	301	0	374	0	0	0	0
17	0	616	0	0	298	0	0	0	0	0	0
18	0	616	0	0	298	0	0	0	0	0	0
19	0	616	0	0	333	0	0	0	0	0	0
20	0	616	0	0	321	0	0	0	0	0	0
21	0	616	0	0	321	0	0	0	0	0	0

Total Usage (MW)

Hour	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage	Net Import
16	9,867	12,278	628	0	2,095	6,889	873	18,846	0	1,642	2,577
17	6,400	12,954	719	0	3,492	6,889	1,713	15,835	0	2,482	4,772
18	2,524	14,642	1,078	0	6,812	6,890	1,831	10,644	10	2,482	6,853
19	65	14,642	1,078	1,168	6,812	6,890	1,831	5,523	10	2,482	8,907
20	0	14,642	1,078	1,168	6,812	6,890	1,831	5,504	10	2,482	9,644
21	0	14,642	1,071	0	6,812	6,890	1,831	5,827	10	2,482	10,341

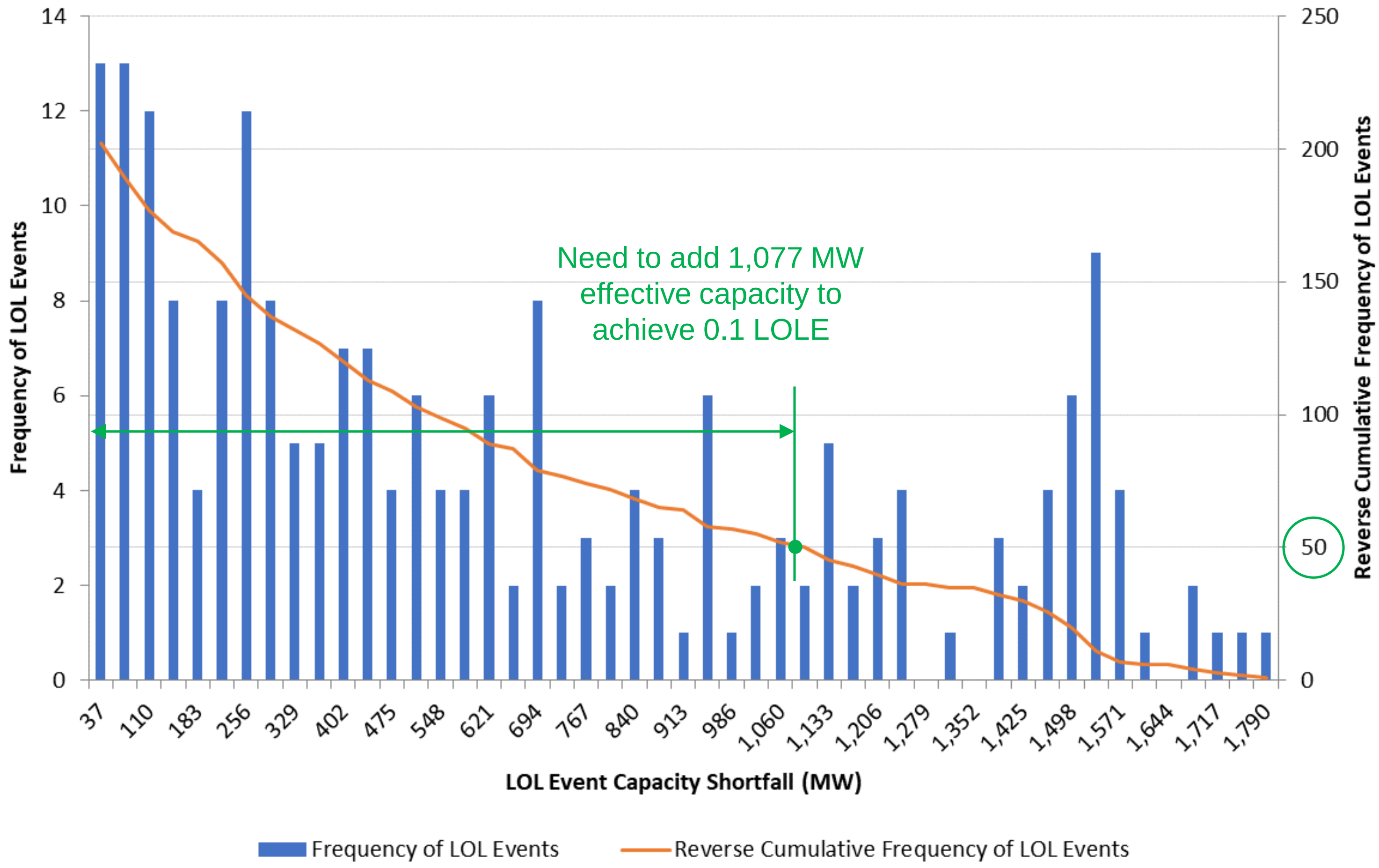
Total Available Capacity (MW)

