Opening

2014-2015 Transmission Planning Process Stakeholder Meeting

Tom Cuccia
Lead Stakeholder Engagement and Policy Specialist
November 19-20, 2014

Today's Agenda – November 19th

Topic	Presenter
Opening	Tom Cuccia
Introduction & Overview	Neil Millar
San Francisco Peninsula Extreme Event Reliability Assessment	Jeff Billinton
Over Generation Assessment	Irina Green
Recommendations for Management Approval of Reliability Projects less than $50 Million	ISO Regional Transmission Engineers
Long-Term Local Capacity Need Analysis	Catalin Micsa and David Le
Locational Effectiveness Factors	David Le

Tomorrow's Agenda – November 20st

Topic	Presenter
Opening	Tom Cuccia
RPS Portfolio Assessment	ISO Regional Transmission Engineers
Summary of LA Basin/San Diego and Imperial Area Interaction	Robert Sparks
2013-2014 CAISO Transmission Planning Process Harry Allen – El Dorado 500 kV Project Economic Analysis	Robert Sparks
Economic Study Assessment	Yi Zhang
Long-Term CRR Assessment	Chris Mensah-Bonsu

Introduction and Overview
Policy-Driven and Economic Assessment

Neil Millar
Executive Director, Infrastructure Development

2014-2015 Transmission Planning Process Stakeholder Meeting
November 19-20, 2014

2014-2015 Transmission Planning Cycle

April 2014 — **March 2015** — **October 2015**

ISO Board Approval of Transmission Plan

Coordination of Conceptual Statewide Plan

Phase 1

Development of ISO unified planning assumptions and study plan

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

Phase 2

Technical Studies and Board Approval

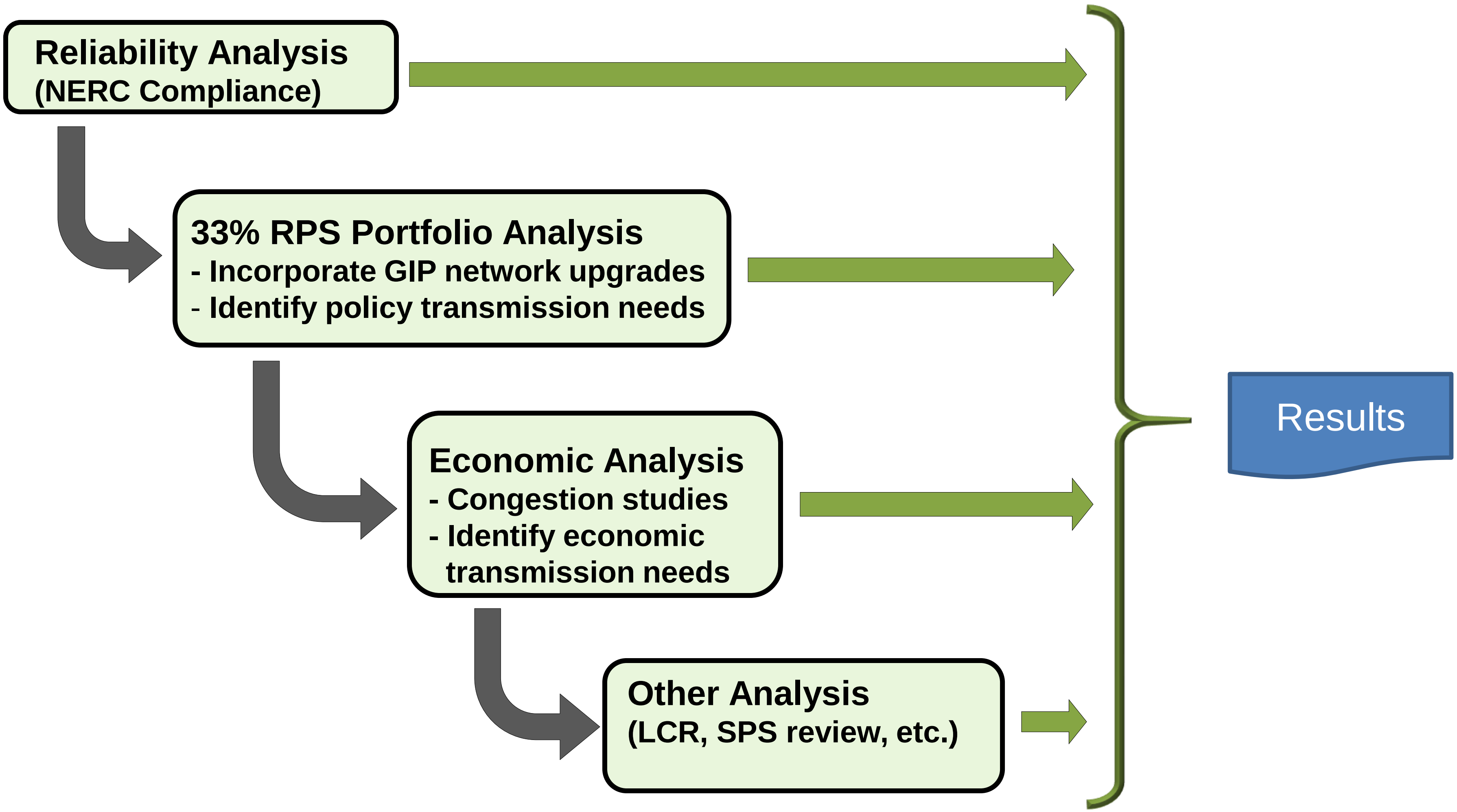
- Reliability analysis
- Renewable delivery analysis
- Economic analysis
- Wrap up of studies continued from previous cycle
- Publish comprehensive transmission plan
- ISO Board approval

Phase 3

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

Continued regional and sub-regional coordination

Development of 2014-2015 Annual Transmission Plan



2014-2015 Ten Year Plan Milestones

- Preliminary reliability study results were posted on August 15
- Stakeholder session September 24th and 25th
- Comments received October 9
- **Today's session - preliminary policy and economic study results**
- Comments due by December 4
- <u>Draft</u> plan to be posted January, 2015

Issues

- Updates related to 2014-2015 TPP reliability analysis:
  - San Francisco Peninsula
  - “Over Generation” frequency response assessment
  - Management approval of certain reliability projects less than $50 million

- Standalone issues:
  - Harry Allen –Eldorado (2013-2014 further study)
  - Locational effectiveness factors

- Interaction between Imperial area policy-driven analysis and LA Basin/San Diego reliability needs.

Management is considering approving a number of reliability transmission projects less than $50 million

- Approving these projects allows streamlining the review and approval process of the annual transmission plan in March
- <u>Only</u> those projects less than $50 million are considered for management approval that:
  - Can reasonably be addressed on a standalone basis
  - Are not impacted by policy or economic issues that are still being assessed.
  - Are not impacted by the approval of the transmission plan (and reliability projects over $50 million) by the Board of Governors in March, 2015
- Management will only approve these projects <u>after</u> the December Board of Governors meeting
- Other projects less than $50 million will be dealt with in the approval of the comprehensive plan in March.

Renewable Portfolio Standard Policy Assumptions

- Portfolios received from the CPUC and CEC on February 27, 2014
    - Posted to ISO website March 5
- As in previous cycles, a "commercial interest" portfolio was the base – focusing on the mid-AAEE scenario as the current trajectory.
- A sensitivity focusing on a high Imperial Valley (2500 MW instead of 1000 MW incremental renewable resources).

Breakout By CREZ				
Scenario Name	33% 2024 Mid AAEE	33% 2024 LowMid AAEE	High DG 33% 2024 Mid AAEE + DSM	33% 2024 Mid AAEE (sensitivity)
Net Short (GWh)	30,551	33,287	26,562	26,562
	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)	Portfolio Totals (MW)
Discounted Core	9,109	9,112	11,440	9,063
Generic	3,311	4,414	0	2,223
Total	12,420	13,526	11,440	11,286
CREZ	MW	MW	MW	MW
Alberta	300	300	300	300
Arizona	400	400	400	400
Baja	100	100	100	100
Carrizo South	900	900	300	900
Distributed Solar - PG&E	984	984	3,449	984
Distributed Solar - SCE	565	565	1,988	565
Distributed Solar - SDGE	143	143	157	143
Imperial	1,000	1,000	1,000	2,500
Kramer	642	642	62	642
Mountain Pass	658	658	165	658
Nevada C	516	516	266	516
NonCREZ	185	191	133	182
Riverside East	3,800	3,800	1,400	1,400
San Bernardino - Lucerne	87	87	42	42
San Diego South	-	384	-	
Solano	-	200	-	
Tehachapi	1,653	2,148	1,285	1,483
Westlands	484	505	389	469
Central Valley North	-	-	-	
Merced	5	5	5	5
Total	12,420	13,526	11,440	11,286
New Transmission Segments	Kramer - 1	Kramer - 1	Kramer - 1	Kramer - 1
	Riverside East - 1	Riverside East - 1		Imperial - 1

California ISO
Shaping a Renewed Future

Sensitivity analysis of high Imperial area renewable generation development:

- Complex interaction between LA Basin/San Diego reliability needs and Imperial area deliverability
- LA Basin/San Diego reliability needs affected by a range of parameters including the completion of approved transmission and the success of approve preferred and conventional resource procurement
- Consequences:
  - Previously approved transmission and resource procurement helps alleviate some of the uncertainty
  - Uncertainty of timeliness of potential reliability mitigations makes analysis of policy-driven needs more challenging
- Reliability and policy analysis presentations address individual issues – we will revisit the interrelationships at the end of the stakeholder session

San Francisco Extreme Event Analysis

Available on Market Participant Portal
Confidential – Subject to Transmission Planning NDA

2014-2015 Transmission Planning Process Stakeholder Meeting

Jeff Billinton
Manager, Regional Transmission - North
November 19-20, 2014

Assessment of Frequency Response during Over Generation Conditions

2014-2015 Transmission Planning Process Stakeholder Meeting

Irina Green

Engineer Lead, Regional Transmission North

November 19-20, 2014

Study objectives

- Evaluate potential over-generation within the ISO Balancing Authority Area (BAA) and its potential consequences
- Assess the ISO's readiness and ability to comply with NERC's standard BAL-003-1 "Frequency Response and Frequency Bias Setting" with 33% renewable resources
- Assess factors affecting Frequency Response
- Identify next steps based on the results of the initial study

Production Simulation Analysis

- Started with production simulation in Grid View for 2024
  - Used the latest WECC Database for the year 2024
- Base case included CPUC Renewable Generation Portfolios with 33% renewable resources in California

Power Flow and Dynamic Base Case Development

- Selected hour of the year to study
  - light spring, low load, high renewable generation
- The hour selected from production simulation case was April 7, 2024 at 11 a.m.
- Prepared power flow cases and dynamic stability models
- Power flow case closely matched the case from the production simulation

Power Flow and Dynamic Base Case Development

- Power flow case – exported from Grid View for the selected hour
- Adjusted reactive support: turned off capacitors, turned on reactors; high voltage was an issue
- Dynamic stability models – from the latest WECC Master Dynamic File
- Added missing dynamic stability models for renewables using typical models according to the type and capacity of the projects
- Used the latest WECC-approved dynamic stability models for inverter-based generation: wind – type 3 (double-fed induction generator) and type 4 (full converter), solar: large PV plant, small PV plant, distributed PV
- Adjusted power flow case to better match the case from production simulation and to ensure that all generation is dispatched within the units' capability

Study Assessment
Contingencies and Metrics

- Contingencies studied:
  - Simultaneous loss of two Palo Verde nuclear units (loss of 2806 MW of generation in the base case)

Metrics:

- The impact of unit commitment on frequency response
- The impact of generator output level on governor response
  - Headroom or unloaded synchronized capacity
  - Speed of governor response
  - Number of generators with governors
  - Governor withdrawal

Power Flow Base Case Assumptions, April 7 2024 11am

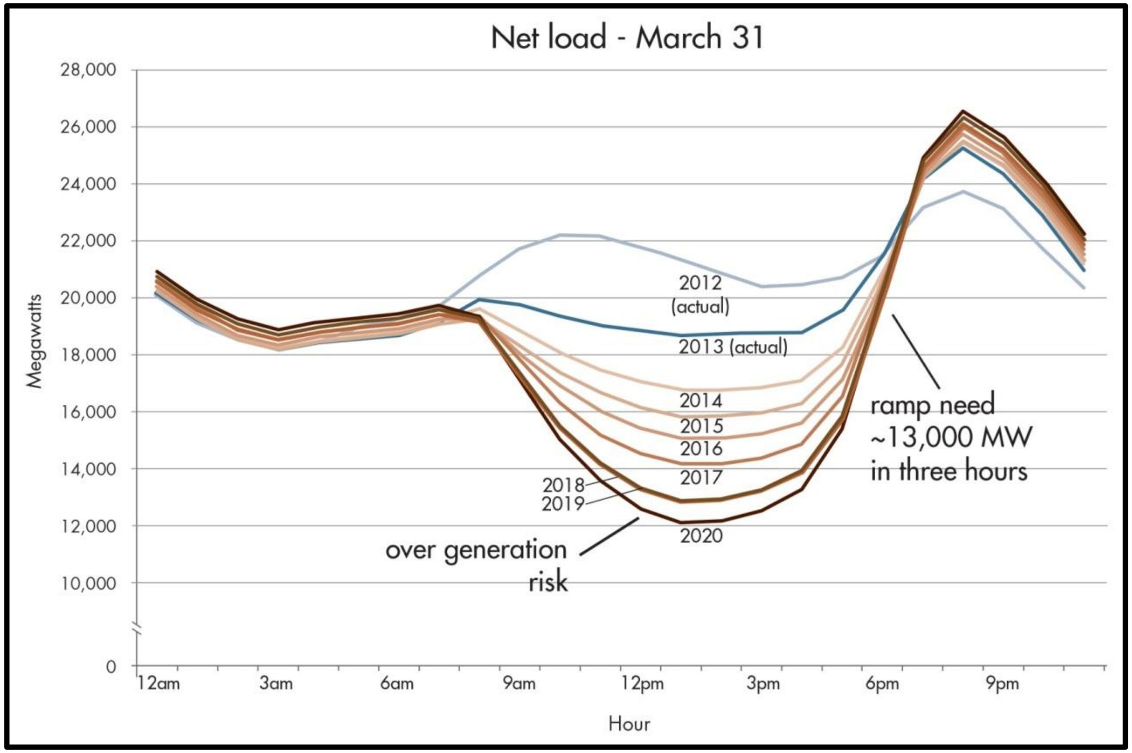
- Load, WECC - 100,410 MW, 53.6% of the summer peak load
- Load, ISO - 24,117 MW, 39.4% of the summer peak load
- Losses, WECC – 3,162 MW
- Losses, ISO – 510 MW
- Generation, WECC – 103,580 MW
- Generation, ISO – 22,650 MW
- COI flow – 1170 MW North-to-South
- Path 15 flow – 2800 MW South-to-North
- Path 26 flow – 760 MW South-to-North
- PDCI schedule - 620 MW North-to-South
- Import to ISO – 1977 MW
- Wind and solar output WECC, 25.8% of total dispatch
- Wind and solar output, ISO, 48.6% of total dispatch

Generation by Type, April 7, 2024 11 am (in MW)

Area		Nuclear	Geothermal	Biomass	Coal	Hydro	Natural Gas	Storage	Solar	Wind
PG&E	Capacity	2,300	1,676	930	223	5,556	15,449	2,719	5,492	2,402
	Dispatch	1,150	695	391	0	589	2,637	-368	2,855	1,525
SCE	Capacity	0	329	380	181	1,563	13,916	834	10,790	4,279
	Dispatch	0	253	193	0	580	3,538	-271	5,766	1,421
SDG&E	Capacity	0	0	40	0	6	4,849	165	1,861	319
	Dispatch	0	0	21	0	0	739	-147	0	0
SMUD	Capacity	0	22	8	0	2,653	2,648	0	413	0
	Dispatch	0	15	1	0	761	328	0	235	0
TIDC	Capacity	0	0	0	0	161	587	0	0	0
	Dispatch	0	0	0	0	140	0	0	0	0
LDWP	Capacity	0	0	20	1,640	294	4,601	1,370	606	437
	Dispatch	0	0	11	328	98	37	392	600	245
IID	Capacity	0	773	130	0	85	990	0	792	0
	Dispatch	0	612	65	0	39	84	0	664	0
Rest of WECC	Capacity	5,380	1,431	1,563	30,814	56,827	68,281	985	5,523	20,165
	Dispatch	3,976	1,131	1,053	22,490	23,459	12,360	-451	4,710	8,713

Non-summer months – net load pattern changes significantly starting in 2014

Illustration of ISO Duck Curve



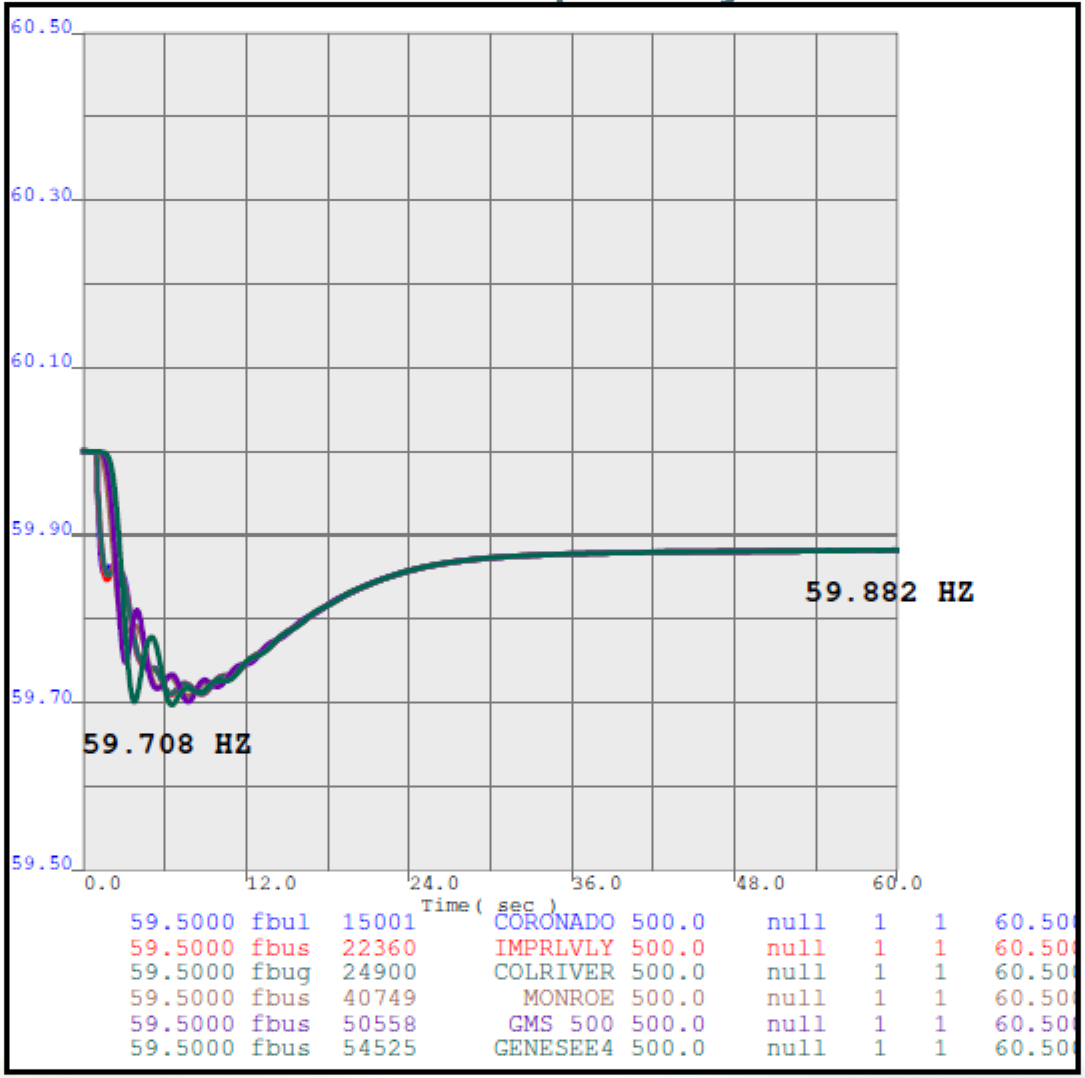
Production Simulation for April 7, 2024, 11 am

<u>ISO load</u>
24,117 MW

<u>Wind & Solar Generation</u>
11,802 MW

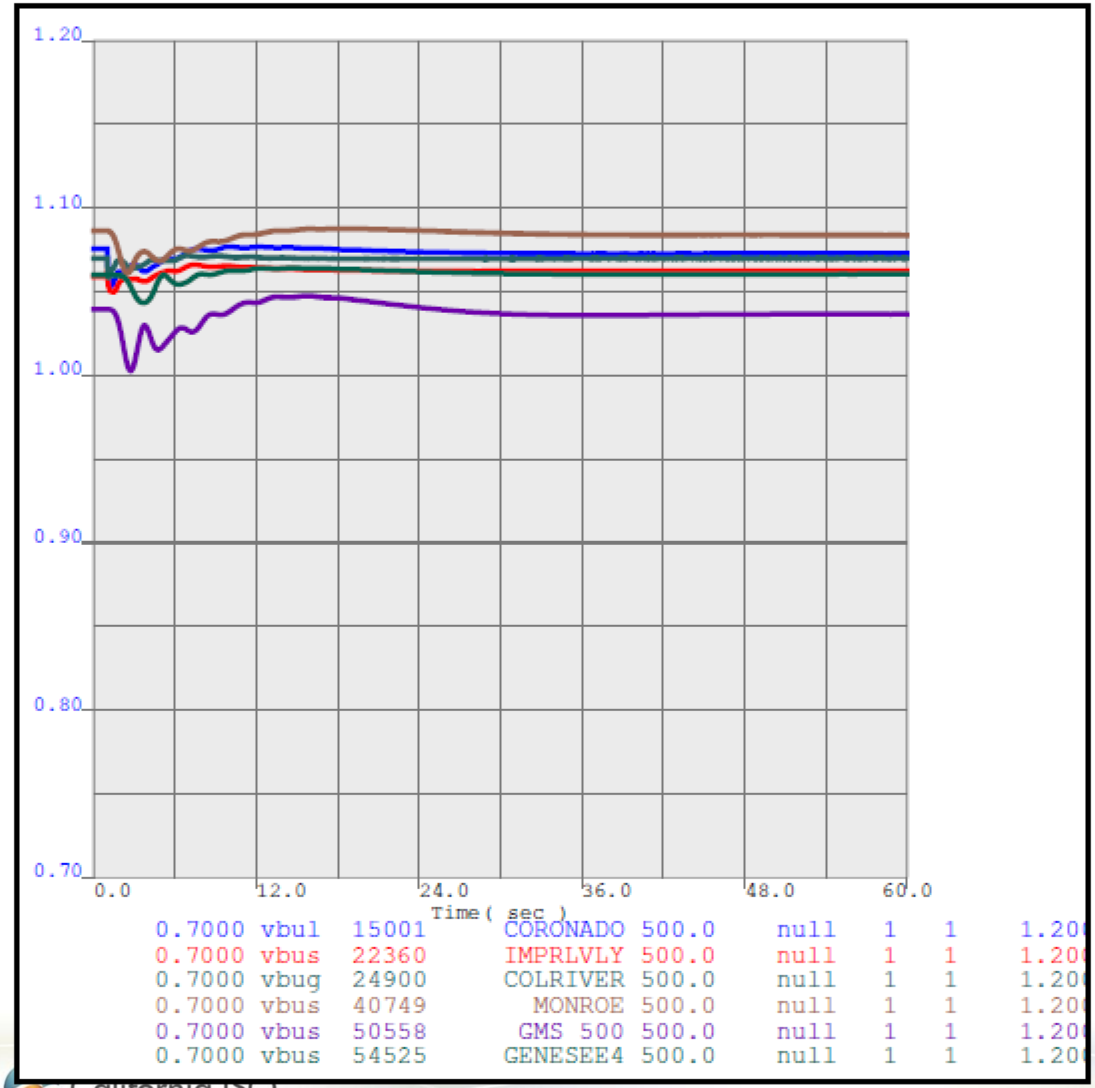
<u>Net load</u>
12,315 MW

Study Results for an Outage of Two Palo Verde Units Frequency on 500 kV buses



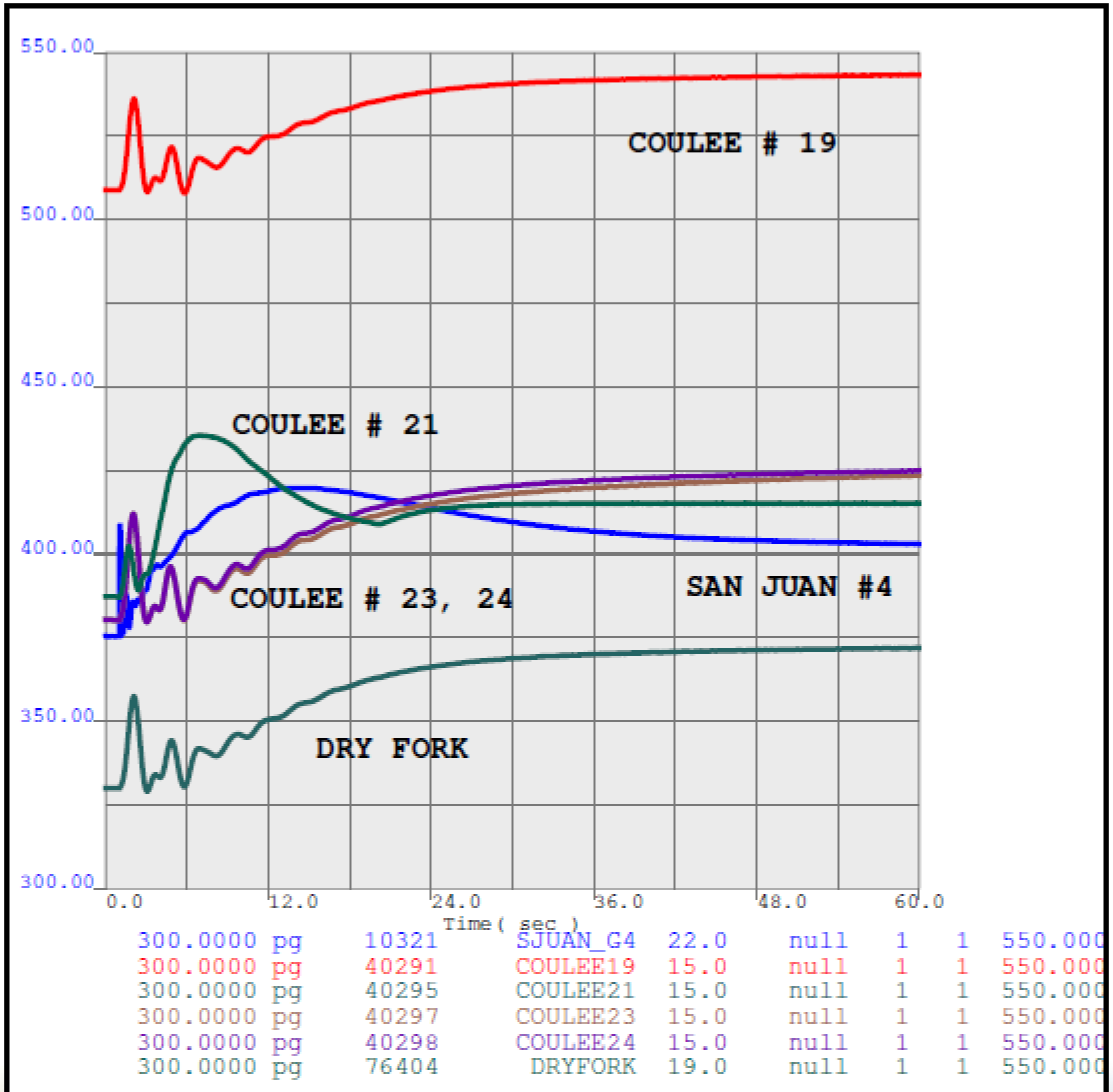
- Nadir 59.708 Hz at 6.5 seconds
- Settling frequency 59.882 Hz
- Change in frequency 0.118 Hz

