# *Agenda*
# Reliability Assessment and Study Updates

*Jody Cross*
*Stakeholder Engagement and Policy Specialist*

*2018-2019 Transmission Planning Process Stakeholder Meeting*
*September 20-21, 2018*

# 2018-2019 Transmission Planning Process Stakeholder Meeting – Day 1 (September 20) Agenda

| Topic | Presenter |
|---|---|
| Introduction | Jody Cross |
| Overview | Jeff Billinton |
| Key Issues | Neil Millar |
| Reliability Assessment - North | Regional Transmission Engineers - North |
| Reliability Assessment - South | Regional Transmission Engineers - South |
| Consideration of Storage as a Transmission Asset | Neil Millar |
| Next Steps | Jody Cross |

# 2018-2019 Transmission Planning Process Stakeholder Meeting – Day 2 (September 21) Agenda

| Topic | Presenter |
|---|---|
| GridLiance Proposed Reliability Solutions | GridLiance |
| SDG&E Proposed Reliability Solutions | SDG&E |
| PG&E Proposed Reliability Solutions | PG&E |
| Policy Assessment Update | Sushant Barave |
| Inter-regional Process Update | Gary DeShazo |
| Economic Study Assumptions and PCM Development | Yi Zhang |
| LCR 10-Year Assessments | Regional Transmission Engineers |
| Economic Valuing of Local Capacity Requirements | Jeff Billinton |
| Special Study – PNW Study Update | Ebrahim Rahimi |
| Wrap-up and Next Steps | Jody Cross |

# 2018-2019 TPP Policy-driven Assessment

Sushant Barave
*Regional Transmission Engineering Lead*

*2018-2019 Transmission Planning Process Stakeholder Meeting*
*September 20-21, 2018*

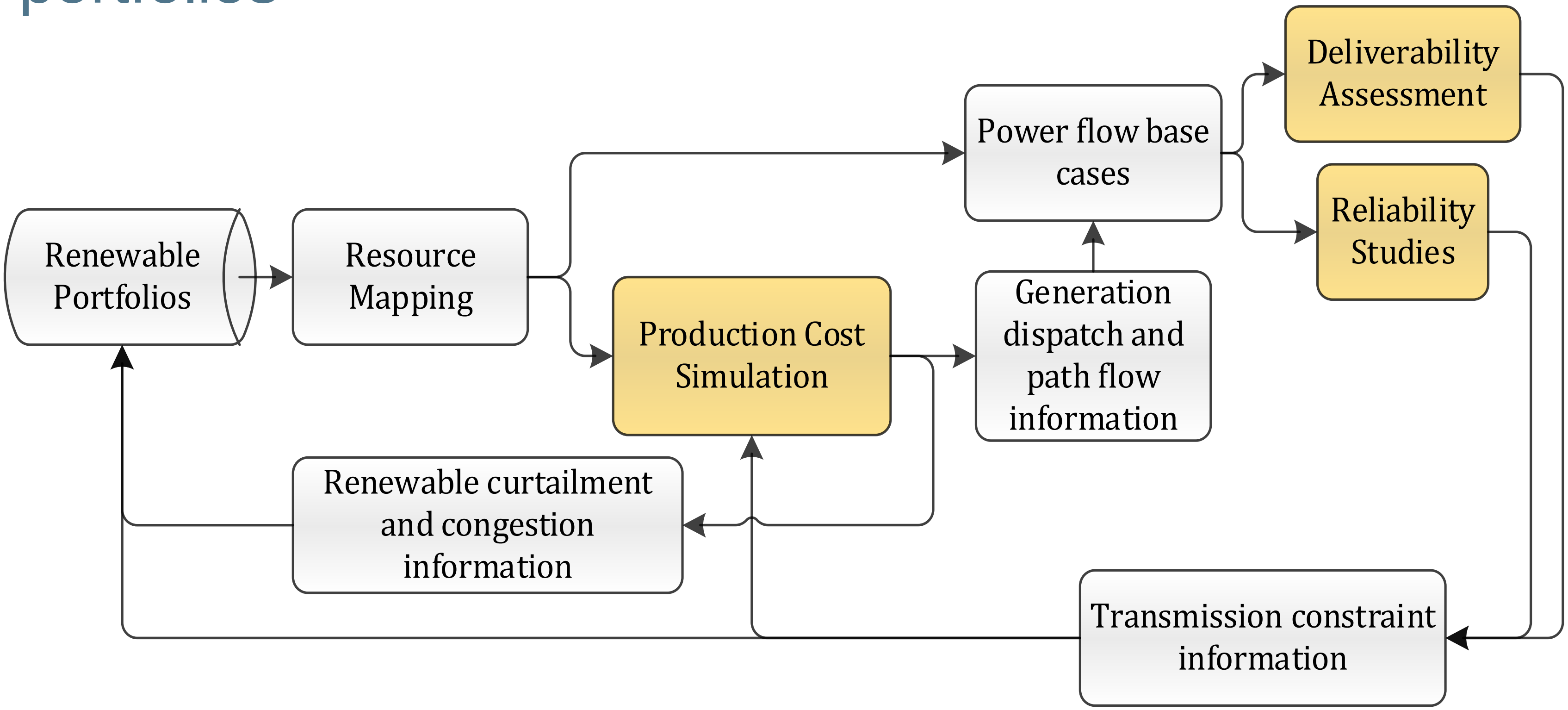
# Outline

- 2018-2019 policy-driven assessment objectives
- Study methodology
- A discussion about key inputs and assumptions
  - Renewable portfolios
  - Resource mapping
  - Study year and topology assumptions
- Next steps and timeline

# Four key objectives of policy-driven assessment in 2018-2019 TPP

1. Study the transmission impacts of the sensitivity portfolio transmitted to the ISO by CPUC
   a. Capture reliability impacts
   b. Test the deliverability of resources selected to be full capacity deliverability status (FCDS)
   c. Analyze renewable curtailment data
2. Evaluate transmission solutions (only Category 2 in this planning cycle) needed to meet state, municipal, county or federal policy requirements or directives as specified in the Study Plan
3. Test the transmission capability estimates used in CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation
4. 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

# Methodology: An iterative process comprised of three types of technical studies, identifies required upgrades and generates transmission input for the next set of portfolios



# Renewable portfolios identified in the integrated resource planning (IRP) process will be used

- CPUC adopted the 2-year integrated resource planning cycle on February 08, 2018 – http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

- The adopted decision prescribed two portfolios to be utilized in 2018-2019 TPP
  - Default scenario
  - 42 MMT scenario

# Only a sensitivity portfolio was transmitted to the ISO for policy-driven studies; no baseline portfolio

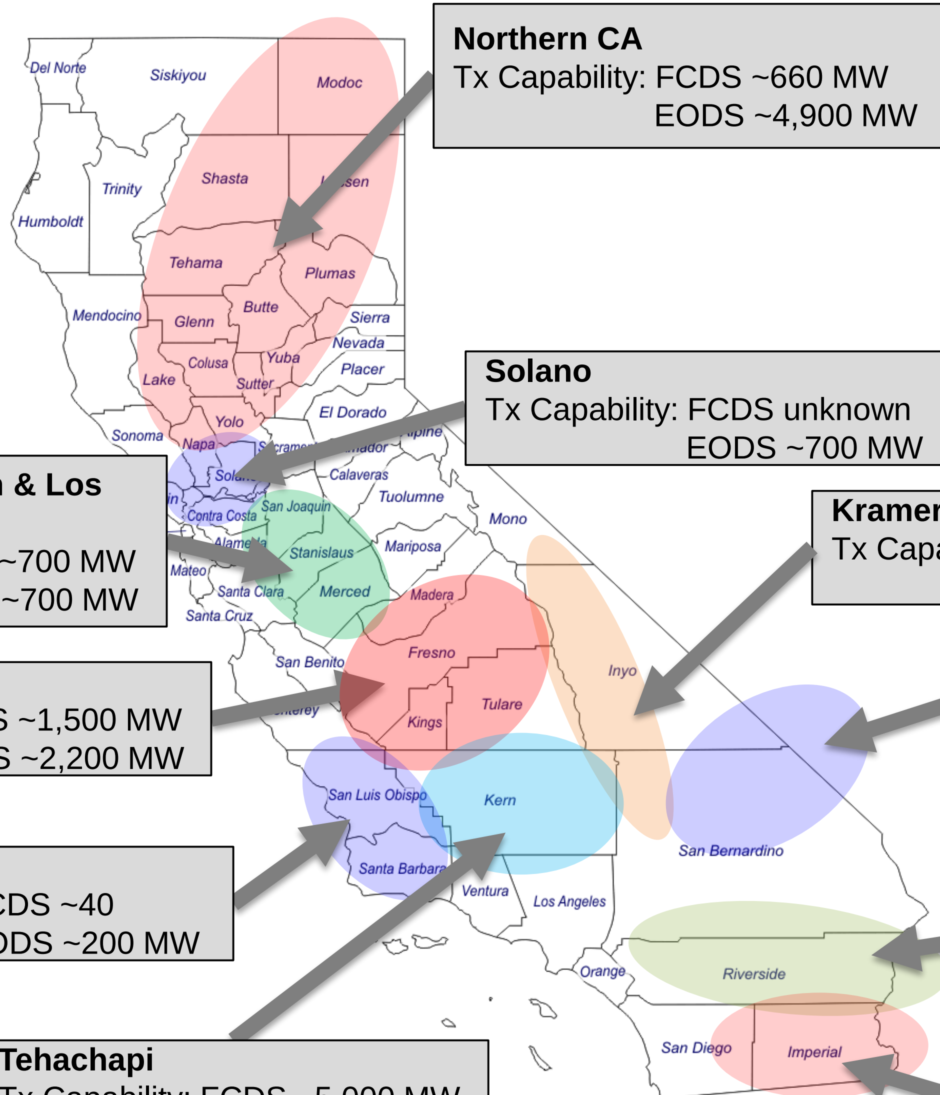
- Default scenario
  - 50% RPS entails ~3,500 MW of new ‘generic’ resources
  - Modeled in the TPP year-10 reliability base cases

- 42 MMT scenario
  - Used as a ‘sensitivity’ study under policy-driven framework

# Major changes to the portfolio models and the nature of modeling/mapping data (compared to prior years)

- “RESOLVE” model instead of the RPS calculator
- CEC staff developed the locational mapping of resources
- Portfolio now includes only the new “generic” resources
- Contracted resources (on-line and planned) are now considered as baseline resources in RESOLVE model
- A mix of resources with Full Capacity Deliverability Status (FCDS) and Energy Only Deliverability Status (EODS)
- 2,000 MW energy storage included in the portfolio is primarily for integration purpose

# Transmission capability estimates provided to the CPUC




**Northern CA**
Tx Capability: FCDS ~660 MW
EODS ~4,900 MW

Starting estimates used as an input into RESOLVE model for generating portfolios

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

**Solano**
Tx Capability: FCDS unknown
EODS ~700 MW

**Central Valley North & Los Banos**
Tx Capability: FCDS ~700 MW
EODS ~700 MW

**Kramer and Inyokern**
Tx Capability: FCDS 1,000 MW
EODS ~1,000 MW

**Nevada SW, Mountain Pass and Eldorado**
Tx Capability: FCDS ~800 MW
EODS ~3,000 MW

**Westlands**
Tx Capability: FCDS ~1,500 MW
EODS ~2,200 MW

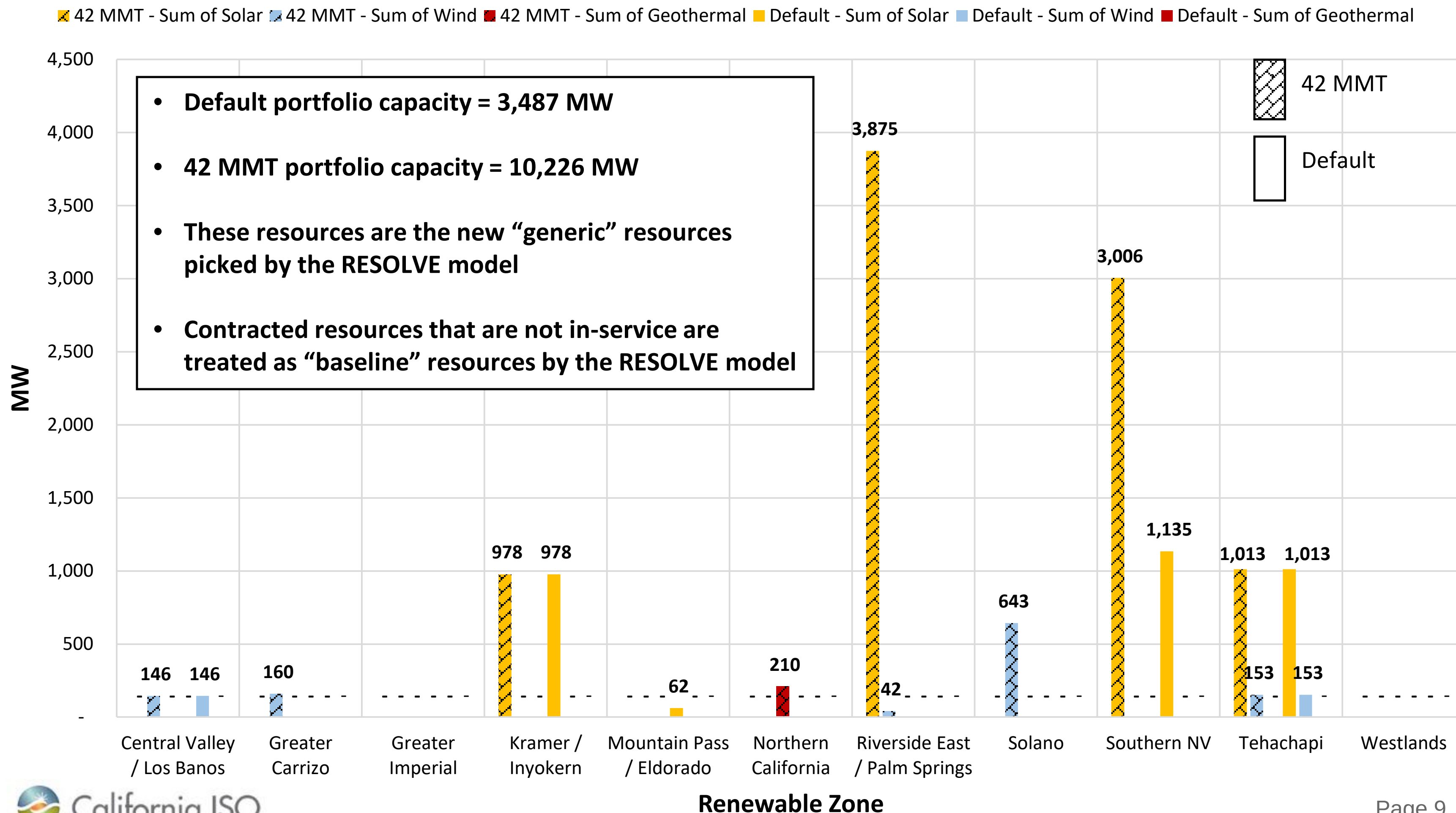
**Greater Carrizo**
Tx Capability: FCDS ~40
EODS ~200 MW

**Riverside East and Palm Springs**
Tx Capability: FCDS ~2950 MW
EODS ~5,500 MW

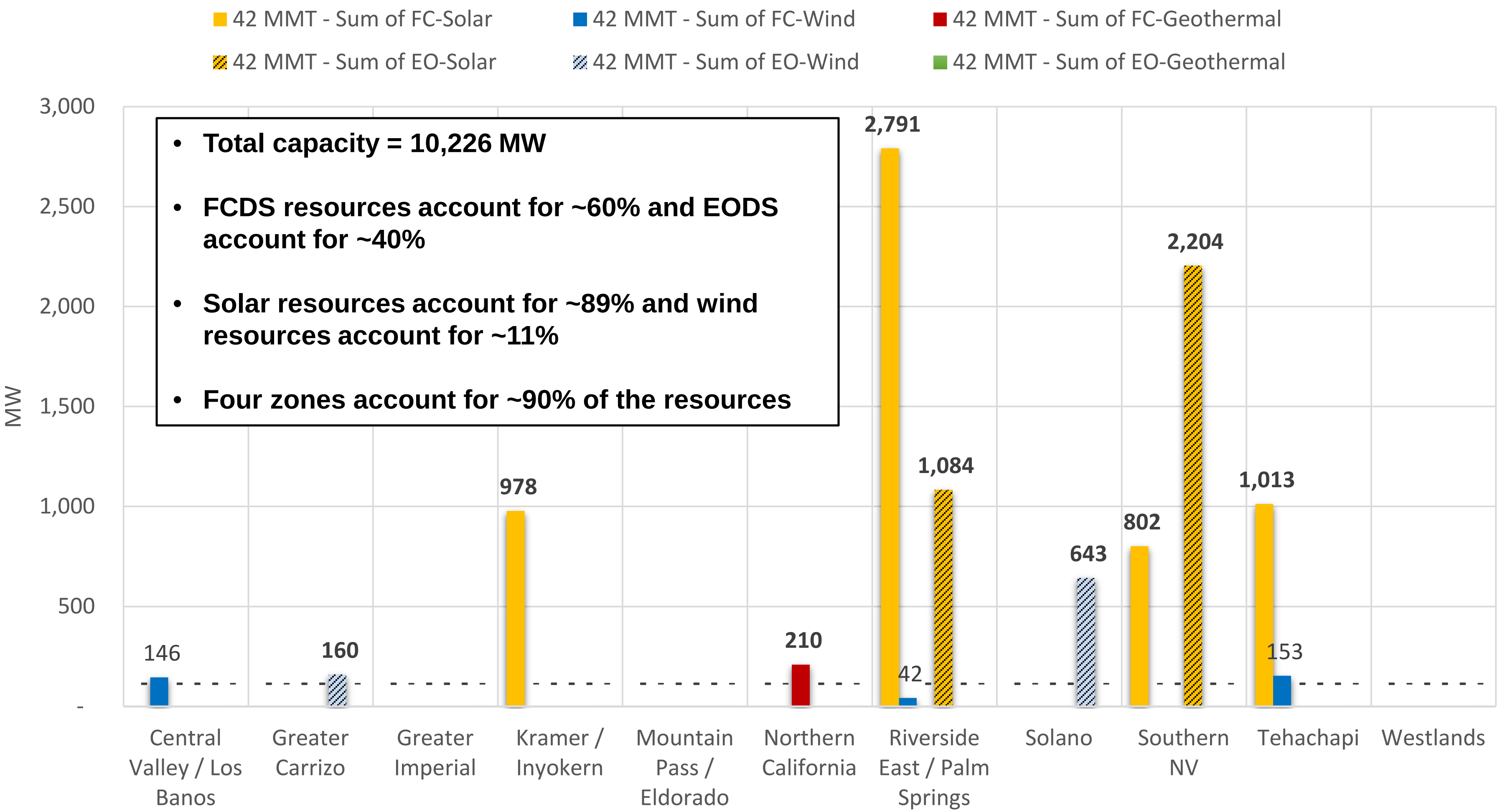
**Tehachapi**
Tx Capability: FCDS ~5,000 MW
EODS ~5,800 MW

**Greater Imperial**
Tx Capability: FCDS ~1,200 MW
EODS ~3,100 MW

# Default portfolio modeled in the year-10 TPP reliability case is a subset of the 42 MMT portfolio which includes FCDS and EODS resources



# EO resources are selected in Greater Carrizo, Solano, Riverside East and Southern NV zones

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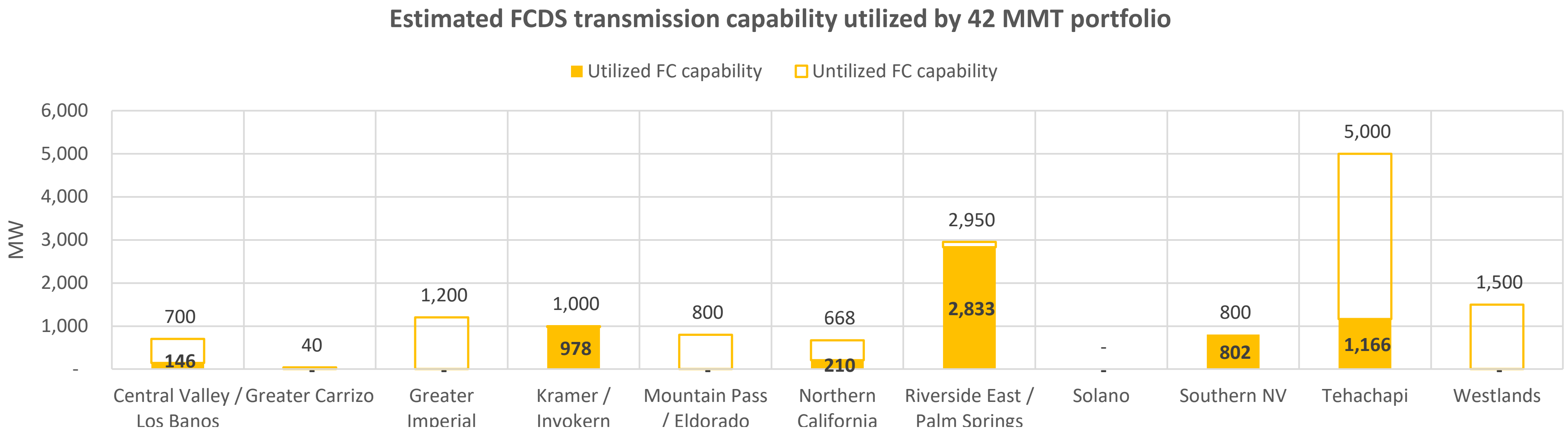
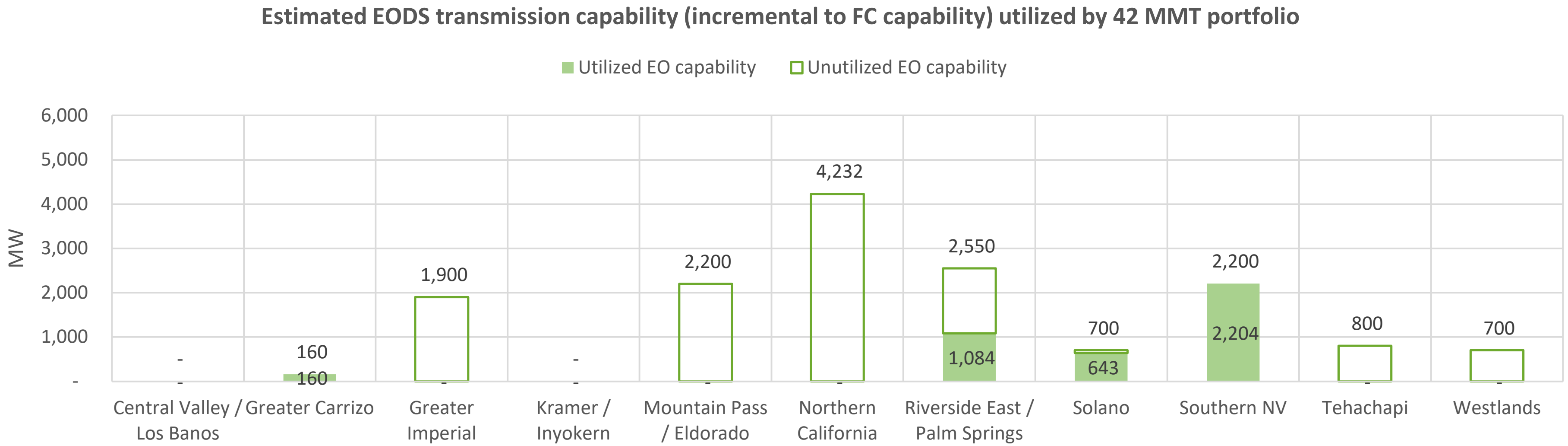
# Estimated FCDS transmission capability is fully utilized by the RESOLVE model in Kramer-Inyokern, Riverside East and Southern NV zones



# The ISO used a proposed resource mapping provided by the CEC staff and made minor modifications

- The portfolios are at a geographic scale that is too broad for transmission planning, which requires specific interconnection locations.
- CEC staff developed a proposed substation allocation* by relying on information from the CPUC, the ISO, RETI 2.0, California Department of Fish and Wildlife, and U.S. Bureau of Land Management (Nevada)
- The ISO relied on specific information about interconnection challenges regarding some locations that resulted in changing resource allocation to substations in Southern NV zone

* https://efiling.energy.ca.gov/GetDocument.aspx?tn=222569

# Substation mapping utilized for portfolio modeling

| Zone | 42 MMT (MW) Solar | Wind | GeoT | Substation selected for modeling purpose |
|---|---|---|---|---|
| Northern CA (all FC) | - | - | 210 | Round Mountain 230 kV |
| Solano (All EO) | - | 281 | - | Tesla 230 kV |
| | - | 42 | - | Contra Costa 230 kV |
| | - | 18 | - | Christie 60 kV |
| | - | 247 | - | Vaca 115 kV |
| | - | 55 | - | Eight Mile 230 kV |
| Central Valley / Los Banos (All FC) | - | 146 | - | Los Banos 230 kV |
| Greater Carrizo (All EO) | - | 41 | - | Carrizo 230 kV |
| | - | 56 | - | Templeton 230 kV |
| | - | 26 | - | Zaca 115 kV |
| | - | 24 | - | Gaviota |
| | - | 13 | - | Palmer 115 kV |
| Tehachapi (All FC) | - | 153 | - | Highwind 230 kV |
| | 627 | - | - | Windhub 230 kV |
| | | | | |
| | 386 | - | - | Highwind 230 kV |
| Kramer / Inyokern (All FC) | 778 | - | - | Kramer 230 kV |
| | | | | |
| | 100 | - | - | Cottonwood 115 kV |
| | 100 | - | - | Gale 115 kV |
| Mountain Pass / Eldorado / Southern NV (FC = 802 MW; Rest all EO) | - | - | - | Valley 138 kV (VEA) |
| | 989 | - | - | Innovation 230 kV (VEA) |
| | - | - | - | Vista 138 kV (VEA) |
| | 445 | - | - | Desert View 230 kV (VEA) |
| | 326 | - | - | Eldorado 230 kV (SCE) - SW_NV |
| | 716 | | | Crazy Eyes 230 kV (proposed) |
| | 530 | | | Gamebird 230 kV (proposed) |
| Riverside East / Palm Springs (FC = 2,791 MW; Rest all is EO) | 1,055 | - | - | Red Bluff 500 kV |
| | 2,820 | - | - | Colorado River 500 kV |
| | - | 42 | - | Devers 230 kV |