Hour	BTMPV	CCGT	CHP	DR	GT	Hydro	Pumped Storage	Renewable	ST	Storage	Net Import
16	9,867	14,642	1,078	1,168	6,813	6,889	1,831	18,846	10	2,482	10,341
17	6,400	14,642	1,078	1,168	6,813	6,889	1,831	15,835	10	2,482	10,341
18	2,524	14,642	1,078	1,168	6,813	6,890	1,831	10,644	10	2,482	10,341
19	65	14,642	1,078	1,168	6,813	6,890	1,831	5,523	10	2,482	10,341
20	0	14,642	1,078	1,168	6,813	6,890	1,831	5,504	10	2,482	10,341
21	0	14,642	1,078	1,144	6,813	6,890	1,831	5,827	10	2,482	10,341

Notes

- Some demand response programs are not available on weekend
- BTM PV and renewable generation drops quickly starting hour 16, solar has almost no contribution from hour 19 on
- Storage provides a large portion of upward load-following and reserves
- 4.2% CCGT and 4.9% GT forced outages
- At hour 19 and 20 all available generation capacity is fully utilized, but import is below the maximum import limit

Stochastic simulation results show LOLE higher than the reliability metrics allows

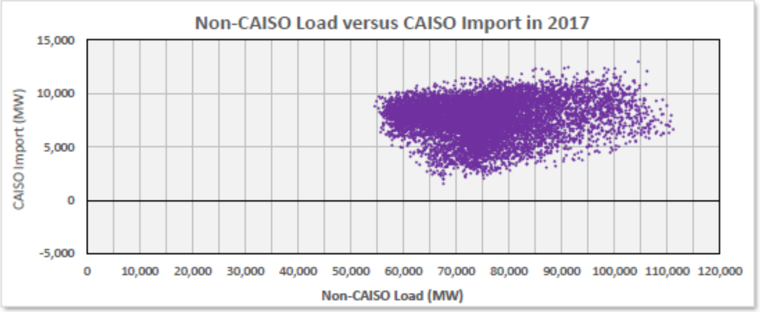


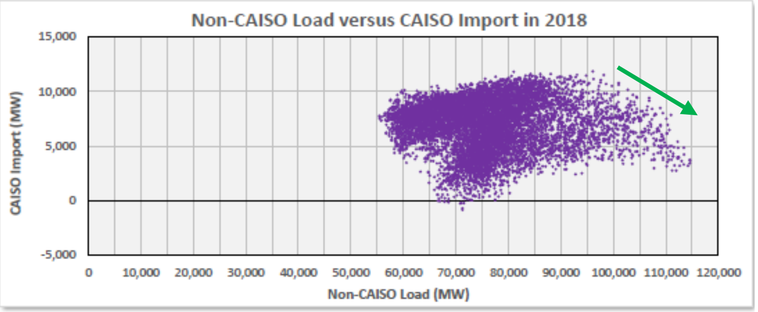
California ISO

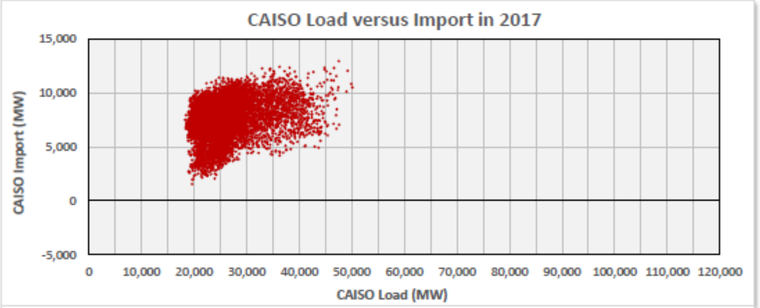
Findings from production cost simulations

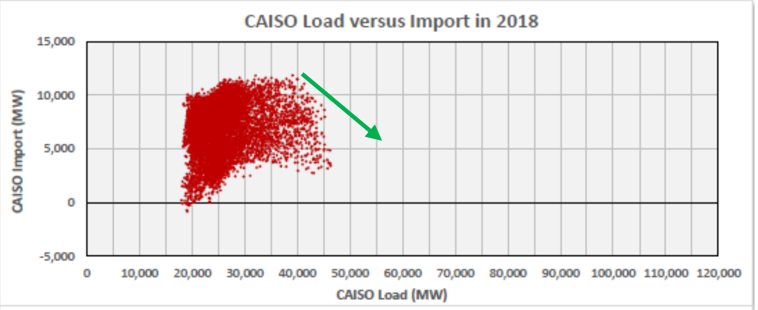
- The HCP does not have sufficient capacity to serve load and meet reserve requirements of the CAISO system during peak net load hours;
- It needs to retain or replace at least 1,077 MW of the retired thermal capacity to reach the 0.1 LOLE reliability criterion
- More diverse resource portfolios could also mitigate the reliability issue
- Import is constrained during peak net load hours and CPUC's assumptions are overly optimistic.