Study Results for an Outage of Two Palo Verde Units Voltage on 500 kV buses



Voltage within the limits

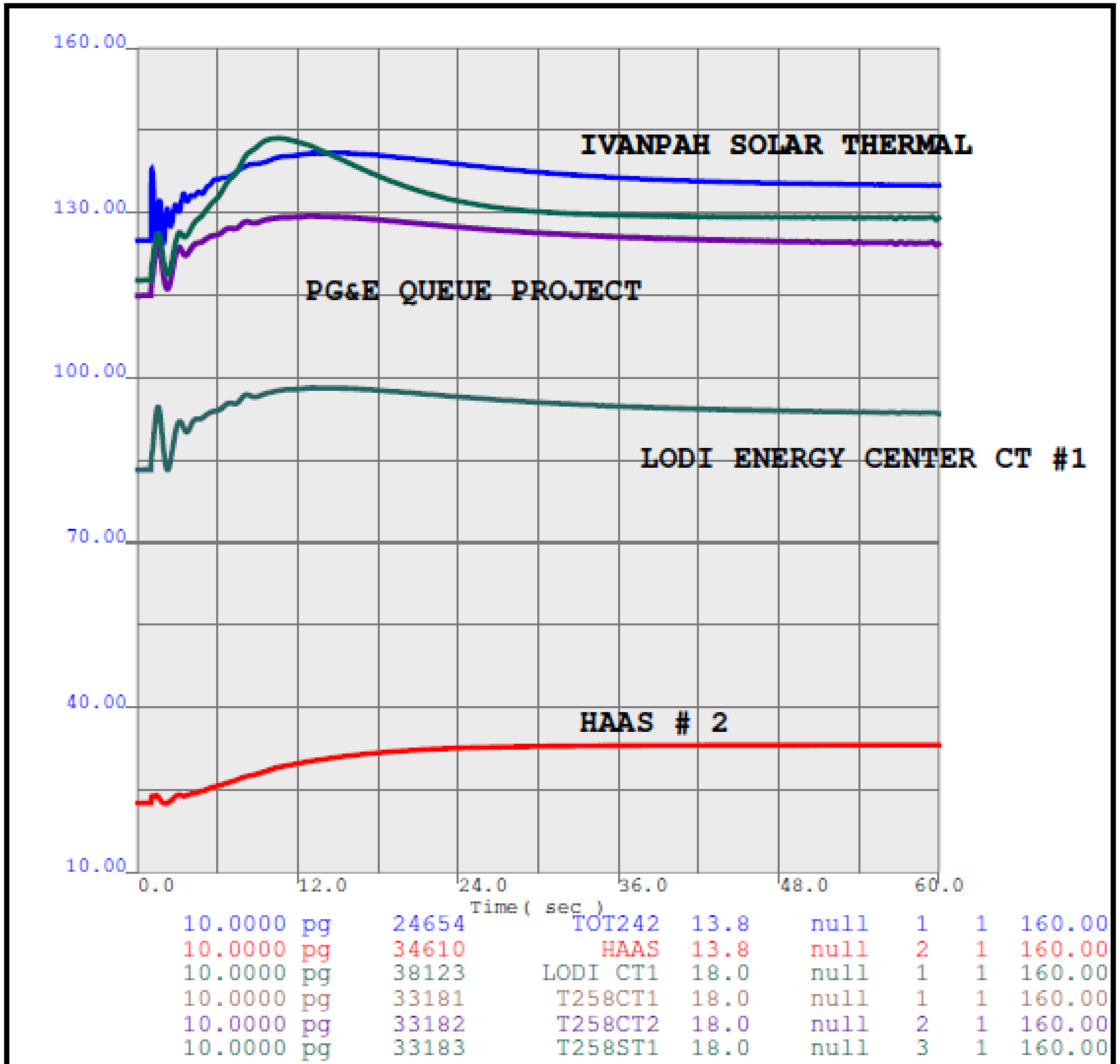
Governor Response
Generators with the highest response (WECC)



- Coulee #23, 24 - 45 MW, 6%, 805 MW capacity
- Coulee#21 – 42 MW, 7%, 600 MW capacity
- Coulee#19 – 34 MW, 6%, 600 MW capacity
- Dry Fork – 28 MW, 6%, 440 MW capacity
- San Juan # 4 – 28 MW, 5%, 553 MW capacity

Grand Coulee – hydro plant in Washington state,
Dry Fork – coal plant in Wyoming,
San Juan - coal plant in New Mexico

Governor Response
Generators with the highest response (CAISO)



- PG&E Project, unit # 3 – 11 MW, 4%, 290 MW capacity

  Units # 1 and 2, 9 MW, 5%, 189 MW capacity
- Haas unit # 2, 11 MW, 14%, 72 MW capacity
- Lodi gas unit # 1, 10 MW, 6%, 185 MW capacity
- Ivanpah, 10 MW, 8%, 133 MW capacity

PG&E project and Lodi – natural gas,
Haas – hydro,
Ivanpah – solar thermal

Frequency Response Obligation (FRO)

- Frequency Response (FR)

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

- FRO for the Interconnection is established in BAL-003-1 Frequency Response & Frequency Bias Setting Standard
- For WECC FRO is 949 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 (285 MW/0.1HZ)

Study Results, Frequency Response Measure and Headroom

	RESPONSE	RESPONSE	RESPONSE		HEADROOM	LOAD	GENERATION	
	MW	MW/0.1 HZ	% of Pmax, all	% of Pmax, responsive governors	MW	MW	ALL, MW	Responsive, MW
WECC	2,705	2,292	1.6%	4.0%	30,152	100,410	103,580	65,597
PG&E	217	184	1.0%	3.9%	3,585	12,470	10,770	5,575
SCE	83	70	0.6%	3.3%	732	9,500	11,280	2,240
SDG&E	18	15	1.7%	5.1%	103	2,150	600	344
Total ISO	318	269	0.9%	3.8%	4,420	24,120	22,650	8,159
ISO/WECC	11.7%	11.7%	53.0%	93.1%	14.7%	24.0%	21.9%	12.4%

Frequency Response Obligation

- Per BAL-003-1 the ISO required response is:
  - 285 MW/0.1 Hz
- Study of April 7, 2024 at 11am identified ISO response as:
  - 269 MW/0.1 Hz
- Based upon analysis, while there will be adequate response from the WECC system the ISO will not have adequate governor response satisfy its obligation per BAL-003-1.

Resources providing governor response in the April 7, 2024 11 am case

- Total generation capacity on-line (pumps and storage not included)

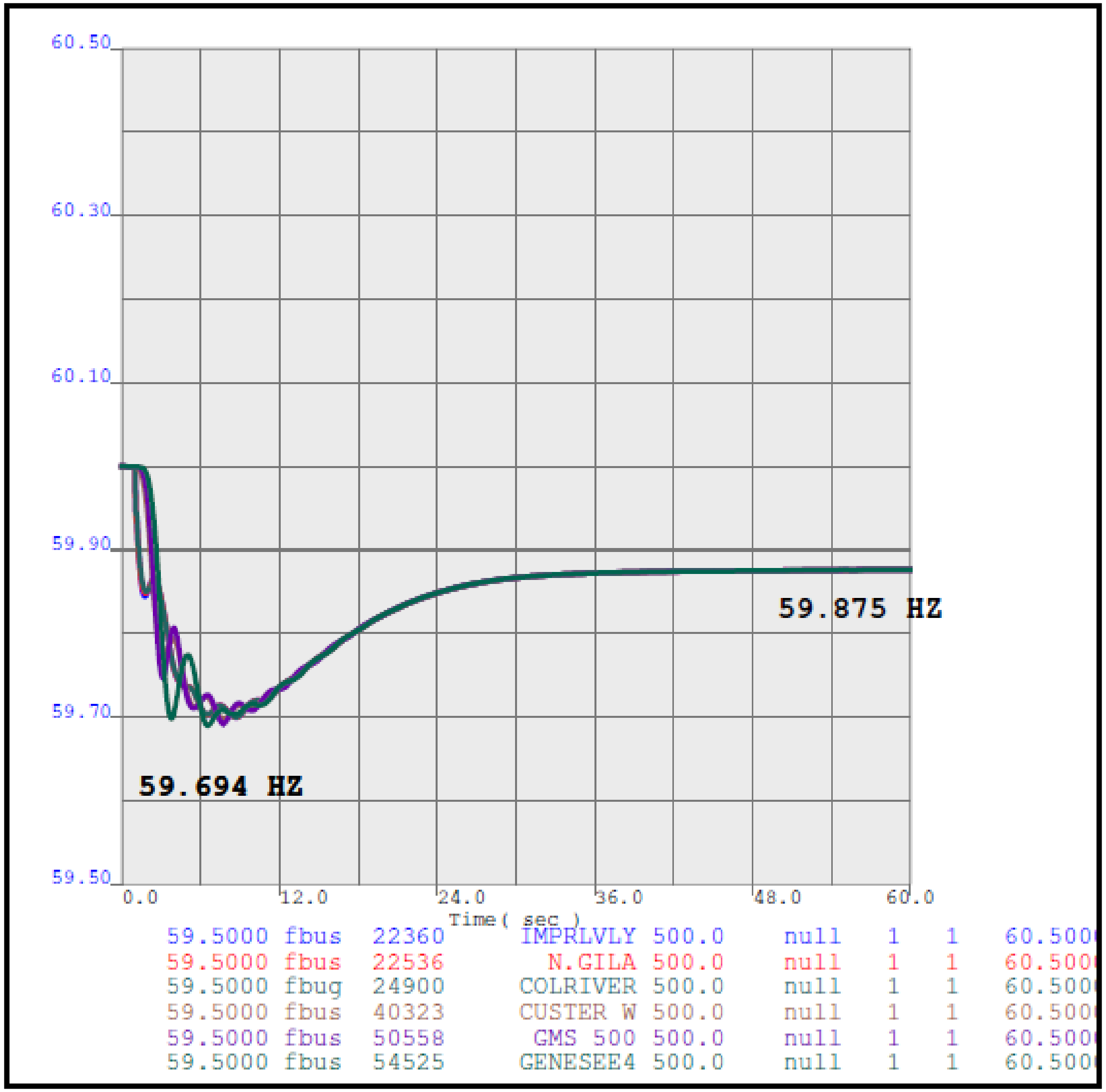
  WECC: 165,332 MW ISO: 36,757 MW
- Total generation capacity with responsive governors,
  WECC: 65,602 MW, ISO: 8,159 MW
- Ratio of governor-responsive generation (Kt)

  WECC: 0.397, ISO: 0.222
- Headroom (responsive governors)

  WECC: 30,128 MW, ISO: 4,420 MW

Governor-responsive generators in the case studied had large headroom due to low dispatch

Sensitivity Study with Reduced Headroom in the ISO



- Reduced headroom of the units with responsive governors from 4420 MW to 1430 MW by turning off some units and re-dispatching generation
- Did not change dispatch in the rest of WECC
- System performance still acceptable, but close to the margin
- WECC response 2137 MW/0.1Hz
- **ISO response 141 MW/0.1Hz**
- 27 MW of load in British Columbia tripped by under-frequency relays

Conclusions

- The study results indicated acceptable frequency performance within WECC.
- The study identified that the ISO's frequency response was below the ISO Frequency Response Obligation in BAL-003-1.
- Compared to the actual system performance during disturbances, the study results were optimistic.
  - Optimistic results were partly due to large headroom of responsive generation modeled in the case based on production simulation dispatch.
  - Amount of headroom of responsive governors is a good indicator of the Frequency Response Metric, but it is not the only one indicator. Response was below the FRO even with the large headroom.
  - Modeling of behind the meter generation.
- Further model validation is needed to ensure that governor response in the simulations matches their response in the real life.
- Explore other sources of governor response.

Further Assessment

- Investigate measures to improve ISO frequency response:
  - load response,
  - response from storage; and/or
  - inverter-based generation
- Study more cases with reduced headroom
- Study other contingencies
- Future work – validate models

Recommendations for Management Approval of Reliability Projects less than $50 Million

PG&E Area

2014-2015 ISO Transmission Planning Process

Chris Mensah-Bonsu, PhD
Sr. Regional Transmission Engineer

November 19-20, 2014

PG&E Reliability Projects Less than $50 Million

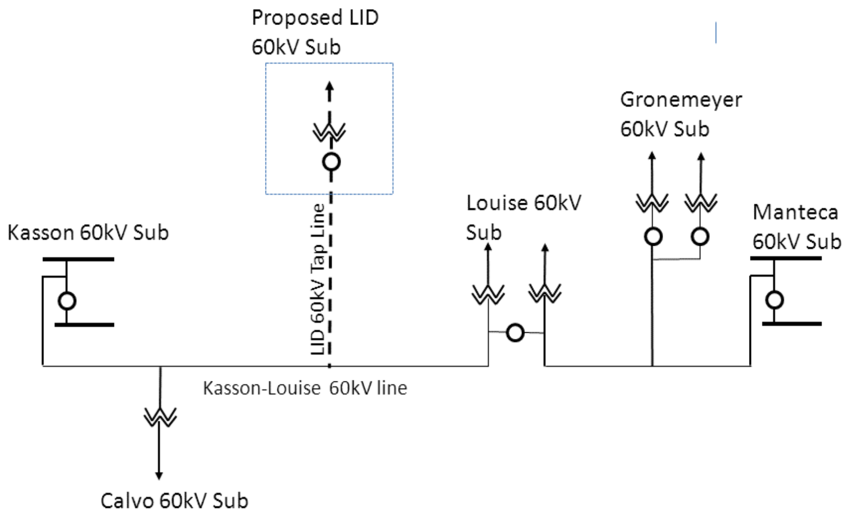
- At this time no projects are being requested for Management Approval in PG&E area.
- Currently reviewing projects submitted to Request Window
  - Due to estimated In-service Date of projects and current action plans to address reliability concerns in areas, ISO may continue to monitor in future cycles and if required approve projects closer to when projects would be initiated.

ISO Recommendations on Proposed Projects Kern Area

Project Name	Type of Project	Submitted By	Is Project Found Needed
Lathrop 60 kV Load Interconnection	Load Interconnection	PG&E	Concur
Aera Energy-East Cat Canyon Load Interconnection	Load Interconnection	PG&E	Concur
Southeast Surface Water Treatment Facility (SESWTF)	Load Interconnection	PG&E	Concur

Three (3) Project Recommended for Concurrence (Load Interconnection)

Central Valley Area Load Interconnection



Need: 14 MW load interconnection.

Project Scope:
New customer owned 60kV substation and a 60 kV transmission line tapped into PG&E's Kasson-Louise 60kV Line.

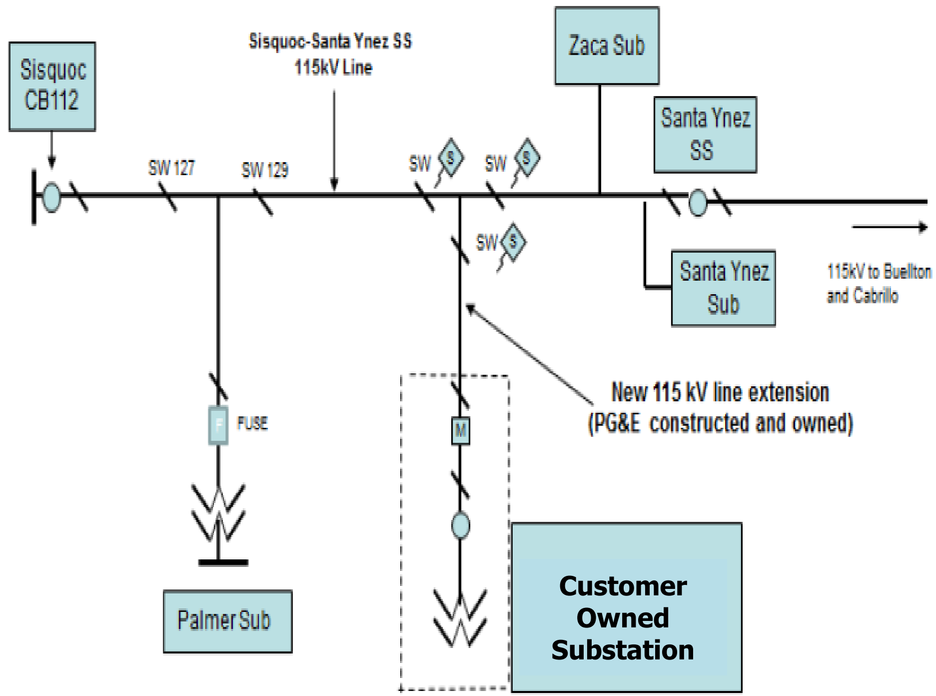
- Interconnection will be designed to be transferred to 115 kV system to accommodate forecast load at new substation with interim connection to 60 kV to meet customer interconnection requirements.

Cost:
$1M - $2M (PG&E)

Other Considered Alternatives:
Permanent interconnection on the Kasson-Louise 60 kV Line was considered; however forecasted load at station would require rebuild of 60 kV system in area.

Expected In-Service: 2015

Kern Area Load Interconnection



Need: 12 MW load interconnection

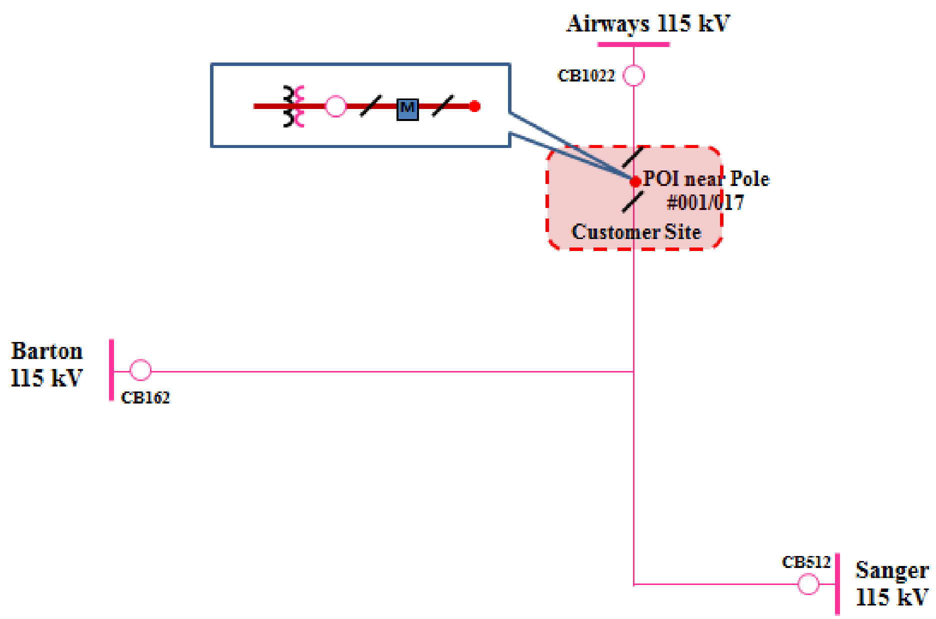
Project Scope: Proposes to connect a new customer owned 115 kV tap line on the PG&E's Santa Ynez-Sisquoc 115 kV Line to a new customer owned substation

Cost: $1.8M

Other Considered Alternatives: Directly interconnect to the to the Palmer Substation 115 kV. Results in expensive conversion of Palmer substation into a 4-breaker ring bus.

Expected In-Service: 1/2017

Fresno Area Load Interconnection



Need: 5 MW load interconnection

Project Scope: This project proposes to connect a new customer owned ~200ft tap line from PG&E's Barton-Airways-Sanger 115kV Line to a new customer owned substation.

Cost: $1.2M - $2.4M

Other Considered Alternatives:
1. Status Quo
2. Interconnect on Manchester-Airways-Sanger 115kV
3. Interconnect on Barton-Airways-Sanger 115kV
4. Interconnect in Airways 115kV bus
5. Interconnect in Barton 1115 12kV feeder
6. Interconnection in Airways 12kV bank

Expected In-Service: December 2016

Recommendations for Management Approval of Reliability Projects less than $50 Million

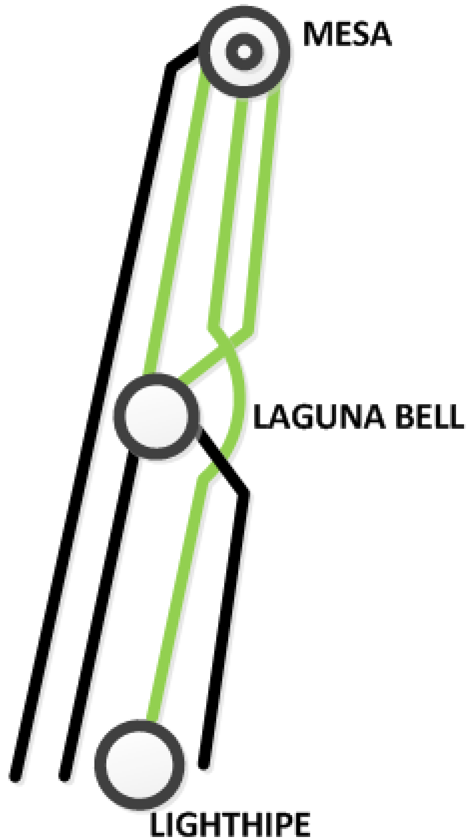
SCE Metro Area

2014-2015 ISO Transmission Planning Process

Nebiyu Yimer
Regional Transmission - South
November 19-20, 2014

One (1) Project Recommended for Management Approval (under $50 Million)

Laguna Bell Corridor Upgrades



<u>Need:</u> NERC Category B & C overloads (2020)

<u>Project Scope:</u> The project will increase the emergency ratings of three (3) 230 kV lines (shown in green) by 32-35% by

- replacing terminal equipment at Laguna Bell and Lighthipe and
- Removing clearance limitations on a total of two spans

<u>Cost:</u> $5 million

<u>Other Considered Alternatives:</u> Utilize available preferred resources

<u>Expected In-Service</u>: December 31, 2020

<u>Interim Plan:</u> N/A

Laguna Bell Corridor Upgrades – Cont'd

Pre-project and post-project maximum line loadings

Transmission line	Contingency type	2024 summer peak loading (%)		
		Pre-project	Post-project	Post-project with available preferred resources
Mesa–Laguna Bell #1 230 kV	B(L-1)	102%	76%	N/A
	B(G-1/L-1)	111%	82%	N/A
	C(L-2)	128%	95%	N/A
	C(L-1/L-1)	137%	102%	<100%
Mesa–Laguna Bell #2 230 kV	B(G-1/L-1)	101%	75%	N/A
	C(L-2)	106%	79%	N/A
	C(L-1/L-1)	110%	81%	N/A
Mesa–Lighthipe 230 kV	C(L-2)	107%	81%	N/A

Recommendations for Management Approval of Reliability Projects less than $50 Million

San Diego Gas & Electric Area

Executive Review of the 2014-2015 ISO Transmission Plan Reliability Project Recommendations

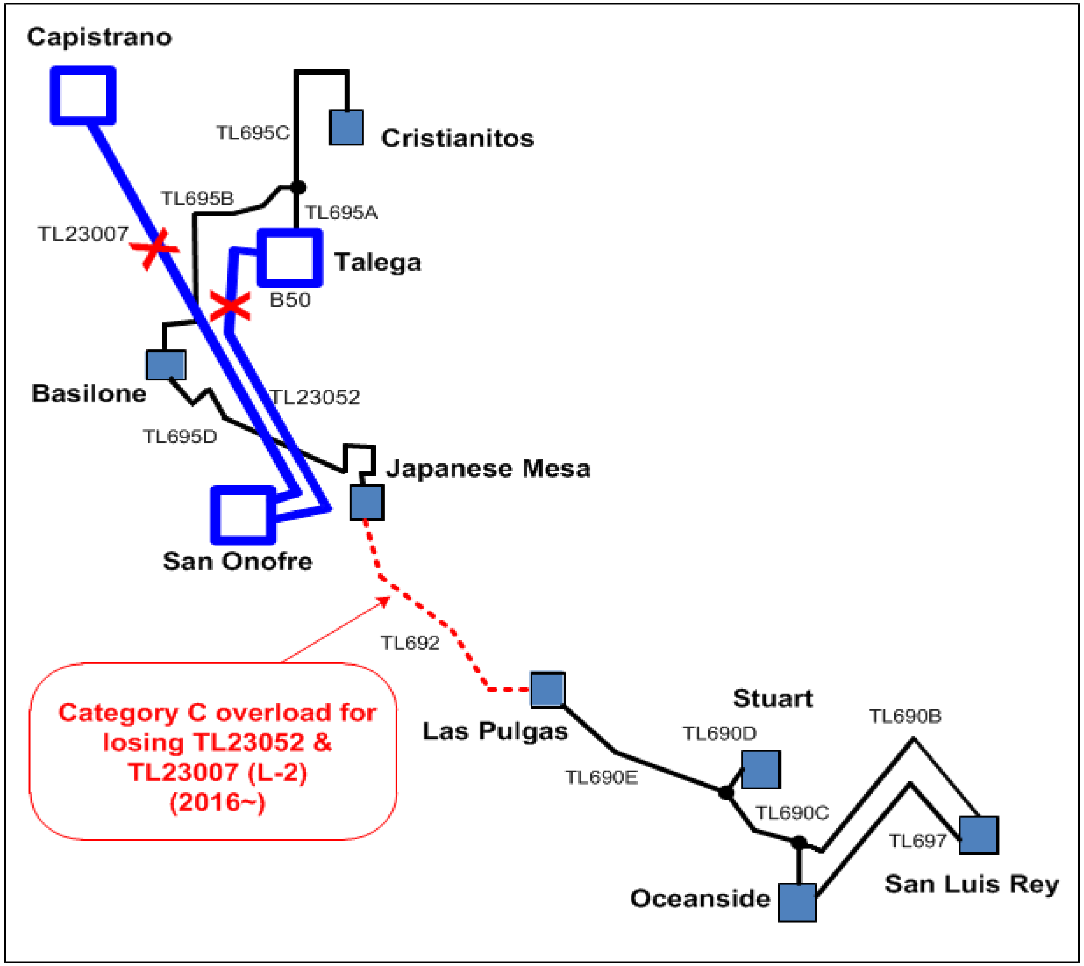
Frank Chen
Sr. Regional Transmission Engineer

November 11, 2014

ISO Recommendations on Proposed Projects San Diego Gas & Electric Area

Project Name	Type of Project	Submitted By	Is Project Found Needed
TL692 Line Reconductor	Reliability	SDG&E	Yes
2nd Pomerado–Poway 69kV Circuit	Reliability	SDG&E	Yes
Mission-Penasquitos 230 kV Circuit	Reliability	ISO	Yes
TL632 Granite Loop-In and TL6914 Reconfiguration	Reliability	SDG&E	Yes
Salt Creek 69 kV Load Substation	Distribution	SDG&E	Concur
Vine 69 kV Load Substation	Distribution	SDG&E	Concur