Modified by the ISO

- Except for one zone, all the substations selected by the CEC staff were perfectly reasonable
- In Southern NV zone, initial resource allocation included modeling ~1776 MW on VEA's 138 kV system
- In the light of challenges associated with interconnecting generation on VEA's 138kV system, the ISO proposed mapping this generation to GridLiance's 230 kV system
- The ISO vetted this modified mapping with the concerned PTOs and the CEC staff

Initially proposed

| Solar | Wind | GeoT | |
|---|---|---|---|
| 1,399 | - | - | Valley 138 kV (VEA) |
| 458 | - | - | Innovation 230 kV (VEA) |
| 377 | - | - | Vista 138 kV (VEA) |
| 445 | - | - | Desert View 230 kV (VEA) |
| 326 | - | - | Eldorado 230 kV (SCE) - SW_NV |
| - | - | - | Crazy Eyes 230 kV (proposed) |
| - | - | - | Gamebird 230 kV (proposed) |

# North and South bulk reliability were merged and are being used to model the 50% portfolios

- Starting base cases
  - Year-10 base cases used for 2018-2019 TPP annual reliability assessment are used as a starting point
- Load assumption
  - The ISO will identify severe snapshots to be modeled based on high transmission system usage hours under high renewable dispatch in respective study areas, and the corresponding load levels were modeled.
- Transmission assumption
  - Same assumptions as the ISO Annual Reliability Assessments for NERC Compliance (all transmission projects approved by the ISO)
- Dispatch assumption
  - For reliability assessment, dispatch renewables based on the identified snapshot
  - For deliverability assessment, according to the deliverability methodology

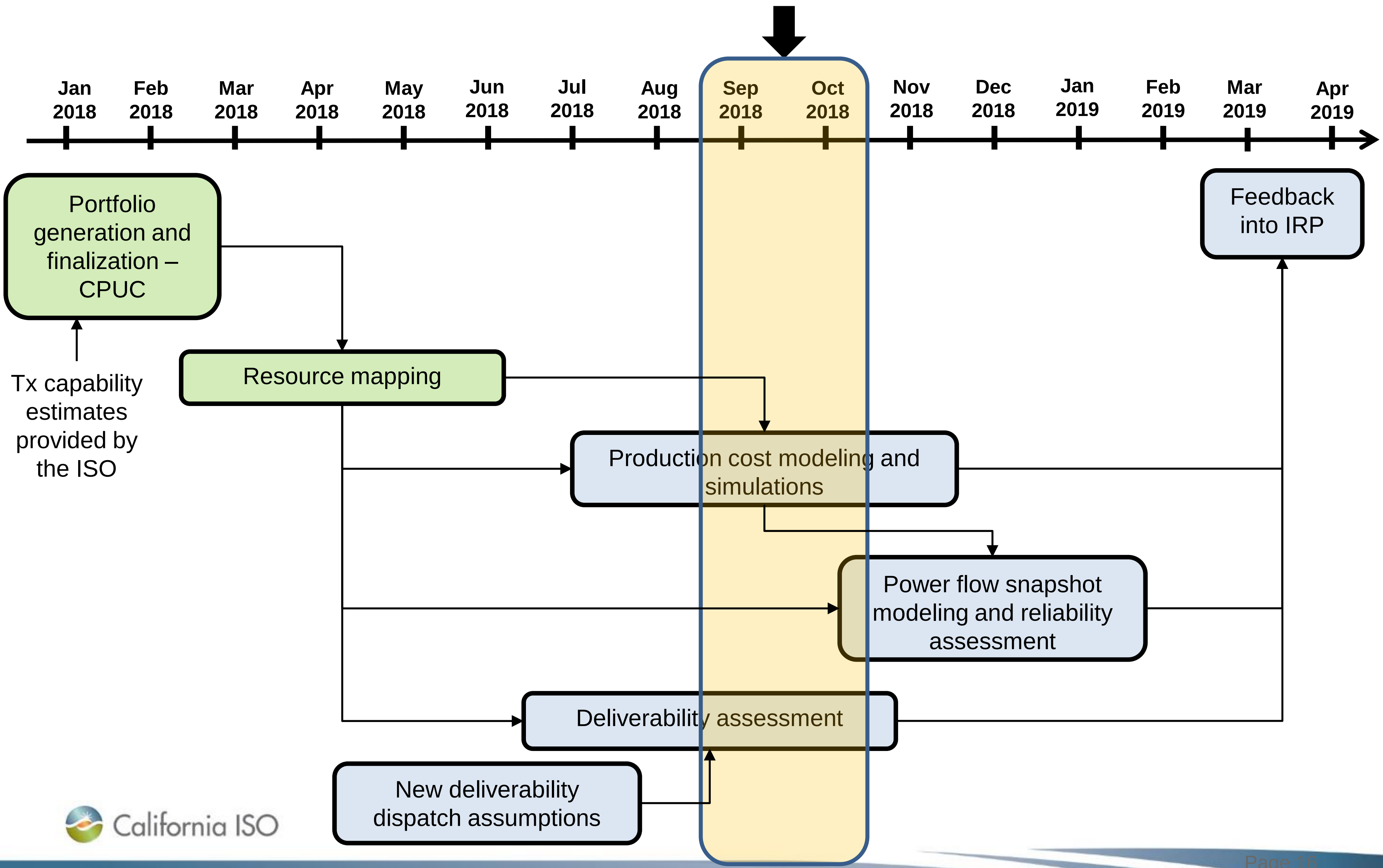
# Next steps

- Capture and analyze renewable curtailment based on production cost simulation runs; if required, run sensitivities to gain more insights

- Select power flow snapshots for reliability assessment; model these snapshots and run contingency analyses

- Document deliverability results

# Timeline and current status

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# Order No. 1000 Interregional Coordination 2018-2019 Transmission Planning Process

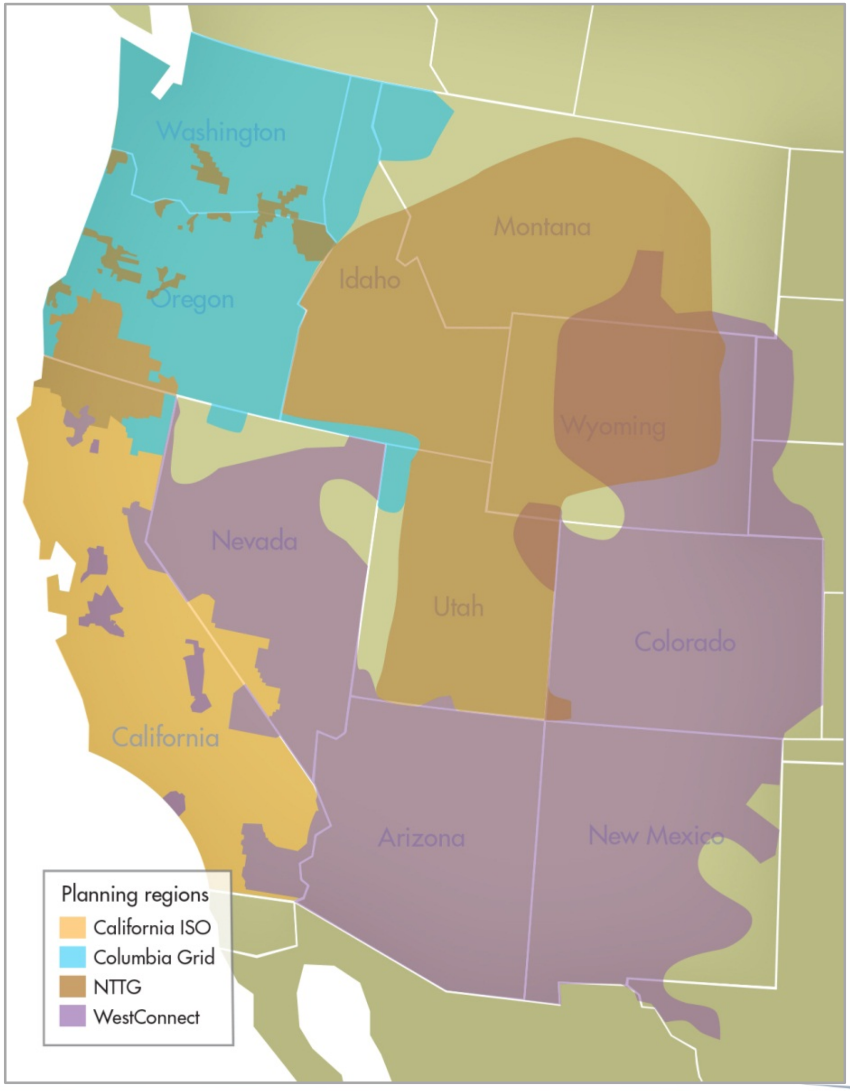
Gary DeShazo
Director, Regional Coordination

2018-2019 Transmission Planning Process Stakeholder Meeting
September 20-21, 2018

# Order 1000 amended Order 890 requiring “public utility transmission providers” to meet six new requirements

- Participate in a regional transmission planning process that produces a regional transmission plan
- Include procedures that consider public policy requirements
- Remove federal right of first refusal for certain new transmission facilities
- Improve coordination between neighboring transmission planning regions for new interregional transmission facilities
- Participate in a regional transmission planning process that has:
  - A regional cost allocation methodology
  - An interregional cost allocation methodology for new transmission facilities that are jointly evaluated by two or more planning regions

# Implementing Order 1000's regional requirement resulted in four western planning regions (WPRs)




California ISO

# The WPR's common tariff requirements for interregional coordination (IC) became effective in 2015

- Establish a process

  *To coordinate and share the results of each region's regional transmission plans to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost effectively than separate regional transmission facilities*

- Develop a formal procedure

  *To identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions*

- An agreement

  *To exchange, at least annually, planning data and information*

- A website or e-mail list

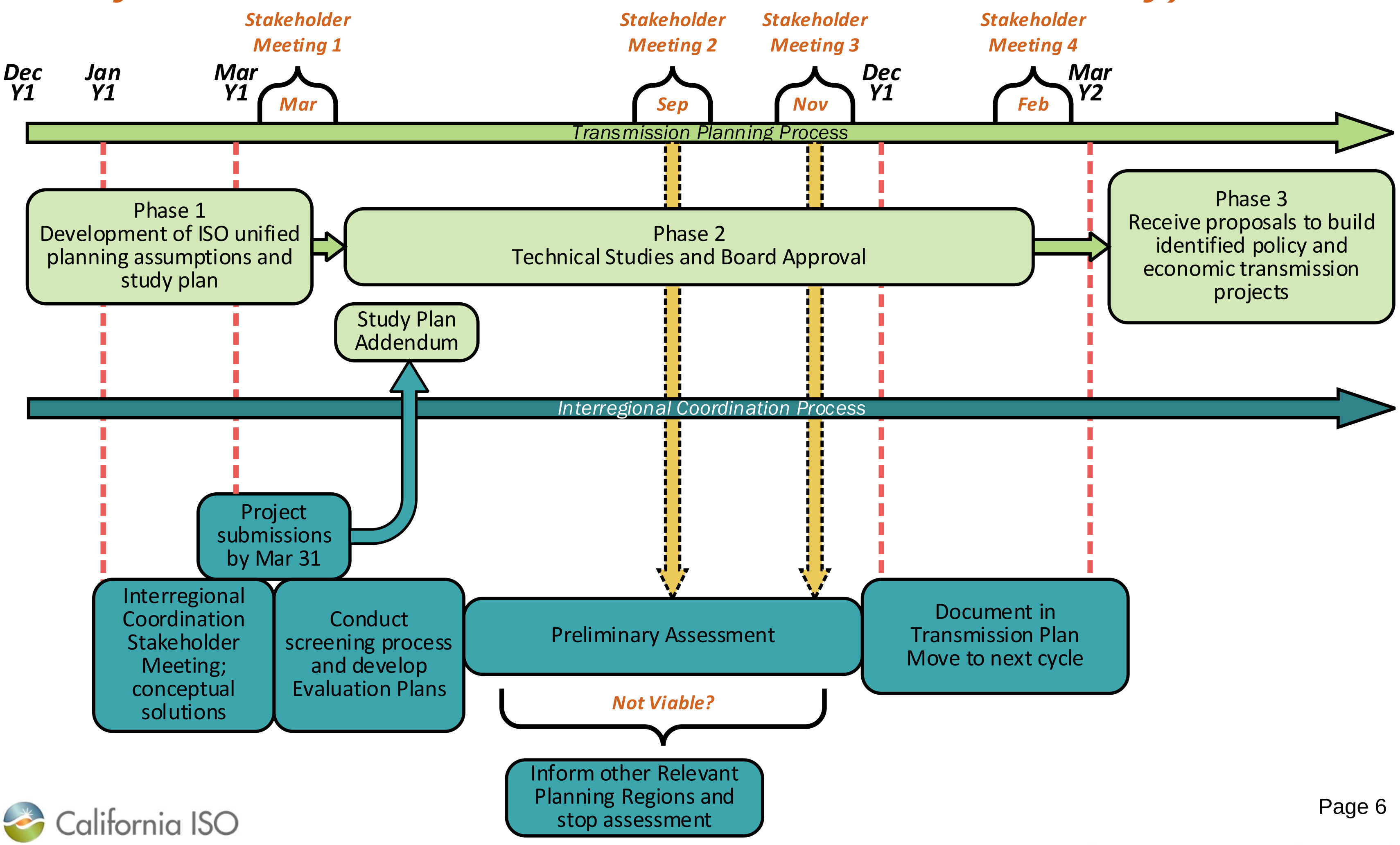
  *for the communication of information related to the coordinated planning process*

# The biennial interregional coordination cycle begins every even numbered year

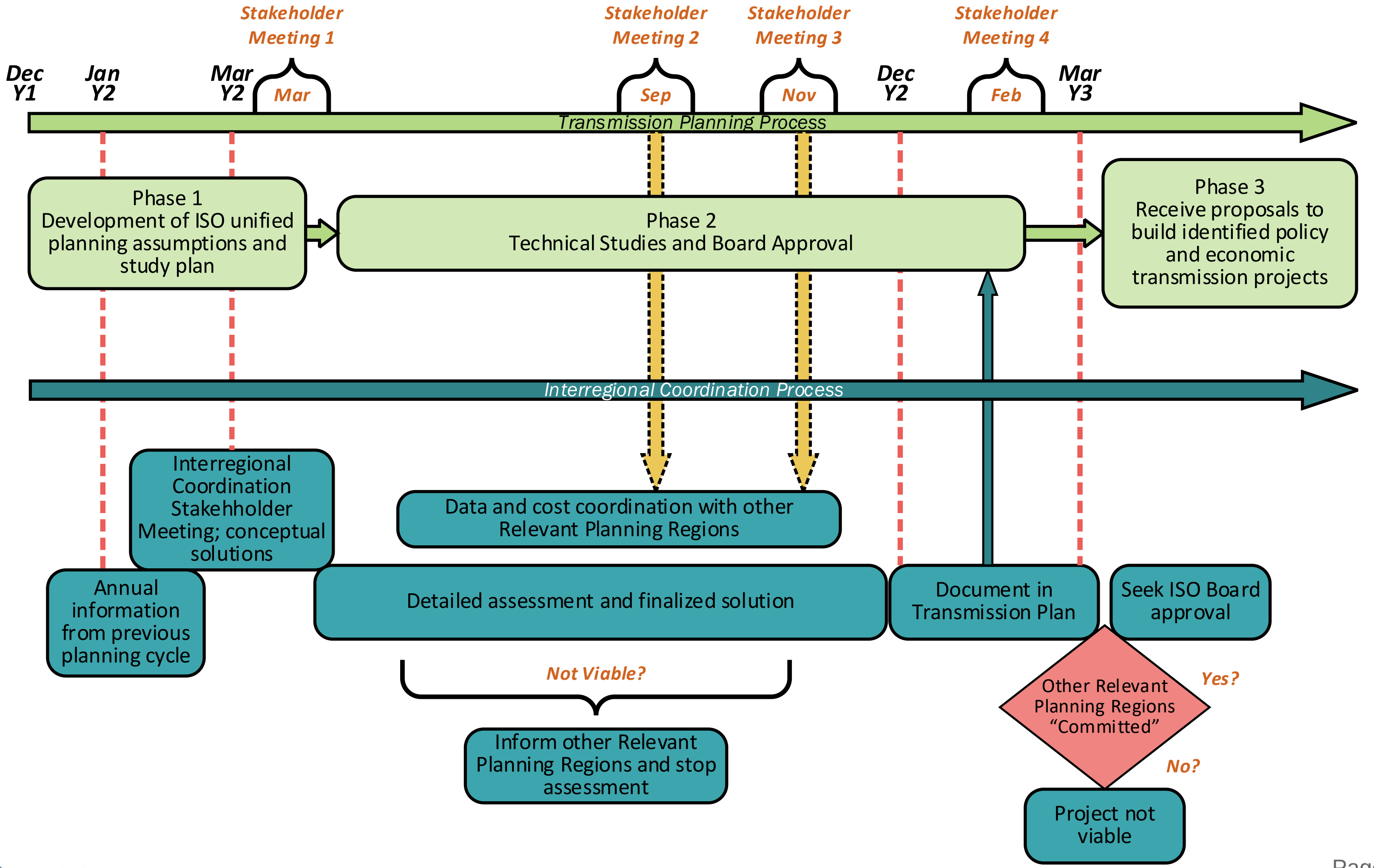
- The WPRs coordinate implementation of each IC cycle
  - "Interregional Coordination and ITP Evaluation Schedule"
  - "ITP Project Submittal Information (Current Regional Planning Cycle)"
- Conducts a biennial "open window" for ITP submittals that closes on March 31 or every even numbered year
- Relevant Planning Regions coordinate the development of ITP Coordination Plans
- Host an annual IC stakeholder meeting in February to share regional transmission plans and seek stakeholder input
- Each WPR developed its own website to provide stakeholder access to IC information

# Interregional coordination will be achieved through each planning region's Order 1000 regional process

## *(Even year - ISO's initial assessment on ITP viability)*



# Odd year - ISOs assessment continues for ITPs considered “viable” in the previous year

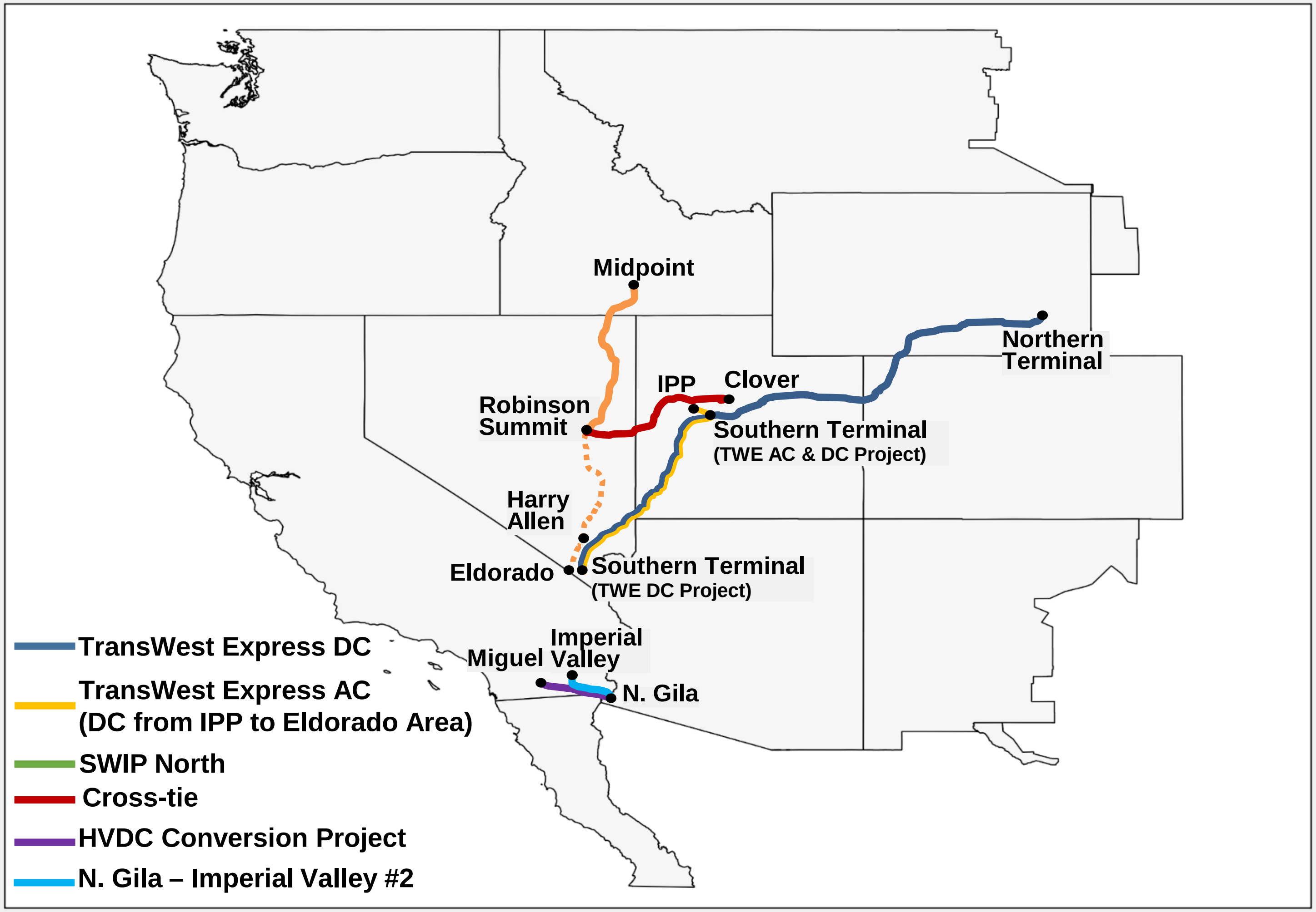


# 2018-2019 ITP Submittal Summary

| ITP | Submitted To | Relevant Planning Region | Cost Allocation Requested |
|---|---|---|---|
| Cross-Tie | ISO, NTTG, WestConnect | NTTG, WestConnect | ISO, NTTG, WestConnect |
| HVDC Conversion | ISO, WestConnect | ISO, WestConnect | Not Requested |
| N. Gila-Imperial Valley #2 | ISO, WestConnect | ISO, WestConnect | ISO, WestConnect |
| SWIP North | ISO, NTTG, WestConnect | ISO, NTTG, WestConnect | ISO, NTTG, WestConnect |
| TransWest Express AC/DC | ISO, NTTG, WestConnect | ISO, NTTG, WestConnect | ISO, WestConnect |
| TransWest Express DC | ISO, NTTG, WestConnect | ISO, NTTG, WestConnect | ISO, WestConnect |

# Proposed Interregional Transmission Projects

## 2018-2019 Interregional Coordination Cycle



# ISO's assessment of ITP viability and need in the 2018-2019 planning process is underway

| Proposed ITP | Sponsor Identified Need | ISO Identified Need |
|---|---|---|
| Cross-Tie | Strengthen interconnection between PacifiCorp and Nevada; facilitate California's RPS and GHG needs | Based on 2018-2019 plan assumptions, none identified |
| HVDC Conversion | Improve/remove existing reliability limitation; decrease San Diego and greater IV/San Diego LCR requirement | LCR assessment in progress |
| NG-IV#2 | Decrease San Diego and greater IV/San Diego LCR requirement | LCR assessment in progress |
| SWIP North | Economic, policy, reliability, reduce congestion on COI, facilitate access to renewables in PacifiCorp | Economic assessment in progress |
| TransWest Express AC/DC | Provide needed transmission capacity between the Desert Southwest and California, facilitate California access to renewables | Based on 2018-2019 plan assumptions, none identified |
| TransWest Express DC | Provide needed transmission capacity between the Desert Southwest and California, facilitate California access to renewables | Based on 2018-2019 plan assumptions, none identified |

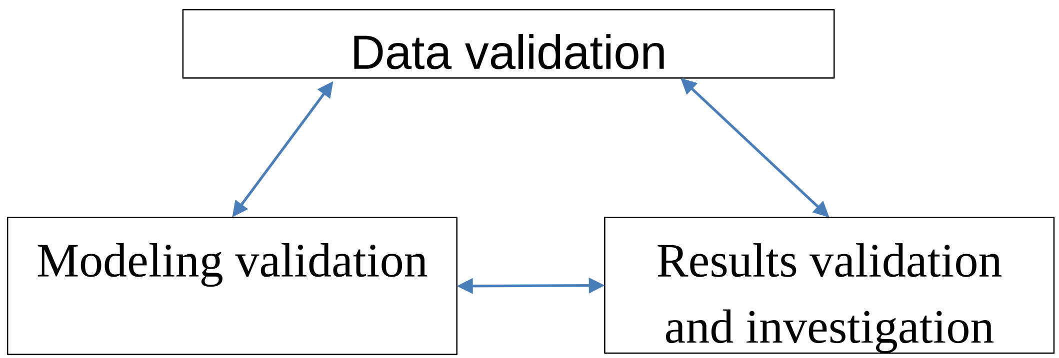
# Economic Planning-
# Production cost model (PCM) development

Yi Zhang
Regional Transmission Engineering Lead

2018-2019 Transmission Planning Process Stakeholder Meeting
September 21-22, 2018

# Anchor Dataset (ADS) PCM status update

- Anchor dataset (ADS) PCM case
  - ADS PCM v1.0 was released end of June
  - Validation is in progress by WECC RAC working groups (PDWG, PMWG) and WECC staff




  - ADS PCM v2.0 is projected to be released around end of September
    - More updates and releases may follow

# ISO planning PCM components

Grid operation

Market operation

Trans/Resource planning

Other econ/env. data

Market model – AS requirements and co-optimization, wheeling, dynamic schedule and pseudo-tie units, market related constraints/nomograms

Fuel and GHG models – NG and Coal prices, CO2 allowance, Fuel price assignment, CO2 price assignment, AB32 hurdle

Load model – Peak demand, annual/monthly energy, load shape, losses estimate, load modifiers

Trans. operation model – Contingency/SPS, nomograms, interfaces, schedule outage and derate

Gen. operation model – Heat rate, ramp rate, renewable profiles, hydro model, schedule outages, FOR, etc.