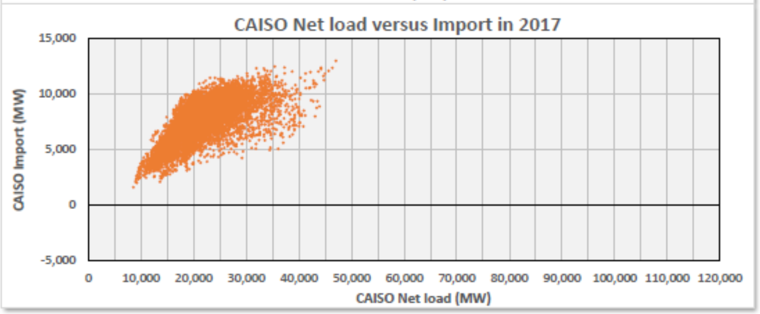
2017-2018 CAISO load vs. import

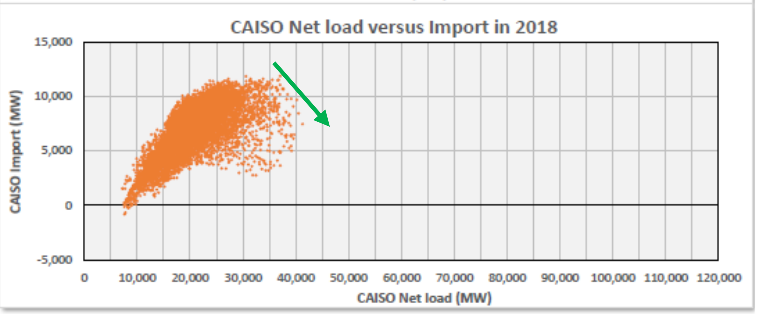












Large Energy Storage System-wide Benefit Study

Purpose of the ISO bulk energy storage case study

- To assess a bulk storage resource's ability to reduce
  - production cost;
  - renewable curtailment; and
  - CO_2 emission.
- No renewable overbuild necessary to achieve 50% RPS
  - The 2017-2018 IRP HCP has renewable resources exceeding 50% RPS target, even after considering curtailment.

Study approach

- A 500 MW and a 1,400 MW new pumped storage resource were added in turn to the deterministic production cost model of the 2017-18 IRP HCP
- Results of the two cases are compared with the results without the new pumped storage resource

Assumptions of the 500 MW 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, pumping and generation)	**1.5**
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 the 1,400 MW new pumped storage resource

Item	Value
Number of units	**4**
Max pumping capacity per unit (MW)	**422**
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	**350**
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, pumping and generation)	**1.5**
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	18.8
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

Benefits of the new pumped storage resources

Case	HCP	500 MW Pumped Storage	1,400 MW Pumped Storage
ISO CO2 Emission (MM Ton)			
By In-ISO Generation	23.45	23.09	22.51
From Import	17.91	17.89	17.91
Sum	41.37	40.98	40.42
WECC-Wide CO2 Emission (MM Ton)	303.64	303.78	303.86
In-ISO Generation (GWh)	205,590	204,963	203,815
Net Import	48,951	49,579	50,727
Import - NW	15,114	15,200	15,320
Import - others	43,284	43,134	43,072
Export	-9,448	-8,755	-7,665
Renewable Generation (GWh)	103,083	103,497	104,131
RPS Achieved (excluding banked RECs)	52.5%	52.7%	53.1%
Renewable Curtailment (GWh)	3,328	2,913	2,279
Production Cost ($million)			
WECC	13,042	12,996	12,926
CAISO	2,869	2,818	2,735

Performance of the new pumped storage resources

	500 MW Pumped Storage	1,400 MW Pumped Storage
Generation (GWh)	1,124.46	3,054.57
Pump Load (GWh)	1,354.77	3,680.20
Total Generation Cost ($000)	3,718.85	10,102.15
Pump Cost ($000)	11,521.33	42,456.91
Energy Revenue ($000)	71,901.48	186,388.19
Reserves Revenue ($000)	16,974.53	30,287.03
Net Revenue ($000)	73,635.83	164,116.16

Study conclusions

- The new pumped storage resources
  - brought significant benefits to the system
    - lower CO_2 emission, renewable curtailment and production costs;
  - took advantage of low cost out-of-state energy during hours without renewable curtailment;
  - improved flexibility of the resource fleet to follow load and provide reserves.

Study conclusions (cont.)

- Net market revenues of the pumped storage resources provided a material contribution towards the levelized annual revenue requirements;
- Other benefits to the system could be attributed to the pumped storage resources, and would need to be;
- Results are sensitive to study assumptions, such as the offer prices of renewable resources when there is curtailment.

Wrap-up
Draft 2018-2019 Transmission Plan

Kristina Osborne
Lead Stakeholder Engagement and Policy Specialist

2018-2019 Transmission Planning Process Stakeholder Meeting
February 14, 2019

Stakeholder Comments

- Stakeholder comments to be submitted by February 28
  - Stakeholders requested to submit comments to: regionaltransmission@caiso.com
  - Stakeholder comments are to be submitted within two weeks after stakeholder meetings
  - ISO will post comments and responses on website