1. TL692 69 kV Circuit Reconductor



Need: NERC Category C overload (2016)

Project Scope: Re-conductor TL692 69 kV line to archive normal rating of 102 MVA from 32 MVA

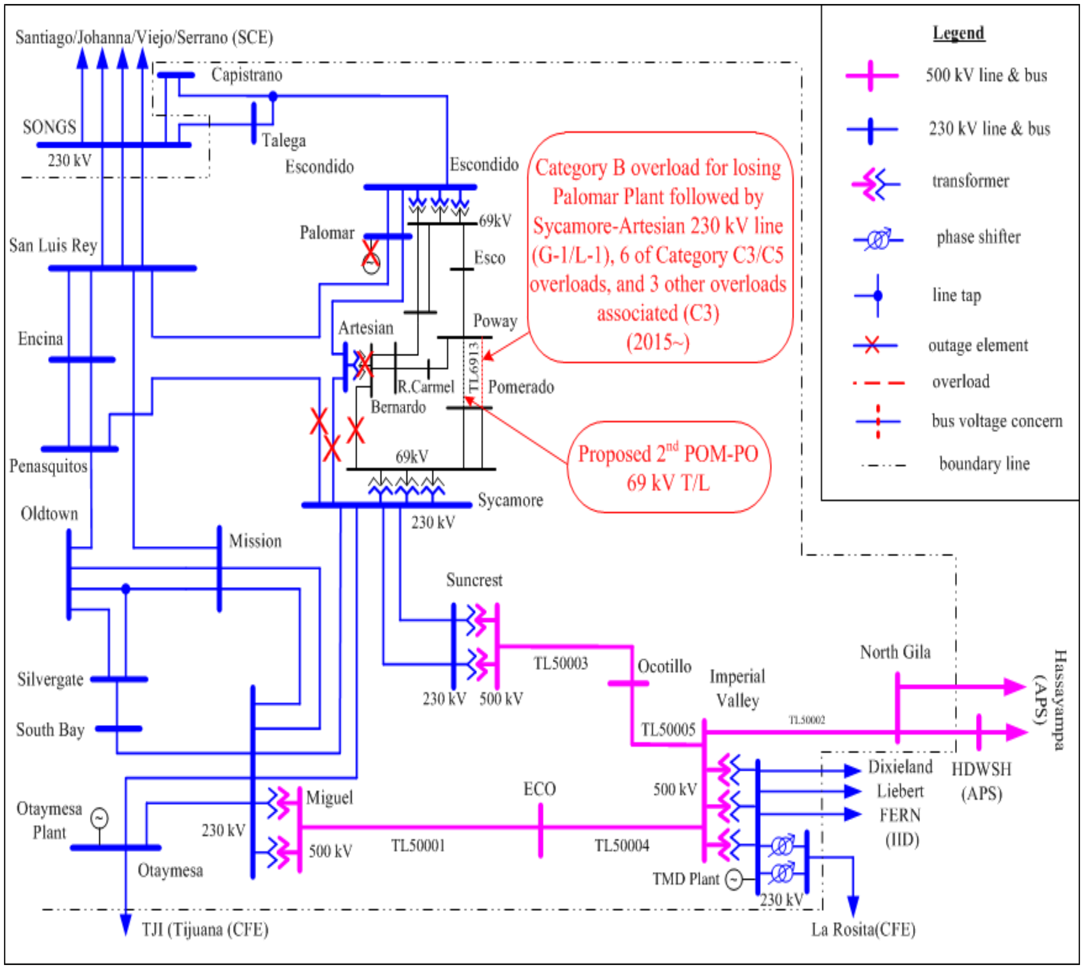
Cost: Minimal incremental cost to advance the wood-to-steel project by two years which costs \$25.9~\$28.5 M to replace wood with steel poles and reconductor for TL692

Other Considered Alternatives:
New SPS to protect TL692 (\$3 millions)

Expected In-Service: June 2016

Interim Plan: NA

2. 2nd Pomerado–Poway 69kV Circuit



Need: CAISO Planning Standards G-1/L-1 and various NERC Category C3/C5 overloads (2015~)

Project Scope: Build 2nd Pomerado-Poway 69kV circuit rated at 174 MVA (2.6 miles) with Poway 69 kV sub and TL6913 right-of-way expansion

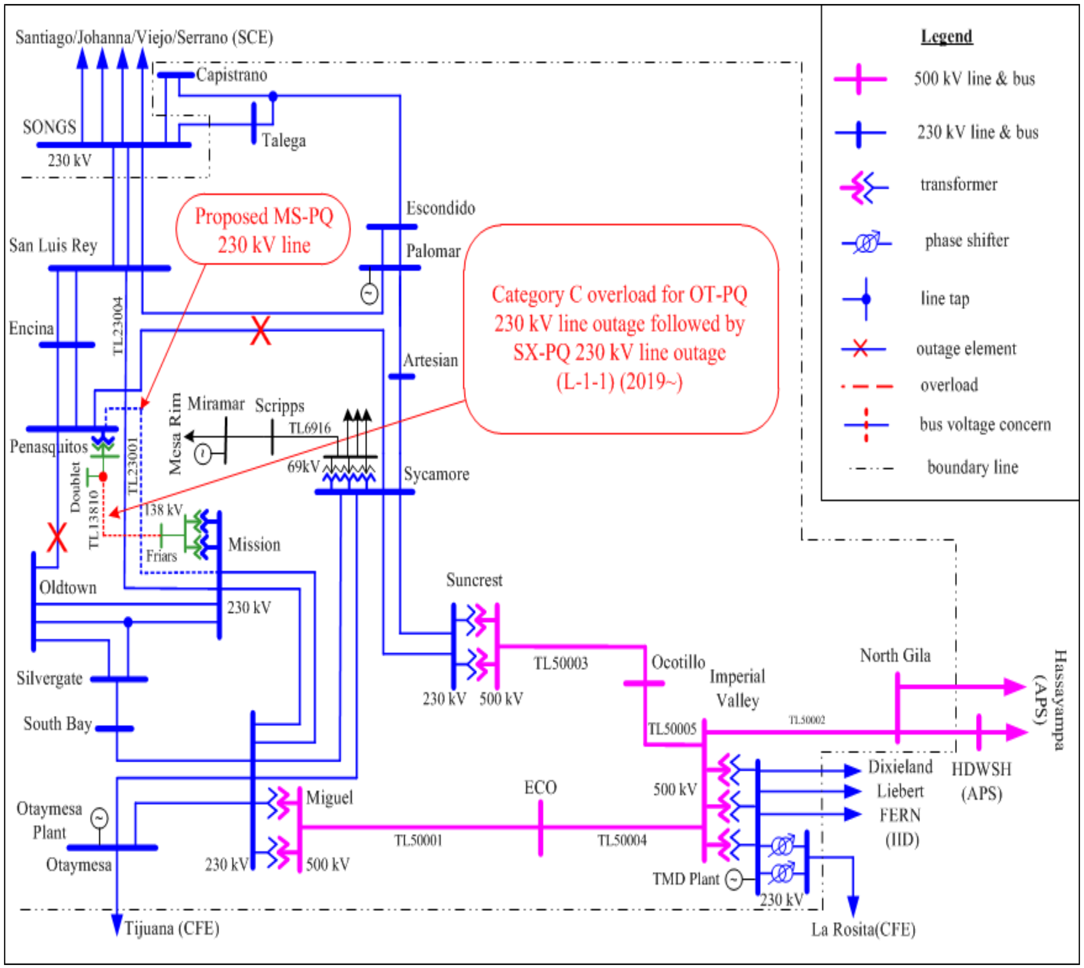
Cost: $17~$19 millions

Other Considered Alternatives:
Re-conductor TL6913 again will be less cost-effective and can't eliminate the Category C overloads associated to the TL6913 outage

Expected In-Service: June 2016

Interim Plan: Operation Procedure to shed up to 80 MW loads in the Poway area

3. Mission-Penasquitos 230 kV Circuit



Need: CAISO Planning Standards violation for High Density Urban Load Area (2019~)

Project Scope: Build Mission-Penasquitos 230 kV Circuit by using de-energized portion of TL23001 after SX-PQ project in-service and adding a double-circuit section to access PQ

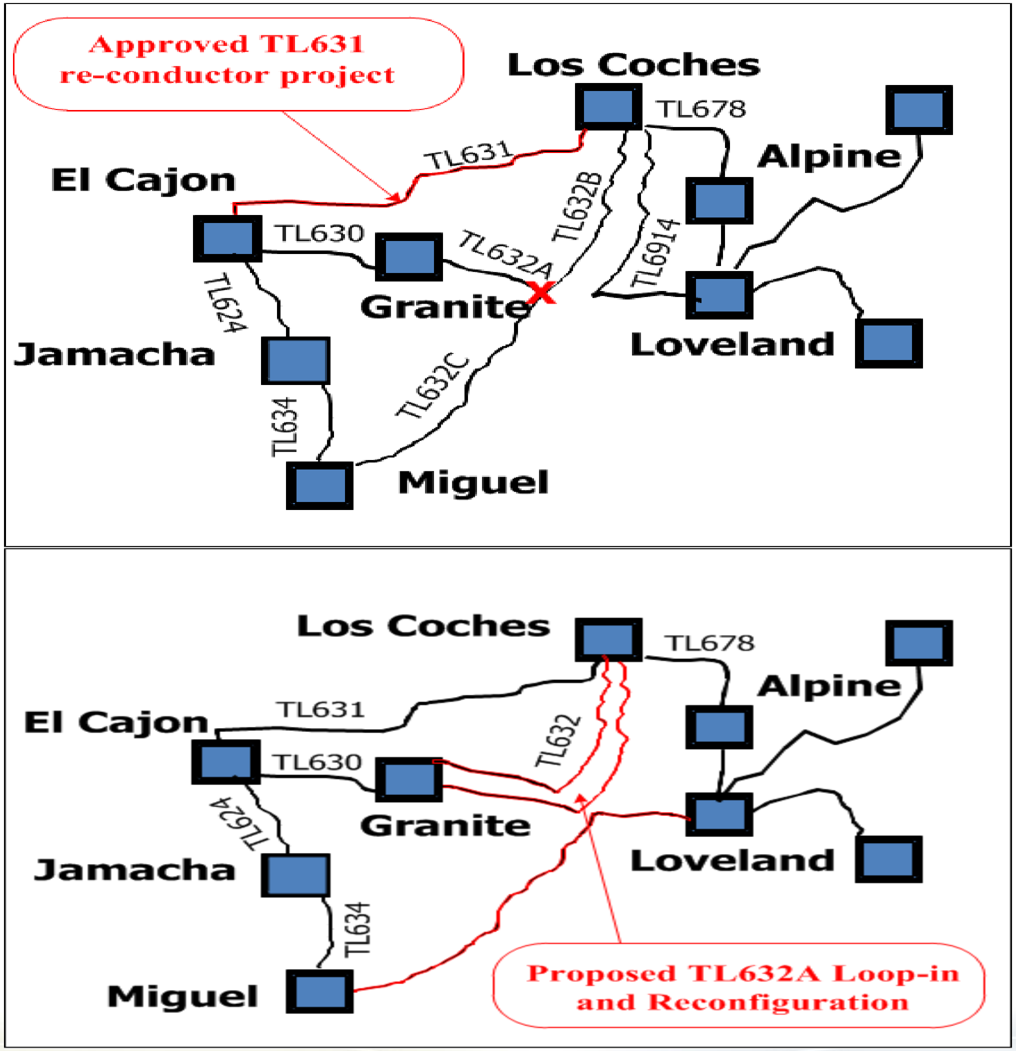
Cost: $22.8~25.5 millions

Other Considered Alternatives:
Upgrade 2 miles of 12.6-mile TL13810 to achieve 204 MVA rating ($4.1~4.5 millions)

Expected In-Service: June 2019

Interim Plan: Operation Procedure to shed up to 195 MW loads in high density urban area

4. TL632 Granite Loop-In and TL6914 reconfiguration



Need: Providing superior mitigation than previously approved TL631 re-conductor project

Project Scope: Remove Granite Tap by Loop-in TL632 to Granite Sub with OH-UG in and out, and reconfigure TL6914 to terminate between Miguel and Loveland

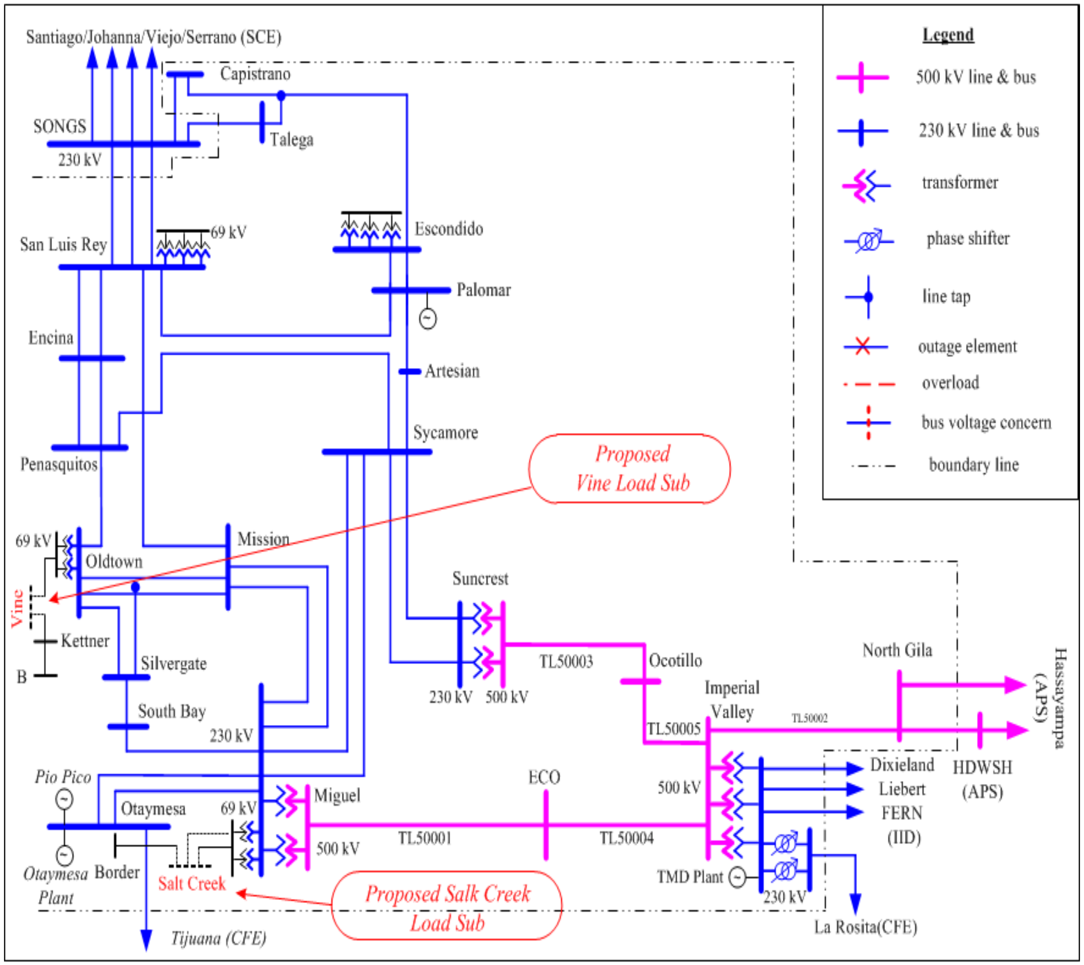
Cost: $15.2~$19.8 millions

Other Considered Alternatives:
Similar plan with TL632 Granite Loop-In in double-circuit lines from GraniteTap to Granite

Expected In-Service: June 2017

Interim Plan: NA

5. Salt Creek 69 kV Load Sub
6. Vine 69 kV Load Sub



<u>Need:</u> Distribution load growth at Salt Creek and Vine

<u>Project Scope</u>: 2-in/1-out 69 kV sources at Salt Creek; 1-in/1-out 69 kV sources at Vine,

<u>Cost:</u> TBD; it costs extra $16.7~18.5 M to build new Miguel-Salt Creek 69 kV line

<u>Other Considered Alternatives:</u>
two 69 kV transmission sources (1-in/1-out) to serve initial Salt Creek sub

<u>Expected In-Service</u>: Salt Creek:2016, Vine: 2017

2024 Long-Term LCR Study Results - Northern Local Areas

Catalin Micsa

Lead Regional Transmission Engineer

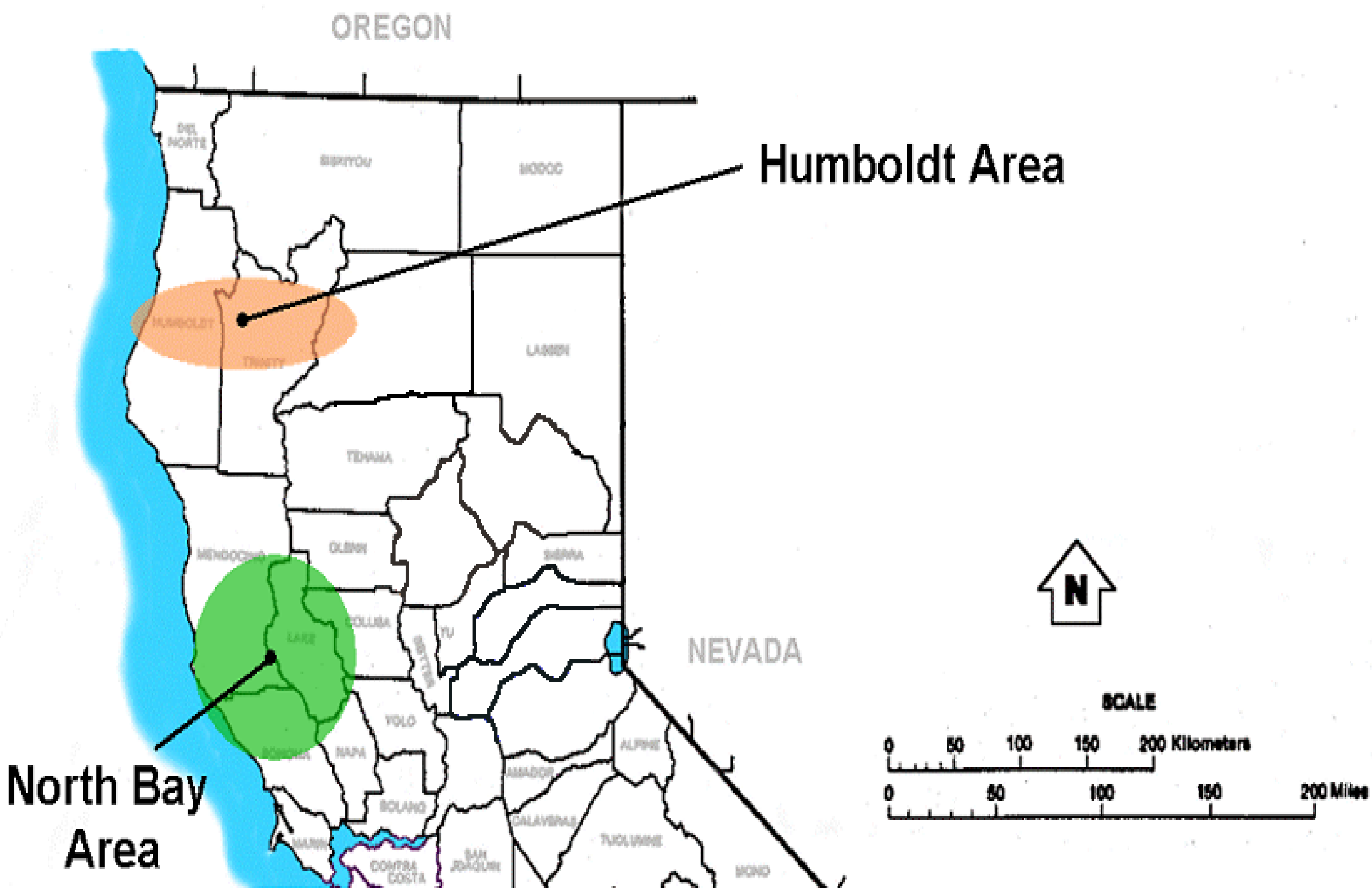
2014-2015 Transmission Planning Process Stakeholder Meeting

November 19-20, 2014

Assessment of LCR needs done by:

Humboldt	Rajeev Annaluru
North Coast/North Bay	Rajeev Annaluru
Sierra	Catalin Micsa
Stockton	Catalin Micsa
Bay Area	Bryan Fong
Fresno	Abhishek Singh
Kern	Chris Mensah-Bonsu

Humboldt Area



Humboldt Load and Resources (MW)

		2019	2024
Load	=	194	196
Transmission Losses	=	10	7
Total Load	=	204	203
Market Generation	=	184	184
QF/Self-Gen Generation	=	55	55
Total Qualifying Capacity	=	**239**	**239**

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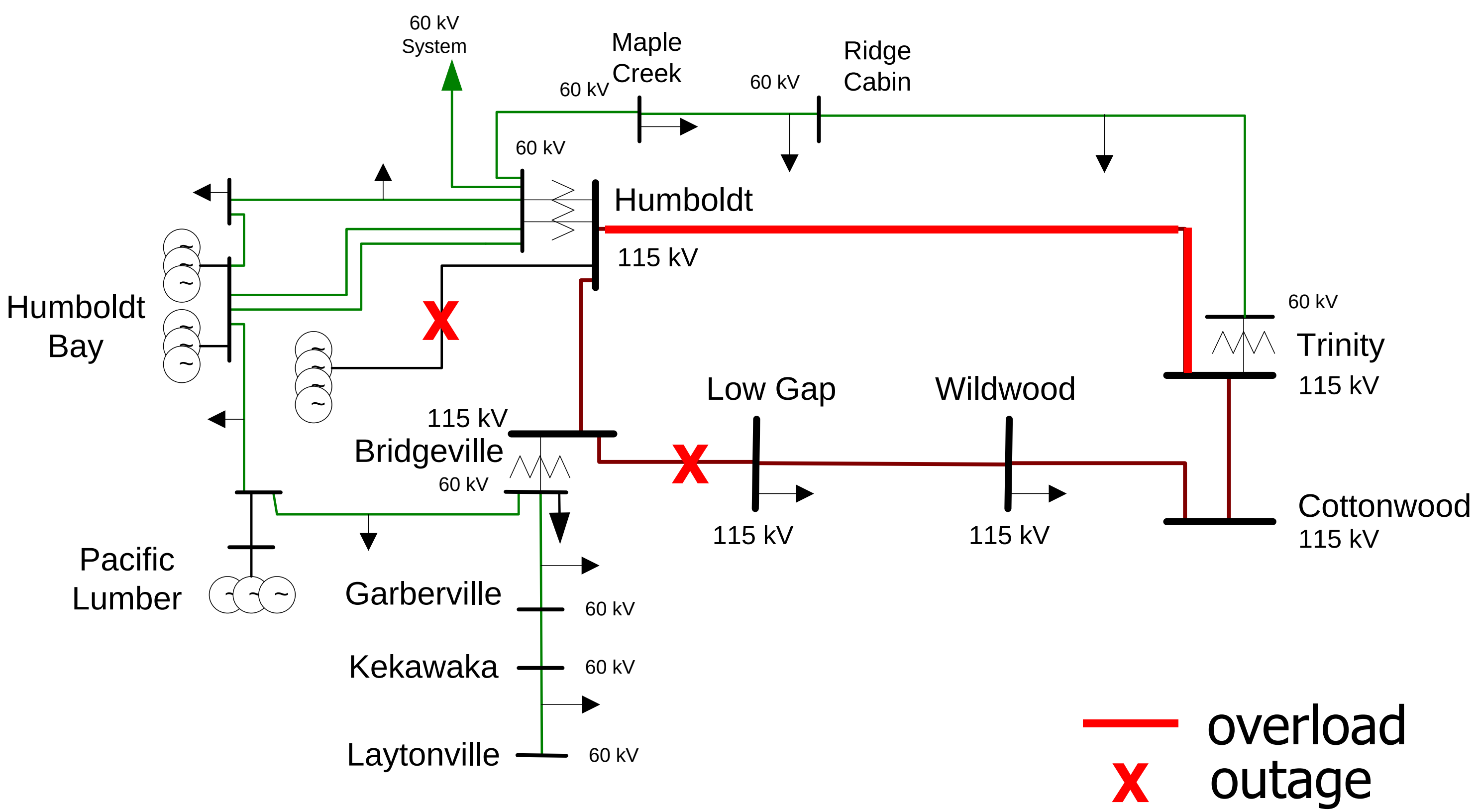
New transmission projects modeled:

1. Laytonville 60 kV Circuit Breaker Installation Project (2016)
2. Maple Creek Reactive Support (2017)
3. Humboldt - Eureka 60 kV Line Capacity Increase (2017)
4. New Bridgeville - Garberville No.2 115 kV Line (2022)

Critical Contingencies Humboldt Area



Critical Contingencies Humboldt Area

Humboldt Overall – Category B

- Contingency: Cottonwood-Bridgeville 115 kV line + one Humboldt PP units out of service
- Limiting component: Thermal overload on Humboldt -Trinity 115 kV line
- 2019 LCR Need: 123 MW (including 36 MW of QF/Self generation)
- 2024 LCR Need: 127 MW (including 36 MW of QF/Self generation)

Humboldt Overall – Category C

- Contingency: Cottonwood – Bridgeville 115 kV line + 115 kV Gen tie to the Humboldt Bay Units
- Limiting component: Thermal overload on the Humboldt - Trinity 115kV Line
- 2019 LCR need: 173 MW (including 36 MW of QF/Self generation)
- 2024 LCR need: 178 MW (including 36 MW of QF/Self generation)

Changes

Compared to 2019 LCR study:

1) New Bridgeville-Garberville 115 kV line
2) Load went down slightly by 1 MW
3) LCR increased slightly by 5 MW