Full network model – Transmission topology, load distribution, generator Pmax and location

TPP Power flow case

# Key assumptions and inputs for the ISO PCM development in 2018-2019 cycle

- Started from ADS PCM v1.0, but will capture the changes identified and approved in the ADS PCM after ADS PCM v1.0
- ISO TPP 2028 power flow case is used to update the PCM network model
- Two cases with different renewable assumptions
  – CPUC default portfolio case
  – CPUC 42MMT portfolio case
- CEC 2028 load forecast  mid-AAEE for load model update
  – AAEE and BTM PV are modeled as resources

# Key system and transmission constraints

- Net export limit 2000 MW
  - Sensitivity of No Export Limit will be tested
- COI and EOR scheduled outages and derates based on facility owners’ submitted data and OASIS data
- Nomograms for major paths based on planning studies or operation procedures
  - COI, Path 15, Path 26
- Contingencies and SPS
  - Critical contingencies identified in ISO’s TPP, LCR, and GIP studies
- Consider imported Ancillary Services in the transmission constraints for inter-ties

# Next steps

- Continue on database development
- Conduct production cost simulations and congestion analysis for
  - Economic assessment
  - Policy driven study
  - PAC NW study
- Continue on assessment of COI DA congestion
- Provide update in the next TPP Stakeholder Meeting

California ISO

# PG&E System LCR Area Types and Profiles

Binaya Shrestha

Regional Transmission Engineer Lead

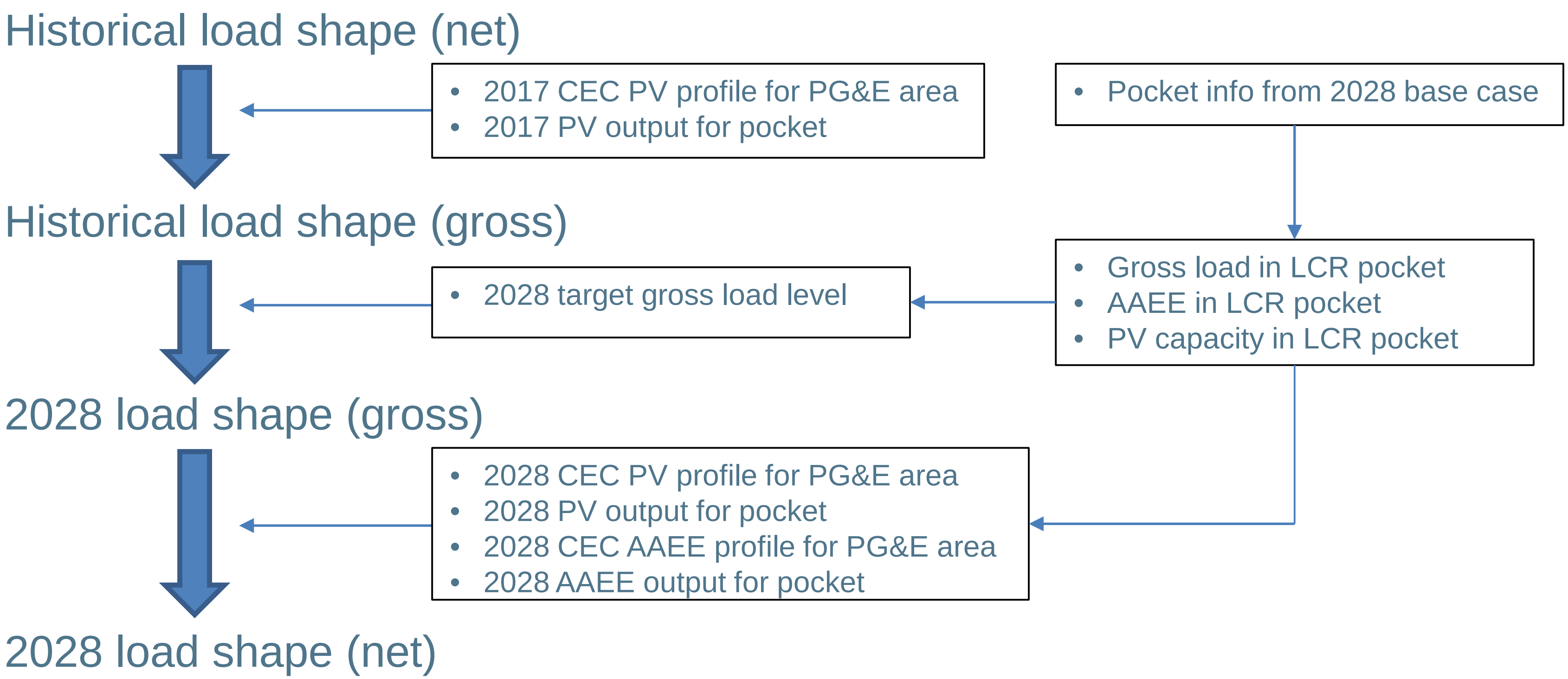
Stakeholder Meeting

September 20-21, 2018

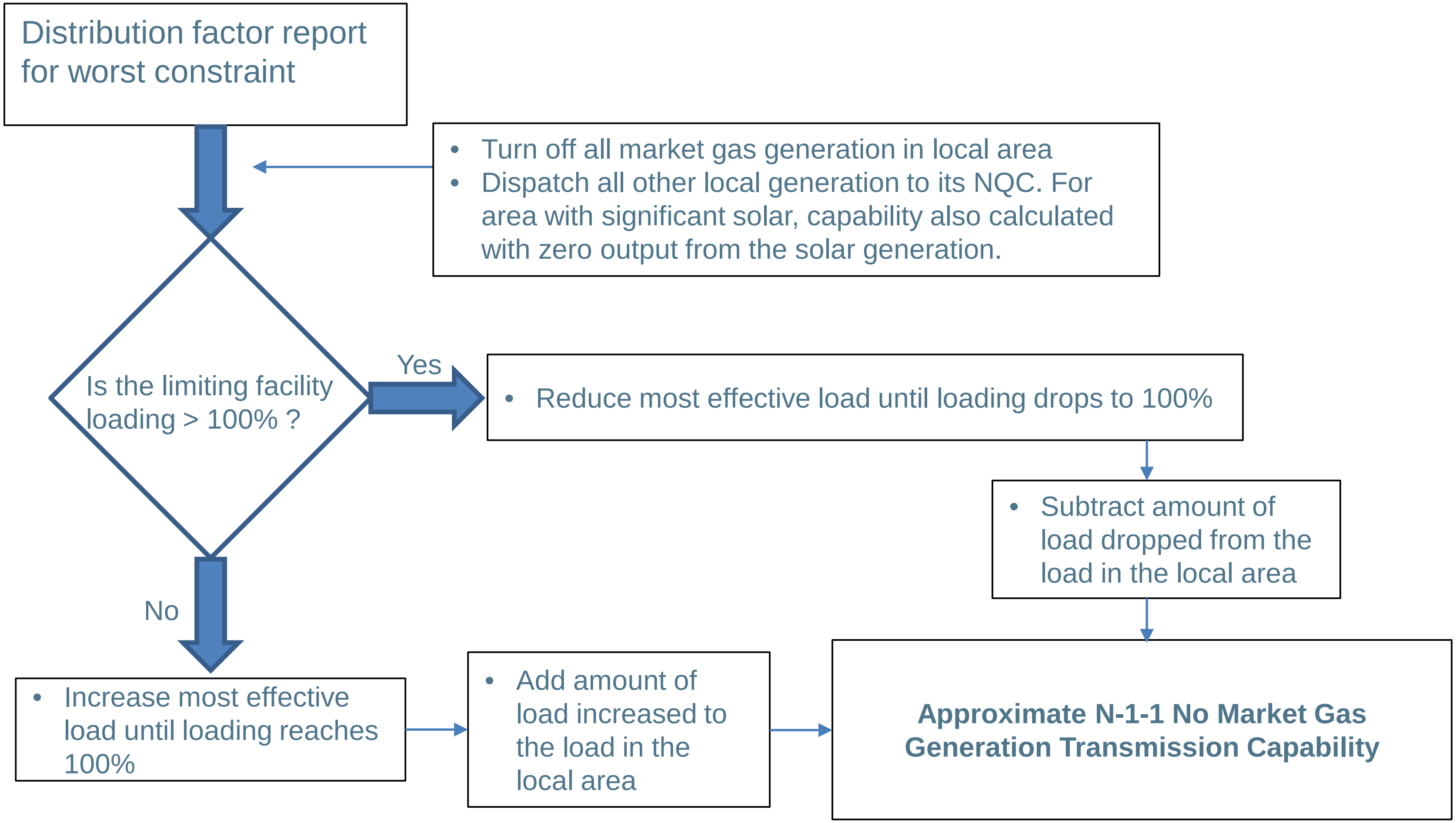
# Purpose of providing area profiles

- Profiles are provided to help develop characteristic of potential preferred resources alternatives.
- The ISO will explore and assess alternatives – conventional transmission and preferred resources – to reduce requirements of the existing local capacity areas and subareas.

# Load Profile and Escalation Process for Defined LCR Area



# N-1-1 No Market Gas Generation Transmission Capability Approximation*




** Based on DC calculation using distribution factors considering thermal limits only.*

# Types of LCR areas/subareas and profiles

<table>
<tr><th>Area Type</th><th>Profiles</th></tr>
<tr><td>Single source pocket (radial)</td><td rowspan="2"><ul><li>2028 hourly (8760) area load profile</li><li>Seasonal daily load profile</li></ul></td></tr>
<tr><td>Multi source pocket</td></tr>
<tr><td>Flow-through</td><td><ul><li>Historical hourly (8760) flow profile</li><li>Historical seasonal daily flow profile</li><li>2028 seasonal daily load profile for the most effective load pocket</li></ul></td></tr>
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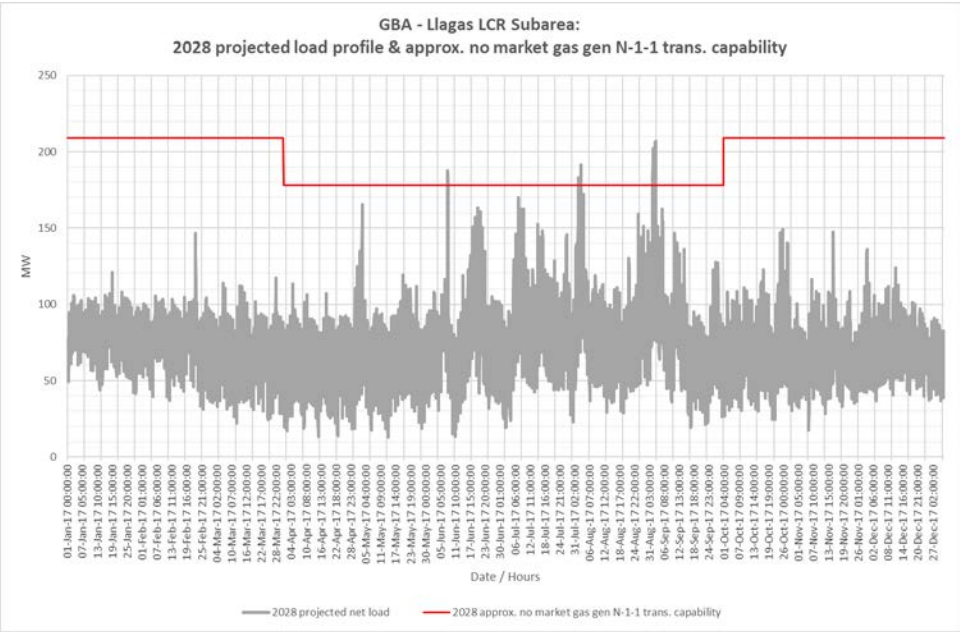
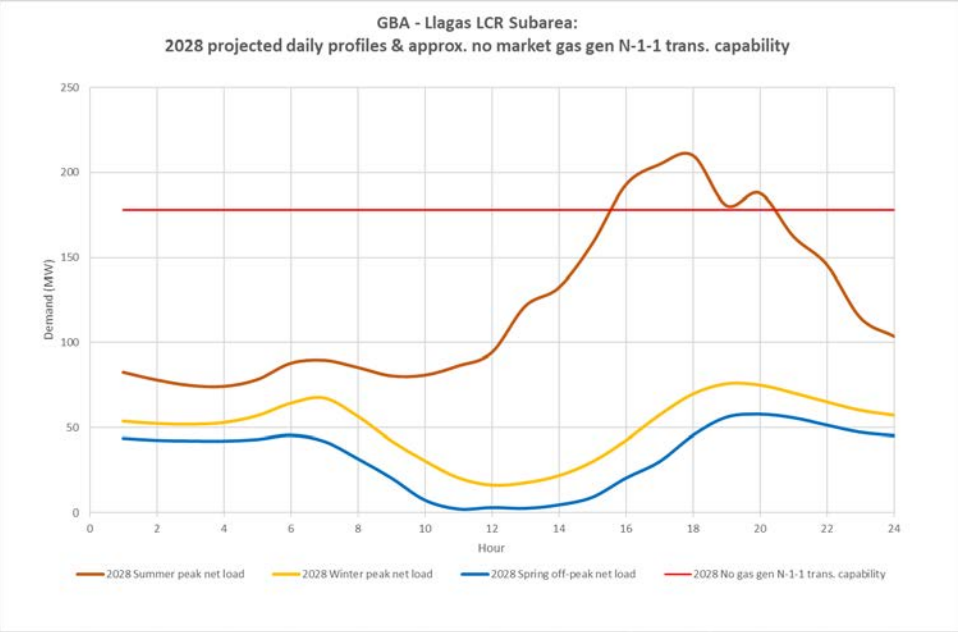
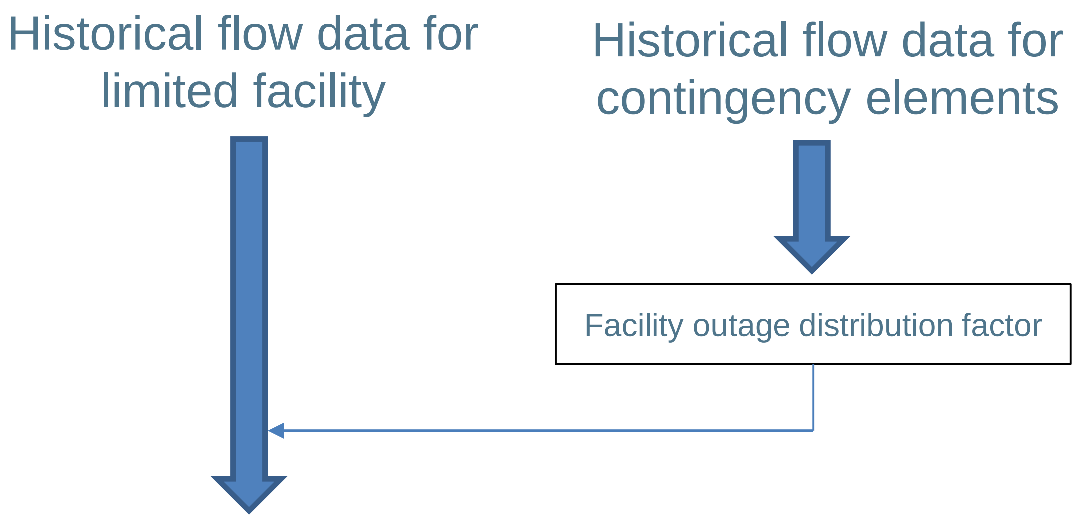
# Sample Radial or Multi-Source Area Load Profiles



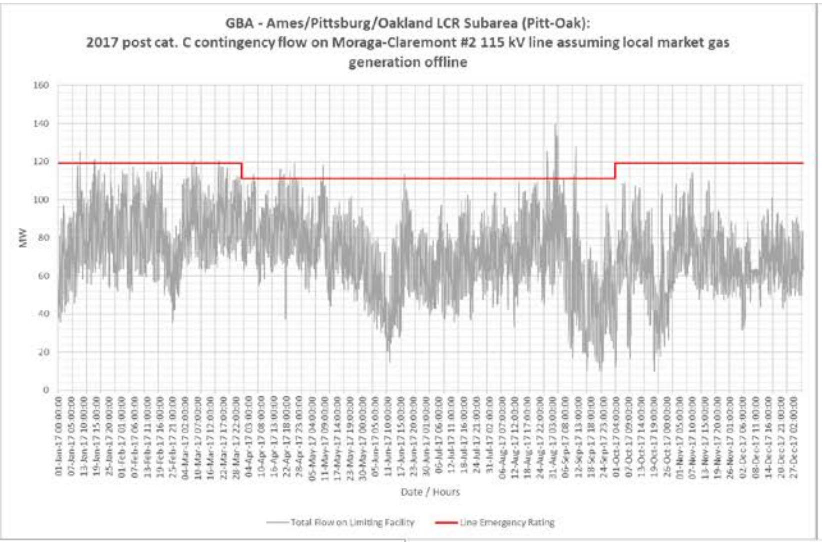



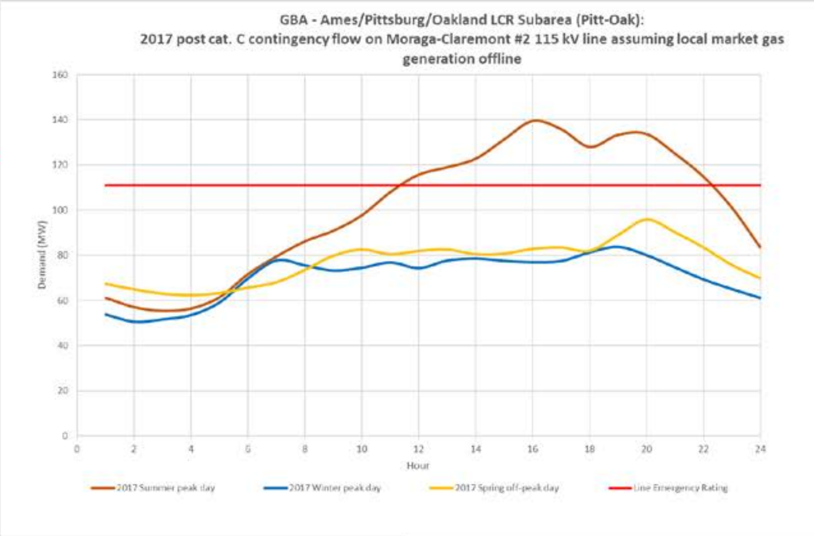
# Flow Profile for Flow-Through Type LCR Area

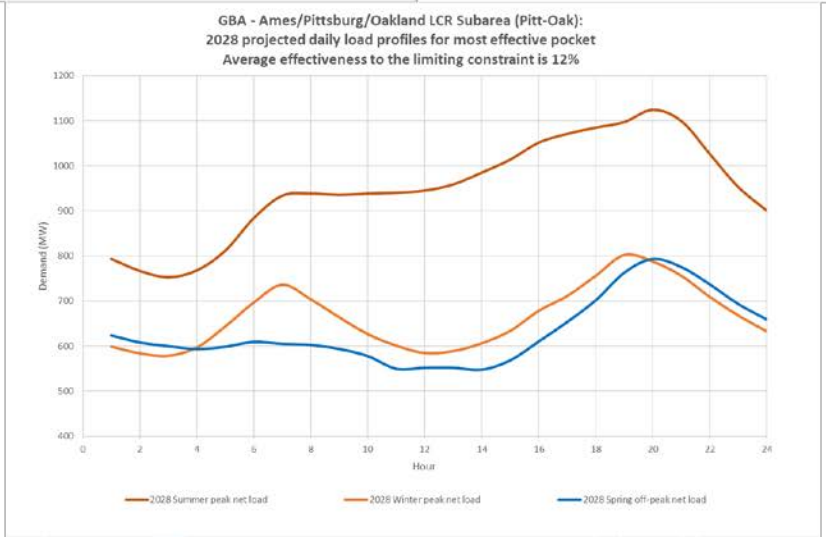



- Post N-1-1 contingency flow shape for limited facility
- Rating of limited facility is also provided to compare line capacity against post contingency flow

# Sample Flow-through Profiles



# 2028 Long-Term LCR Study Draft Results
# Greater Bay Area

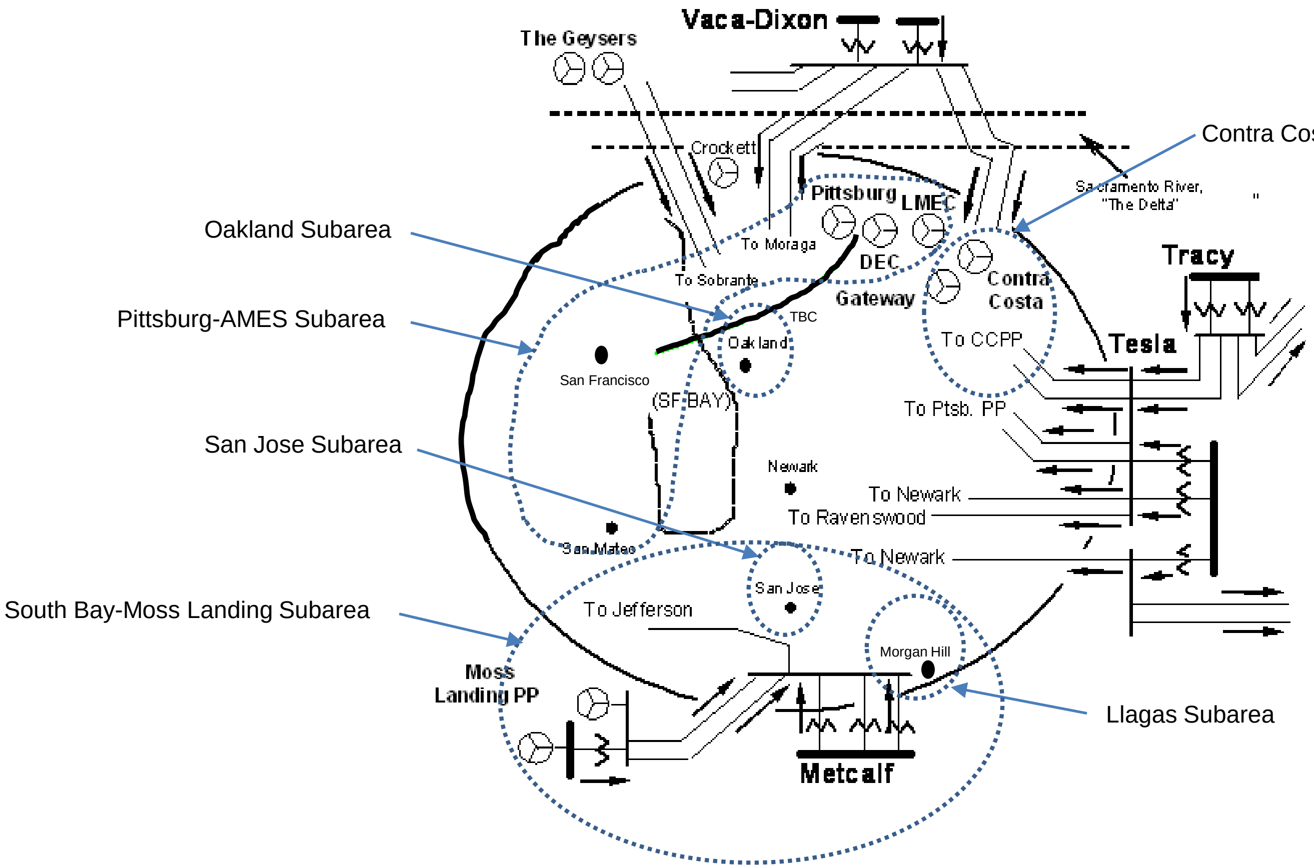
Binaya Shrestha

Regional Transmission Engineer Lead

Stakeholder Meeting

September 20-21, 2018

# Greater Bay Area Transmission System & LCR Subareas



# New major transmission projects

| Project Name | Expected ISD |
|---|---|
| Trimble-San Jose B 115 kV Line Limiting Facility Upgrade | Dec-18 |
| Moss Landing–Panoche 230 kV Path Upgrade | Dec-18 |
| Trimble-San Jose B 115 kV Series Reactor | Jan-19 |
| South of San Mateo Capacity Increase (revised scope) | Feb-19<br>Mar-26 |
| Metcalf-Evergreen 115 kV Line Reconductoring | May-19 |
| East Shore-Oakland J 115 kV Reconductoring Project | Apr-21 |
| Morgan Hill Area Reinforcement (revised scope) | May-21 |
| Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade | Apr-22 |
| Oakland Clean Energy Initiative Project | Aug-22 |
| Vaca Dixon-Lakeville 230 kV Corridor Series Compensation | Aug-22 |

# Power plant changes

Additions:

- No new resource addition

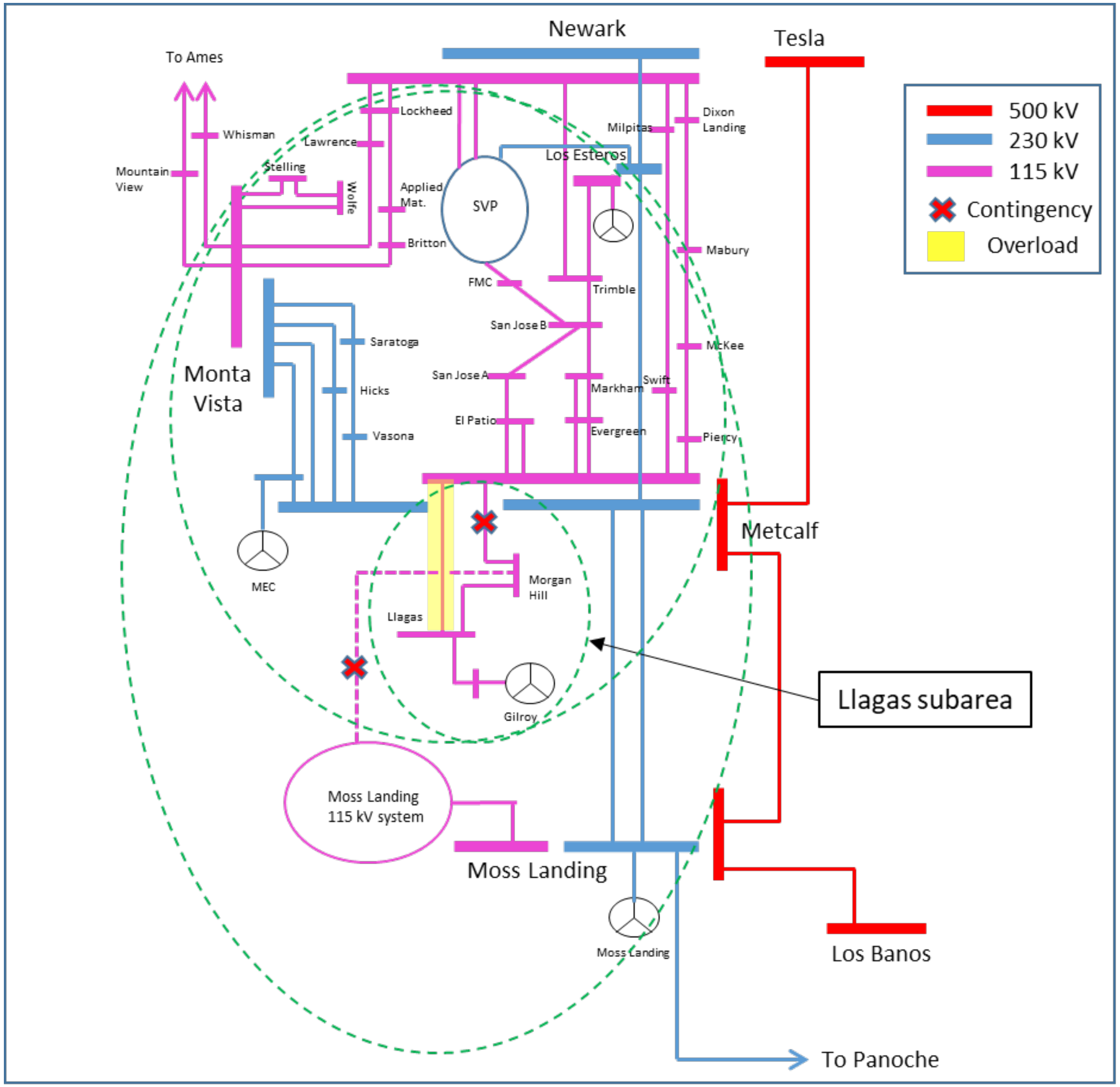
Retirements:

- No new retirements
- Oakland CTs considered offline

# Load and Resources

| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 11,576 | Market | 6,312 |
| AAEE | -653 | Wind | 331 |
| Behind the meter DG | -309 | Muni | 276 |
| **Net Load** | **10,614** | QF | 304 |
| Transmission Losses | 268 | Future preferred resource and energy storage | 10 |
| Pumps | 264 | **Total Qualifying Capacity** | **7,233** |
| **Load + Losses + Pumps** | **11,146** | | |

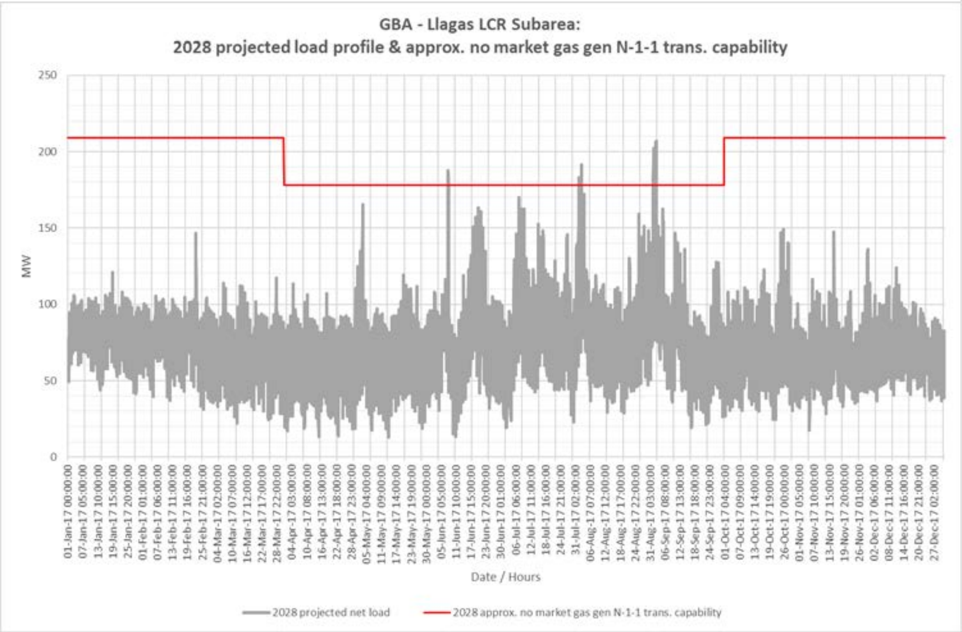
# Llagas Subarea : One-line diagram

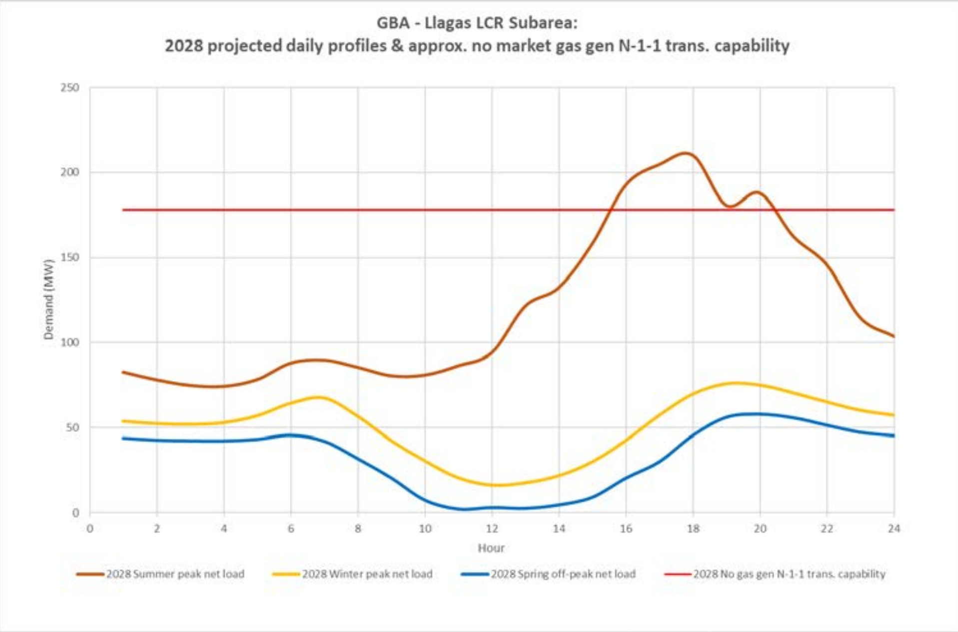


# Llagas Subarea : Requirements

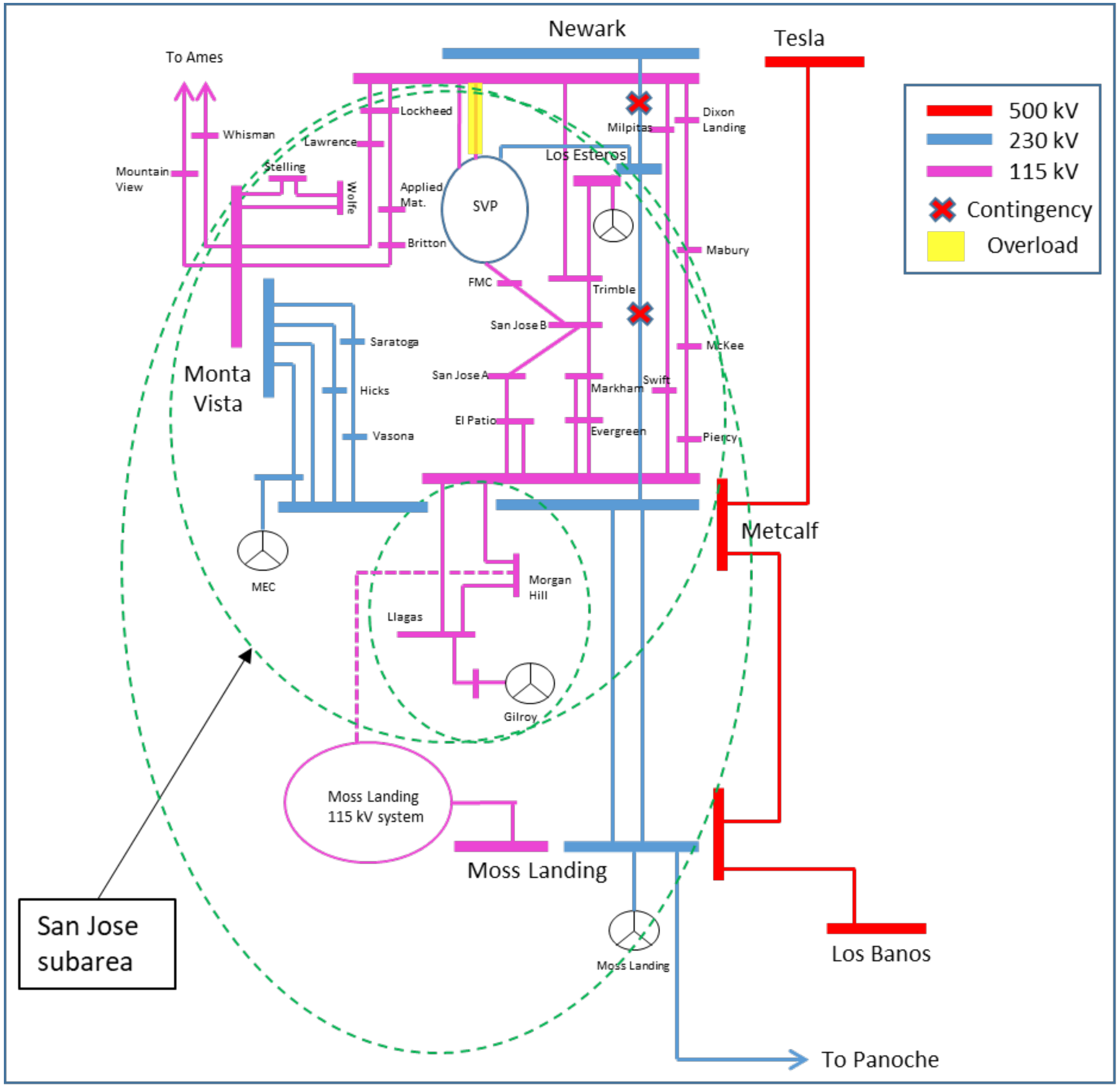
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | None | None | No requirement |
| 2028 | First limit | C | Morgan Hill-Llagas 115 kV line | Metcalf-Morgan Hill and Morgan Hill-Green Valley 115 kV lines | 26 |

# Llagas Subarea : Load Profiles



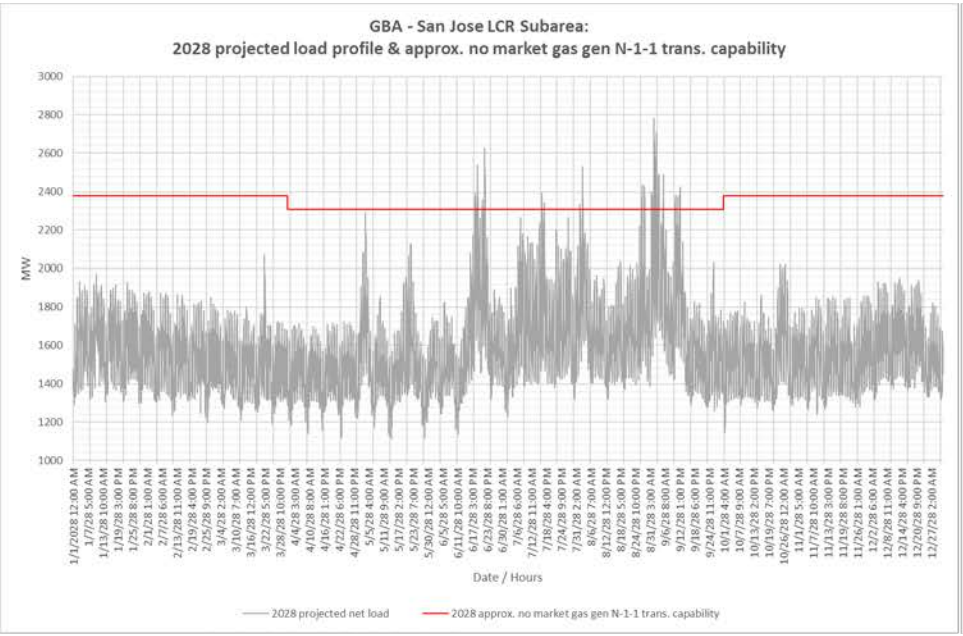
# San Jose Subarea : One-line diagram

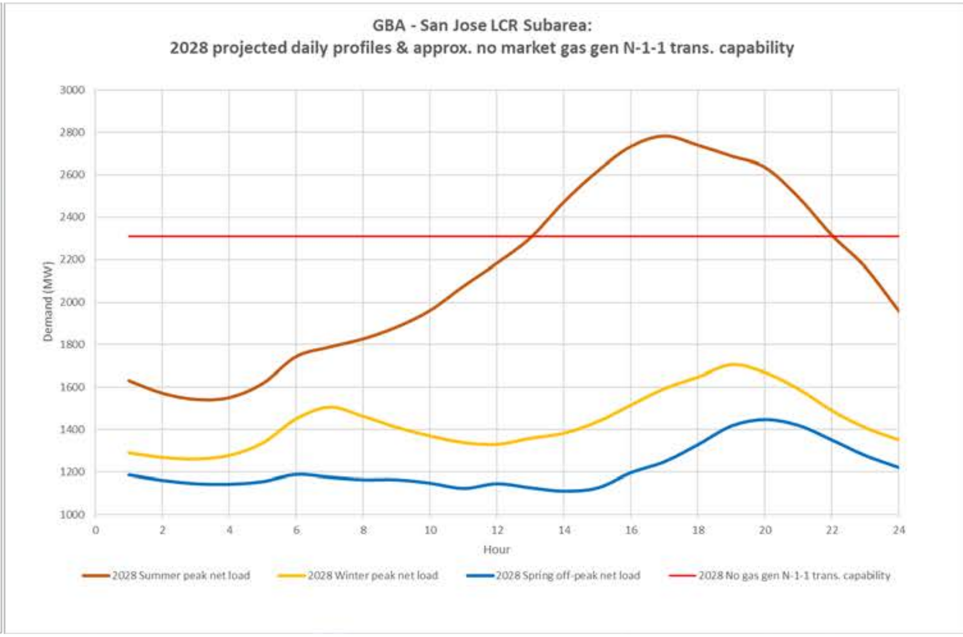


# San Jose Subarea : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | El Patio-San Jose A 115 kV line | Newark-Los Esteros 230 kV line & DVR unit | 868 |
| 2028 | First limit | C | Newark-NRS #1 115 kV line | Newark-Los Esteros & Metcalf-Los Esteros 230 kV lines | 1543 (204) |
| 2028 | Second limit | C | Newark-NRS #2 115 kV line | Newark-Los Esteros & Metcalf-Los Esteros 230 kV lines | 1435 (156) |

# San Jose Subarea : Load Profiles

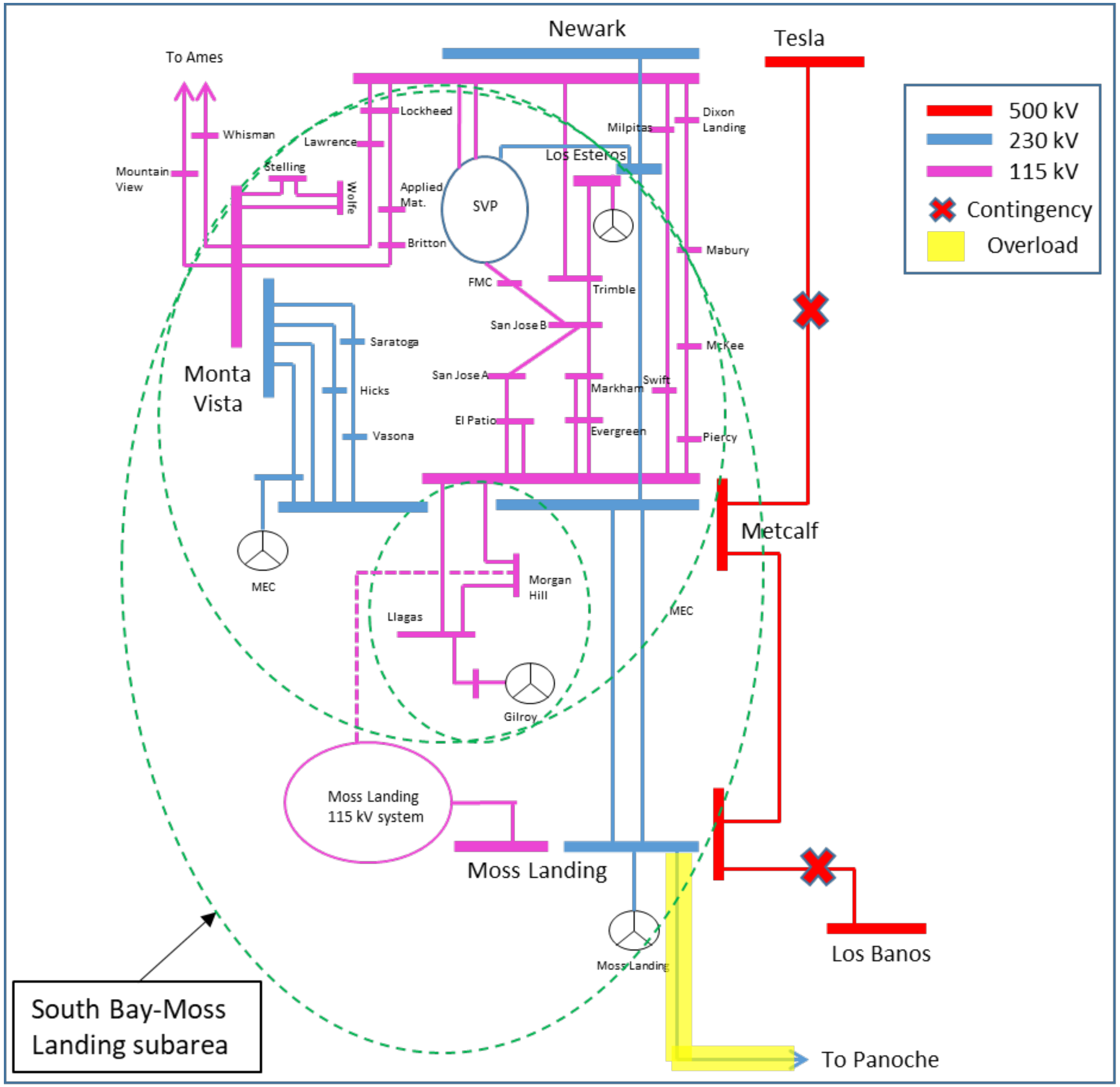



California ISO

ISO Public

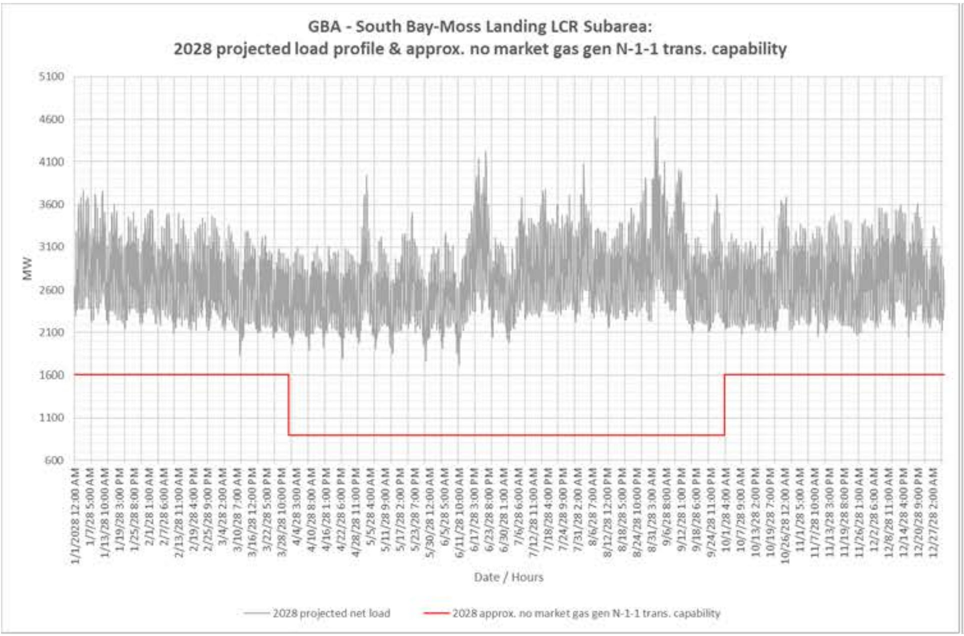
# South Bay-Moss Landing Subarea : One-line diagram

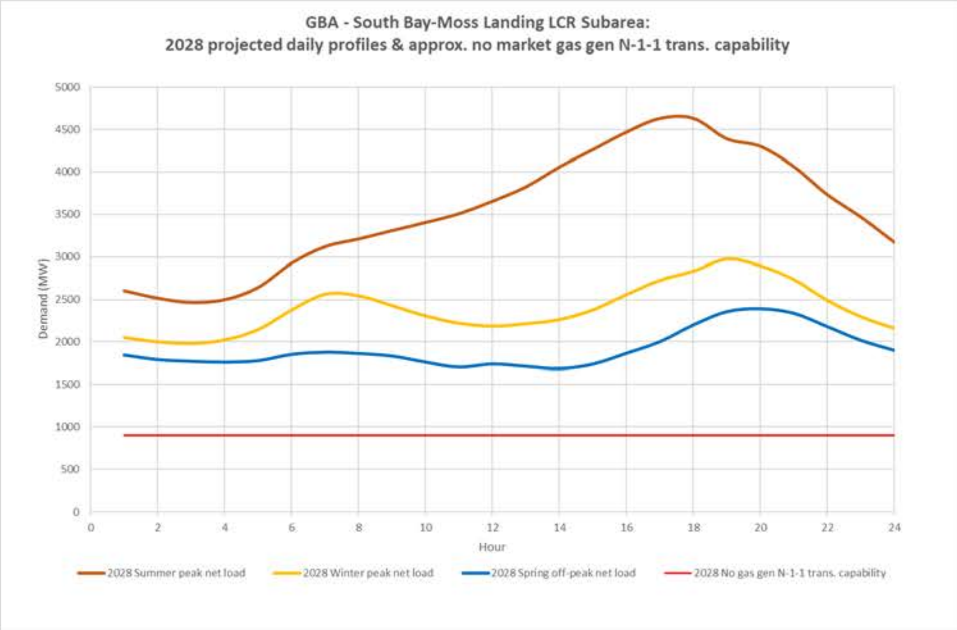


# South Bay-Moss Landing Subarea : Requirements

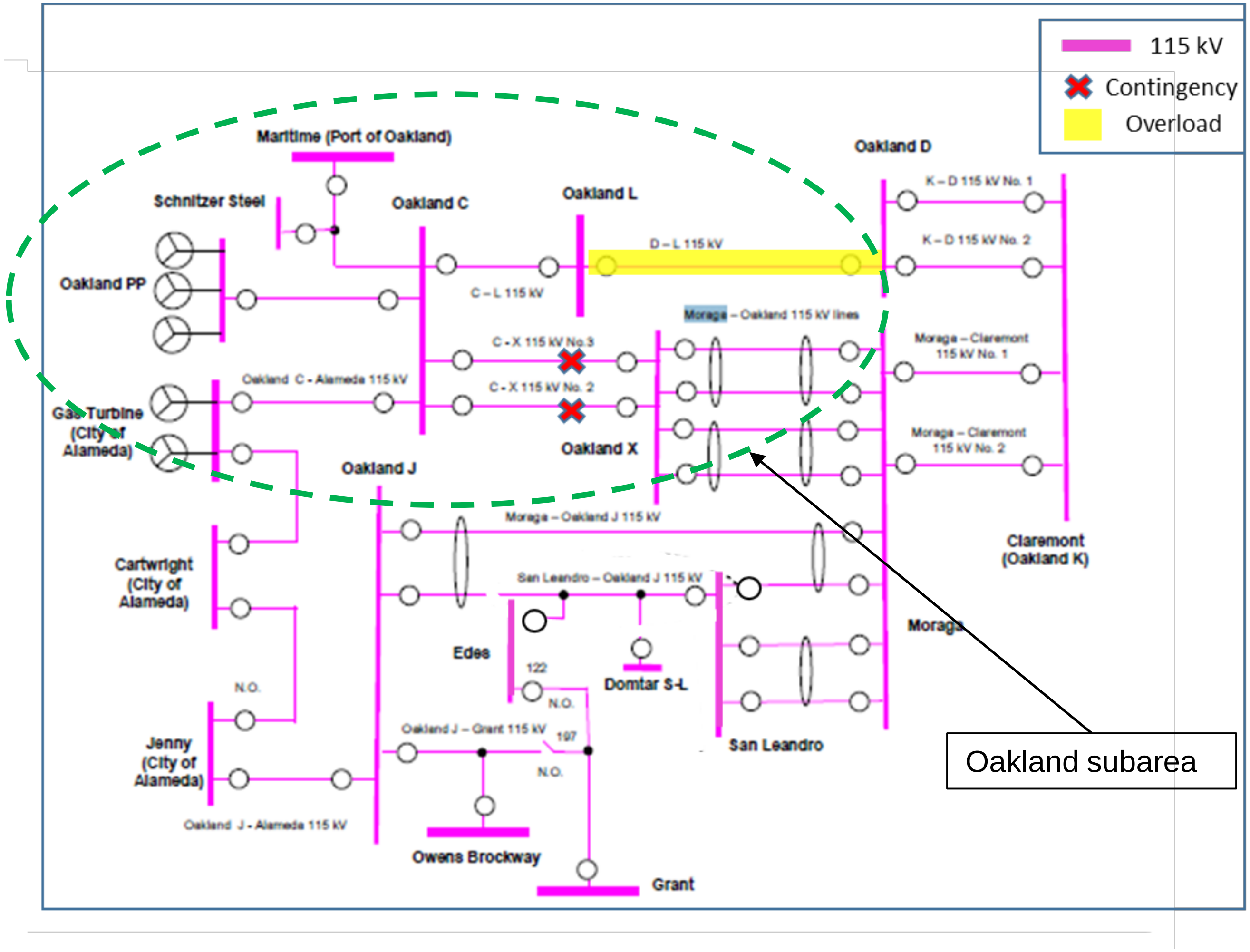
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | No requirement |
| 2028 | First Limit | C | Thermal overload of Moss Landing-Las Aguilas 230 kV | Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV | 2100 |
| 2028 | Second Limit | C | Thermal overload of Newark-NRS 115 kV | Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV | 2010 |