Your comments and questions are welcomed

Please send written comments to:
RegionalTransmission@caiso.com

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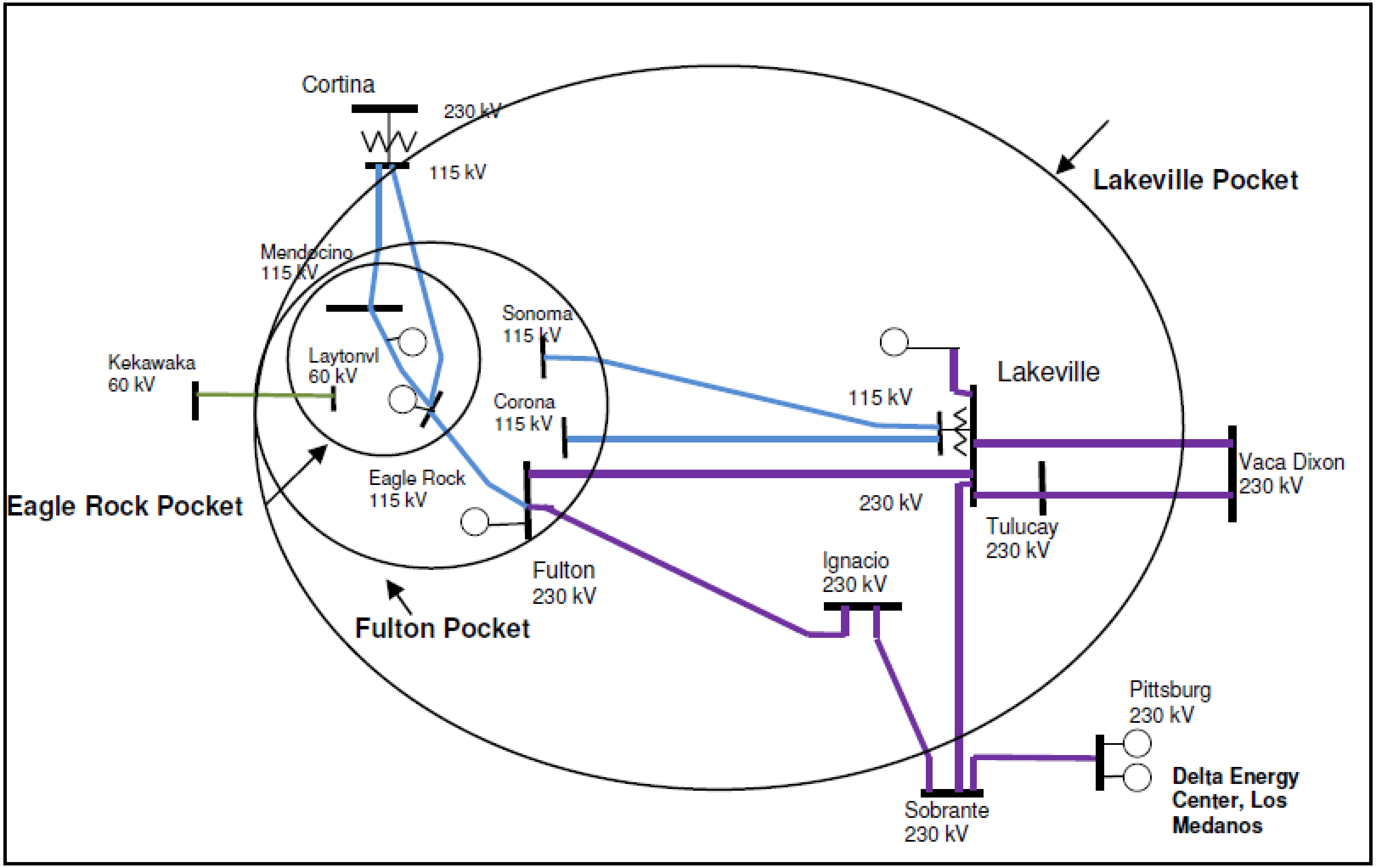
North Coast/North Bay Load and Resources (MW)

		2019	2024
Load	=	1447	1511
Transmission Losses	=	37	39
Total Load	=	**1484**	**1550**
Market Generation	=	771	771
Wind Generation	=	0	0
Muni Generation	=	113	113
QF Generation	=	17	17
Total Qualifying Capacity	=	**901**	**901**

New transmission projects modeled:

1. Mendocino Coast Reactive Support (2015)
2. Laytonville 60 kV Circuit Breaker Installation Project (2016)
3. Fulton - Fitch Mountain 60 kV Line Reconductor (2016)
4. Tulucay 230/60 kV Transformer No. 1 Capacity Increase (2016)
5. Napa - Tulucay No. 1 60 kV Line Upgrades (2017)
6. Vaca Dixon - Lakeville 230 kV Reconductoring (2018)
7. Clear Lake 60 kV System Reinforcement (2020)
8. Mare Island - Ignacio 115 kV Reconductoring Project (2020)
9. Fulton 230/115 kV Transformer (2021)
10. Ignacio - Alto 60 kV Line Voltage Conversion (2021)

North Coast and North Bay



Eagle Rock Sub-Area

Eagle Rock Sub-area – Category B

Contingency: Cortina-Mendocino 115 kV line, with Geyser #11 unit out

2019 LCR need: 201 MW (includes 3 MW of QF/Muni generation)

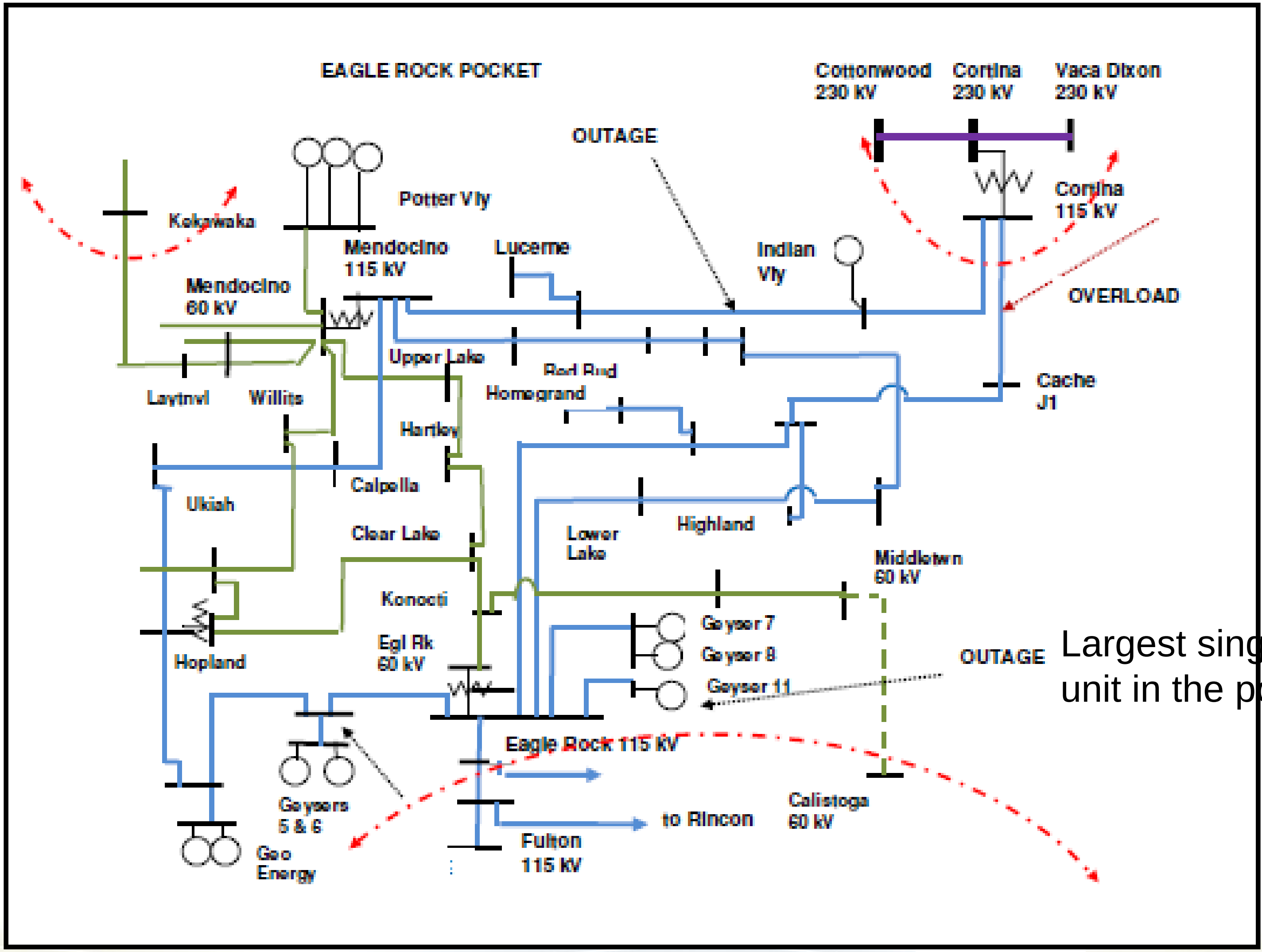
2024 LCR need: 219 MW (includes 3 MW of QF/Muni generation)

Limiting component: Thermal overload on Eagle Rock-Cortina 115 kV line

Eagle Rock Sub-area – Category C

Same as Category B

Eagle Rock Sub-Area



Largest single unit in the pocket

Fulton Sub-area

Fulton Sub-area – Category C

Contingency: Fulton-Lakeville and Fulton-Ignacio 230 kV lines

2019 LCR need: 310 MW (includes 70 MW of QF/Muni generation)

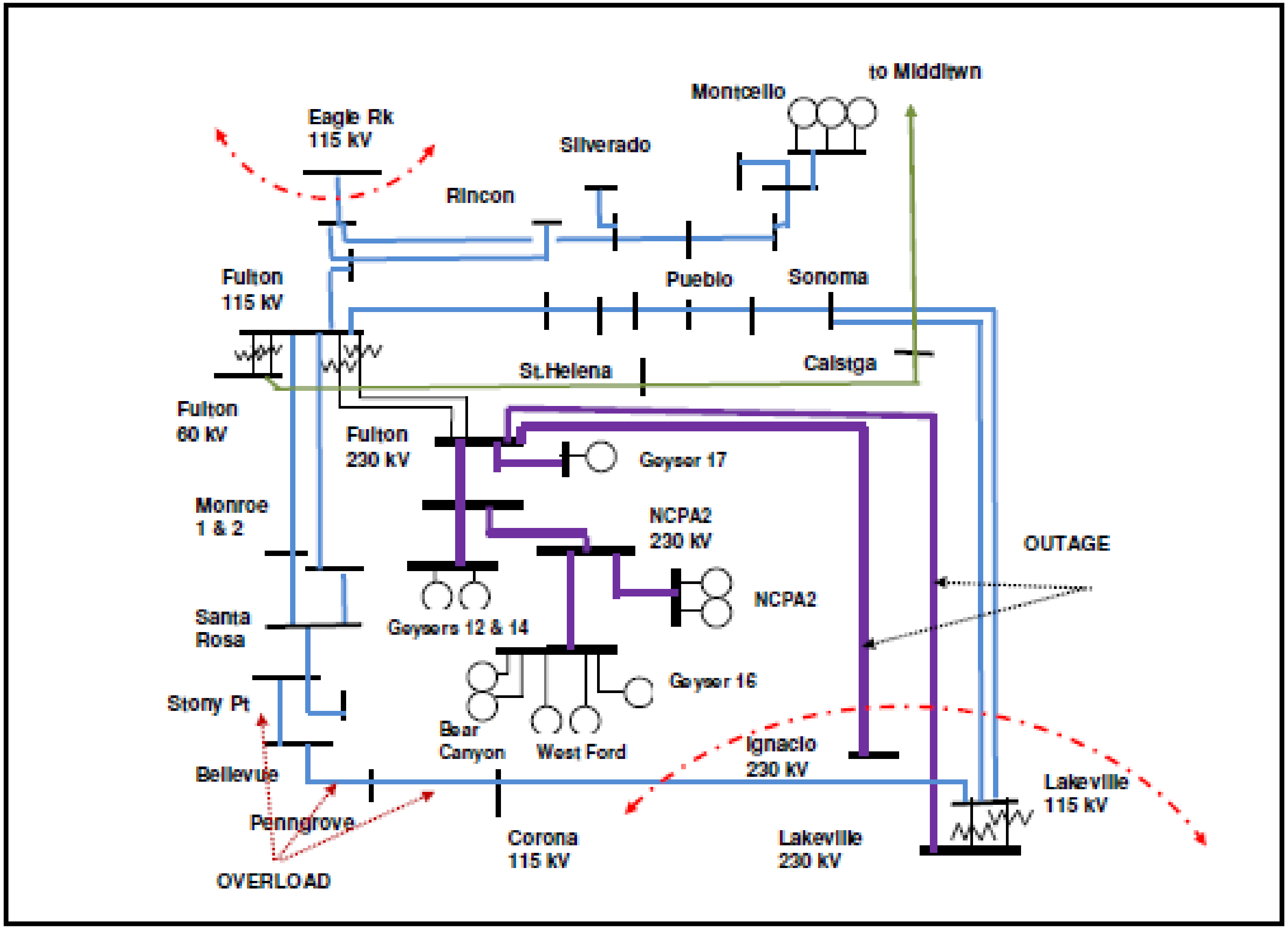
2024 LCR need: 312 MW (includes 70 MW of QF/Muni generation)

Limiting component: Thermal overload on Santa Rosa-Corona 115 kV line

Fulton Sub-area – Category B

No requirement.

Fulton Sub-area



Lakeville Sub-area

Lakeville Sub-area (NC/NB Overall) – Category B

Contingency: Vaca Dixon-Tulucay 230 kV line with Delta Energy Center power plant out of service

2019 LCR need: not limiting due to the system upgrades, same as Fulton sub-area: 310 MW (includes 70 MW of QF/Muni generation)

2024 LCR need: not limiting due to the system upgrades, same as Fulton sub-area: 312 MW (includes 70 MW of QF/Muni generation)

Limiting component: Thermal overload on the Vaca Dixon-Lakeville 230 kV line

Lakeville Sub-area (NC/NB Overall) – Category C

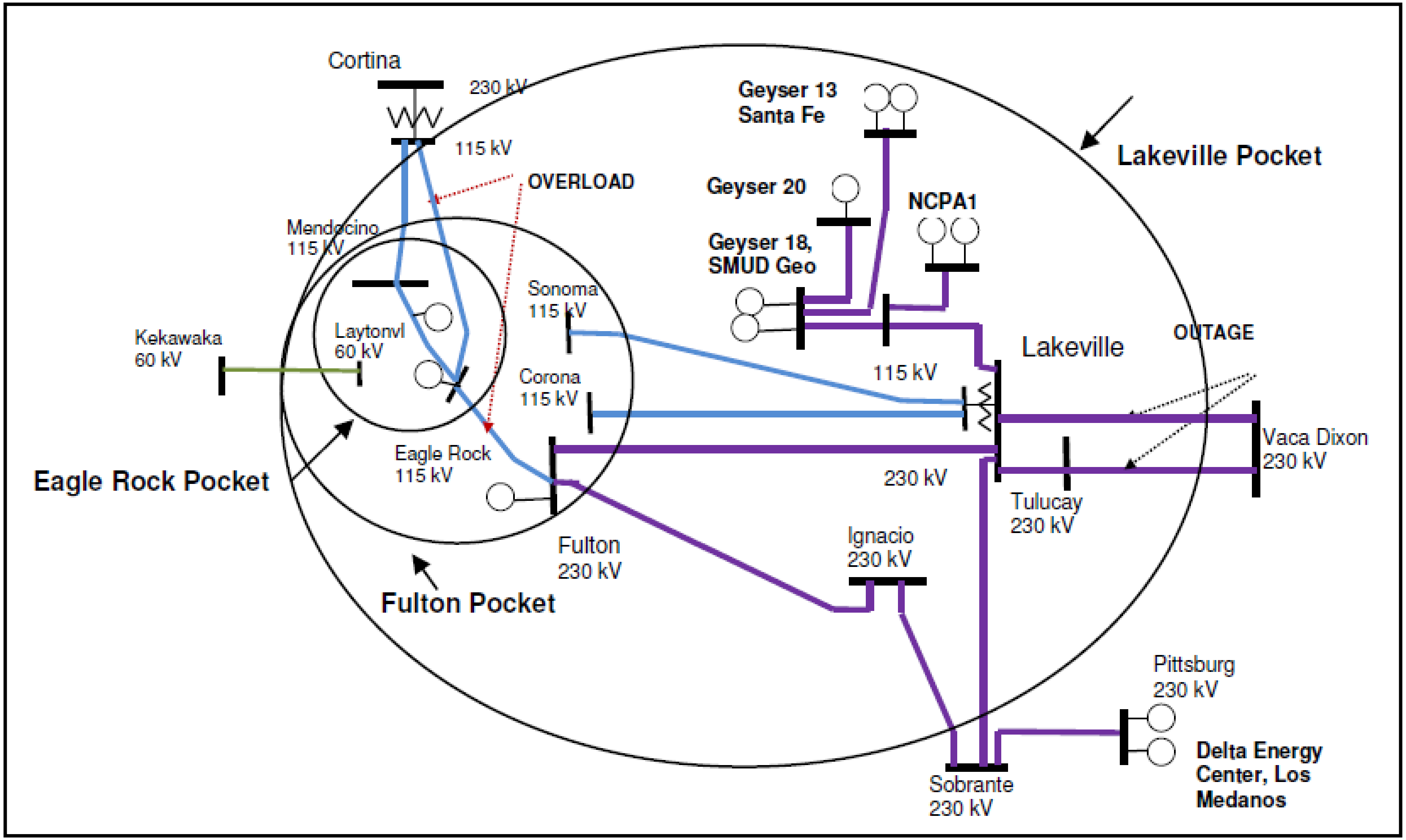
Contingency: Vaca Dixon-Tulucay and Vaca Dixon-Lakeville 230 kV lines

2019 LCR need: 516 MW (includes 130 MW of QF/Muni generation)

2024 LCR need: 505 MW (includes 130 MW of QF/Muni generation)

Limiting component: Thermal overload on the Eagle Rock-Cortina

Lakeville Sub-area Category C



LCR need depends on the generation in the Pittsburg area.

Changes

Compared to 2019 LCR study:

1. Load forecast is higher by 66 MW
2. LCR need has decreased by 11 MW
3. Two small renewable projects

Your comments and questions are welcomed

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

Sierra Area Load and Resources (MW)

		2019	2024
Load	=	1976	2177
Transmission Losses	=	100	84
Total Load	=	**2076**	**2261**
Market Generation	=	771	771
Muni Generation	=	1107	1107
QF Generation	=	192	192
Total Qualifying Capacity	=	**2070**	**2070**

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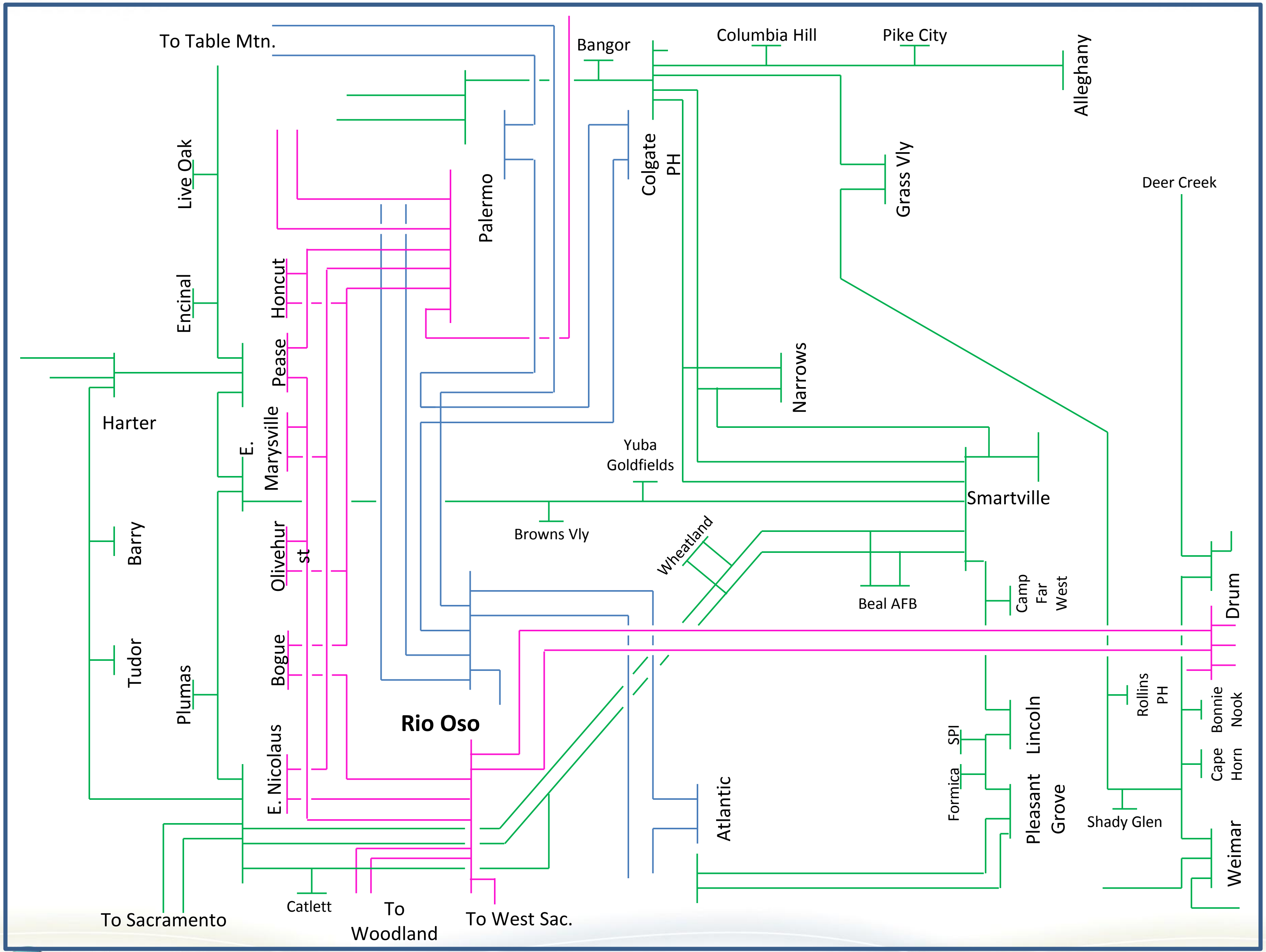
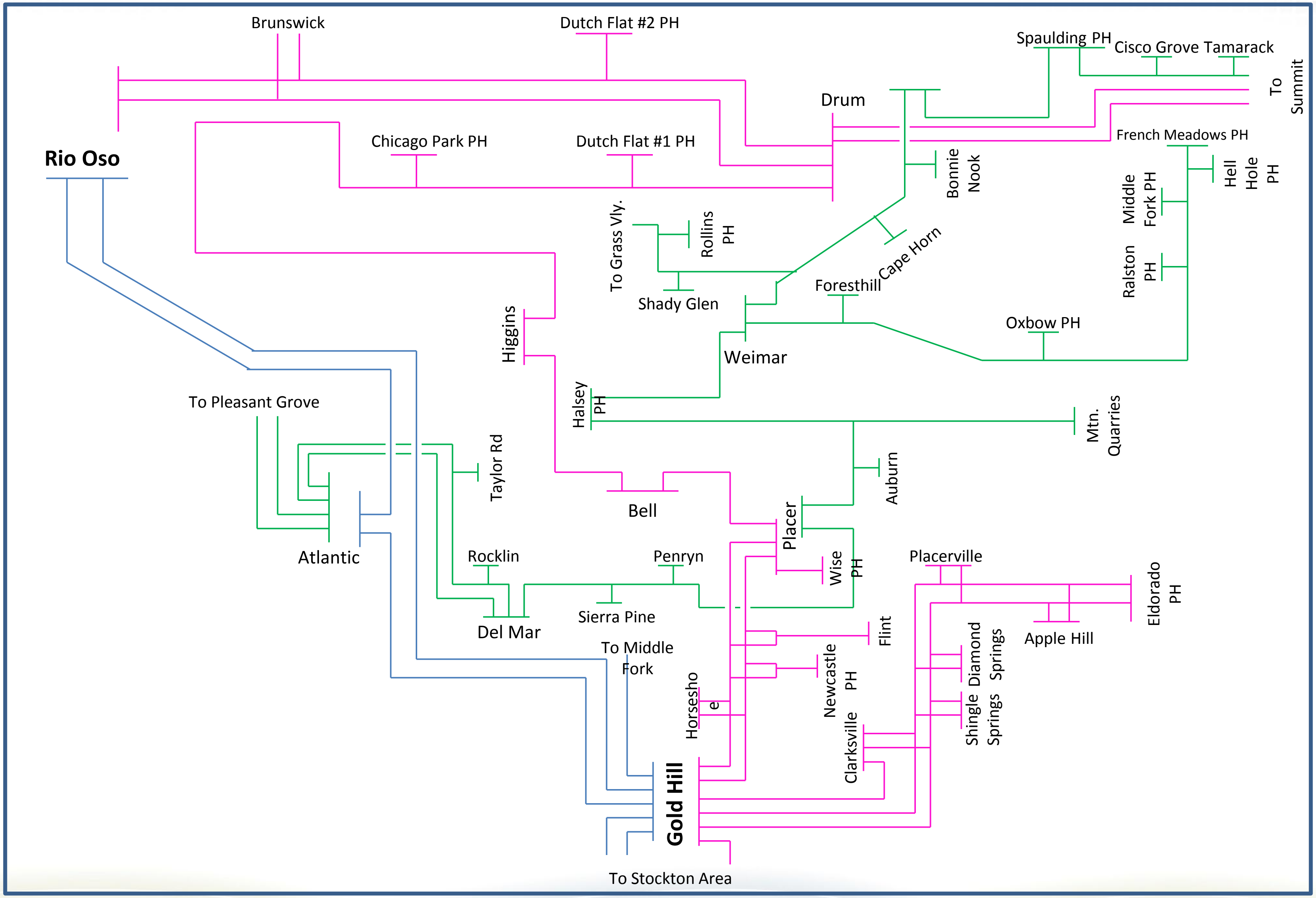
Northern Sierra



Southern Sierra



New transmission projects modeled:

1. East Nicolaus 115 kV Area Reinforcement (2016)
2. Gold Hill-Missouri Flat #1 and #2 115 kV line Reconductoring (2018)
3. Pease 115/60 kV Transformer Addition (2018)
4. Pease-Marysville #2 60 kV line (2019)
5. Rio Oso #1 and #2 230/115 kV Transformer Replacement (2019)
6. Rio Oso Area 230 kV Voltage Support (2019)
7. South of Palermo 115 kV Reinforcement (2019)
8. New Atlantic-Placer 115 kV Line (2019)
9. New Rio Oso-Atlantic 230 kV line (2020)
10. Vaca Dixon-Davis Voltage Conversion (2021)

Critical Sierra Area Contingencies Placerville

Placerville Sub-area – Category C

2019 LCR need: No requirements

2024 LCR need: 16 MW (includes 0 MW of QF and Muni generation)

Contingency: Gold Hill-Clarksville and Gold Hill-Missouri Flat #2 115 kV lines

Limiting component: Thermal overload on the Gold Hill-Missouri Flat #1 115 kV line

Placerville Sub-area – Category B

2019 LCR need: No requirements

2024 LCR need: 13 MW (includes 0 MW of QF and Muni generation)

Contingency: Gold Hill-Missouri Flat #2 115 kV line with one of the El Dorado units out of service

Limiting component: Low voltage at Placerville 115 kV bus

Critical Sierra Area Contingencies
Placer, Drum-Rio Oso and South of Palermo

Placer Sub-area – Category B & C

2019 LCR need: 60 MW (includes 38 MW of QF and Muni generation)

2024 LCR need: 62 MW (includes 38 MW of QF and Muni generation)

Contingency: New Atlantic-Placer 115 kV line with Chicago Park unit out of service

Limiting component: Thermal overload on the Drum-Higgins 115 kV line

Drum-Rio Oso Sub-area

Eliminated due to the Rio Oso Transformer Replacement project.

South of Palermo Sub-area

Eliminated due to the South of Palermo 115 kV Reinforcement project.

Critical Sierra Area Contingencies
Pease

Pease Sub-area – Category C

2019 LCR need: 93 MW (includes 70 MW of QF generation)

2024 LCR need: 127 MW (includes 70 MW of QF generation)

Contingency: Palermo-Pease and Pease-Rio Oso 115 kV lines

Limiting component: Thermal overload on the Table Mountain-Pease 60 kV line and low voltage at Pease 115 kV bus

Pease Sub-area – Category B

2019 LCR need: 51 MW (includes 70 MW of QF generation)

2024 LCR need: 82 MW (includes 70 MW of QF generation)

Contingency: Palermo-Pease 115 kV line and YCEC unit

Limiting component: Thermal overload on the Table Mountain-Pease 60 kV line

Critical Sierra Area Contingencies
South of Rio Oso

South of Rio Oso Sub-area – Category C

2019: No requirement due to New Atlantic-Rio Oso 230 kV line project.

2024 LCR need: 362 MW (includes 31 MW of QF and 593 MW of Muni generation)

Contingency: Rio Oso-Gold Hill and Rio Oso-Atlantic 230 kV lines

Limiting component: Thermal overload on the remaining Rio Oso-Atlantic 230 kV line

South of Rio Oso Sub-area – Category B

2019: No requirement due to New Atlantic-Rio Oso 230 kV line project.

2024: No requirement due to New Atlantic-Rio Oso 230 kV line project.

Critical Sierra Area Contingencies South of Table Mountain

South of Table Mountain Sub-area – Category C

2019 LCR need: 1102 MW (includes 192 MW of QF and 1107 MW of Muni generation)

2024 LCR need: 1478 MW (includes 192 MW of QF and 1107 MW of Muni generation)

Contingency: Table Mountain-Rio Oso 230 kV and Table Mountain-Palermo 230 kV DCTL outage

Limiting component: Thermal overload on the Table Mountain-Pease 60 kV line and Caribou-Palermo 115 kV line

South of Table Mountain Sub-area – Category B

2019 LCR need: 525 MW (includes 192 MW of QF and 1107 MW of Muni generation)

2024 LCR need: 907 MW (includes 192 MW of QF and 1107 MW of Muni generation)

Contingency: Table Mountain-Rio Oso 230 kV line and Belden Unit

Limiting component: Thermal overload on the Table Mountain-Palermo 230 kV line

Sierra Area LCR Aggregate

Available generation	Market (MW)	Muni (MW)	QF (MW)	Max. Qualifying Capacity (MW)
2019	771	1107	192	2070
2024	771	1107	192	2070

	Existing Generation Capacity Needed (MW)		Deficiency (MW)		Total MW Need	
	2019	2024	2019	2024	2019	2024
Category B (Single)	525	907	0	0	525	907
Category C (Multiple)	1102	1478	0	0	1102	1478

Each unit is only counted once, regardless in how many sub-areas it is needed.

In order to come up with an aggregate deficiency, where applicable the deficiencies in each smaller sub-area has been accounted for (based on their effectiveness factors) toward the deficiency of a much larger sub-area.

Changes

Compared to 2019 LCR study:

1) No new transmission projects or resources
2) Load + Losses went up by 185 MW
3) Long-Term LCR has increased by 376 MW mainly due to load growth (load is more effective)

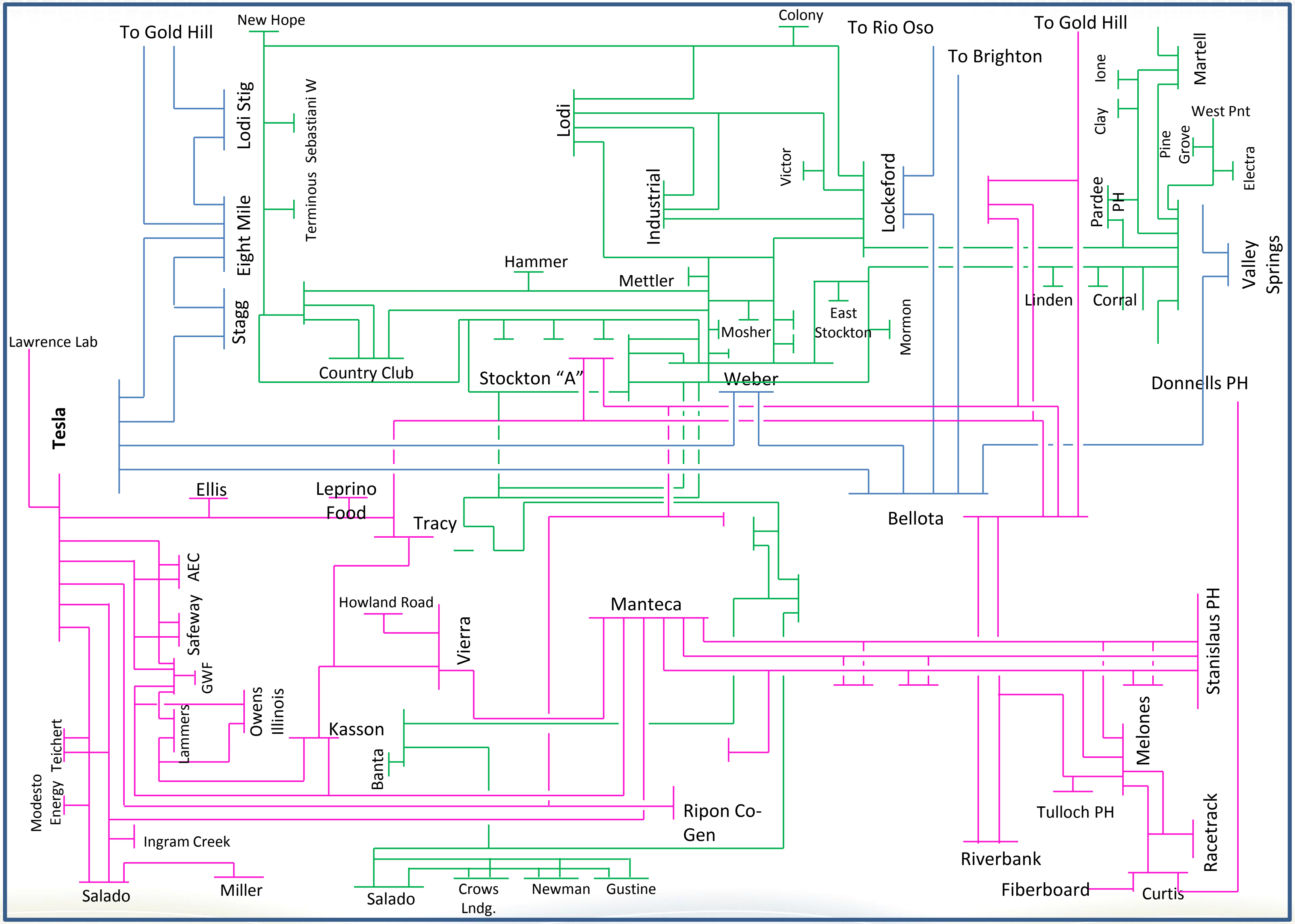
Your comments and questions are welcome.

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

Stockton Area Load and Resources (MW)

		2019	2024
Load	=	1118	975
Transmission Losses	=	18	17
Total Load	=	**1136**	**992**
QF Generation	=	158	156
Muni Generation	=	137	114
Market Generation	=	392	392
Total Qualifying Capacity	=	**687**	**662**

Stockton Area



New transmission projects modeled:

1. Tesla 115 kV Capacity Increase (2016)
2. Weber 230/60 kV Transformer Nos. 2 and 2A Replacement (2016)
3. Ripon 115 kV New Line Reconfiguration (2016)
4. Stockton 'A' - Weber 60 kV Line Nos. 1 and 2 Reconductor (2017)
5. Mosher Transmission Project (2017)
6. Weber - French Camp 60 kV Line Reconfiguration (2018)
7. West Point - Valley Springs 60 kV Line (Reconductor) (2019)
8. West Point - Valley Springs 60 kV Line Project (Second Line) (2019)
9. Vierra 115 kV Looping (2019)
10. Lockeford - Lodi Area 230 kV Development (2020)

Critical Stockton Area Contingencies
Tesla-Bellota Sub-area

Tesla-Bellota Sub-area – Category C

2019 LCR need: 260 MW (129 MW of QF and 114 MW of Muni generation)

2024 LCR need: 313 MW (129 MW of QF and 114 MW of Muni generation)

Contingency: Tesla-Schulte #2 115 kV lines and Tesla-Vierra.

Limiting component: Thermal overload on the Tesla-Schulte #1 115 kV line.

Tesla-Bellota Sub-area – Category B

2019 LCR Need: 163 MW (129 MW of QF and 114 MW of Muni generation).

2024 LCR Need: 287 MW (129 MW of QF and 114 MW of Muni generation).

Contingency: Tesla-Schulte #2 115 kV line and the loss of GWF Tracy #3.

Limiting component: Thermal overload on the Tesla-Schulte #1 115 kV line.

Critical Stockton Area Contingencies
Stanislaus Sub-area

Stanislaus Sub-area – Category C

2019 LCR need: Same as Category B

2024 LCR need: Same as Category B

Stanislaus Sub-area – Category B

2019 LCR need: 112 MW (includes 19 MW of QF and 94 MW of Muni generation)

2024 LCR need: 133 MW (includes 19 MW of QF and 94 MW of Muni generation)

Contingency: Bellota-Riverbank-Melones 115 kV line and Stanislaus PH

Limiting component: Thermal overload on the River Bank Jct.-Manteca 115 kV line

Critical Stockton Area Contingencies Weber and Lockeford Sub-areas

Weber Sub-area – Category C

2019 LCR need: 22 MW (includes 0 MW of QF generation)

2024 LCR need: 34 MW (includes 0 MW of QF generation)

Contingency: Stockton A-Weber #1 and #2 60 kV lines

Limiting component: Thermal overload on the Stockton A-Weber #3 60 kV line

Weber Sub-area – Category B

2024 LCR need: No Category B requirement.

Lockeford Sub-area

Eliminated due to the Lockeford-Lodi area 230 kV development project. (2020)

Stockton Area LCR Aggregate

Available generation	Market (MW)	Muni (MW)	QF (MW)	Max. Qualifying Capacity (MW)
2019	392	137	158	687
2024	392	114	156	662

	Existing Generation Capacity Needed (MW)		Deficiency (MW)		Total MW Need	
	2019	2024	2019	2024	2019	2024
Category B (Single)	163	287	0	0	163	287
Category C (Multiple)	308	347	43	0	351	347

Each unit is only counted once, regardless in how many sub-areas it is needed.

In order to come up with an aggregate deficiency, where applicable the deficiencies in each smaller sub-area has been accounted for (based on their effectiveness factors) toward the deficiency of a much larger sub-area.

Changes

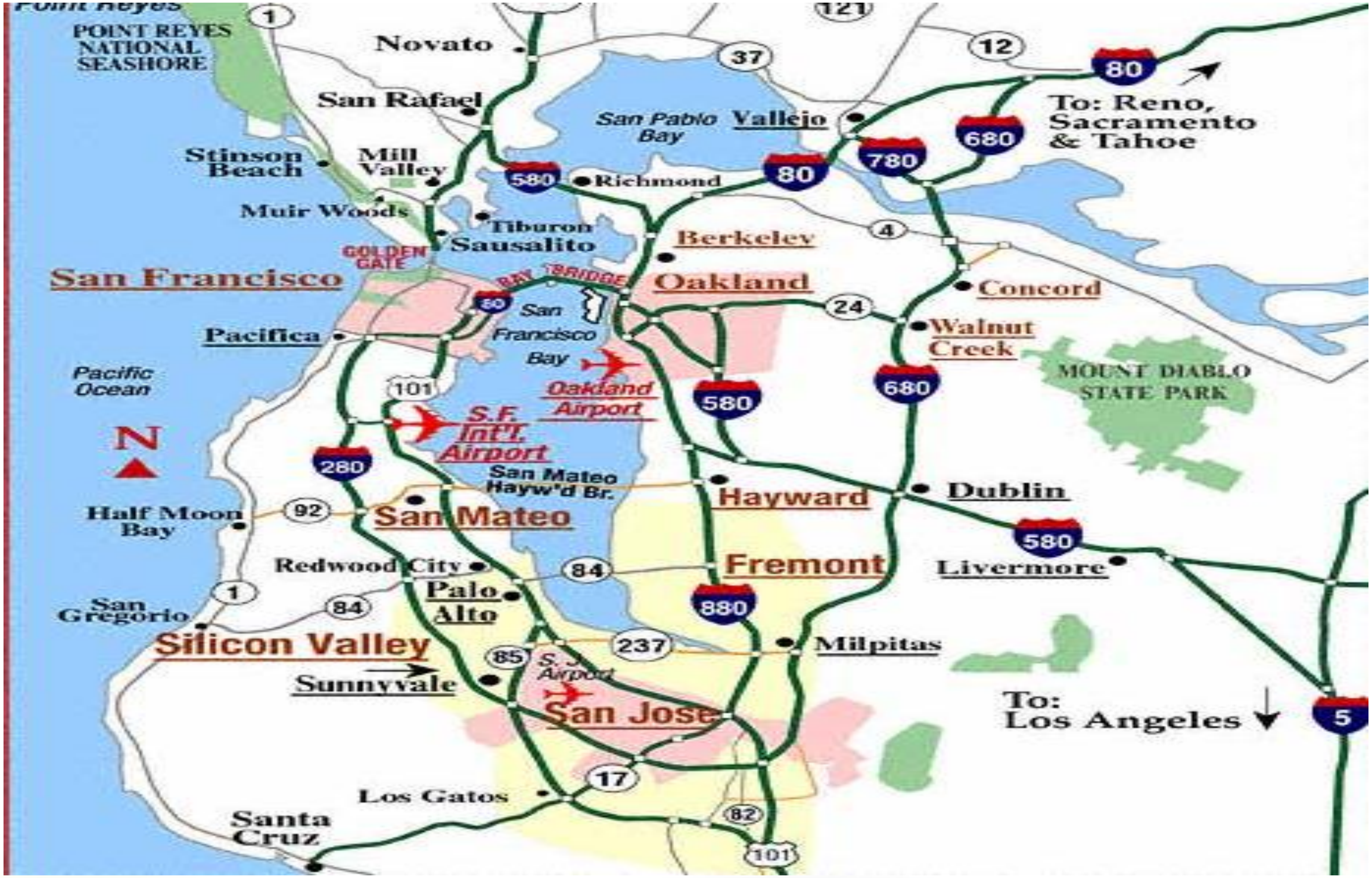
Compared to 2019 LCR study:

1) Lockeford sub-area eliminated due to the Lockeford - Lodi Area 230 kV Development project (2020)
2) Load + Losses went down by 144 MW mainly due to the elimination of the Lockeford sub-area
3) Long-Term LCR has increased due to load growth and decreased due to the elimination of deficiency and need in the Lockeford sub-area resulting in an overall slight decrease of 4 MW

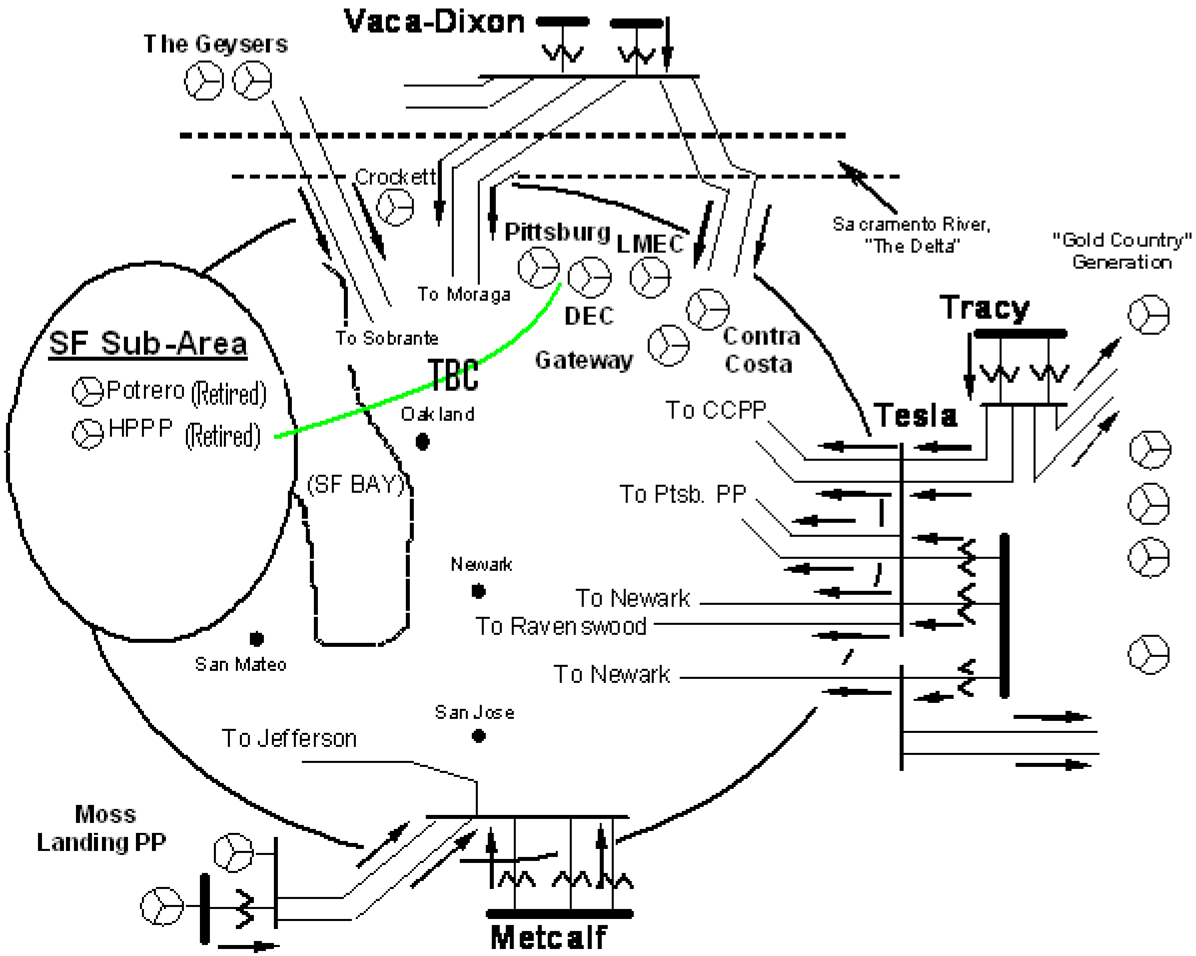
Your comments and questions are welcome.

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

Greater Bay Area Map



Greater Bay Area Transmission System



New transmission projects modeled:

1. Pittsburg - Tesla 230 kV Reconductoring (2016)
2. Pittsburg - Lakewood SPS Project (2016)
3. Monta Vista - Wolfe 115 kV Substation Equipment Upgrade (2016)
4. NRS - Scott No. 1 115 kV Line Reconductor (2016)
5. Almaden 60 kV Shunt Capacitor (2017)
6. Bay Meadows 115 kV Reconductoring (2017)
7. Newark - Ravenswood 230 kV Line (2017)
8. Contra Costa - Moraga 230 kV Line Reconductoring (2017)
9. Moraga Transformer Capacity Increase (2017)
10. Christie 115/60 kV Transformer Addition (2017)
11. Contra Costa Sub 230 kV Switch Replacement (2017)
12. Embarcadero - Potrero 230 kV Transmission Project (2017)
13. Cooley Landing - Los Altos 60 kV Line Reconductor (2017)
14. Moraga - Oakland "J" SPS Project (2017)
15. Cooley Landing 115/60 kV Transformer Capacity Upgrade (2017)
16. Evergreen - Mabury 60 to 115 kV Conversion (2017)
17. Monta Vista - Los Gatos - Evergreen 60 kV Project (2017)
18. Moraga - Castro Valley 230 kV Line Capacity Increase Project (2017)

New transmission projects modeled: (cont.)

19. Pittsburg 230/115 kV Transformer Capacity Increase (2018)
20. Tesla - Newark 230 kV Path Upgrade (2018)
21. Metcalf - Evergreen 115 kV line Reconductoring (2018)
22. Vaca Dixon - Lakeville 230 kV Reconductoring (2018)
23. Stone 115 kV Back-tie Reconductor (2018)
24. Newark - Applied Materials 115 kV Substation Equipment Upgrade (2018)
25. Monta Vista - Los Altos 60 kV Reconductoring (2019)
26. Jefferson - Stanford #2 60 kV Line (2019)
27. North Tower 115 kV Looping Project (2019)
28. Potrero 115 kV Bus Upgrade (2019)
29. Ravenswood - Cooley Landing 115 kV Line Reconductor (2019)
30. South of San Mateo Capacity Increase (2019)
31. Monta Vista 230 kV Bus Upgrade (2019)
32. Metcalf - Piercy & Swift and Newark - Dixon Landing 115 kV Upgrade (2019)
33. East Shore - Oakland J 115 kV Reconductoring Project (2019)
34. San Mateo - Bair 60 kV Line Reconductor (2021)
35. Morgan Hill Area Reinforcement (2021)
36. Mountain View/Whisman - Monta Vista 115 kV Reconductoring (2024)
37. Del Monte - Fort Ord 60 kV Reinforcement Project – Phase 2 (2025)

Power plant changes

Additions:

- Oakley
- 3 small wind resources
- DG (2024 only)

Assumed Retirements:

- Moss Landing (OTC)
- Pittsburg (OTC)
- Oakland (non-OTC – 2024 only)

Greater Bay Area Load

<u>2019 1-in-10 Year Load Representation</u>

Total Load = 9,868 MW

Transmission Losses = 200 MW

Pumps = 262 MW

Total Load + Losses + Pumps = 10,330 MW

<u>2024 1-in-10 Year Load Representation</u>

Total Load = 9,853 MW

Transmission Losses = 194 MW

Pumps = 264 MW

Total Load + Losses + Pumps = 10,311 MW

San Jose Sub Area

San Jose Sub-area – Category B

Contingency: Metcalf-Evergreen #2 115 kV line with Duane PP out of service

Limiting component: Thermal overload of Metcalf-Evergreen #1 115 kV line

2019 LCR need: 119 MW (includes 263 MW of QF/Muni generation)

2024 LCR need: None

San Jose Sub-area – Category C

Contingency: Metcalf El Patio #1 or #2 overlapped with the outage of Metcalf-Evergreen #2 115 kV line

Limiting component: Thermal overload of Metcalf-Evergreen #1 115 kV line

2019 LCR need: 385 MW (includes 263 MW of QF/Muni generation)

2024 LCR need: 170 MW (includes 263 MW of QF/Muni generation)

Llagas Sub Area

Llagas Sub-area – Category B

Contingency: Metcalf D-Morgan Hill 115 kV with one of the Gilroy peakers off-line
Limiting component: Thermal overload on the Morgan Hill-Llagas 115 kV line as well as 5% voltage drop at the Morgan Hill substation
2019 LCR need: 158 MW (includes 0 MW of QF/Muni generation)
2024 LCR need: None

Llagas Sub-area – Category C

Contingency: Metcalf D-Morgan Hill 115 kV line followed by Spring 230/115 kV bank
Limiting component: Thermal overload on the Morgan Hill-Llagas 115 kV line
2019 LCR need: Same as Category B
2024 LCR need: 23 MW (includes 0 MW of QF/Muni generation)

Oakland Sub Area

Oakland Sub-area – Category B

Contingency: Moraga – Claremont #1 or #2 230 kV line with one Oakland CT off-line

Limiting component: Remaining Moraga – Claremont 230 kV line

2019 LCR need: 141 MW (includes 49 MW of QF/Muni generation)

2024 LCR need: 151 MW (includes 49 MW of QF/Muni generation)

Oakland Sub-area – Category C

Contingency: Overlapping C-X #2 and C-X #3 115 kV cables

Limiting component: Thermal overload on the Moraga – Claremont #1 or #2 230 kV line.

2019 LCR need: 141 MW (includes 49 MW of QF/Muni generation)

2024 LCR need: 155 MW (includes 49 MW of QF/Muni generation)

Oakland power plant continue to be needed.

Pittsburg/Oakland Sub Area

Pittsburg/Oakland and/or Pittsburg sub-area needs are eliminated due to:

1. Pittsburg - Tesla 230 kV Reconductoring (2016)
2. Contra Costa - Moraga 230 kV Line Reconductoring (2017)
3. Moraga Transformer Capacity Increase (2017)
4. Vaca Dixon - Lakeville 230 kV Reconductoring (2018)

Contra Costa Sub Area

Contra Costa Sub-area – Category B

Contingency: Kelso-Tesla 230 kV line with the Gateway off-line
Limiting component: Thermal overload on the Delta Switching Yard Tesla 230 kV line
2019 LCR need: 1629 MW (includes 264 MW of MUNI pumps and 256 MW of wind generation)
2024 LCR need: 1509 MW (includes 264 MW of MUNI pumps and 256 MW of wind generation)

Contra Costa Sub-area – Category C

Same as Category B

Greater Bay Area Overall

Bay Area Overall – Category B

Contingency: Tesla-Metcalf 500 kV line with Delta Energy Center out of service

Limiting component: Reactive margin within the Bay Area

2019 LCR need: 3600 MW (including 485 MW of QF, 519 MW of MUNI and 258 MW of wind generation)

2024 LCR need: 4133 MW (including 485 MW of QF, 519 MW of MUNI, 120 MW of DG and 258 MW of wind generation)

Bay Area Overall – Category C

Contingency: overlapping Tesla-Metcalf 500 kV line and Tesla-Newark #1 230 kV line

Limiting component: Thermal overload on the Tesla-Newark #1 or Lone Tree–Cayatano 230 kV lines

2019 LCR need: 4224 MW (including 485 MW of QF, 519 MW of MUNI and 258 MW of wind generation)

2024 LCR need: Same as Category B

Greater Bay Area

Available Generation

Year	QF (MW)	Muni (MW)	Wind (MW)	DG (MW)	Market (MW)	Max. Qualifying Capacity (MW)
2019	485	519	258	0	5589	6851
2024	485	519	258	178	5589	7029

Total LCR need

	Existing Generation Capacity Needed (MW)		Deficiency (MW)		Total MW Need	
	2019	2024	2019	2024	2019	2024
Category B (Single)	3600	4133	0	0	3600	4133
Category C (Multiple)	4224	4133	0	0	4224	4133

Changes

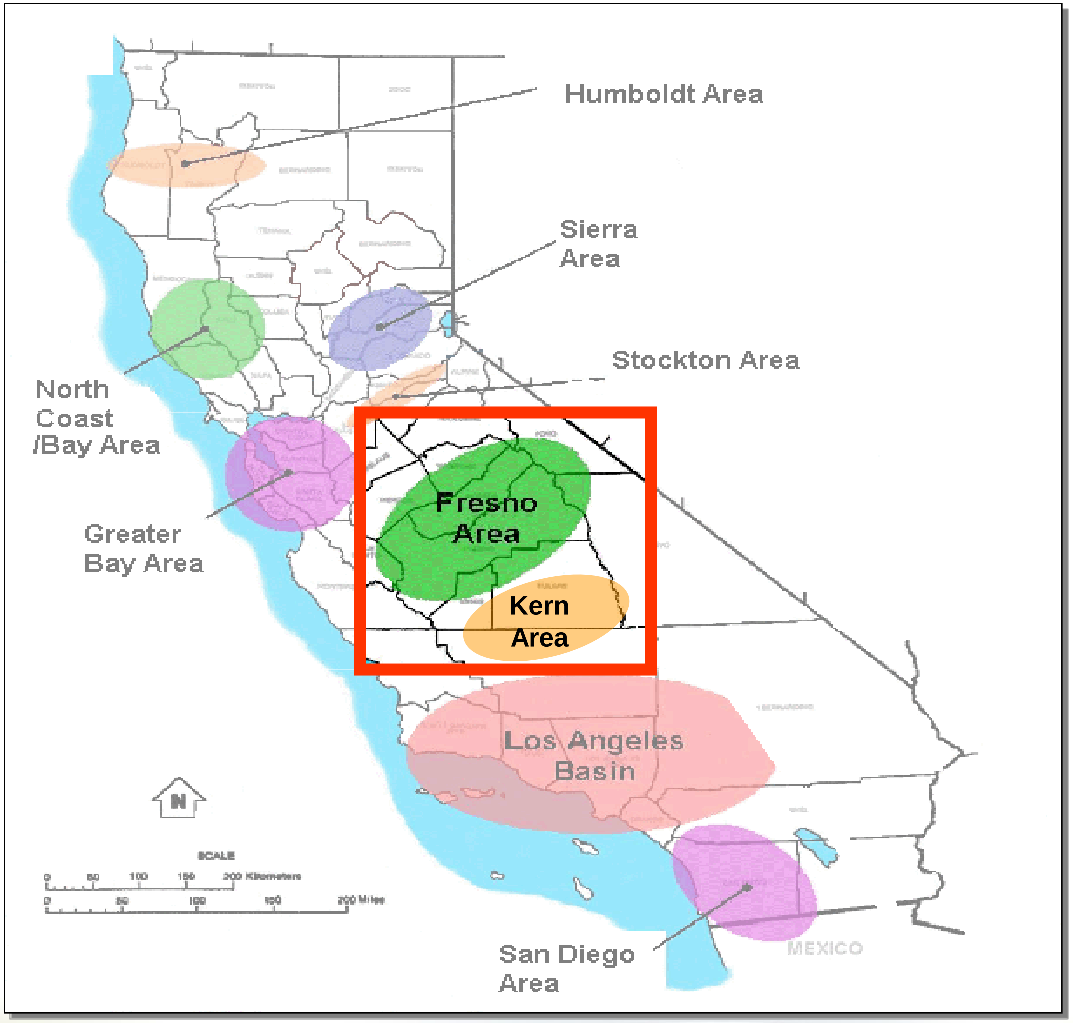
Compared to 2019 LCR study:

1) Few new transmission projects; among them and most important - Morgan Hill Area Reinforcement (2021)
2) 27 new DG (~150 MW)
3) 3 new renewable resources (~28 MW)
4) Load forecast is lower by 19 MW
5) LCR need has decreased by 91 MW

Your comments and questions are welcome.