# South Bay-Moss Landing Subarea : Load Profiles



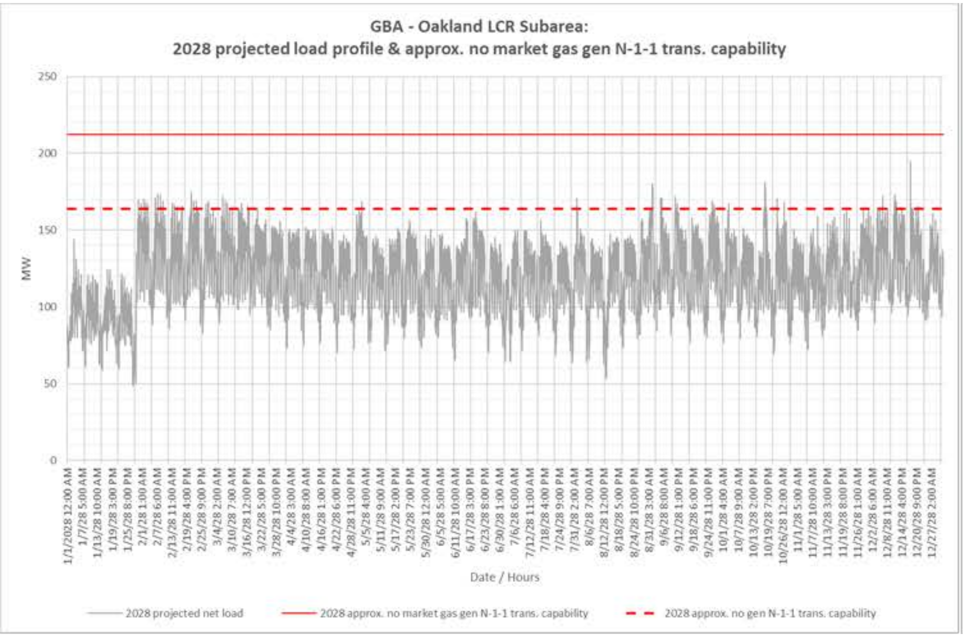
# Oakland Subarea : One-line diagram

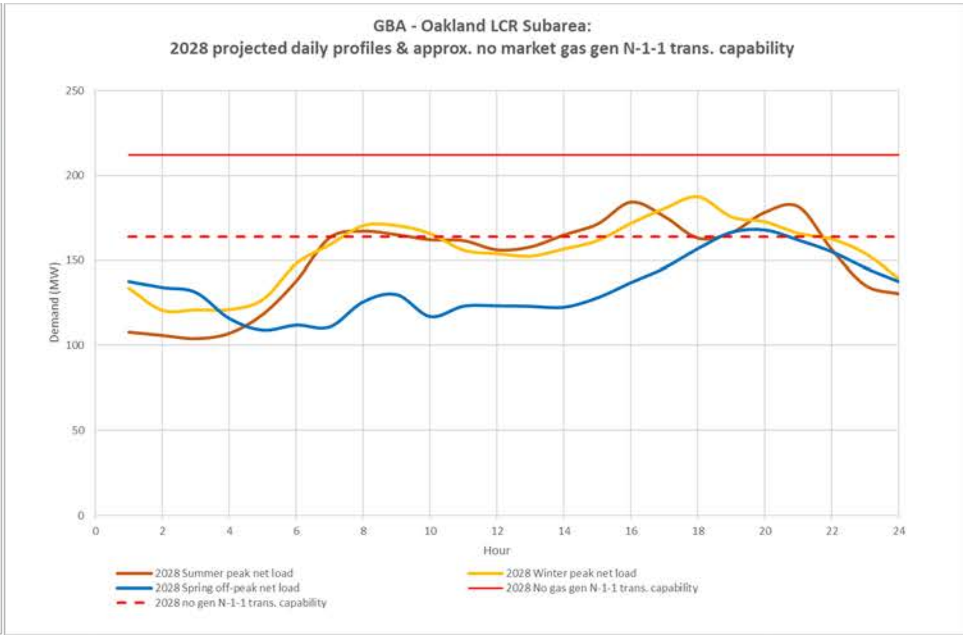


# Oakland Subarea : Requirements

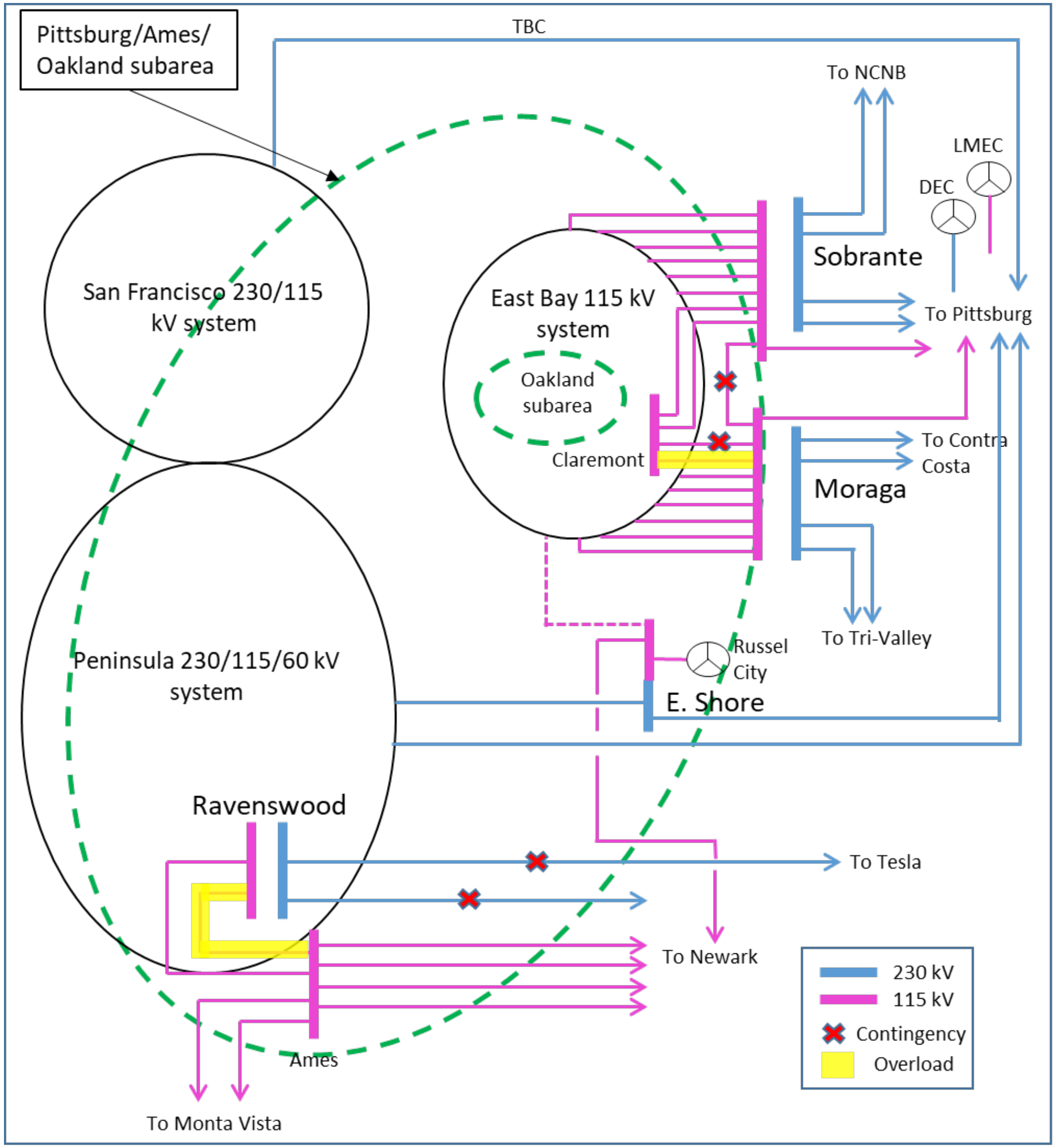
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | None | None | No requirement |
| 2028 | First limit | C | Oakland D-L 115 kV cable | Oakland C-X #2 & #3 115 kV cables | 14 |
| 2028 | Second limit | C | Oakland C-X #2 115 kV cable | Oakland D-L & C-X #3 115 kV cables | 13 |

# Oakland Subarea : Load Profiles



# Ames/Pittsburg/Oakland Subarea : One-line diagram



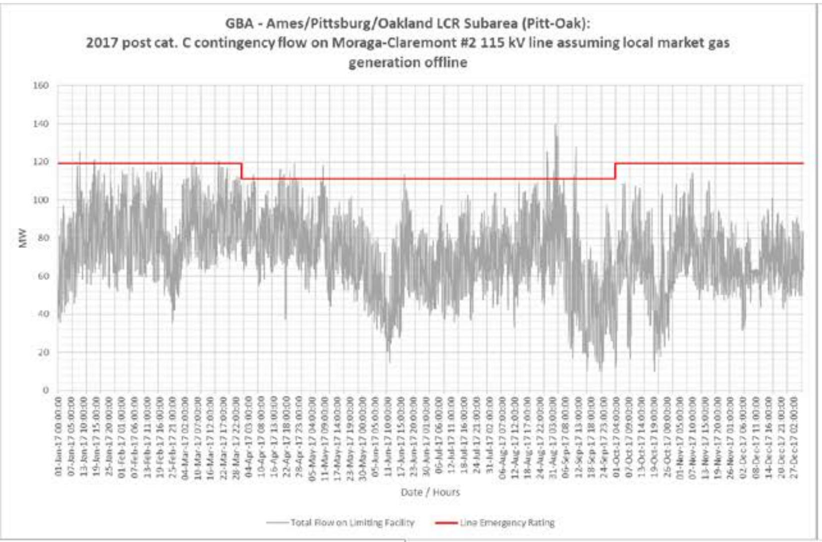
# Ames/Pittsburg/Oakland Subarea : Requirements

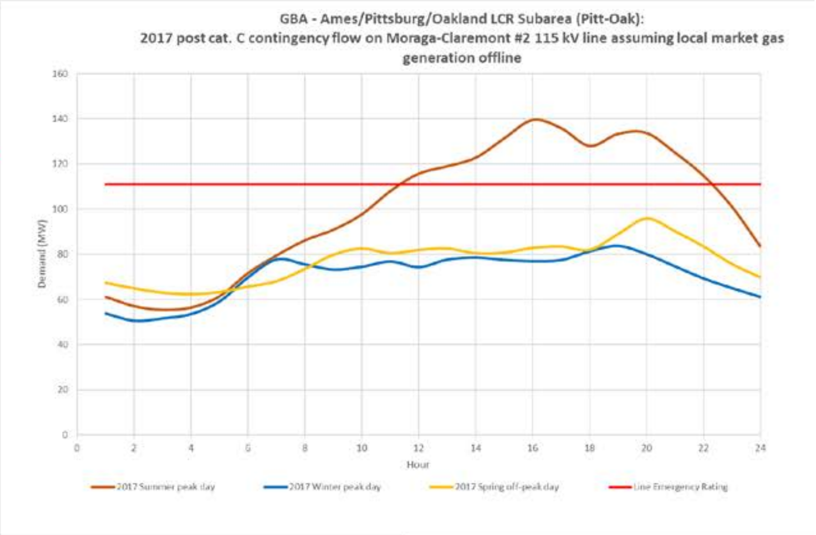
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | None | None | No requirement |
| 2028 | First limit | C | Ames-Ravenswood #1 115 kV line | Newark-Ravenswood & Tesla-Ravenswood 230 kV lines | 2022 |
| | | | Moraga-Claremont #2 115 kV line | Moraga-Sobrante & Moraga-Claremont #1 115 kV lines | |
| | | | | | |

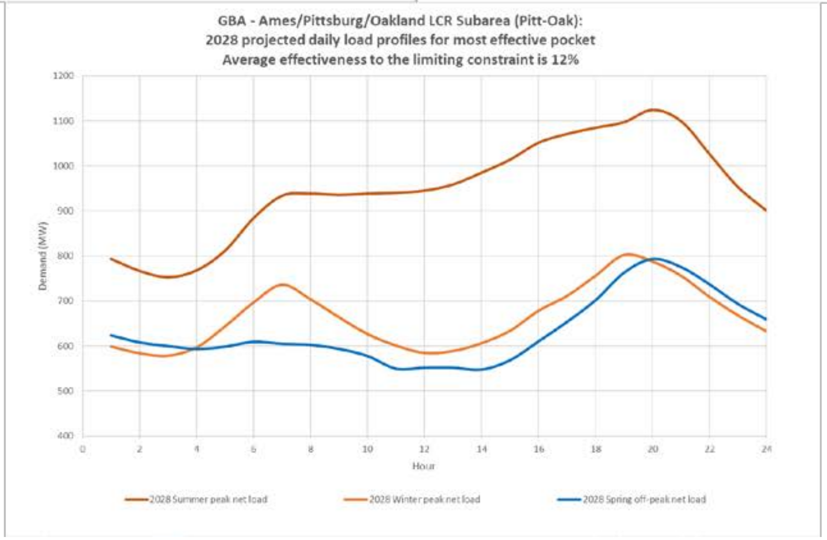
# Associated NCNB Area : Requirement

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | C | Thermal overload on Eagle Rock-Cortina 115 kV line | Fulton-Lakeville and Fulton-Ignacio 230 kV lines | 751 |

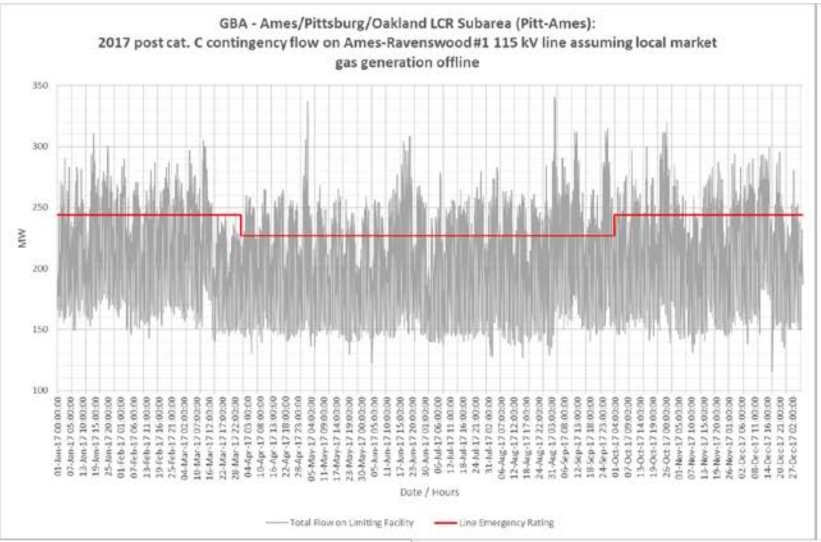
# Ames/Pittsburg/Oakland Subarea (Pitts-Oak) : Flow Profiles

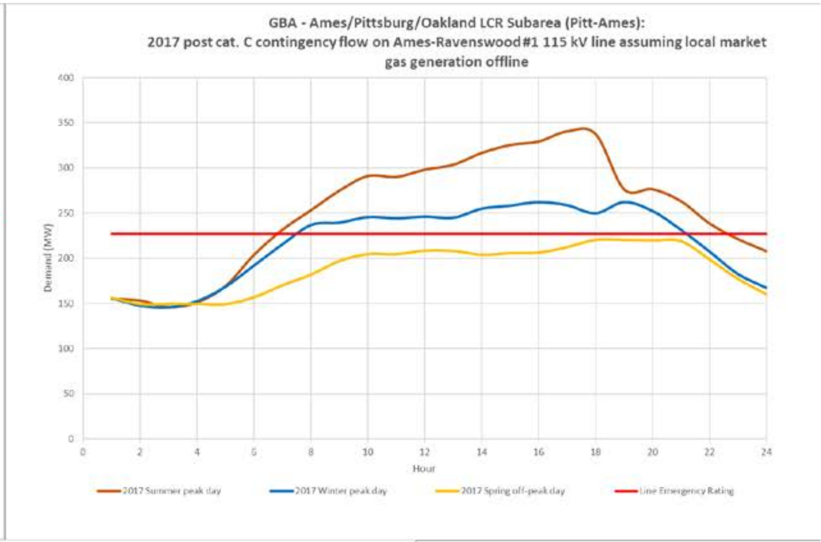


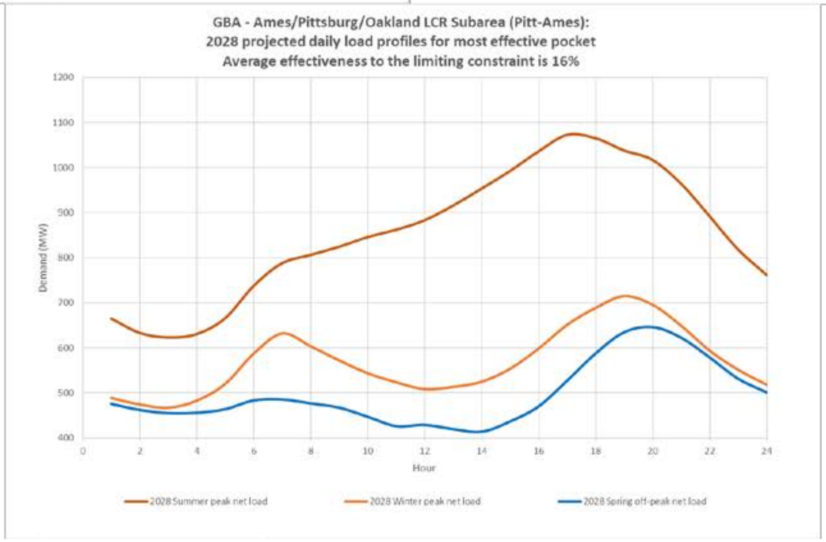



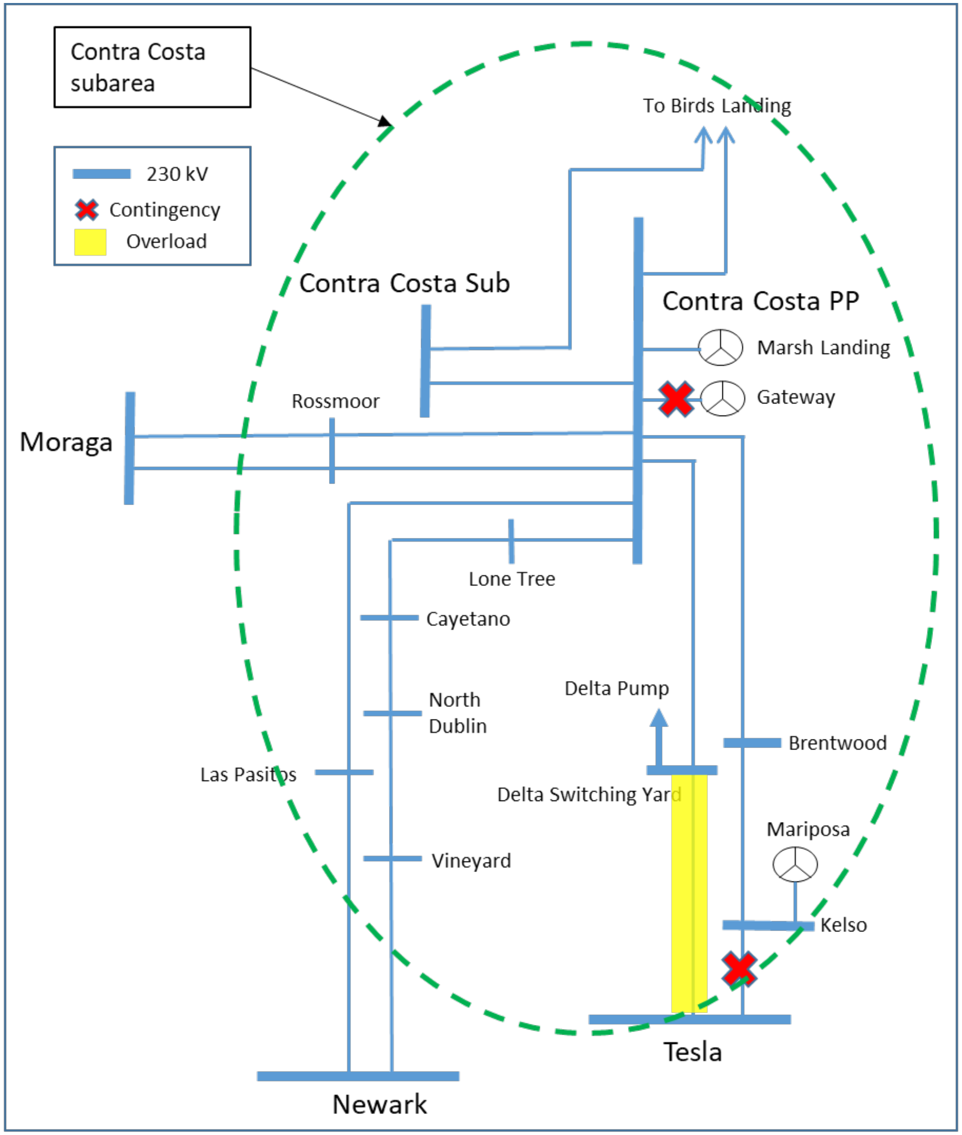
# Ames/Pittsburg/Oakland Subarea (Pitts-Ames) : Flow Profiles



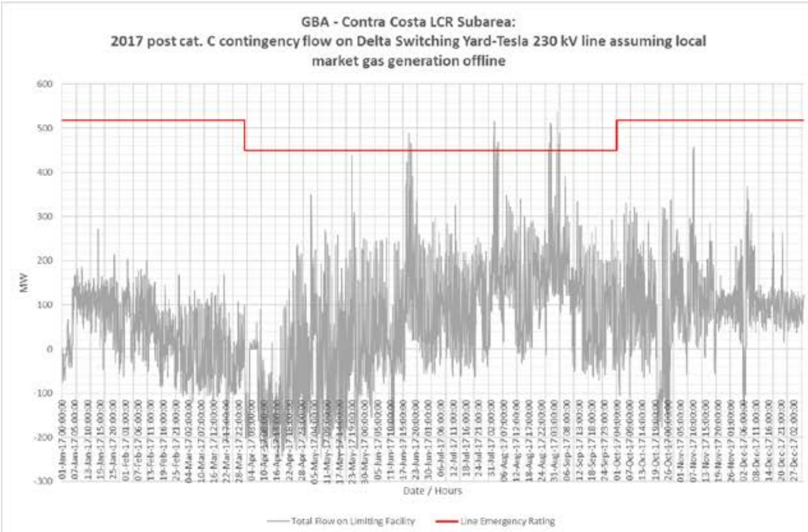
# Contra Costa Subarea : One-line diagram

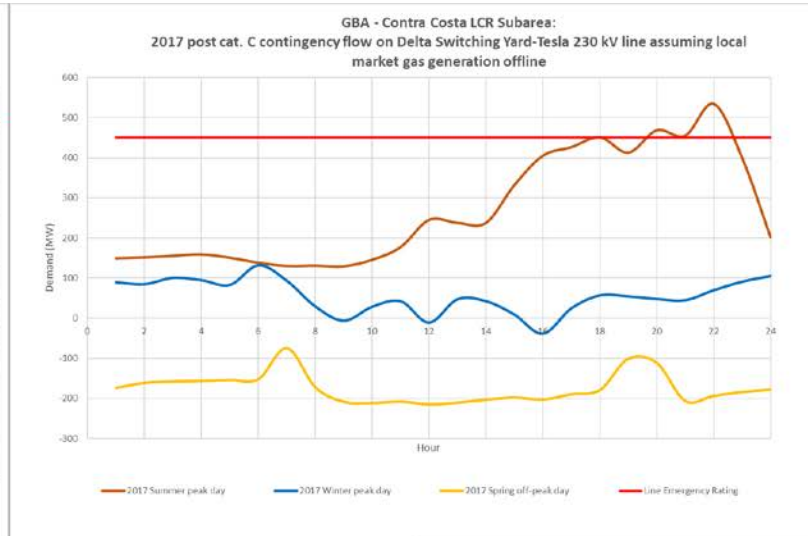


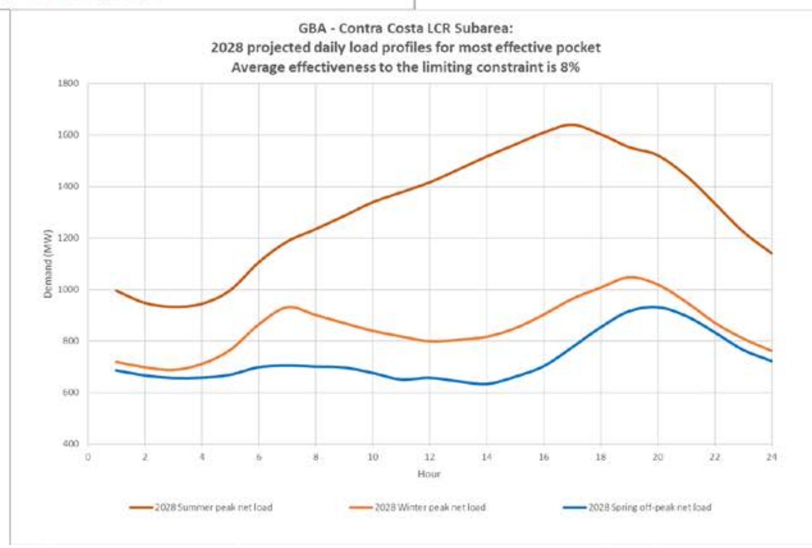
# Contra Costa Subarea : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | Delta Switching Yard-Tesla 230 kV line | Kelso-Tesla 230 kV line and Gateway unit | 1274 |
| 2028 | First limit | C | Same as Category B | | |

# Contra Costa Subarea : Flow Profiles



# Greater Bay Area Overall: Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | Reactive margin | Tesla-Metcalf 500 kV line & DEC unit | 4795 |
| 2028 | First limit | C | Aggregate of subareas | | 6948 (204) |

# Greater Bay Area Total Generation & LCR Need

| Generation | Market (MW) | Wind (MW) | Muni (MW) | QF (MW) | Total MW |
|---|---|---|---|---|---|
| | 6312 | 331 | 276 | 304 | 7223 |

| 2028 LCR Need | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW Need |
|---|---|---|---|
| Category B (Single) | 4795 | 0 | 4795 |
| Category C (Multiple) | 6744 | 204 | 6948 |

# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| Llagas | 179 | 77 | 181 | 13 | 191 | 26 |
| San Jose | 2374 | 177 | 2517 | 293 | 2926 | 1543 |
| South Bay – Moss Landing | 3977 | 1653 | 4192 | 1977 | 4555 | 2100 |
| Oakland | 177 | 20 | 175 | 0 | 188 | 14 |
| Pittsburg – Ames – Oakland | NA* | 2430 | NA* | 1630 | NA* | 2022 |
| Contra Costa | NA* | 1067 | NA* | 1145 | NA* | 1274 |
| Overall | 10230 | 4461 | 10441 | 4752 | 11146 | 6948 |

*Note: LCR increases from 2023 to 2028 are all mostly due to load increase*
** Flow-through area. No defined load pocket.*

# 2028 Long-Term LCR Study Draft Results
# Sierra Area

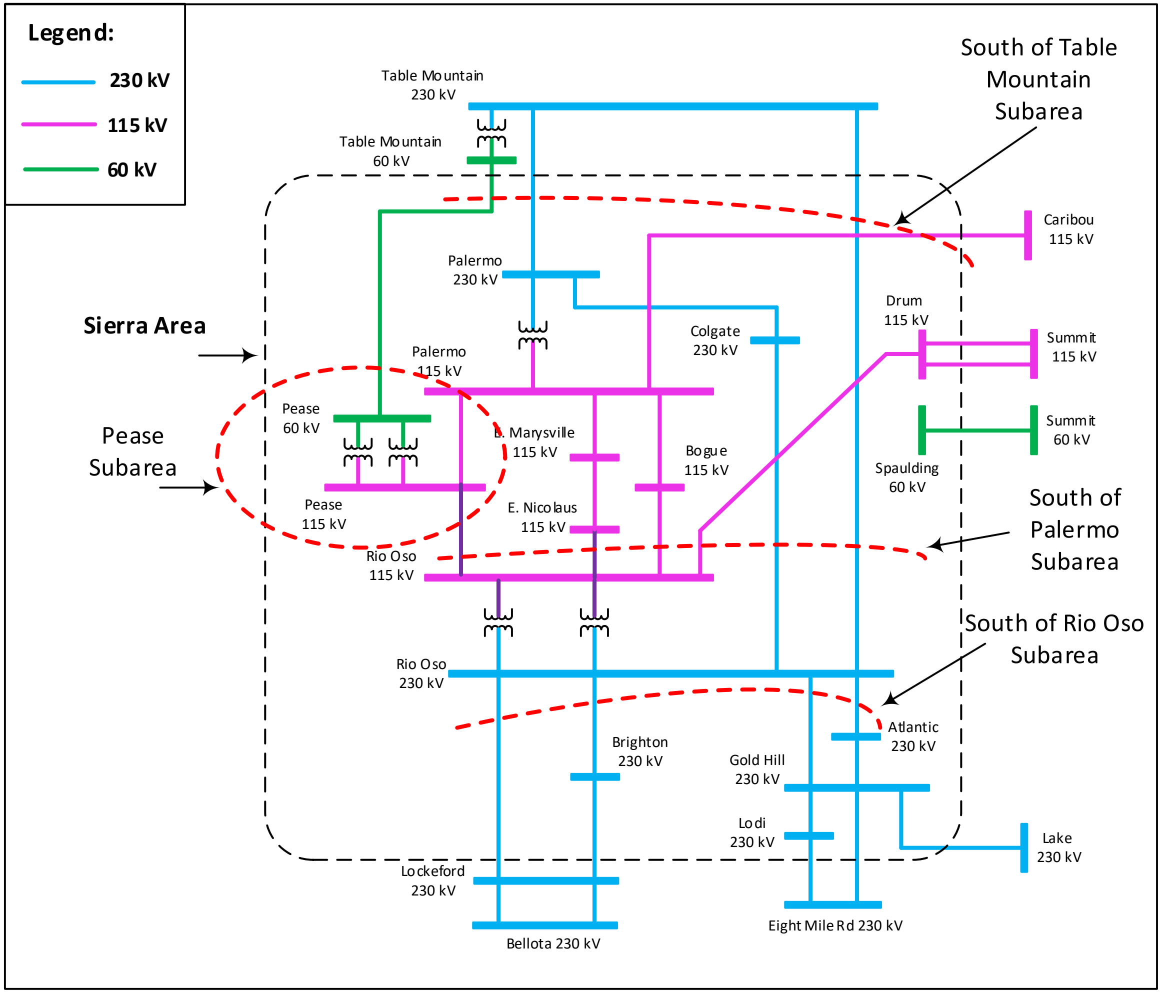
Ebrahim Rahimi

Lead Regional Transmission Engineer

Stakeholder Meeting

September 20-21, 2018

# Sierra Area Transmission System & LCR Subareas



# New major transmission projects

| Project Name | Expected ISD |
|---|---|
| West Point-Valley Springs 60 kV Line Reinforcement | Nov-19 |
| Mosher Transmission Project | Dec-19 |
| Pease 115/60 kV Transformer Addition | Dec-19 |
| South of Palermo 115 kV Reinforcement Project | Dec-21 |
| Vaca-Davis Area Reinforcement | Dec-21 |
| Rio Oso 230/115 kV Transformer Upgrades | Jun-22 |
| Rio Oso Area 230 kV Voltage Support | Jun-22 |
| Vierra 115 kV Looping Project | Jan-23 |
| Atlantic – Placer 115 kV Line Project | On-hold |

# Power plant changes

Additions:

- No new resource addition

Retirements:

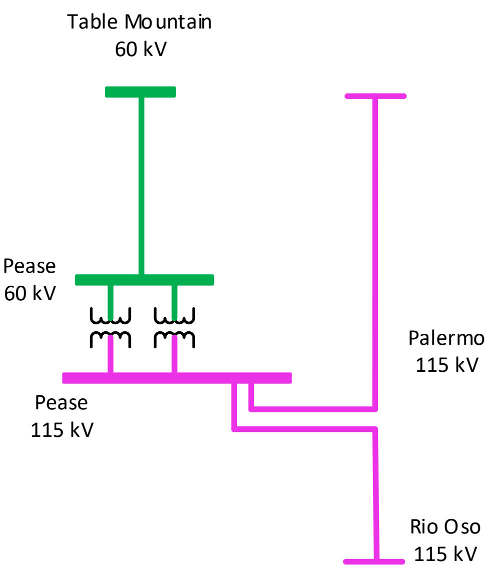
- No new retirements

# Load and Resources

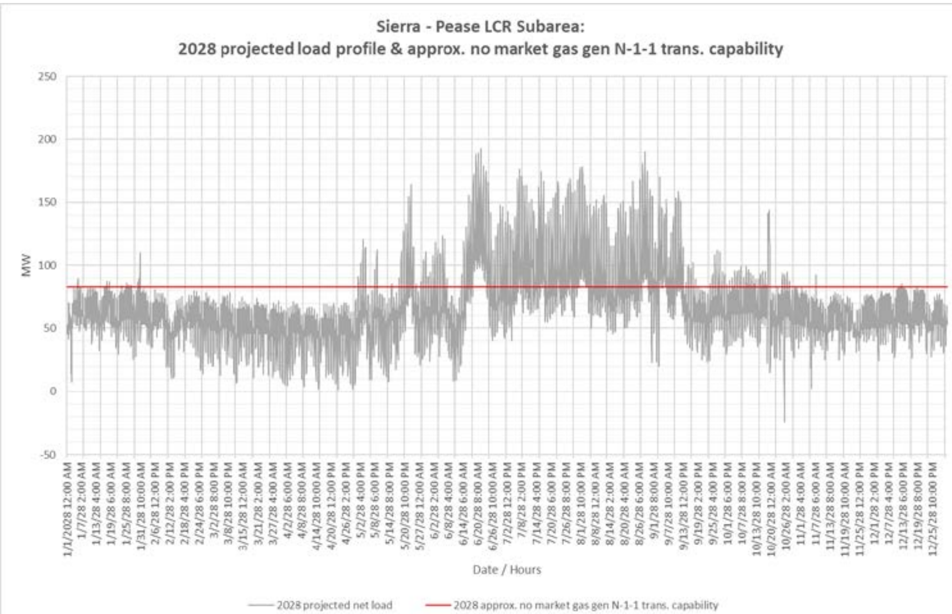
| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 1,974 | Market | 1,004 |
| AAEE | -117 | Wind | 0 |
| Behind the meter DG | 0 | Muni | 1,108 |
| **Net Load** | **1,856** | QF | 38 |
| Transmission Losses | 84 | **Total Qualifying Capacity** | **2,150** |
| Pumps | 0 | | |
| **Load + Losses + Pumps** | **1,940** | | |

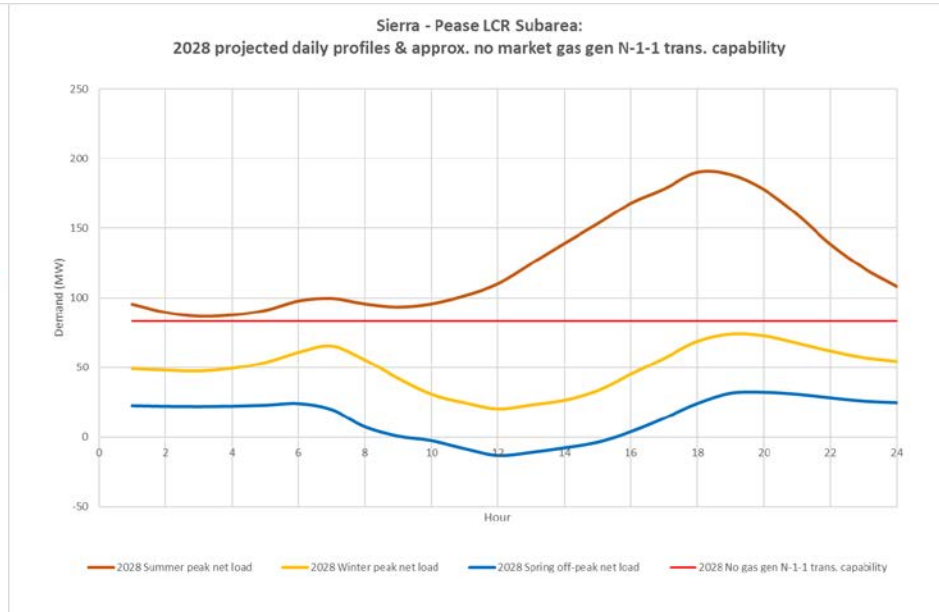
# Pease Sub Area : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | No requirement |
| 2028 | First Limit | C | Thermal overload of Table Mountain – Pease 60 kV | Palermo – Pease 115 kV and Pease – Rio Oso 115 kV | 92 |
| 2028 | Second Limit | C | Thermal overload of Table Mountain – Pease 60 kV | Pease 115/60 kV Tx 1<br>Pease 115/60 kV Tx 2 | 54 |
| 2028 | Third Limit | C | None | None | NA |



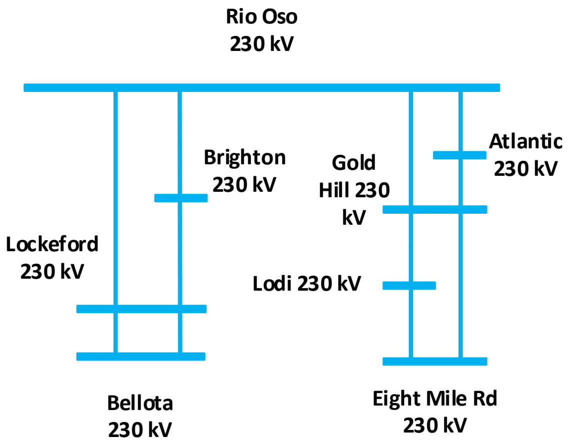
# Pease Sub Area : Load Profiles



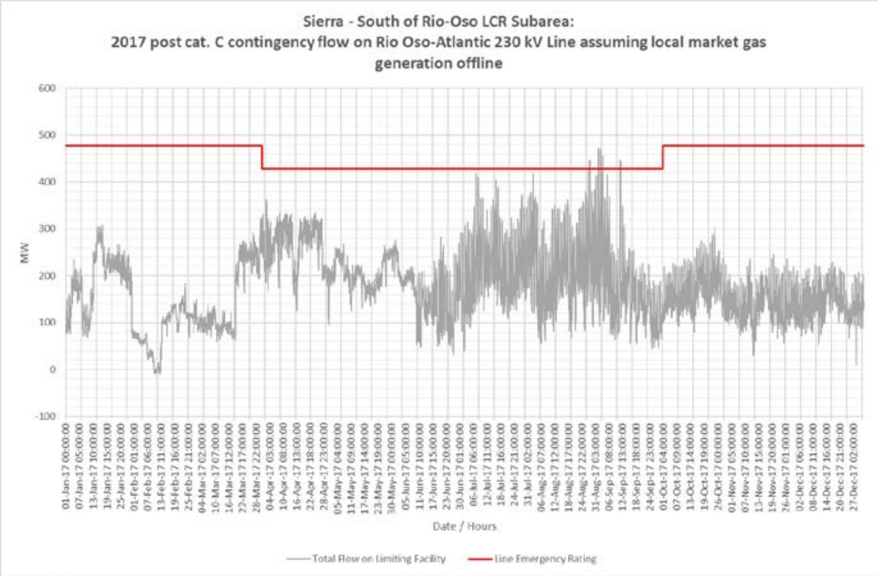



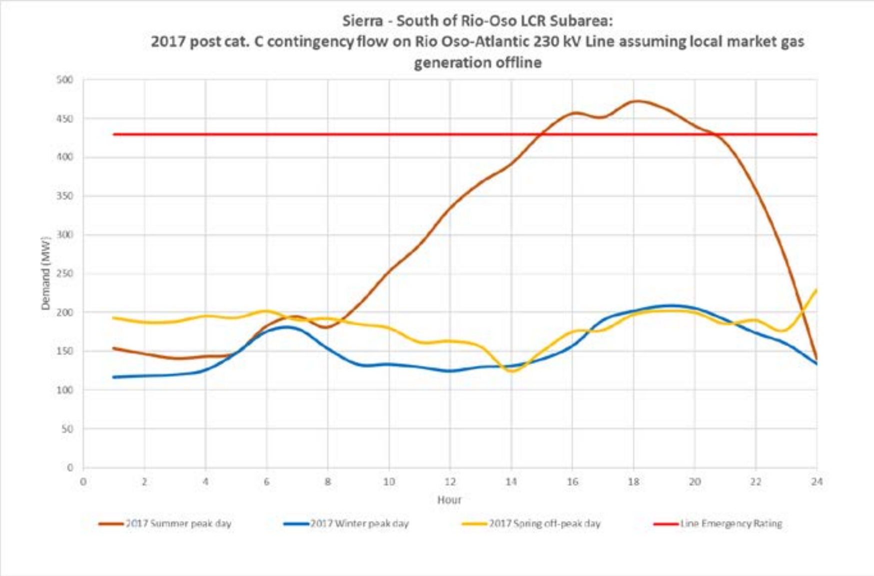
# South of Rio Oso Sub Area : Requirements

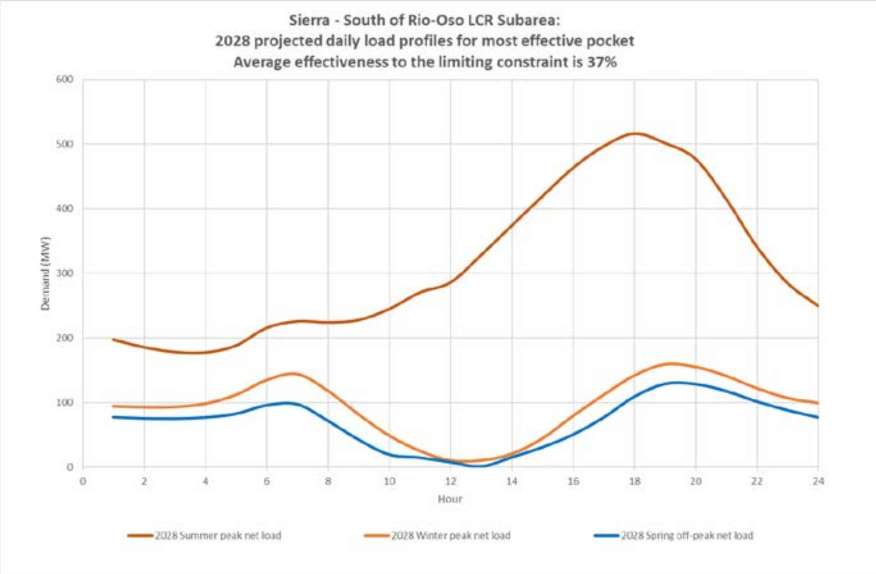
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | Rio Oso – Atlantic 230 kV | Rio Oso – Gold Hill 230 kV | 428 |
| 2028 | First limit | C | Rio Oso – Atlantic 230 kV | Rio Oso – Gold Hill 230 kV<br>Rio Oso – Brighton 230 kV | 532 |
| 2028 | Secon d limit | C | Rio Oso – Atlantic 230 kV | Rio Oso – Gold Hill 230 kV<br>Rio Oso – Lockeford 230 kV | 458 |
| 2028 | Third limit | C | Rio Oso – Gold Hill 230 kV | Rio Oso – Atlantic 230 kV<br>Rio Oso – Brighton 230 kV | 300 |



# South of Rio Oso Sub Area : Flow Profiles

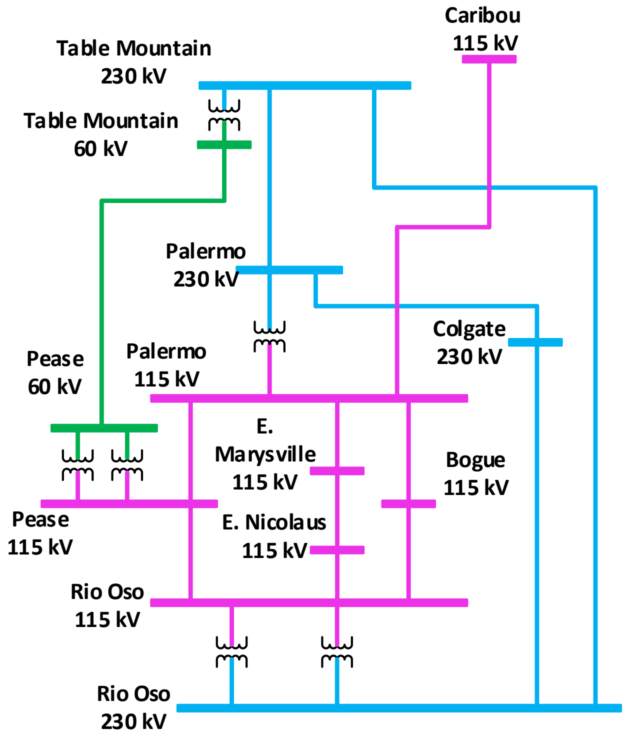


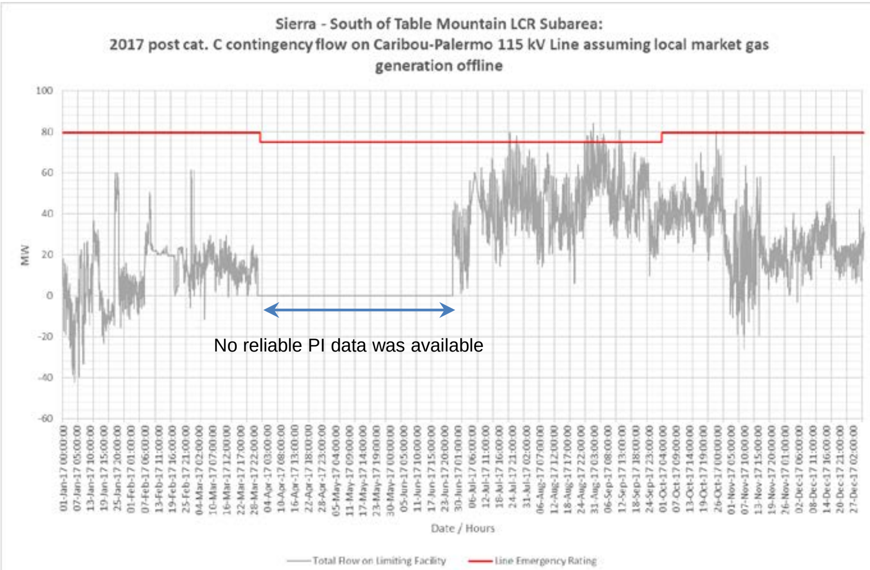



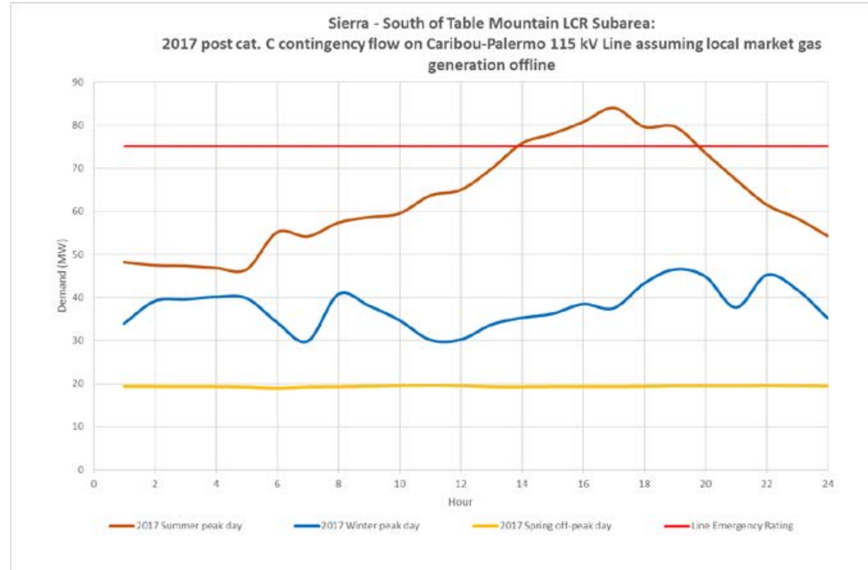
# South of Table Mountain Sub Area : Requirements

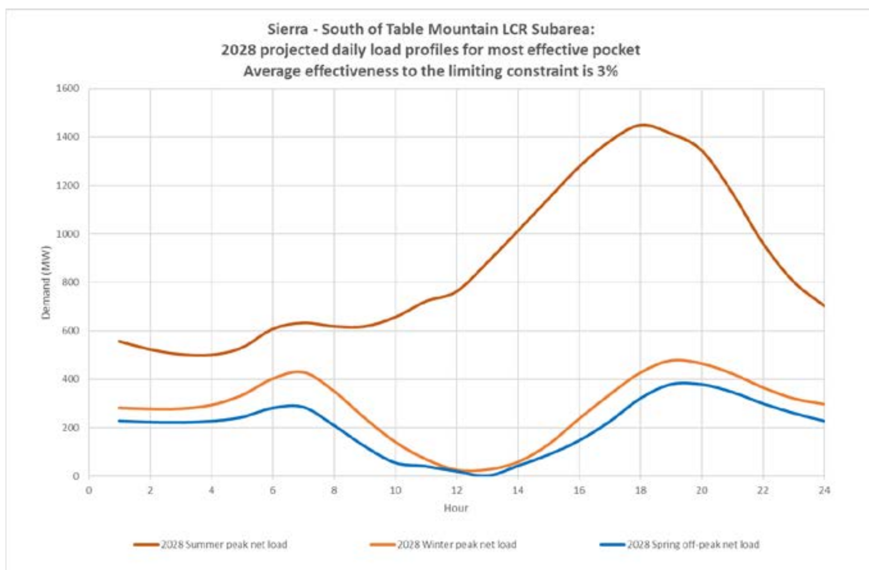
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | Caribou – Palermo 115kV | Table Mountain – Palermo 230 kV | 1053 |
| 2028 | Second limit | B | Table Mountain – Pease 60 kV | Table Mountain – Palermo 230 kV | 963 |
| 2028 | Third limit | B | Table Mountain – Palermo 230 kV | Table Mountain – Rio Oso 230 kV | 941 |
| 2028 | First limit | C | Caribou – Palermo 115kV | Table Mountain – Palermo 230 kV<br>Table Mountain – Rio Oso 230 kV | 1510 |
| 2028 | Second limit | C | Table Mountain – Pease 60 kV | Table Mountain – Palermo 230 kV<br>Table Mountain – Rio Oso 230 kV | 1450 |