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

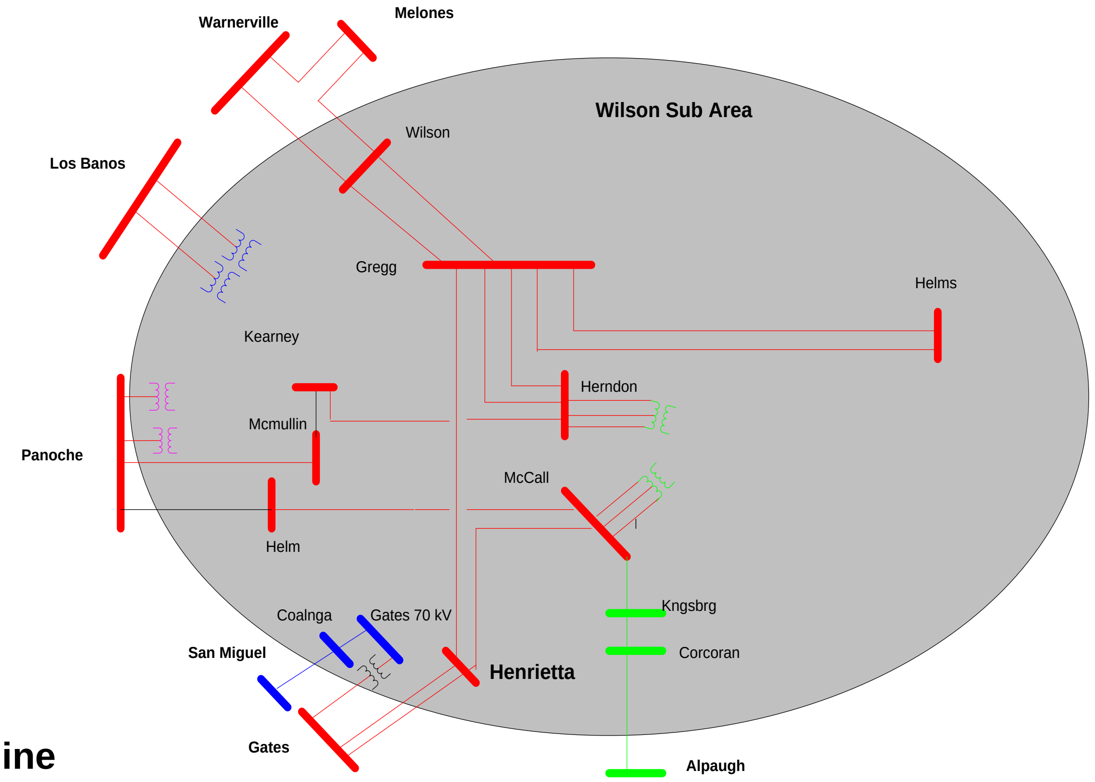
Fresno and Kern LCR Areas



Greater Fresno Area
Electrical Boundaries and LCR Sub-Areas

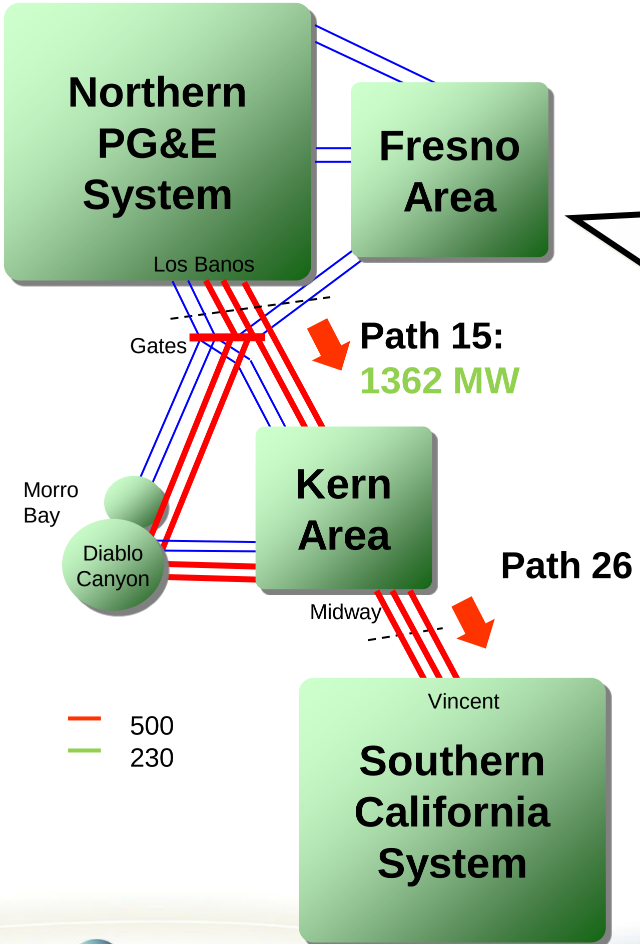
Electrical Boundaries:

- Gates – McCall 230 kV line
- Gates – Gregg 230 kV line (New)
- Gates – Gregg 230 kV line (Old)
- Gates 230/70 kV transformer #5
- Panoche 230/115 kV transformer #1
- Panoche 230/115 kV transformer #2
- Panoche – Kearney 230 kV line
- Panoche – Helm 230 kV line
- Warnerville – Wilson 230 kV line
- Melones – Wilson 230 kV line
- Los Banos 230/70 kV transformer #3
- Los Banos 230/70 kV transformer #4
- San Miguel – Coalinga #1 70 kV line
- Smyrna – Alpaugh – Corcoran 115 kV line



Fresno Area Overview

Area Generation, Load, Transmission and Path Flows



Fresno LCR Area

Total Generation and Load:
- **Generation: 2848 MW (2019)**
- **Generation: 3657 MW (2024)**
- **Load (1-in-10 Summer-Peak): 3258 MW (2019)**
- **Load (1-in-10 Summer-Peak): 3806 MW (2024)**

Transmission Upgrades:
- **Discussed in the next two slides.**

2024 New Generation:
- **56 new small resources added**
  - **48 DG (515 MW)**
  - **8 Renewable Gen (294 MW)**

New transmission projects modeled:

1. Fresno Reliability (stages: 2014, 2015, 2016, 2016)
2. Shepherd Substation Interconnection (2015)
3. Cressey - Gallo 115 kV Line (2016)
4. Lemoore 70 kV Disconnect Switches Replacement (2016)
5. Kearney 230/70 kV Transformer Addition (2017)
6. Kearney - Caruthers 70 kV Line Reconductor (2017)
7. Caruthers - Kingsburg 70 kV Line Reconductor (2017)
8. Reedley-Dinuba 70 kV Line Reconductor (2017)
9. Reedley-Orosi 70 kV Line Reconductor (2017)
10. Helm - Kerman 70 kV Line Reconductor (2017)
11. Ashlan - Gregg and Ashlan - Herndon 230 kV Line Reconductor (2017)
12. Oakhurst/Coarsegold UVLS (2017)
13. Gregg - Herndon #2 230 kV Line Circuit Breaker Upgrade (2017)
14. Los Banos - Livingston Jct - Canal 70 kV Switch Replacement (2017)
15. Warnerville - Bellota 230 kV Line Reconductoring (2017)
16. Gates No. 2 500/230 kV Transformer (2018)

New transmission projects modeled: (cont.)

17. Series Reactor on Warnerville-Wilson 230 kV Line (2018)
18. Reedley 70 kV Reinforcement (2018)
19. Reedley 115/70 kV Transformer Capacity Increase (2018)
20. Cressey - North Merced 115 kV Line Addition (2018)
21. Kearney - Kerman 70 kV Line Reconductor (2018)
22. Kearney - Herndon 230kV Line Reconductor (2019)
23. McCall - Reedley #2 115 kV Line (2019)
24. Oro Loma - Mendota 115 kV Conversion Project (2019)
25. Wilson 115 kV Area Reinforcement (2019)
26. Borden 230 kV Voltage Support (2019)
27. Northern Fresno 115 kV Area Reinforcement (2020)
28. Kerchhoff PH #2 - Oakhurst 115 kV Line (2020)
29. Oro Loma 70 kV Area Reinforcement (2020)
30. New Gates - Gregg 230 kV Line (2020)
31. Wilson - Le Grand 115 kV line reconductoring (2021)
32. Woodward 115 kV Reinforcement (2024)

Fresno Area LCR
Hanford Sub-Area

Limiting Contingencies:

Category B: None

Category C:

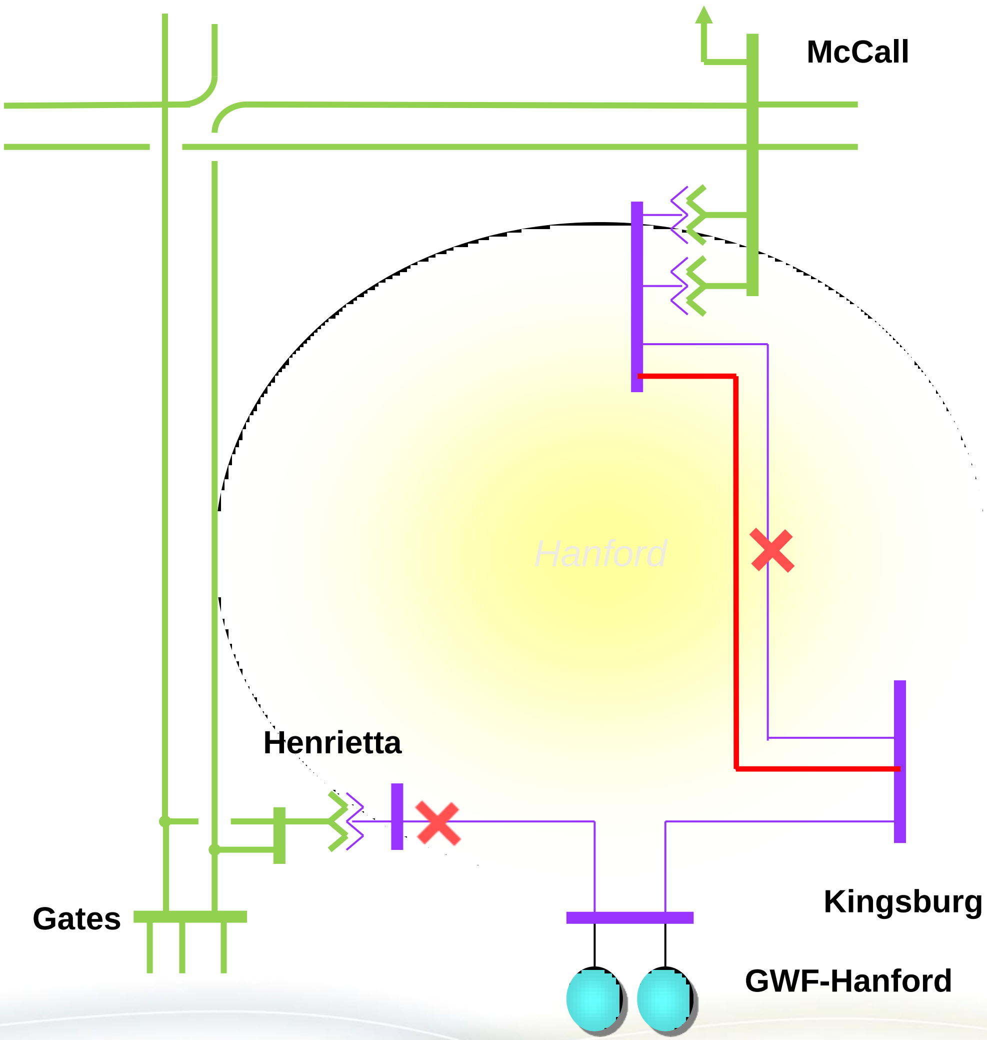
- **L-2: McCall-Kingsburg #2 115 kV & Henrietta- GWF 115 kV**
- **Constraint: McCall-Kingsburg # 1 115 kV**

LCR Results (MW):

Contingency	**Cat. B**	**Cat. C**
2019 LCR	**51**	**96**
2024 LCR	**0**	**63**

Including:

QF	0	0
Muni	0	0
Deficiency	0	0



Fresno Area LCR
Reedley Sub-Area

Limiting Contingencies:

Category C:

- **L-1-1: McCall-Reedley (McCall-Wahtoke) 115 kV & Sanger-Reedley 115kV**
- **Constraint: Kings River-Sanger-Reedley 115 kV**

LCR Results (MW):

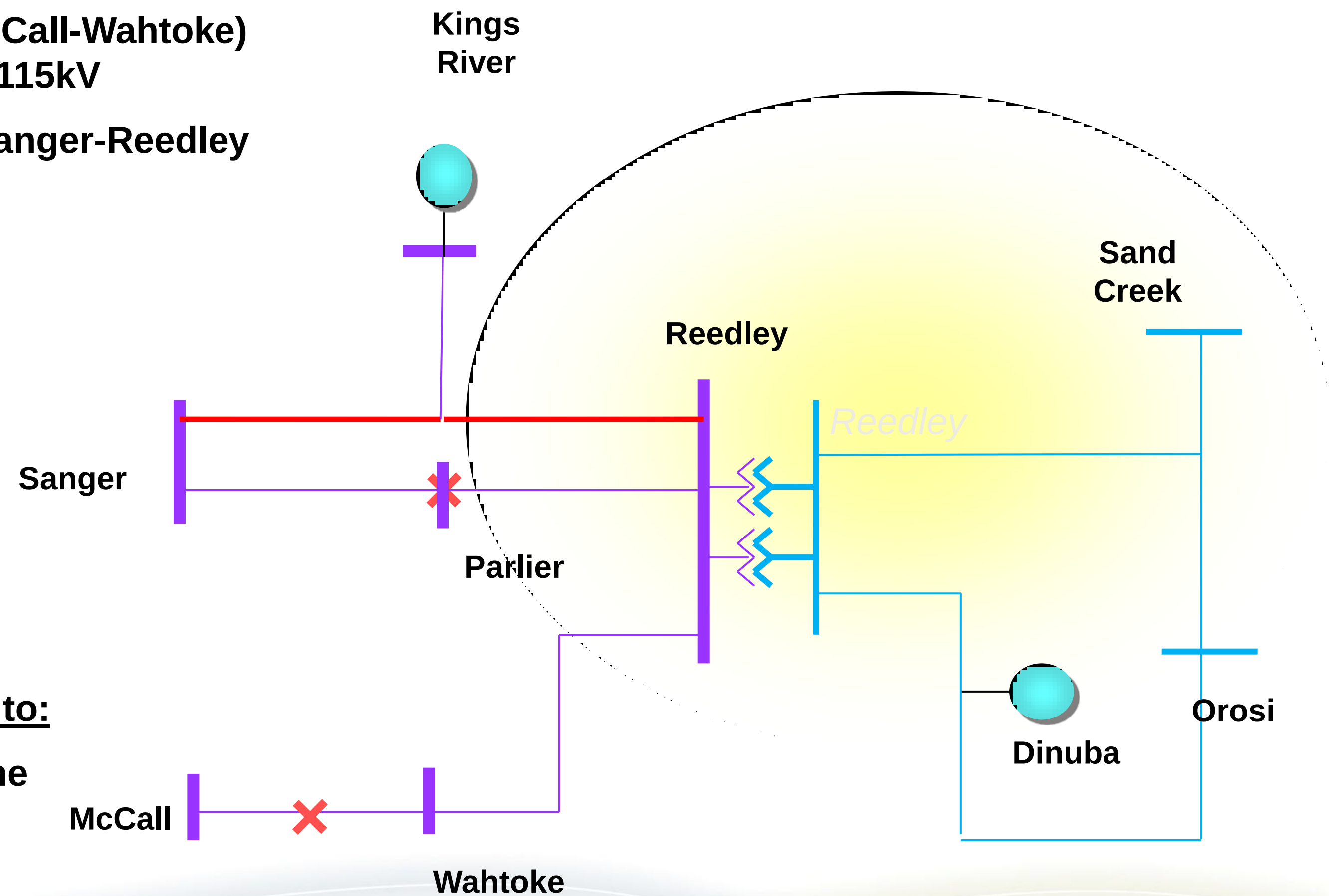
Contingency	Cat. C
2019 LCR	54

Including:

QF	10
Muni	0
Deficiency	44

2024 Sub-area eliminted due to:

McCall-Reedley # 2 115 kV line



Fresno Area LCR
Borden Sub-Area

Limiting Contingencies:

Category B:

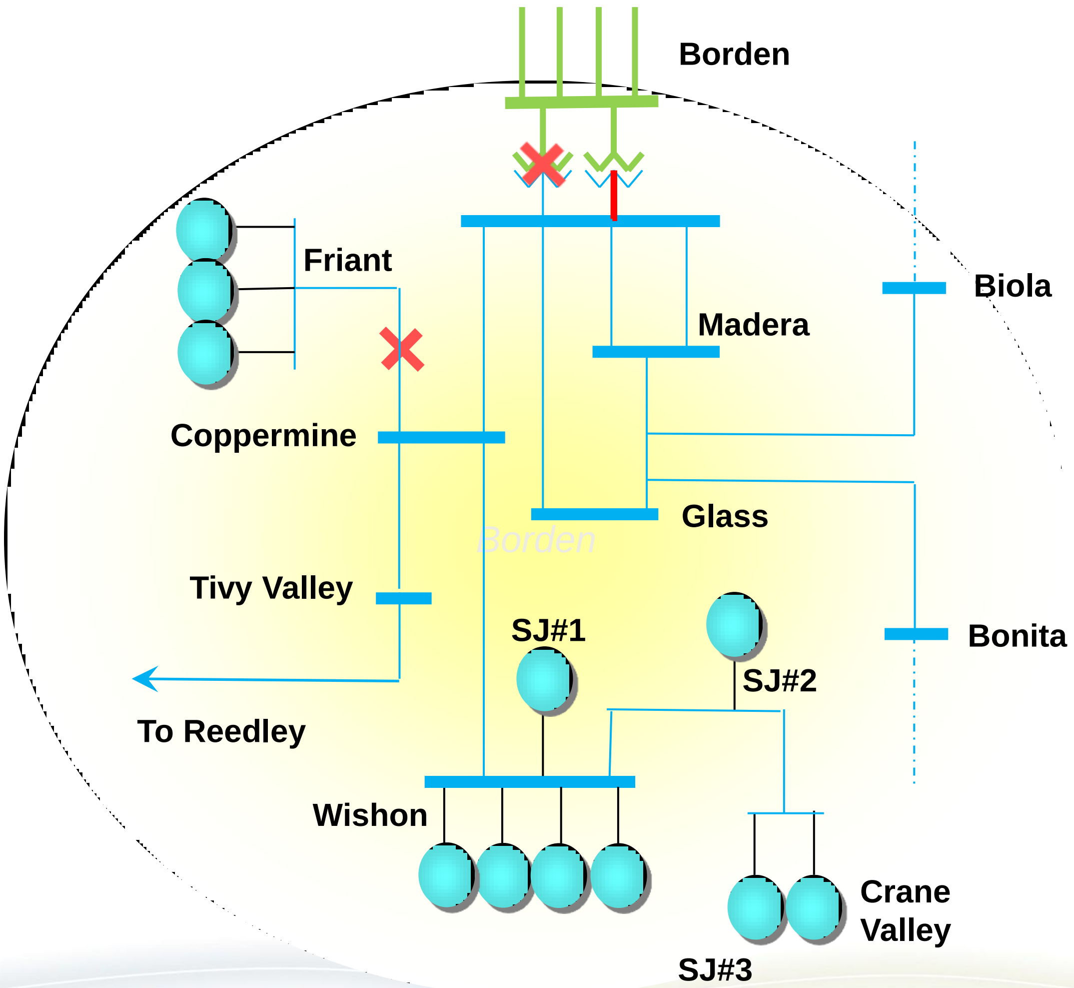
- **T-1: Borden 230/70 kV # 4**
- **Constraint: Borden 230/70 kV # 1**

Category C:

- **L-1T-1: Friant - Coppermine 70 kV and Borden 230/70 kV # 4**
- **Constraint: Borden 230/70 kV # 1**

LCR Results (MW):

Contingency	Cat. B	Cat. C
2024 LCR	63	83
Including:		
QF	20	20
Muni	-	-
Deficiency	4	24



Fresno Area LCR
Wilson Sub-Area

Limiting Contingencies:

Category B:

- **G-1/L-1: Dairyland-Le Grand 115 kV & Exchequer Generation**
- **Constraint: Panoche-Oro Loma 115 kV-(From Panoche Jn To Hammonds)**

Category C:

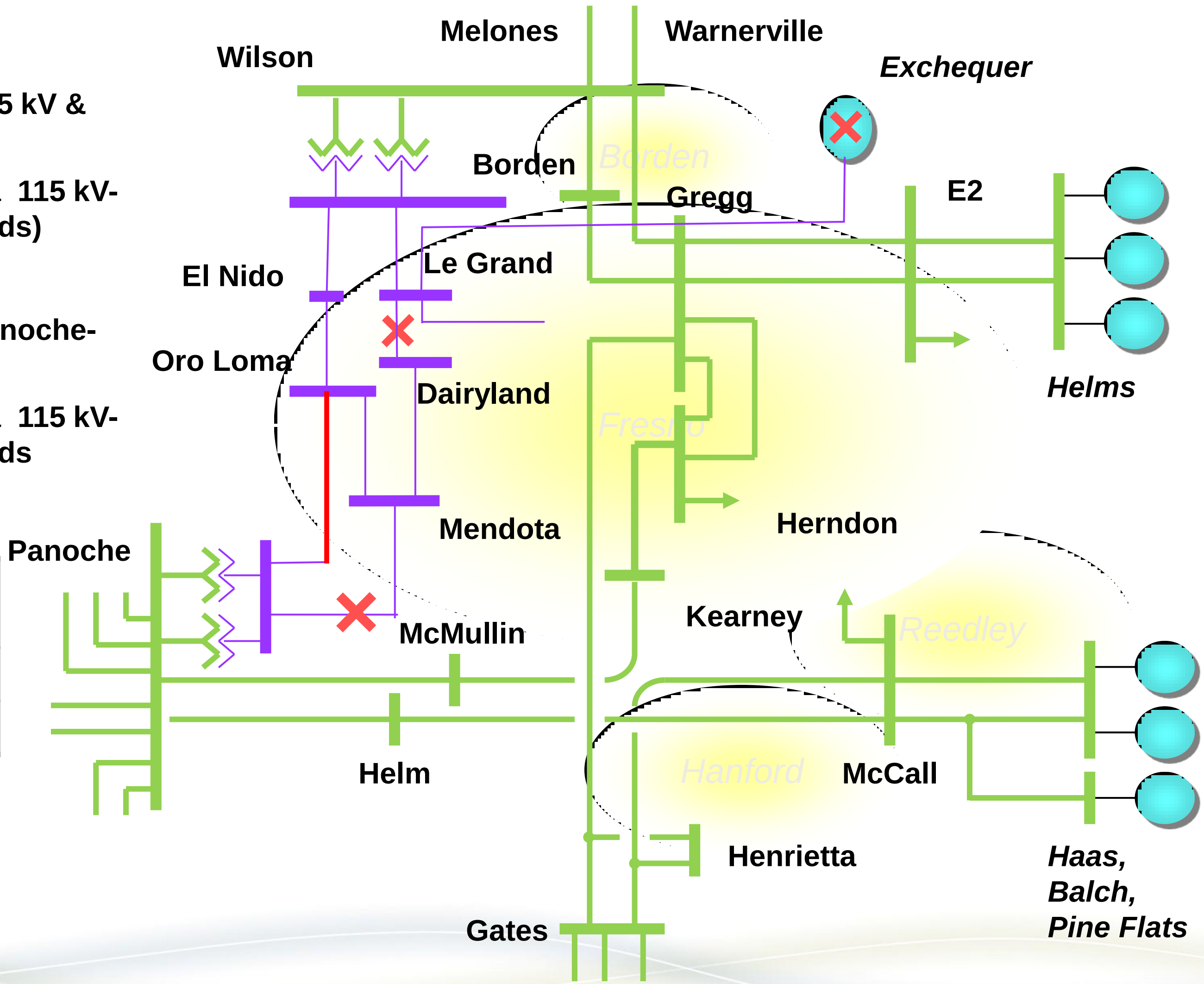
- **L-1-1: Dairyland-Le Grand & Panoche-Mendota 115 kV Line**
- **Constraint: Panoche-Oro Loma 115 kV-(From Panoche Jn To Hammonds**

LCR Results (MW):

Contingency	Cat. B	Cat. C
2019 LCR	1463	1545
2024 LCR	1471	2182

Including:

QF	180	180
Muni	136	136
DG (2024 only)	515	515



Changes

Compared to 2019 LCR study:

1) Few new transmission projects – including New Gates-Gregg 230 kV line
2) 56 new DG and renewables resources (~809 MWs)
3) One new 70 kV sub-area identified
4) One sub-area eliminated due to new transmission projects
5) Load increased by 548 MW
6) LCR has increased by 637 MW

Your comments and questions are welcome.

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

Kern Area Overview
Area Generation, Load and Transmission

Kern LCR Area

Total Generation and Load for 2019:
- **Generation (NQC plus new unit): 312 MW**
- **Load (1-in-10 Summer-Peak): 745 MW**

Total Generation and Load for 2024:
- **Generation (NQC plus new units): 262 MW**
- **Load (1-in-10 Summer-Peak): 255 MW**

New transmission projects modeled:

1. Kern - Old River 70 kV No.2 Reconductoring (2016)
2. San Bernard - Tejon 70 kV Line Reconductor (2017)
3. Kern PP 115 kV Area Reinforcement (2018)
4. Taft - Maricopa 70 kV Line Reconductor (2018)
5. Semitropic - Midway 115 kV Line Reconductor (2018)
6. Taft 115/70 kV Transformer #2 Replacement (2018)
7. Wheeler Ridge Voltage Support (2018)
8. Wheeler Ridge - Weedpatch 70 kV Line Reconductor (2018)
9. Kern PP 230 kV Area Reinforcement (2019)
10. Wheeler Ridge Junction Substation (2021)

Kern Area LCR

West Park Sub-Area

2019 Limiting Contingencies:

Category B and C:

- **G-1/L-1: Kern-West Park #1 OR #2 115 kV with PSE-Bear generation out of service**
- **Constraint: Remaining Kern-West Park 115 kV line**

2019 LCR Results (MW):

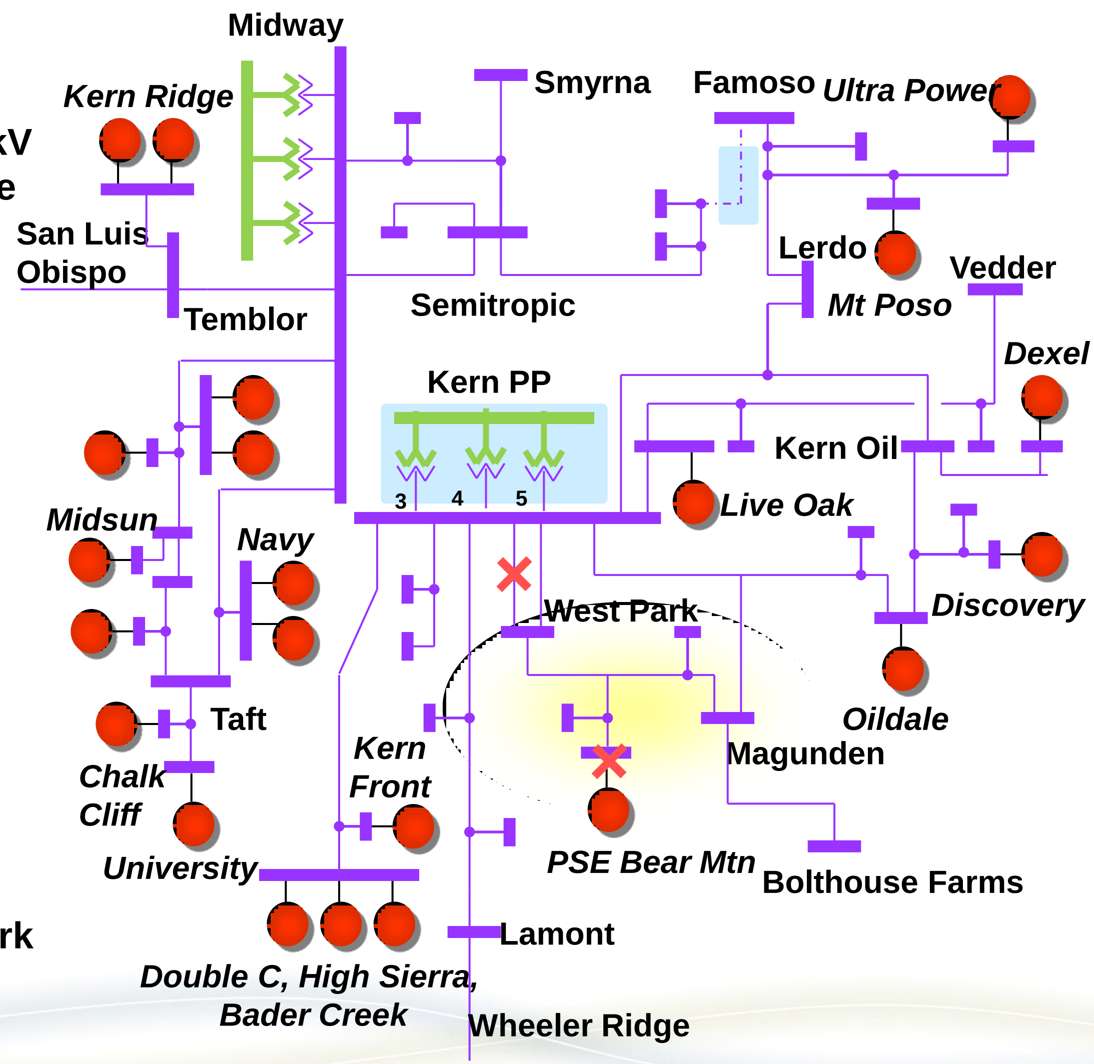
Contingency	Cat. B	Cat. C
LCR	77	77

Including:

QF	45	45
Deficiency	32	32

2024 Sub-area eliminted due to:

- **Wheeler Ridge Junction substation**
- **Reconductoring of Kern PP - West Park 115 kV lines**



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Kern Area LCR

South Kern PP Sub-Area

Limiting Contingencies:

Category B:

- **G-1/L-1: Kern-Magunden-Witco 115 kV with PSE Live Oak gen. out of service**
- **Constraint: Kern-Live Oak 115 kV line**

Category C:

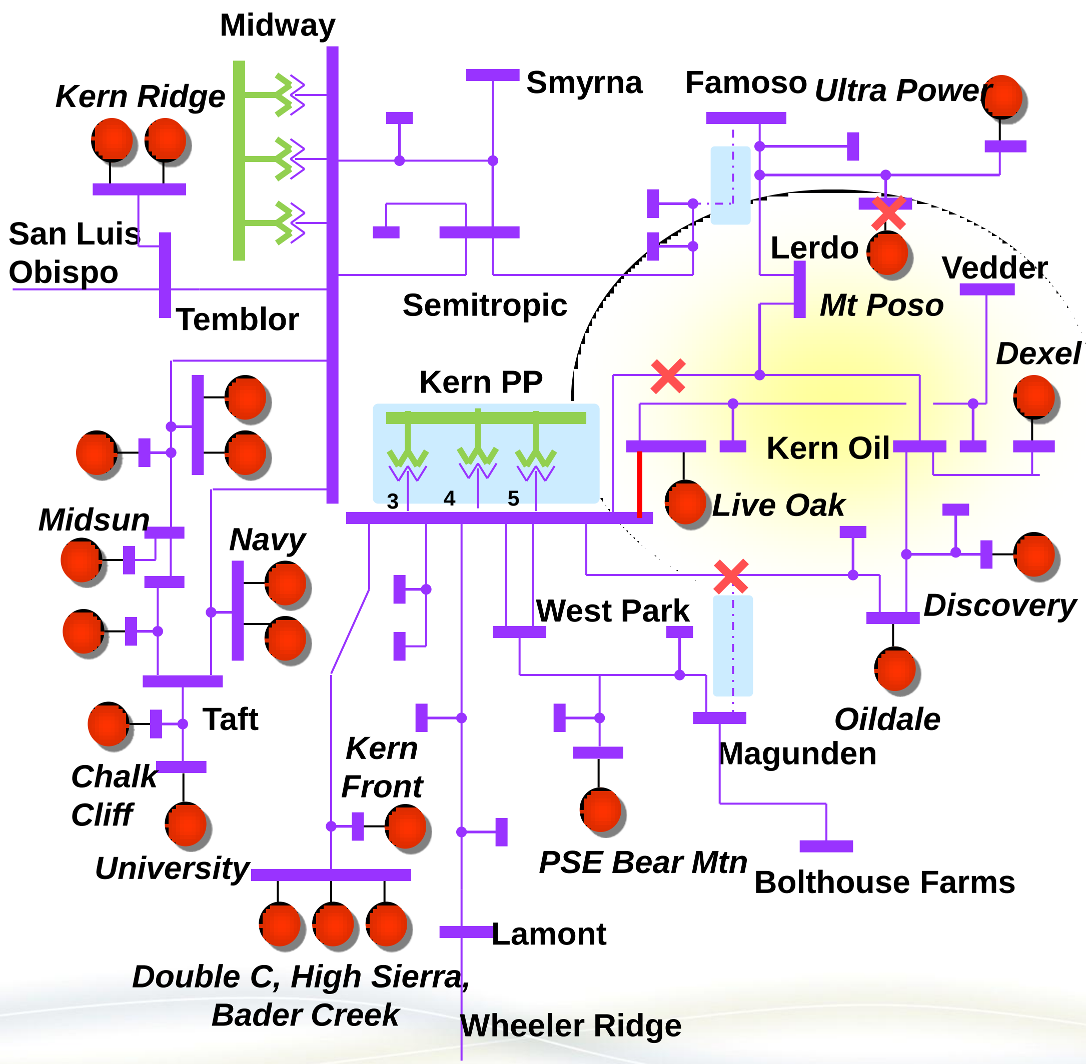
- **Kern-Magunden-Witco & Kern-7th Standard 115 kV lines**
- **Constraint: Kern-Live Oak 115 kV line**

LCR Results (MW):

Contingency	Cat. B	Cat. C
2019 LCR	111	116
2024 LCR	150	154

Including:

QF	179	179
DG (2024 only)	83	83



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Changes

Compared to 2019 LCR study:

1) Wheeler Ridge Junction Substation
2) Local area has been redefined
3) 5 new DG resources (~83 MWs)
4) Load has decreased by 490 MW mainly due to new definition
5) LCR has decreased by about 39 MW mainly due to new transmission projects

Your comments and questions are welcome.

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

2024 Long-Term LCR Study Results – Southern Local Areas

David Le

Senior Advisor - Regional Transmission Engineer

2014-2015 Transmission Planning Process Stakeholder Meeting

November 19 - 20, 2014

Big Creek/Ventura Area

Big Creek/Ventura Area*

*Demand Assumptions***

Year	Load (MW)	AAEE (MW)	Pump Load (MW)	Transmission Losses (MW)	Total (MW)
2024	3,914	-236	361	72	4,111

Notes:

* Geographic area (i.e., excluding Saugus substation load); AAEE forecast (bus-by-bus) provided by the California Energy Commission

** Does not include EE from LTPP process; this information, as well as other preferred resources, will be provided further in the draft ISO Transmission Plan

Critical Area Contingencies

Rector Sub-area – Category B

- Contingency: Vestal-Rector #1 or #2 230 kV line with Eastwood out of service
- Limiting component: Remaining Vestal-Rector 230 kV line
- 2024 LCR need: 560 MW (QF: 10 MW)
- AAEE Assumptions: 94 MW

Rector Sub-area – Category C

Same as Category B

Vestal Sub-area – Category B

- Contingency: Magunden-Vestal #1 or #2 230 kV line with Eastwood out of service
- Limiting component: Remaining Magunden-Vestal 230 kV line
- 2024 LCR need: 693 MW (QF: 131 MW)
- AAEE: 95 MW

Vestal Sub-area – Category C

Same as Category B

Critical Area Contingencies

Santa Clara Sub-area – Category C

- Contingency: Pardee-Santa Clara 230 kV line followed by DCTL Moorpark-Santa Clara #1 and #2 230 kV lines
- Limiting component: Voltage collapse
- 2024 LCR need: 272 MW (QF: 67 MW)
- AAEE and LTPP EE Assumptions: 29 MW

Santa Clara Sub-area – Category B

No requirements

Critical Area Contingencies

Moorpark Sub-area – Category C

- Contingency: Pardee-Moorpark #3 230 kV line followed by DCTL Pardee-Moorpark #1 and #2 230 kV lines
- Limiting component: Voltage collapse
- 2024 LCR need: 471 MW (QF: 96 MW)
- AAEE and LTPP EE Assumptions: 93 MW

Moorpark Sub-area – Category B

No requirements

Critical Area Contingencies

Big Creek/Ventura Overall – Category C

- Contingency: Sylmar-Pardee #1 or #2 230 kV line followed by Lugo-Victorville 500 kV or vice versa
- Limiting component: Remaining Sylmar-Pardee 230 kV line
- 2024 LCR need: 2,783 MW (includes 791 MW QF)
- AAEE and LTPP EE assumptions: 311 MW

Big Creek/Ventura Overall – Category B

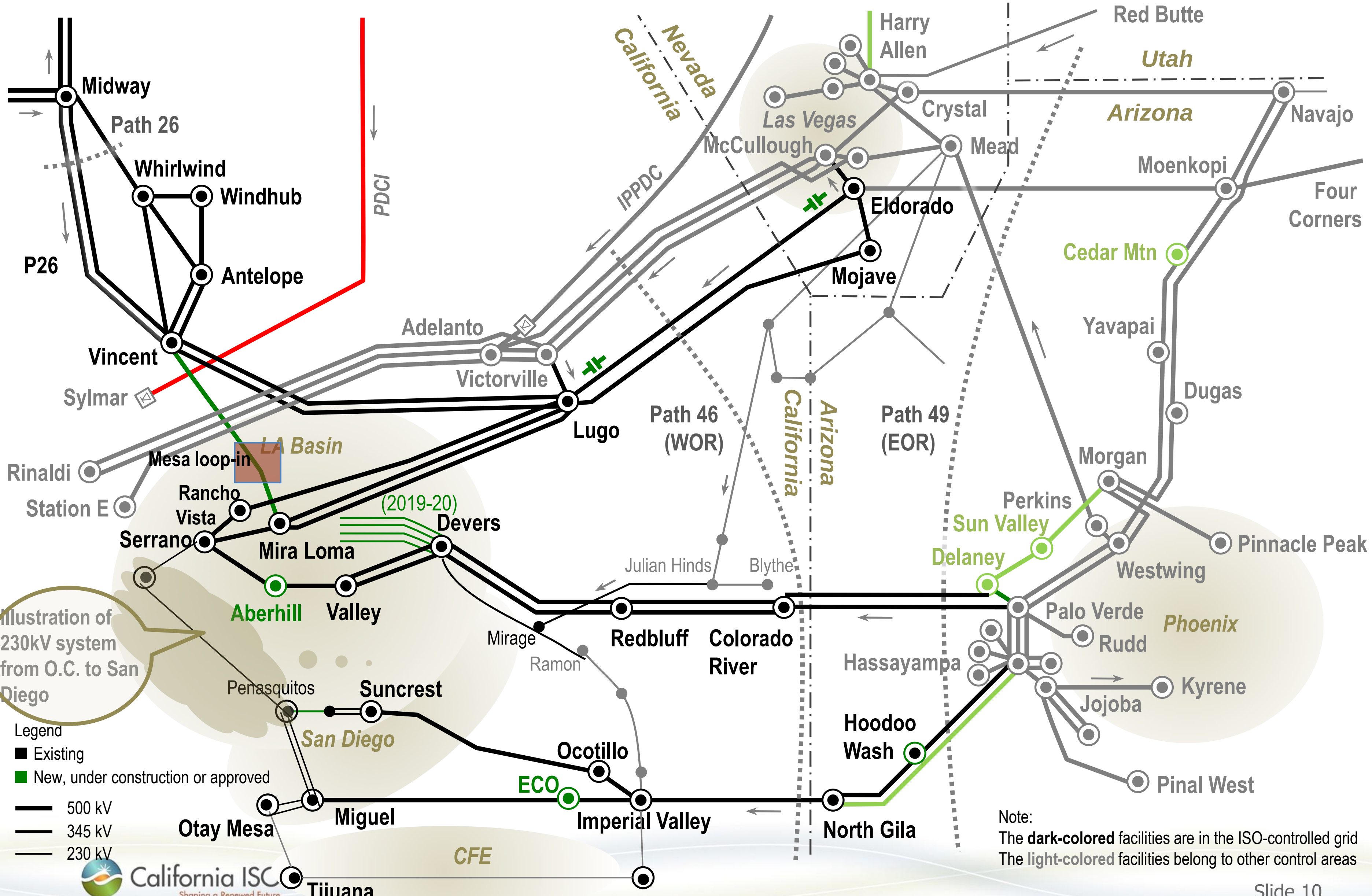
- Contingency: Sylmar-Pardee #1 or #2 230 kV line with Pastoria power plant (CCGT) out of service
- Limiting component: Remaining Sylmar-Pardee 230 kV line
- 2024 LCR need: 2,603 MW (includes 791 MW QF)
- AAEE and LTPP EE assumptions: 311 MW

Conclusions

- No resource deficiency identified for the Big Creek/Ventura LCR and its sub-areas
- It is critical to have AAEE and LTPP Track 1 resources implemented for the local area to meet the reliability need for the Big Creek/Ventura LCR and sub-LCR areas

Combined LA Basin/San Diego Area and LA Basin-San Diego-Imperial Valley Area

Combined LA Basin and San Diego LCR Area



Note:
The **dark-colored** facilities are in the ISO-controlled grid
The light-colored facilities belong to other control areas

Combined LA Basin & San Diego Area Loads (2024 study case)

*Demand Assumptions**

Area	Load (MW)	AAEE (MW)	Pump Load (MW)	Transmission Losses (MW)	Total Net Load (MW)
San Diego	5,682	-338	0	169	5,513
LA Basin	22,721	-1,147	30	550	22,154
Total	28,403	-1,485	30	719	27,667

Notes:

* Additional Achievable Energy Efficiency (AAEE) forecast (bus-by-bus) provided by the California Energy Commission; SCE and SDG&E provided forecast loads at each bus (i.e., substation)

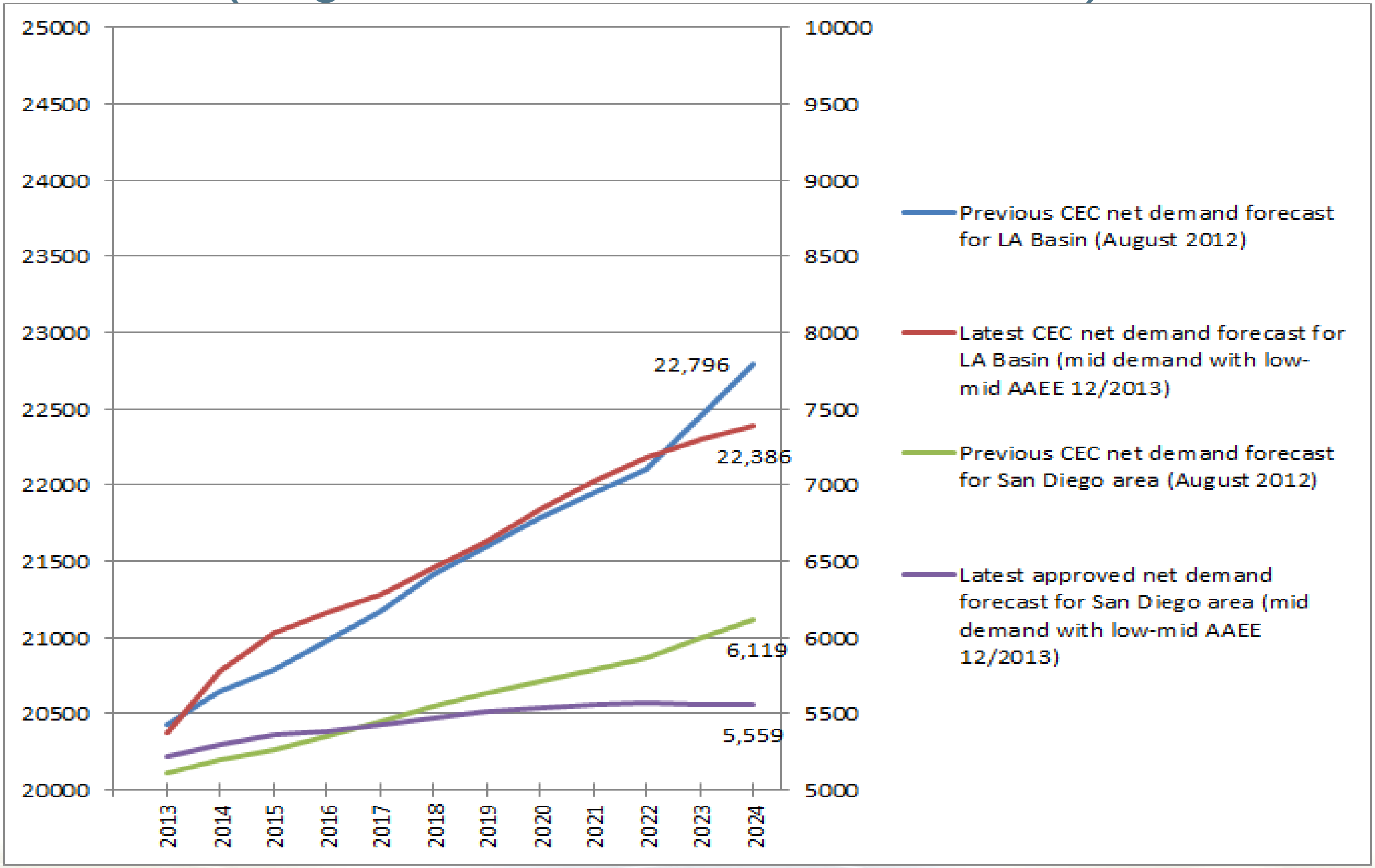
Comparison of Load Forecast in the 2013-2014 Transmission Planning Process (2023 study case)

Area	Load (MW)	AAEE (MW)	Pump Load (MW)	Transmission Losses (MW)	Total Net Load (MW)
San Diego	5,980	-197	0	192	5,975
LA Basin	22,563	-786	0	430	22,207
Total	28,543	-983	0	622	28,182

Notes:

Comparing with 2023 study case in the last planning cycle (2013-2014 TPP), the net loads for both San Diego and LA Basin are 515 MW less, mainly due to increase in the AAEE forecast.

Comparison of the CEC Net Demand Forecasts (August 2012 vs. December 2013)



Transmission Upgrades Modeled

1. East County 500kV Substation (ECO)
2. Mesa Loop-In Project and South of Mesa 230kV line upgrades (SCE's service area)
3. Imperial Valley Phase Shifting Transformers (2x400 MVA)
4. Delany – Colorado River 500kV Line (Arizona – SCE Intertie)
5. Hassayampa – North Gila #2 500kV Line (APS)
6. Bay Blvd. Substation Project
7. Sycamore – Penasquitos 230kV Line
8. Talega Synchronous Condensers (2x225 MVAR)
9. San Luis Rey Synchronous Condensers (2x225 MVAR)
10. SONGS Synchronous Condenser (225 MVAR)
11. Santiago Synchronous Condenser (225 MVAR) (SCE service area)
12. Miguel-Otay Mesa-South Bay-Sycamore 230 kV re-configuration
13. Artesian 230/69 kV Substation and loop-in project
14. Imperial Valley – Dixieland 230 kV tie with IID
15. Bypass series capacitors on the Imperial Valley-N.Gila, ECO-Miguel, and Ocotillo-Suncrest 500kV lines

Critical LA Basin-San Diego Area Contingencies

Category C

- Contingency: Ocotillo – Suncrest 500kV line, followed by ECO – Miguel 500kV line
  - Limiting component: Imperial Valley phase shifters, Otay Mesa – Tijuana 230kV line
  - Most constrained contingency for the LA Basin-San Diego sub-area
  - **2024 Total LCR need**:
    - ❑ **<u>In LA Basin:</u>**
      - 6,754 MW (included 2,208 MW of QF, Muni, Renewables and Energy Storage)
      - Total "fast" demand response: 756 MW (198 MW of which was LTPP Track 4 DR assumption)
      - EE (from AAEE and LTPP): 1,270 MW
    - ❑ **<u>In San Diego Sub-area:</u>**
      - 3,061 MW (included 300 MW of QF, RPS Renewables, LTPP DG proxy assumptions and Energy Storage)
      - Total "fast" demand response: 17 MW
      - EE (from AAEE): 338 MW

Critical Contingencies (cont’d)

Category C (cont’d)

- If full LTPP Track 1 and 4 authorizations are procured, there would be no deficiency
- Potential deficiency up to 500 MW, if there are:
  - Less LA Basin LTPP procurement implementation (i.e., 608 MW less), and
  - Less existing demand response implementation (i.e., 198 MW which are LTPP Track 4 assumptions)
- If full amount of existing “fast” DR is implementable (862 MW) for both the LA Basin and San Diego areas, then no deficiency was identified
- Loads are about 515 MW less for both the LA Basin and San Diego areas when compared to the 2023 study case in the last planning cycle (2013-2014 TPP).

Critical Contingencies (cont’d)

Category C

- Contingency: ECO-Miguel 500kV line, followed by the Ocotillo – Suncrest 500kV line
  - Second most constrained contingency for the LA Basin-San Diego sub-area
  - Limiting component: Voltage instability
  - 2024 **Total LCR need**:
    - ❑ **<u>In LA Basin:</u>**
      - o 6,754 MW (included 2,208 MW of QF, Muni, Renewables and Energy Storage)
      - o Total “fast” demand response: 181 MW
      - o EE (from AAEE and LTPP): 1,270 MW
    - ❑ **<u>In San Diego Sub-area:</u>**
      - o 2,691 MW (included 300 MW of QF, RPS Renewables, LTPP DG proxy assumptions and Energy Storage)
      - o Total “fast” demand response: 17 MW
      - o EE (from AAEE): 338 MW
  - No deficiency

LA Basin-San Diego-Imperial Valley Area Critical Contingency

Category B & C

- Contingency: G-1 Otay Mesa power plant, followed by Imperial Valley - N.Gila 500kV line
  - Limiting component: Voltage instability
  - 2024 **Total LCR need**:
    - ❑ **<u>In LA Basin:</u>**
      - 6,754 MW (included 2,208 MW of QF, Muni, Renewables and Energy Storage)
      - Total “fast” demand response utilized: 181 MW
      - EE (from AAEE and LTPP): 1,270 MW
    - ❑ **<u>In San Diego-Imperial Valley area:</u>**
      - 4,046 MW (included 708 MW (NQC) of QF, RPS Renewables, LTPP DG proxy assumptions and Energy Storage)
      - Total “fast” demand response utilized: 17 MW
      - EE (from AAEE): 338 MW
  - No deficiency

Conclusions

- In summary

LTPP Procurement, DR and AAEE Scenarios	Results
1. If authorized LTPP Tracks 1 and 4 resources are procured fully (with Track 4 DR assumptions)	Then there is no deficiency
2. If LTPP Tracks 1 and 4 are not fully procured (i.e., 608 MW less than authorized amount for the LA Basin), OR 3. If AEE level does not materialize as forecast (again with Track 4 DR assumptions)	Then there would be resource deficiency
4. If LTPP Tracks 1 and 4 are not fully procured, <u>or</u> AAEE fails to materialize at forecast levels, <u>but existing DR can be successfully "repurposed" with adequate operational characteristics to satisfactorily be implemented for use by the ISO to meet contingency conditions</u>	Then it is anticipated that there would be no resource deficiency

Conclusions (cont'd)

- DR needs to be "fast" product with response time within 20 minutes to allow Operator adequate response time.
- The LCR need for the San Diego sub-area continues to be caused by the overlapping Category C (N-1-1) contingency by 500kV lines in southeastern San Diego area.
- The LCR need for the San Diego – Imperial Valley LCR area continues to be caused by the overlapping Category B (G-1/N-1) or C (i.e., N-1, followed by G-1) contingency for the major 500kV line east of Imperial Valley Substation
- With lower CEC demand forecast (due to larger AAEE projection for the LA Basin and San Diego areas), the primary constraints are the thermal constraints on the transmission facilities between SDG&E and CFE system (i.e., Imperial Valley phase-shifting transformers and the Otay Mesa – Tijuana 230kV line) under overlapping N-1-1 contingency
- The voltage instability concern is the next constraint. This transmission constraint may become the primary reliability constraint for the LA Basin/San Diego areas under higher load conditions beyond the 2024 time frame.