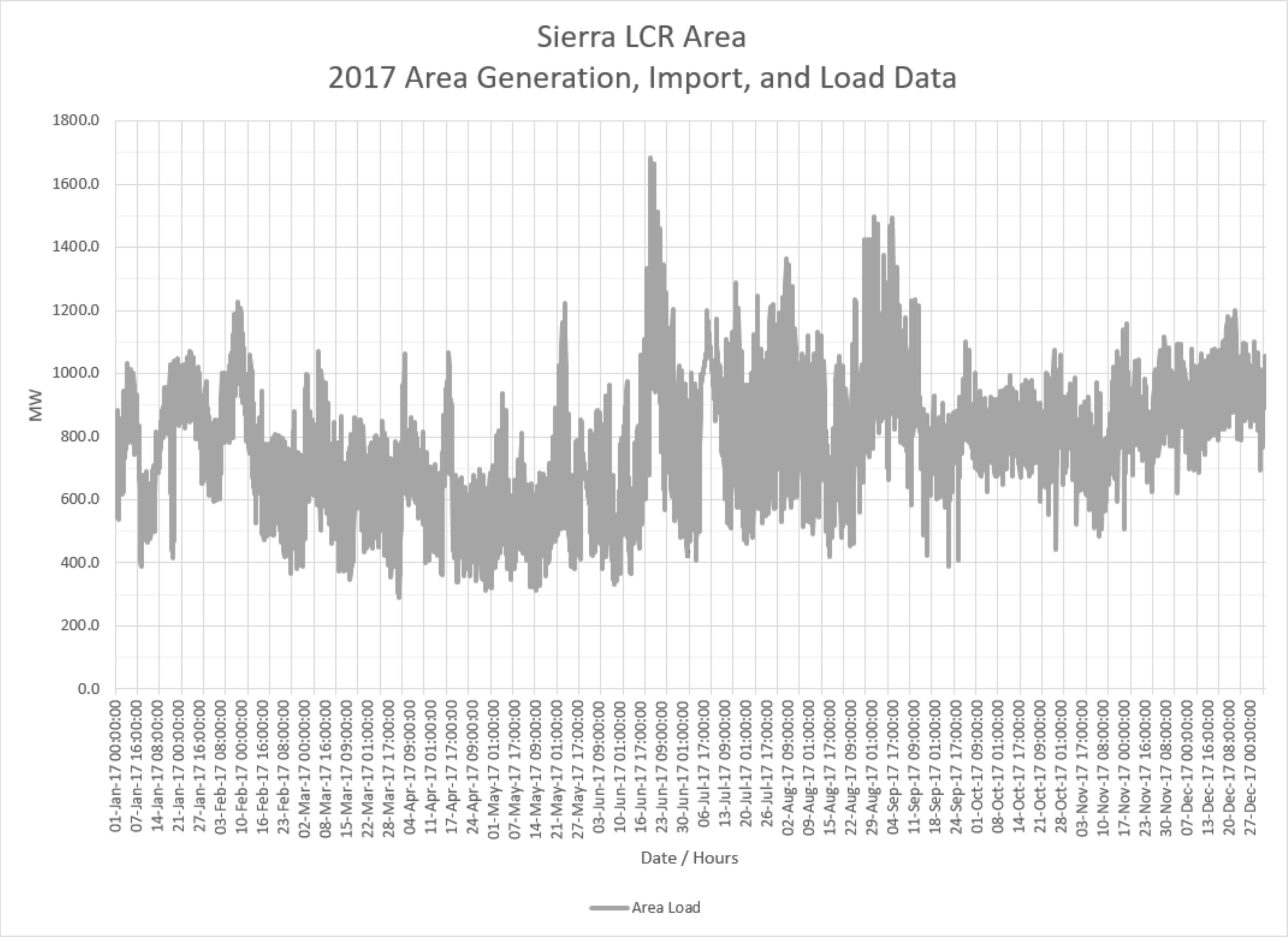
# South of Table Mountain Sub Area : Flow Profiles



# Sierra Area Overall : Load Profiles



# Sierra Area Total LCR Need

| 2028 LCR Need | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW Need |
|---|---|---|---|
| Category B (Single) | 998 | 0 | 1,053 |
| Category C (Multiple) | 1,510 | 0 | 1,510 |

# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| South of Palermo | NA * | 1702 | NA * | <629 | NA * | <624 |
| Placer | 168 | 77 | 174 | 89 | 180 | 0 |
| Drum-Rio Oso | NA | 506 | NA | 0 | NA | 0 |
| Pease | 150 | 92 | 157 | 75 | 169 | 92 |
| South of Rio Oso | NA | 831 | NA | 554 | NA | 532 |
| South of Table Mountain | NA | 1,964 | NA | 1,924 | NA | 1,510 |
| Total | 1,758 | 2,247 | 1,822 | 1,924 | 1,940 | 1,510 |

*Note: LCR increases from 2023 to 2028 are all mostly due to load increase. The South of Palermo, Rio Oso Transformer upgrade, and Atlantic-Placer Projects remove the need for LCR in South of Palermo, Drum-Rio Oso, and Placer subareas, respectively.*
** Flow-through area. No defined load pocket.*

# 2028 Long-Term LCR Study Draft Results
# Stockton Area

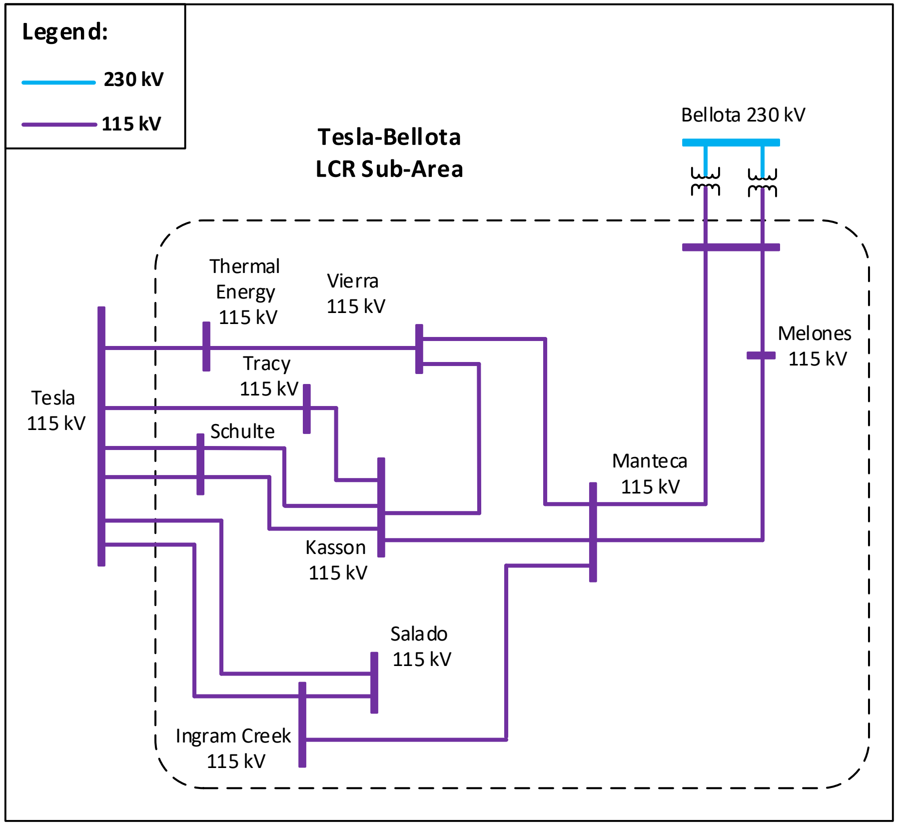

Ebrahim Rahimi

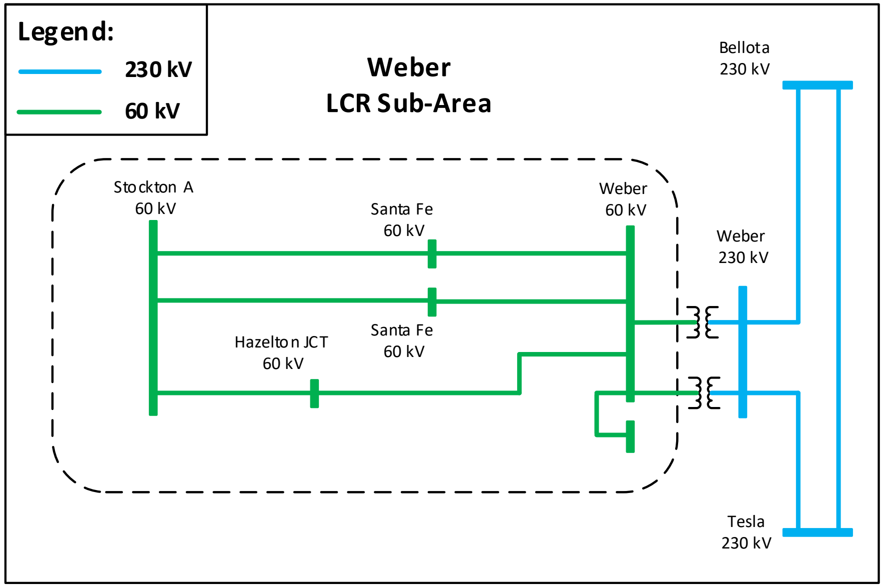
Lead Regional Transmission Engineer


Stakeholder Meeting

September 20-21, 2018

# Stockton Area Transmission System & LCR Subareas



# New major transmission projects

| Project Name | Expected ISD |
|---|---|
| Weber-Stockton A #1 & #2 60 kV lines Reconductor | Jun-19 |
| Ripon 115 kV Line | Dec-18 |
| Vierra 115 kV Looping Project | Jan-23 |
| Lockeford-Lodi Area 230 kV Development | Dec-23 |

# Power plant changes

Additions:

- No new resource addition

Retirements:

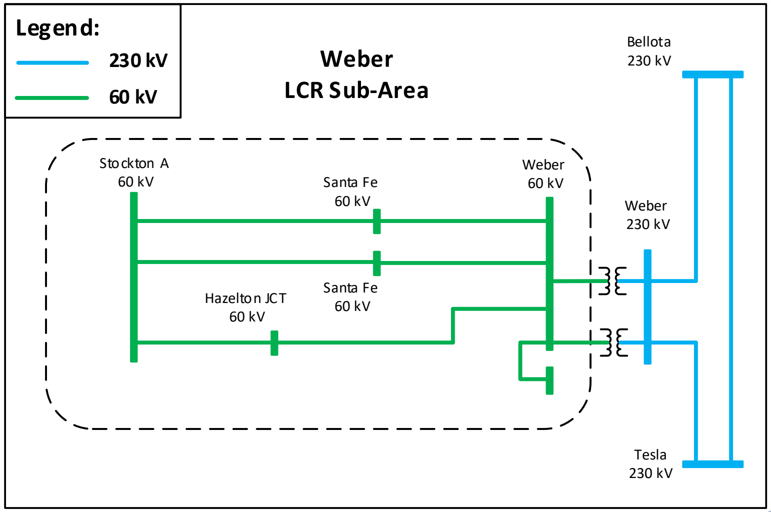
- No new retirements

# Load and Resources

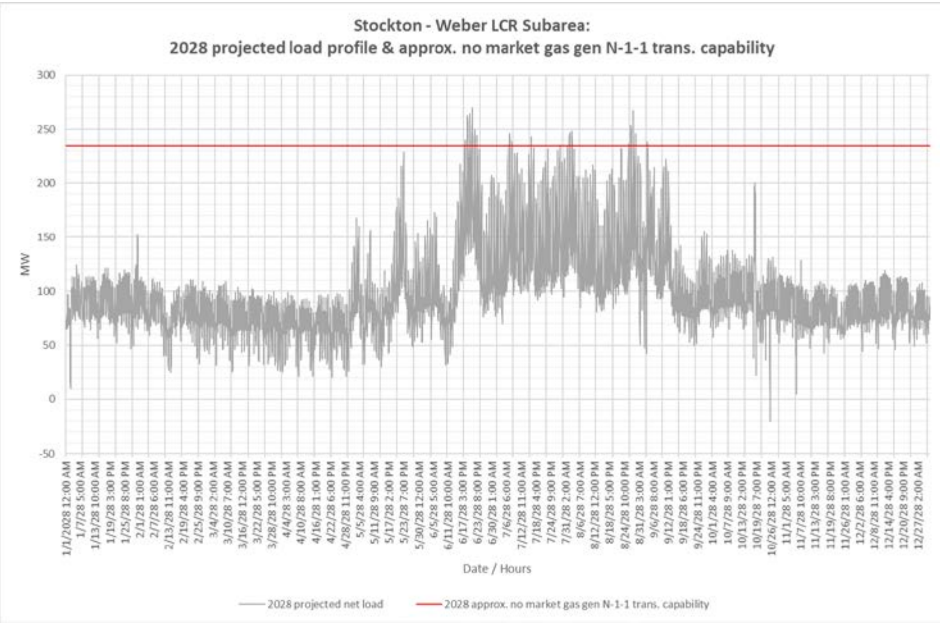
| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 1,203 | Market | 543 |
| AAEE | -71 | Wind | 0 |
| Behind the meter DG | 0 | Muni | 126 |
| **Net Load** | **1,132** | QF | 18 |
| Transmission Losses | 21 | **Total Qualifying Capacity** | **687** |
| Pumps | 0 | | |
| **Load + Losses + Pumps** | **1,153** | | |

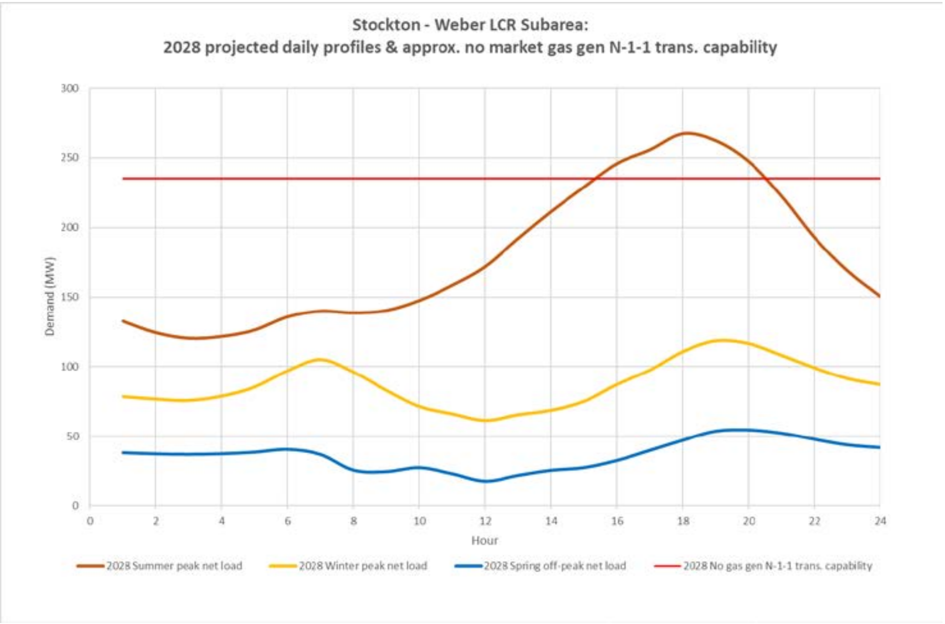
# Weber Sub Area : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | No requirement |
| 2028 | First Limit | C | Stockton A-Weber #3 | Stockton A-Weber #1 and #2 60 kV lines | 30 |
| 2028 | Second Limit | C | None | None | NA |



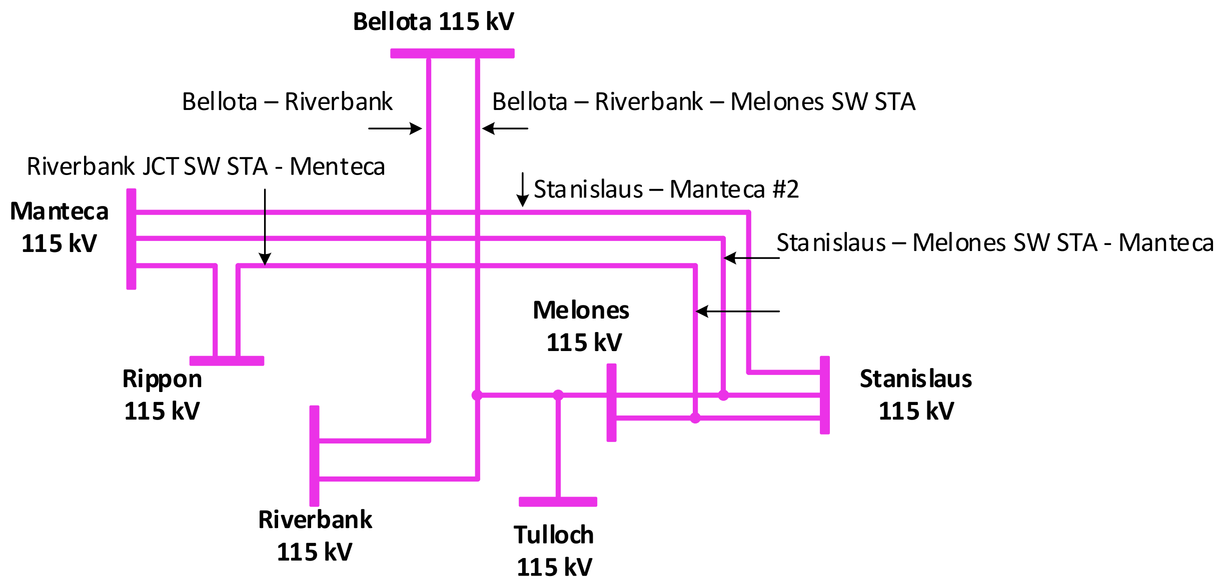
# Weber Subarea : Load Profiles



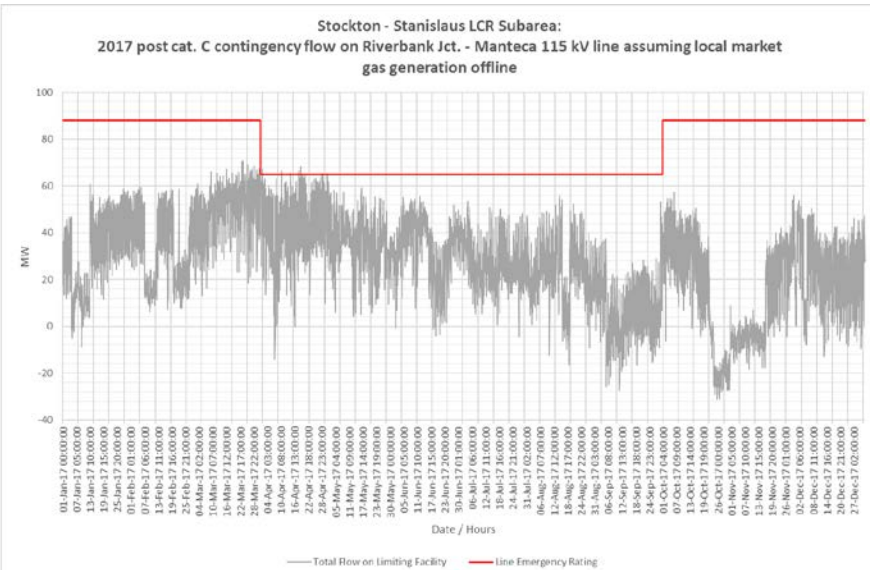



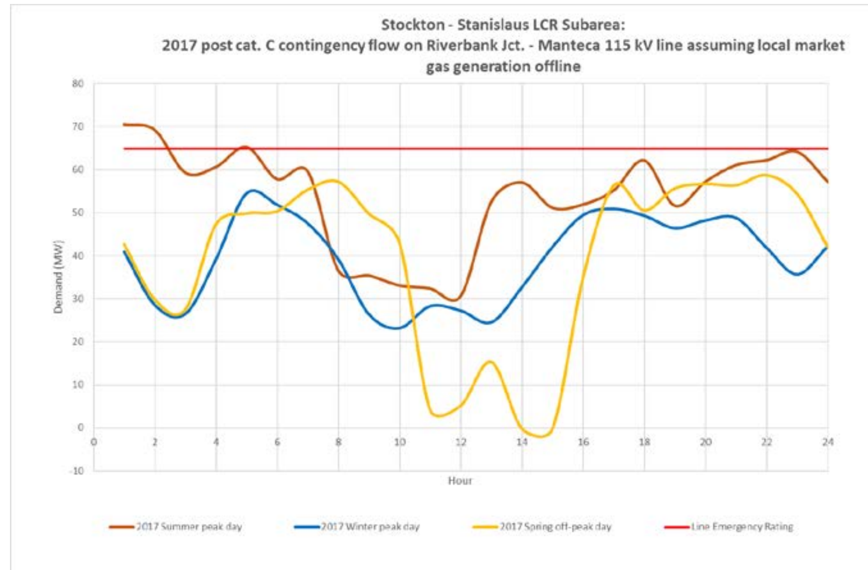
# Stanislaus Sub Area : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | River Bank Jct. – Manteca 115 kV Line | Bellota-Riverbank-Melones 115 kV line and Stanislaus PH | 174 |
| 2028 | First limit | C | None | None | NA |



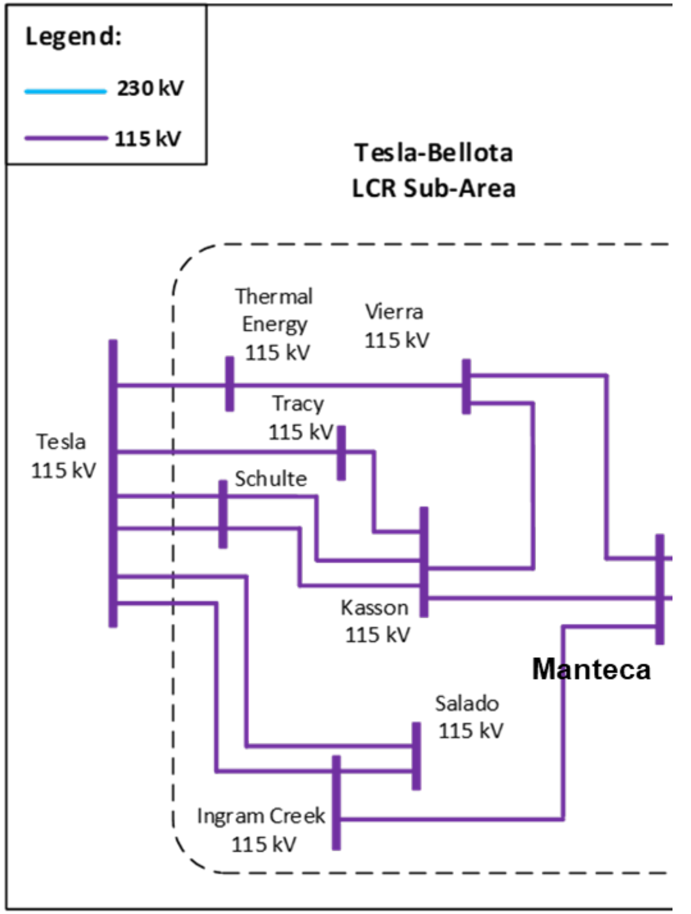
# Stanislaus Subarea : Flow Profiles



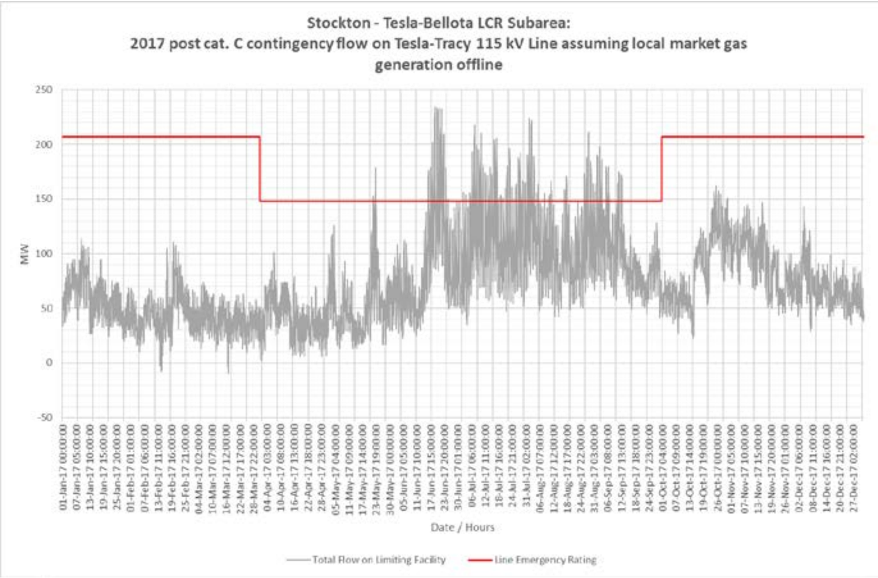



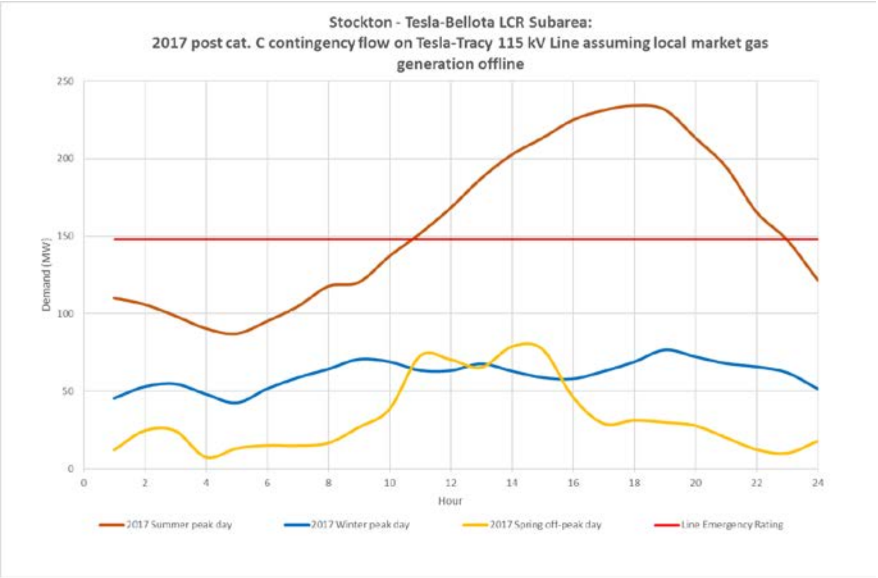
# Tesla-Bellota Sub Area : Requirements

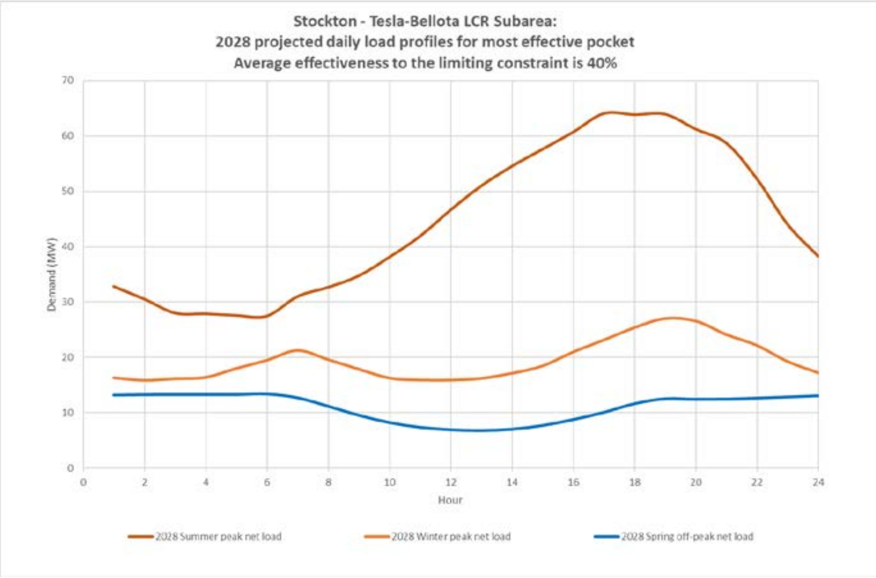
| Year | Limit | Cat. | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | Tesla – Tracy 115 kV | Tesla – Vierra 115 kV and GWF Tracy #3 unit | 303 |
| 2028 | Second limit | B | Tesla – Vierra 115 kV | Tesla – Tracy 115 kV and GWF Tracy #3 unit | 291 |
| 2028 | Third limit | B | Tesla – Tracy 115 kV | Schulte - Lammers115 kV and GWF Tracy #3 unit | 239 |
| 2028 | First limit | C | Tesla – Tracy 115 kV | Schulte - Lammers115 kV and Schulte-Kasson-Manteca 115 kV | 507 (213) |
| 2028 | Second limit | C | Tesla – Vierra 115 kV | Schulte - Lammers115 kV and Schulte-Kasson-Manteca 115 kV | 460 (167) |
| 2028 | Second limit | C | Tesla – Schulte #2 115 kV | Tesla – Vierra 115 kV and Tesla – Schulte #1 115 kV | 247 |