Conclusions (cont'd)

- Series capacitors on the southern 500kV lines are bypassed normally to prevent thermal loading concerns under summer peak load conditions
- Further Special Protection System (SPS) require further considerations and implementations in the ISO transmission planning process to mitigate loading concerns for the Miguel transformers and Sycamore-Suncrest 230kV lines under overlapping contingency conditions
- Locational effectiveness factors for major contingencies will be provided in the draft ISO Transmission Plan

Additional consideration is being given to potential transmission reinforcement on a contingency basis:

- Forecast assumptions and approved transmission and resource procurement result in no deficiency
- Consideration must be given to the risk of unrealized forecast assumptions (AAEE and repurposing of DR) as well as lower than authorized procurement.
- Additional analysis has been performed on new proposals such as IID-proposed STEP Hoober – SONGS HVDC Inter-tie project. Other new proposals such as Midway-Devers 500kV line and Alberhill-Talega HVDC will also be evaluated and the results will be included in the draft ISO 2014-2015 Transmission Plan.
- Additional analysis including the CFE-ISO Intertie will be performed as the needs arise.
- This will supplement technical results developed in the 2013-2014 transmission planning cycle for other previously identified alternatives or electrically similar projects (such as TE-VS, HVDC submarine cable, Valley-Inland 500kV AC or DC line, Imperial Valley – Inland 500kV AC or DC line)

LA Basin Area and Sub-Areas

Critical Area Contingencies

El Nido Sub-area – Category C

- Contingency: Hinson-La Fresa 230 kV line out followed by Double Circuit Tower Line Redondo-La Fresa #1 and #2 230 kV lines
- Limiting component: Voltage collapse
- 2024 LCR need: 110 MW (included 50 MW of QF and Muni generation)
- AAEE and LTPP EE assumptions: 95 MW
- Mesa Loop-In Project helps reducing LCR need in this sub-area

El Nido Sub-area – Category B

No requirements

Critical Area Contingencies

West of Devers Sub-area – Category C

- Previous critical contingency: San Bernardino-Etiwanda 230 kV line out followed by San Bernardino-Vista 230 kV line or vice versa
- Previous reliability concern: voltage collapse
- 2024 LCR need: 0 MW (No requirements)
- Mesa Loop-in Project helps eliminating this reliability concern

West of Devers Sub-area – Category B

No requirements

Critical Area Contingencies

Valley-Devers Sub-area – Category B & C

- Mesa Loop-in Project and Delany-Colorado River 500kV Line Project help eliminate this reliability concern

LA Basin Area – Category C

- Contingency: Alberhill-Serrano 500kV line, followed by an N-2 of Red Bluff-Devers 500kV lines #1 & 2
  - Limiting component: voltage instability
  - 2024 LCR need:
    - 5,000 - 5,485 MW (included 2,208 MW of QF, Muni, Renewables and Energy Storage)
      - 2,226 MW of this need is located in the Eastern LA Basin area
      - The lower value (5,000 MW) is associated with the use of Valley Direct Load Trip RAS (VDLT RAS) if this
    - AAEE and LTPP EE: 1,203 MW
    - Total utilized existing and new (LTPP) "fast" demand response: 273 MW

Critical Area Contingencies

Western LA Basin Sub-area – Category C

- Contingency: Mesa – Lighthipe 230 kV, followed by Mesa – Redondo 230 kV line
- Limiting component: Mesa – Laguna Bell #1 230 kV line
- 2024 LCR need (the total need is the sum of individual items listed below):
  - Western LA Basin sub-area: 3,778 MW (included conventional generation, solar DG PV, and energy storage)
  - Eastern (Valley) sub-area: 485 MW – Western LA Basin is expanded to include resources in the Valley sub-area to meet its reliability need
  - AAEE and LTPP EE: 866 MW
  - Total utilized existing and new (LTPP) “fast” demand response: 273 MW

Western LA Basin Sub-area – Category B

Non binding – multiple combinations possible

Conclusions

- No resource deficiencies as long as AAEE, LTPP Tracks 1 and 4 resources, and ISO Board-approved transmission projects are implemented.
- However, if less resources are to be procured, there could be deficiency for the combined LA Basin / San Diego area in the scenario where the existing “fast” demand response is not adequately implemented or procured.
- DR needs to be “fast” product with response time within 20 minutes to allow Operator adequate response time.
- The Mesa Loop-In Project eliminates the LCR need for some sub-areas in the Eastern LA Basin and helps reduce the LCR need in the El Nido sub-area
- Addition of the Mesa Loop-in Project, as well as reduction of conventional resources in the Western LA Basin necessitates the expansion of the Western LA Basin sub-area to include the Valley sub-area to provide resources to meet its local reliability need
- The LCR need for the larger LA Basin area continues to be driven by the overlapping Category B (G-1/N-1) or Category C (N-1-1) contingency in southern San Diego area

San Diego Sub-Areas and San Diego/Imperial Valley Area

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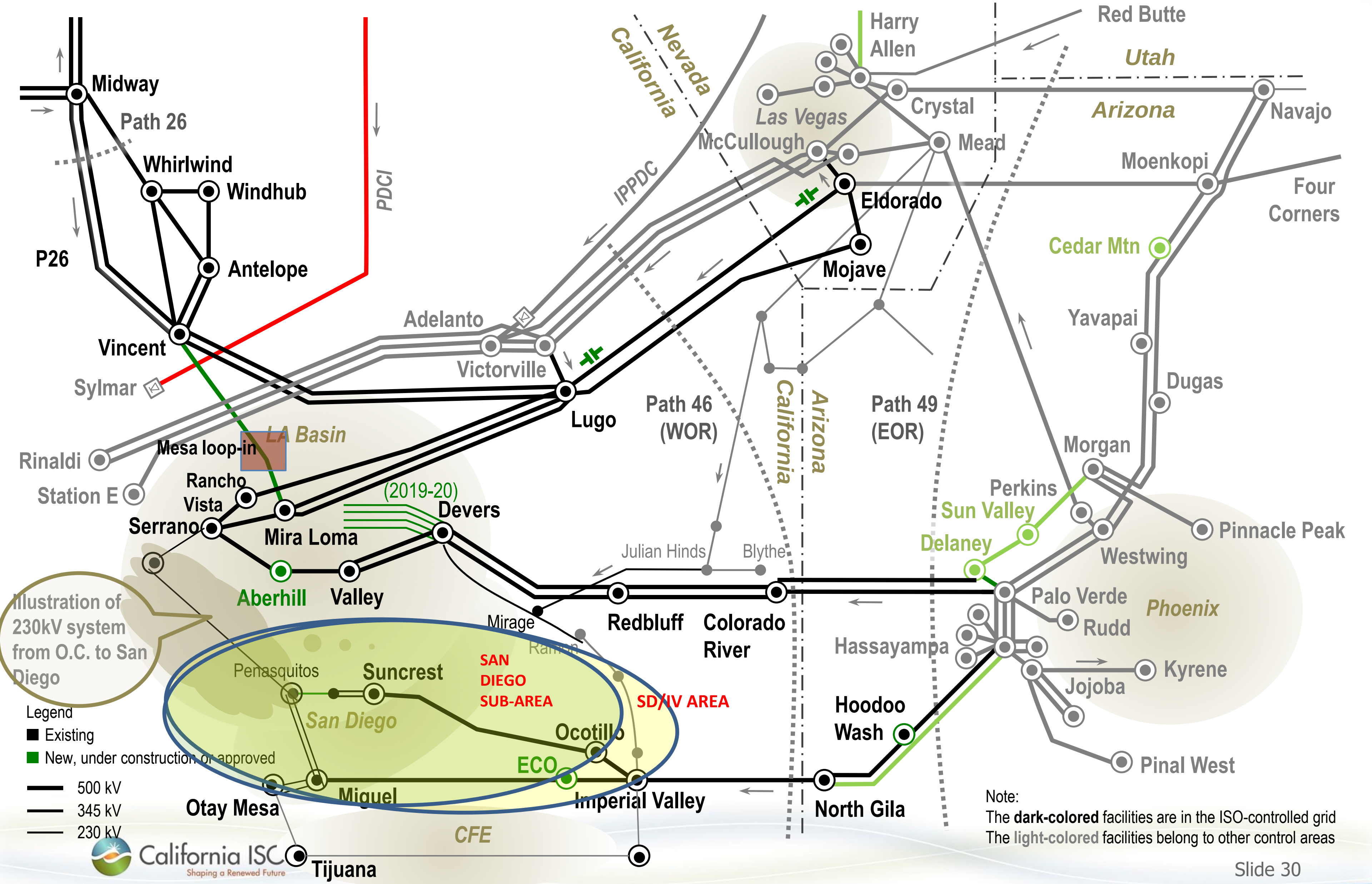
Shaping a Renewed Future

San Diego Sub-area and San Diego-Imperial Valley Area



California ISO
Shaping a Renewed Future

Areas and sub-areas studied

- El Cajon sub-area
- Mission sub-area
- Bernardo sub-area
- Esco sub-area
- Pala sub-area
- Miramar sub-area
- Border sub-area
- San Diego sub-area
- San Diego-Imperial Valley area

El Cajon Sub-area Critical Contingency

Category C:

- Contingency: loss of El Cajon-Jamacha 69 kV (TL624) followed by loss of Miguel–Granite–Los Coches 69 kV (TL632) or vice versa
- Limiting component: Garfield-Murray 69 kV (TL631) overloaded
- 2024 LCR need: 8 MW (included 0 MW of QF generation)
- AAEE assumptions: 17 MW

Category B:

No requirements

Mission Sub-area Critical Contingency

Category C:

- Contingency: Loss of Mission-Kearny 69 kV (TL663) followed by the loss of Mission-Mesa Heights 69kV (TL676)
- Limiting component: Kearny-Clairmont Tap 69kV line (TL670) and Clairmont-Clairmont Tap 69 kV and Clairmont Tap – Rose Canyon 69kV line sections' overloading concerns
- 2024 LCR: 51 MW (includes 4 MW of QF and 47 MW of deficiency – this could potentially be evaluated for potential future energy storage or transmission upgrades in the future)
- AAEE assumptions: 11 MW
- Existing local subtransmission reliability concerns were identified in previous LCR studies. This reliability concern is not related to either SONGS or Encina power plant (OTC) retirement.

Category B:

No requirements

Bernardo Sub-area Critical Contingency

Category C:

- Contingency: Loss of Artesian-Sycamore 69 kV (TL6920) followed by loss of Poway-Rancho Carmel 69 kV (TL648)
- Limiting component: Felicita Tap-Bernardo 69 kV (TL689) overloaded
- 2024 LCR: 0 MW due to the Artesian 230 kV substation upgrades
- AAEE assumptions: 10 MW

Category B:

No requirements

Esco Sub-area Critical Contingency

Category C:

- Contingency: loss of Pomerado-Poway 69 kV (TL6913), followed by the loss of Bernardo-Rancho Carmel 69kV (TL633) line
- Limiting component: overloading concern on Esco-Escondido-Warren Canyon Tap-Poway 69kV line
- 2024 LCR: 75 MW (included 38 MW of QF generation and 47 MW of deficiency) after completion of the Bernardo-Rancho Carmel 69kV upgrade
- AAEE assumptions: 8 MW
- This is an existing reliability concern which was identified in previous LCR studies. The deficiency is not related to SONGS and OTC retirement.
- This deficiency would be mitigated by a second Pomerado-Poway 69kV line project. This project is being presented to ISO Management for consideration and approval.

Category B:

No requirements

Pala Sub-area Critical Contingency

Category C:

- Contingency: loss of Pendleton-San Luis Rey 69 kV line (TL6912) followed by loss of Lilac-Pala 69kV (TL6908)
- Limiting component: Melrose-Morro Hill Tap 69kV (TL694) overloaded
- 2024 LCR: 37 MW (includes 0 MW of QF generation)
- AAEE assumptions: 6 MW

Category B:

No requirements

Border Sub-area Critical Contingency

Category C:

- Contingency: loss of Bay Boulevard-Otay 69 kV #1 (TL645) followed by loss of Bay Boulevard-Otay 69 kV #2 (TL646)
- Limiting component: Imperial Beach-Bay Boulevard 69 kV (TL647) overloaded
- 2024 LCR: 41 MW (includes 5 MW of QF generation)
- AAEE assumptions: 10 MW

Category B:

No requirements

Miramar Sub-area Critical Contingencies

Category C:

- Contingency: loss of Miguel-Bay Blvd. 230 kV (TL23042A), followed by the loss Sycamore-Penasquitos 230 kV line
- Limiting component: Sycamore-Scripps 69kV line
- 2024 LCR: 80 MW (includes 0 MW of QF)
- AAEE assumptions: 12 MW

Category B:

- Contingency: Miramar Energy facility #1 or 2, system readjusted, followed by the loss of Miguel-Bay Blvd. 230 kV (TL23042A
- Limiting component: Sycamore-Scripps 69 kV (TL6916)
- 2024 LCR: 48 MW (includes 0 MW of QF)
- AAEE assumptions: 12 MW

Conclusions

- No resource deficiencies as long as AAEE, LTPP Tracks 1 and 4 resources, and ISO Board-approved transmission projects are implemented.
- However, if less resources are to be procured, there could be deficiency for the combined LA Basin / San Diego area in the scenario where the existing “fast” demand response is not adequately implemented or procured.
- DR needs to be “fast” product with response time within 20 minutes to allow Operator adequate response time.
- The LCR need for the San Diego sub-area continues to be caused by the overlapping Category C (N-1-1) contingency by 500kV lines in southeastern San Diego area.
- The LCR need for the San Diego – Imperial Valley LCR area continues to be caused by the overlapping Category B (G-1/N-1) contingency for major 500kV line east of Imperial Valley Substation

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

Methodology for Calculating Locational Effectiveness Factors (LEFs)

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2014-2015 Transmission Planning Process Stakeholder Meeting

November 19 - 20, 2014

Overview

- Calculating LEFs based on thermal loading constraints
- Calculating LEFs based on post-transient voltage stability concerns
  - Nodal analysis approach
  - Zonal analysis approach

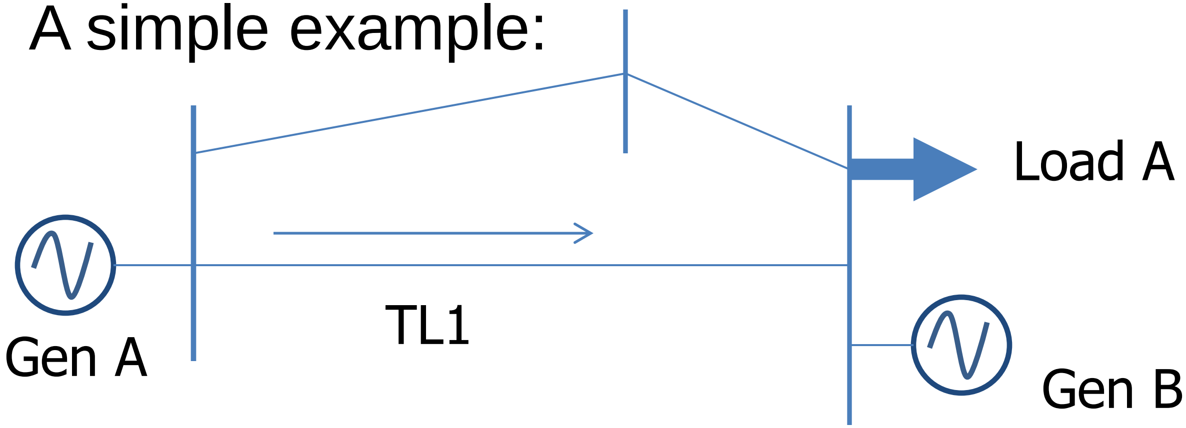
Calculation of LEFs Based on Thermal Loading Constraints

- Calculation of LEFs based on thermal loading constraints
  - A rather straightforward process because they do not change significantly based on the operating point of the system
  - Instead, the LEFs are significantly influenced by the characteristics or configuration of studied transmission system
- Step-by-step process to calculate LEFs based on thermal constraints:
  - Identify transmission loading concerns (i.e., overloading) by power flow studies; the worst overload/contingency is identified for the purpose of the LEF calculation.
  - The LEF of a tested resource is calculated by increasing its output incrementally (for example, 10 MW) and decreasing by the same total amount to all other resources outside of the study area but within the ISO BAA.
  - Re-run power flow studies with the contingency to determine the new loading on the affected transmission facility.
  - LEF is calculated as the following:

    LEF = {[Trans. loading (after) – Trans. loading (before)] / 10 MW}*100

Calculation of LEFs Based on Thermal Loading Constraints (cont'd)

- A simple example:



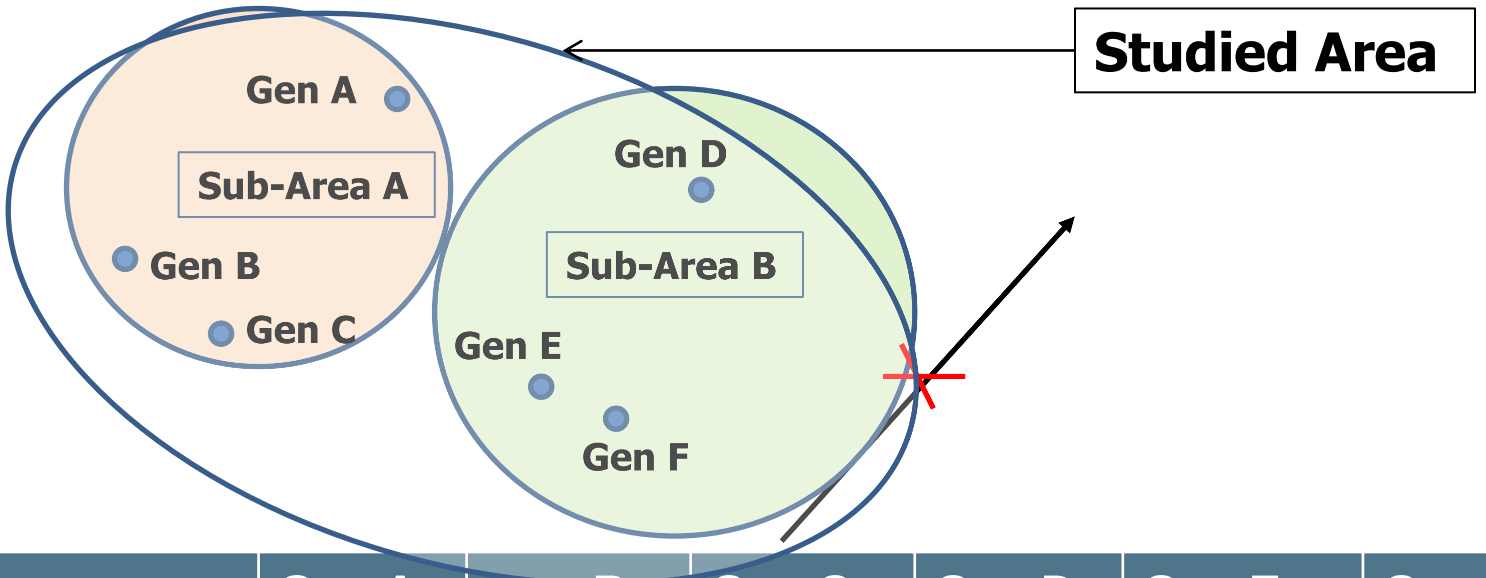
  - ❖ TL1 loading is 105 MW (before injection of additional 10 MW at Gen B)
  - ❖ TL1 loading is 100 MW (after injection of additional 10 MW at Gen B)
  - ❖ Gen B LEF = {[100 – 105] / 10}*100 = -50%
  - ➢ Gen B is 50% effective in reducing loading on TL1

Calculation of LEFs Based on Voltage Stability Constraints

- Calculation of LEFs based on voltage stability constraints is a complicated process because they can change based on the operating point of the system and are dependent on the following:
  - Amount of resources (i.e., generation, demand response, energy storage, AAEE, etc.) assumed in the power flow model, and
  - Level of transmission upgrade assumptions
- There are two potential methodologies to determine LEFs in an LCR area:
  - Nodal analysis:
    - If the LCR area is small
    - Resource requirements needed for mitigation are low enough to be modeled at individual bus
  - Zonal analysis:
    - If the LCR area is large and consists of several sub-areas
    - Resource requirements needed for mitigating **regional** voltage stability concerns are too large to be modeled at individual bus; this would allow for realistic, practical and consistent study process for **all** sub-areas.

Calculation of Generation Effectiveness Factors Based on Voltage Stability Constraints (cont'd)

Example of a simple nodal analysis



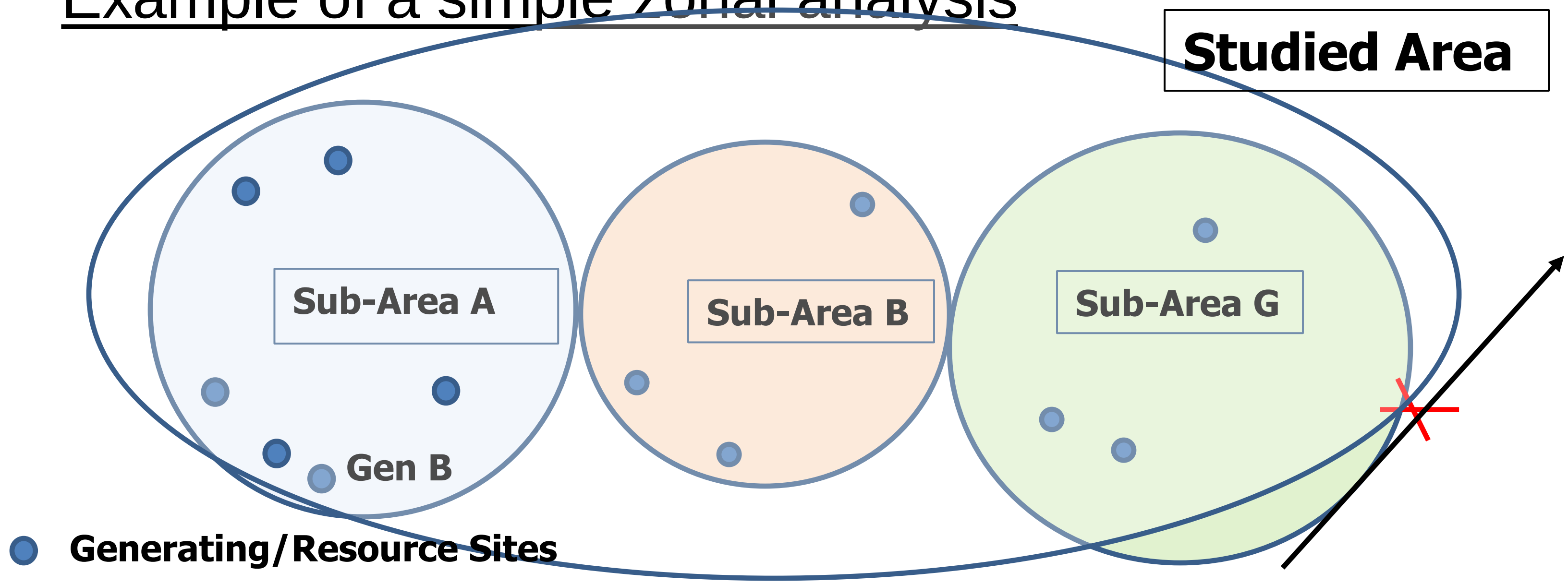
	Gen A	Gen B	Gen C	Gen D	Gen E	Gen F
Additional Capacity Need* (MW)	2,000	1,800	1,600	1,200	1,150	1,180
LEF (%)	57.5	63.9	71.9	95.8	100.0	97.5

Calculation of LEFs Based on Voltage Stability Constraints (cont'd)

- The following are advantages and disadvantages of nodal analyses used in determining LEFs based on voltage instability concerns:
  1. **Advantages:**
     - Specific LEF for each bus can be calculated
  2. **Disadvantages:**
     - Not practical, realistic nor feasible for modeling at each bus where additional required capacity is large (i.e., thousands or tens of thousands of MW) to mitigate voltage instability concerns in the less effective sub-areas
     - Would result in <u>inconsistent</u> study approach in a large LCR area where there exists pockets of effective and in-effective sub-areas (i.e., it would not be consistent if nodal analyses are performed for a more effective sub-area, but zonal analyses would need to be performed for less or non-effective sub-areas)

Calculation of LEFs Based on Voltage Stability Constraints (cont'd)

Example of a simple zonal analysis



	Sub-Area A	Sub-Area B	Sub-Area C
Additional Capacity Need* (MW)	16,000	7,000	3,000
LEF (%)	18.8	42.9	100.0

Calculation of LEFs Based on Voltage Stability Constraints (cont'd)

- The following are advantages and disadvantages of zonal analyses used in determining LEFs :
  1. **Advantages:**
     - Practical and feasible in modeling large amount of capacity resources in a very large area that has multiple sub-areas to mitigate voltage instability concerns that affect the entire region;
     - Can be performed consistently for all sub-areas under consideration;
     - Would avoid other reliability issues if the resources are spread out to multiple buses rather than at one bus (i.e., delivery issues);
     - Able to obtain power flow solution in modeling large amount of resources in multiple buses rather than at one single bus (see previous example where one sub-area requires 16,000 MW to mitigate voltage instability concern)
  2. **Disadvantages:**
     - Not having LEF for each bus;
     - Having perception of being arbitrary in creating sub-areas vs. having more specific number for each bus.

Conclusions

- For thermal loading constraints, calculating LEF at each bus is a rather straightforward process because it does not need to model large amount of additional generation to identify the effectiveness factors at each bus.
- For voltage stability concerns, it is more complicated to determine the LEF for each bus if the capacity requirement is too large to model or to obtain power flow solution. This is further exacerbated with the fact that the resources elsewhere would have to be reduced in order to balance loads and resources in the power flow model.
- Nodal analyses (for voltage stability constraints) would perform well if the LCR study area is small and the required incremental resource capacity need is not too large and is feasible for modeling at a specific bus.
- Zonal analyses (for voltage stability constraints) would perform better and allow for consistent evaluation approach for a very large LCR study area that consist of multiple sub-areas that have significant differences in effectiveness factors in mitigating regional voltage instability concerns.
- Additional studies may need to be performed to evaluate for different scenarios with various levels of baseline resource and transmission upgrade assumptions to see how the LEF changes. The LEFs, for voltage stability assessment, are very sensitive to changes on baseline resource and transmission upgrade assumptions.

Wrap-Up

2014-2015 Transmission Planning Process Stakeholder Meeting

Tom Cuccia
Lead Stakeholder Engagement and Policy Specialist
November 19-20, 2014

Next Steps

Date	Milestone
November 20, 2014	Stakeholder Meeting - Day 2
November 20 – December 4	Stakeholder comments to be submitted to regionaltransmission@caiso.com
January 2015	2014-2015 Draft Transmission Plan posted
February 2015	Stakeholder Meeting on contents of draft Transmission Plan