# Tesla - Bellota Sub Area : Flow Profiles

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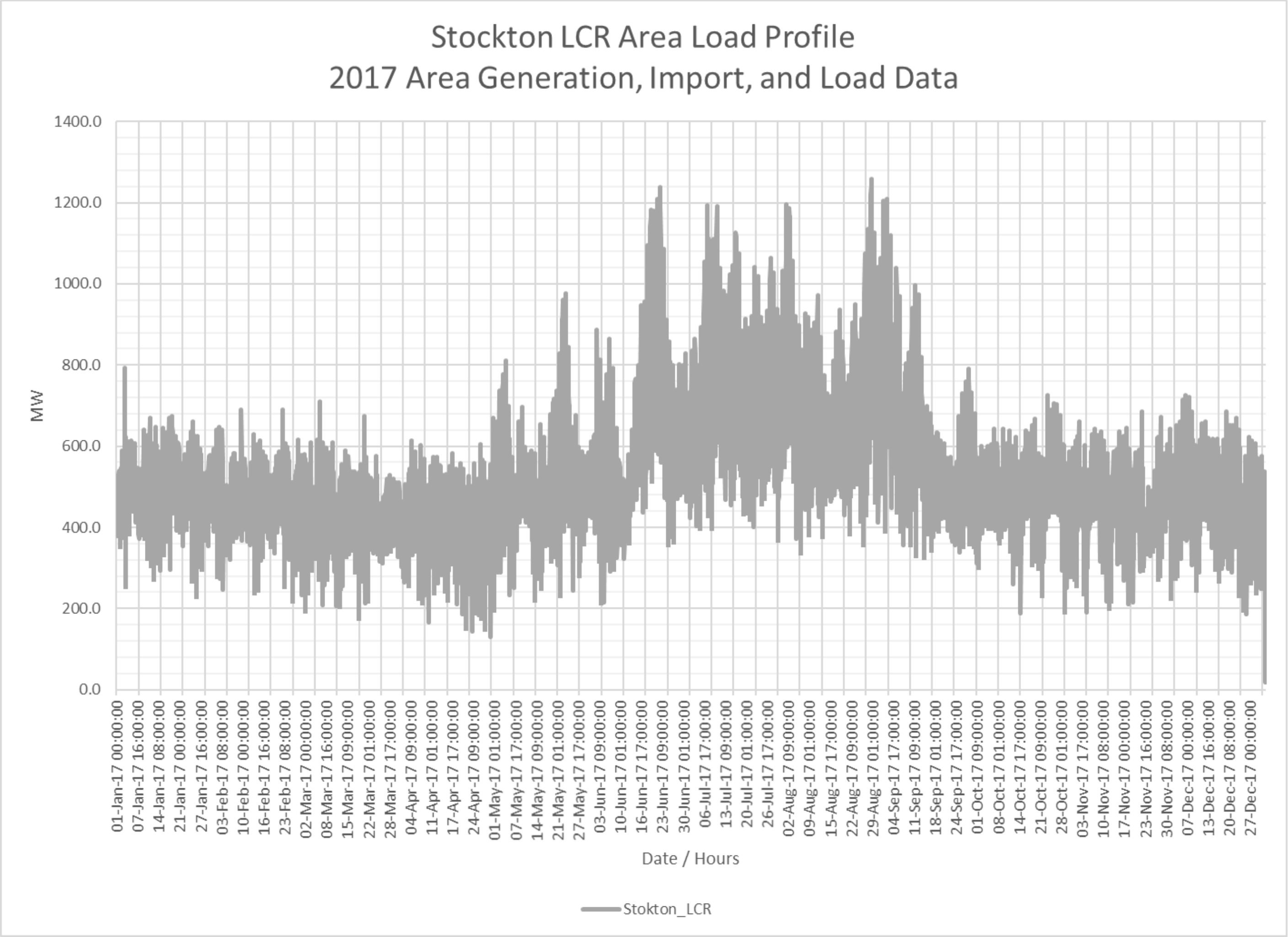
# Stockton Area Overall : Load Profiles



# Stockton Area Total LCR Need

| 2028 LCR Need | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW Need |
|---|---|---|---|
| Category B (Single) | 303 | 0 | 303 |
| Category C (Multiple) | 294 | 213 | 507 |

# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| Lockeford | 184 | 83 | 198 | 103 | 226 | 0 |
| Weber | 229 | 21 | 219 | 17 | 256 | 30 |
| Stanislaus | NA * | 152 | NA * | 147 | NA * | 174 |
| Tesla-Bellota | 761 | 673 | 809 | 319 | 897 | 507 |
| Overall | 1,174 | 777 | 1,226 | 439 | 1,379 | 537 |

*Note: LCR increases from 2023 to 2028 are all mostly due to load increase. The Lockeford Area 230 kV Development Project removes the need for LCR in Lockeford subarea.*
** Flow-through area. No defined load pocket.*

# 2028 Long-Term LCR Study Draft Results Greater Fresno Area

Vera Hart

Senior Regional Transmission Engineer

Stakeholder Meeting

September 20-21, 2018

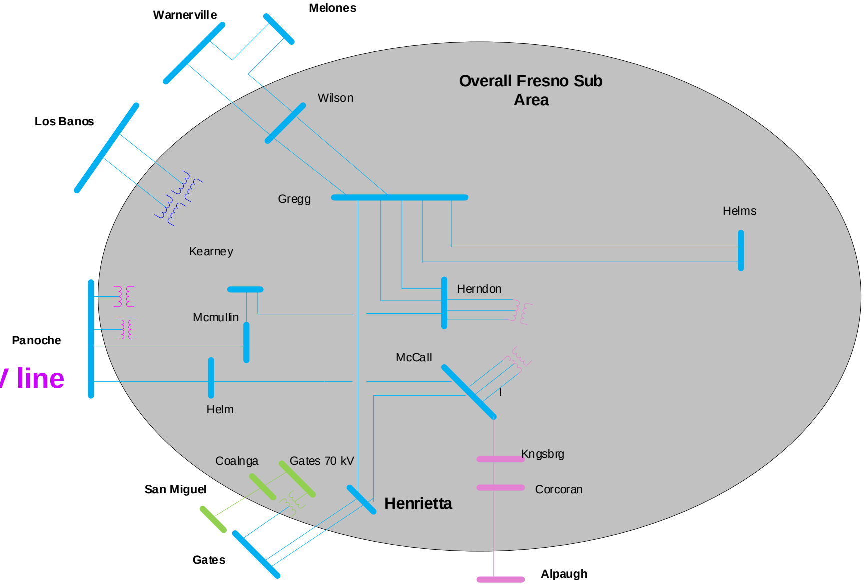
# Greater Fresno Area

## Electrical Boundaries and LCR Sub-Areas

### Electrical Boundaries:

- Gates – Mustang #1 230 kV line
- Gates – Mustang #2 230 kV line
- Panoche – Tranquility #1 230 kV line
- Panoche – Tranquility #2  230 kV line
- Warnerville – Wilson 230 kV line
- Melones – Wilson 230 kV line
- Panoche 230/115 kV transformer #1
- Panoche 230/115 kV transformer #2
- Smyrna – Alpaugh – Corcoran 115 kV line
- Los Banos #3 230/70 kV transformer
- Los Banos #4 230/70 kV transformer
- San Miguel – Coalinga #1 70 kV line
- Gates 230/70 kV transformer #1

### LCR Sub-Areas:



# New major transmission projects

| Project Name | Expected ISD |
|---|---|
| Borden 230 kV Voltage Support | 19-Feb |
| Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade | 18-May |
| Helm-Kerman 70 kV Line Reconductor | 18-Mar |
| Lemoore 70 kV Disconnect Switches Replacement | 18-Jun |
| Los Banos-Livingston Jct-Canal 70 kV Switch Replacement | 18-Jun |
| Oro Loma 70 kV Area Reinforcement | 20-May |
| Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects Include Battery at Dinuba) | 21-Dec |
| Reedley 115/70 kV Transformer Capacity Increase | Completed |
| Wilson 115 kV Area Reinforcement | 23-Dec |
| Wilson-Le Grand 115 kV line reconductoring | 20-Dec |
| Panoche – Oro Loma 115 kV Line Reconductoring | 20-Dec |
| Wilson 115 kV SVC | 19-Dec |
| Gates #12 500/230 kV Transformer Addition | 19-Dec |
| Kearney - Hearndon 230 kV Line Reconductoring | 19-May |
| Northern Fresno 115 kV Area Reinforcement | 20-Mar |
| Bellota-Warnerville 230kV line Reconductoring | 23-Dec |
| Herndon-Bullard 230kV Reconductoring Project | 21-Jan |

# Power plant changes

Additions:

- Over 300MW New Solar Units

Retirements:

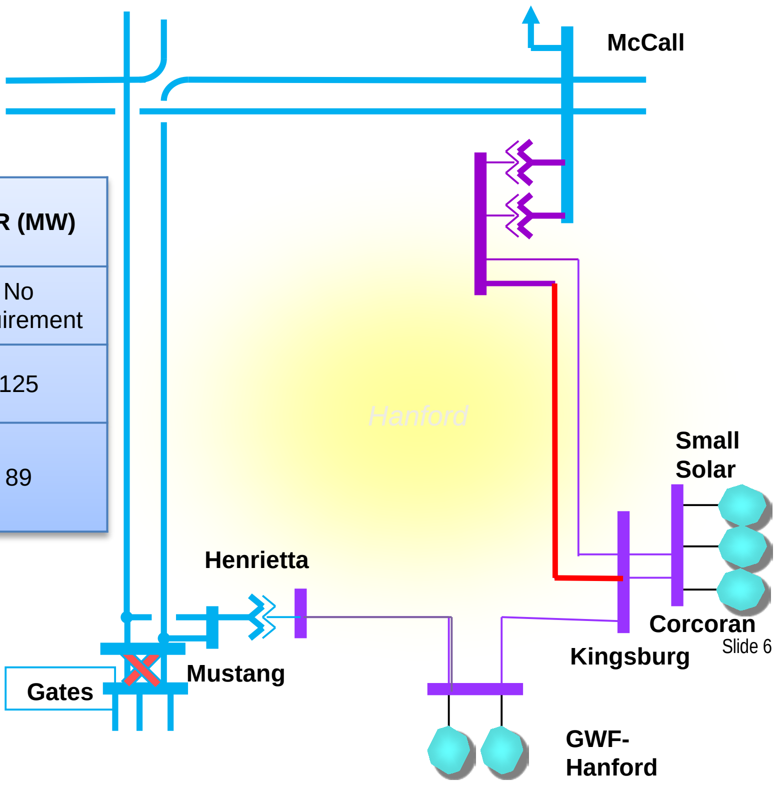
- None

# Load and Resources

| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 3,617 | Market | 4,362 |
| AAEE | -227 | Wind | 13 |
| Behind the meter DG | -2.8 | Muni | 311 |
| **Net Load** | **3,387** | QF | 28 |
| Transmission Losses | 109 | **Total Qualifying Capacity** | **4,701** |
| Pumps | 0 | | |
| **Load + Losses + Pumps** | **3,496** | | |

# Hanford Sub-Area Requirements

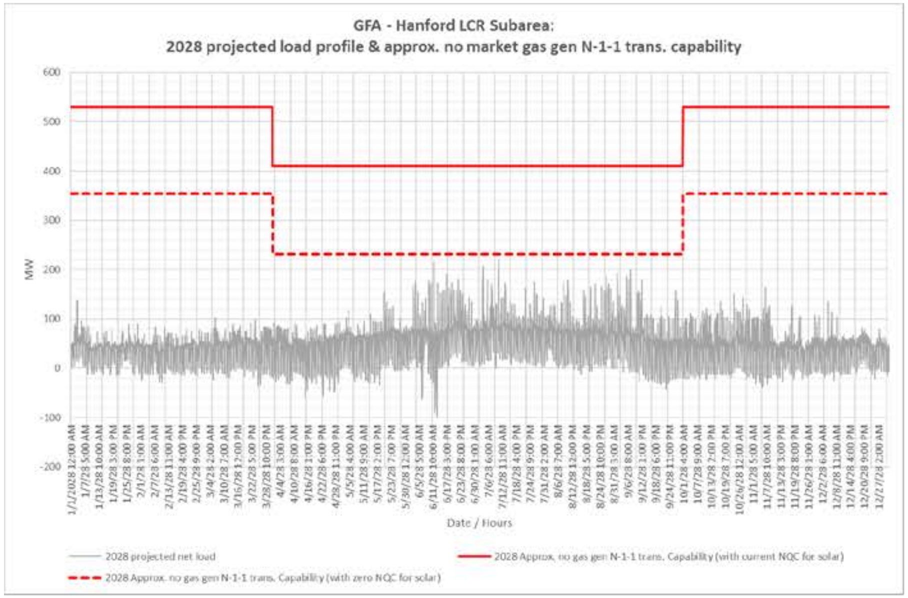
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | No requirement |
| 2028 | First Limit | P7 | McCall-Kingsburg #1 115kV Line | Mustang-Gates #1 and #2 230kV Lines | 125 |
| 2028 | Second Limit | P6 | McCall-Kingsburg #1 115kV Line | McCall-Kingsburg #2 115kV Line and Henrietta #3 230/115kV TB | 89 |

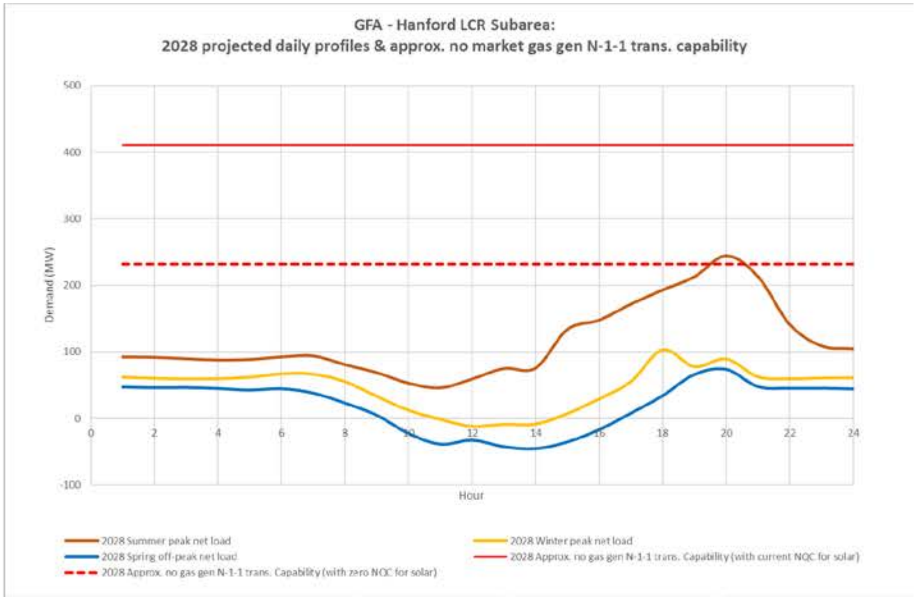





California ISO

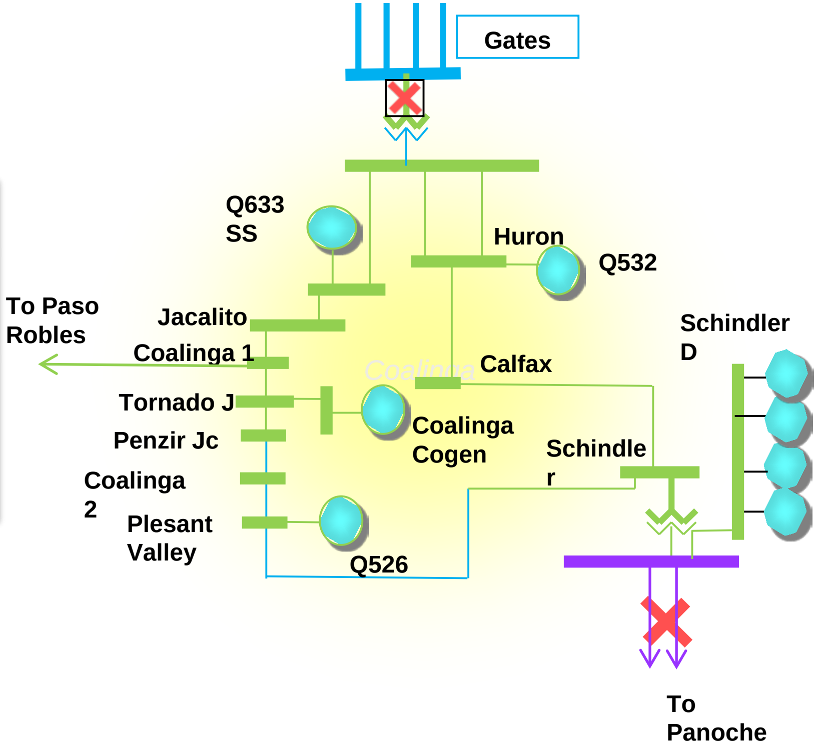
# Hanford Sub-Area: Load Profiles



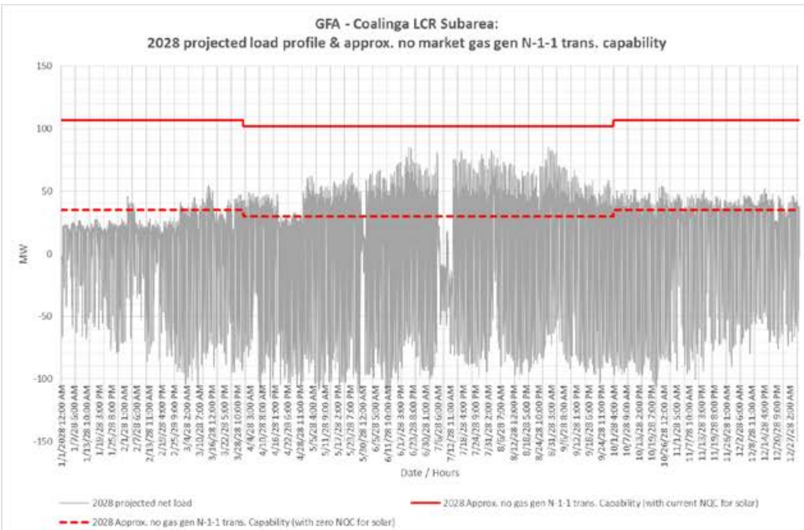



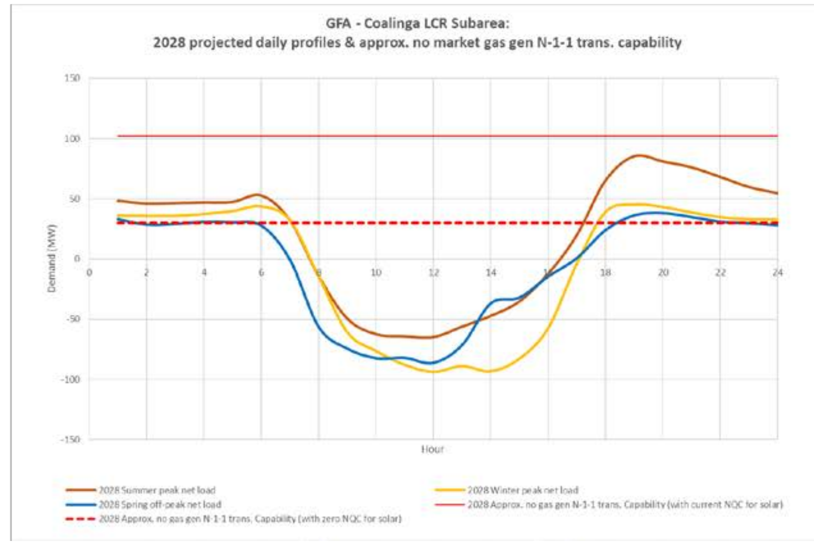
# Coalinga Sub-Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | No requirement |
| 2028 | First Limit | P1-P7 | Voltage Instability | T-1/L-2: Gates 230/70kV TB #5 and Panoche-Schindler #1 & #2 115kV common tower lines | 17 |



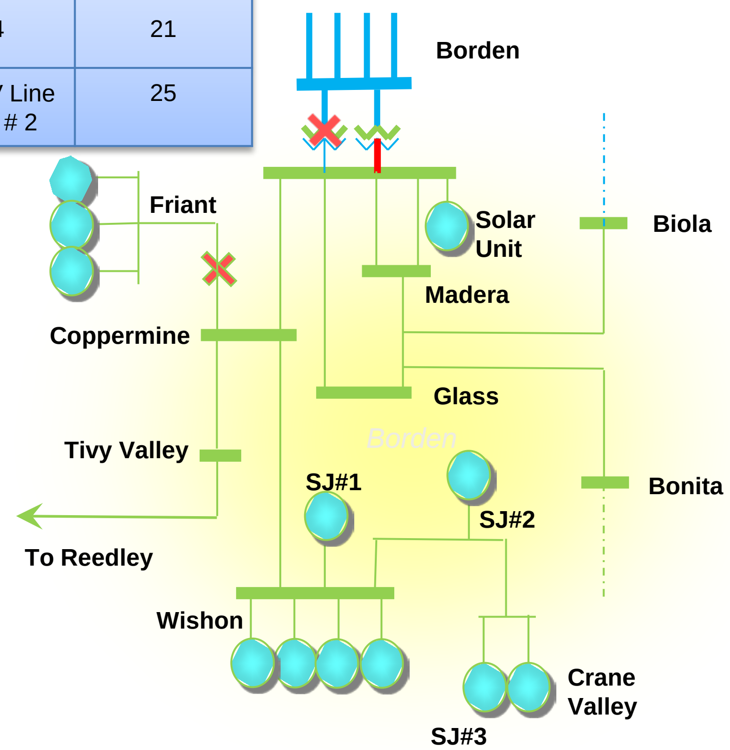
# Coalinga Sub-Area: Load Profiles



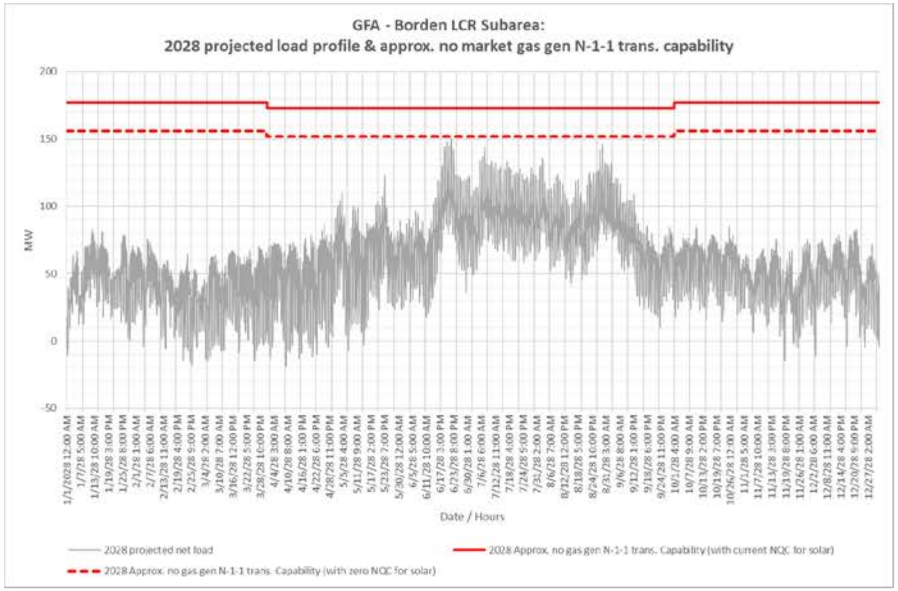



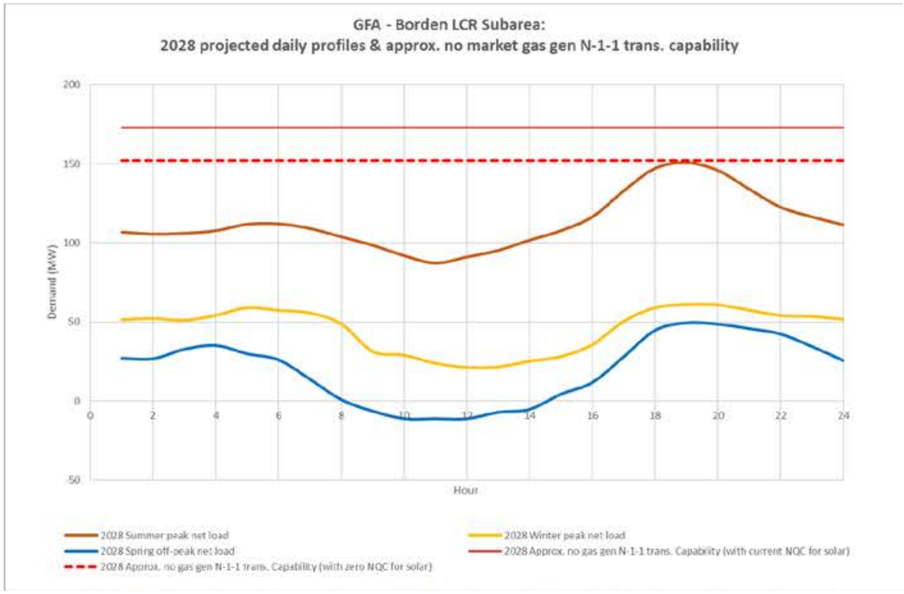
# Borden Sub-Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | P1 | Borden 230/70 kV TB # 1 | Borden 230/70 kV # 4 | 21 |
| 2028 | First Limit | P6 | Borden 230/70 kV TB # 1 | Friant - Coppermine 70 kV Line and Borden 230/70 kV TB # 2 | 25 |

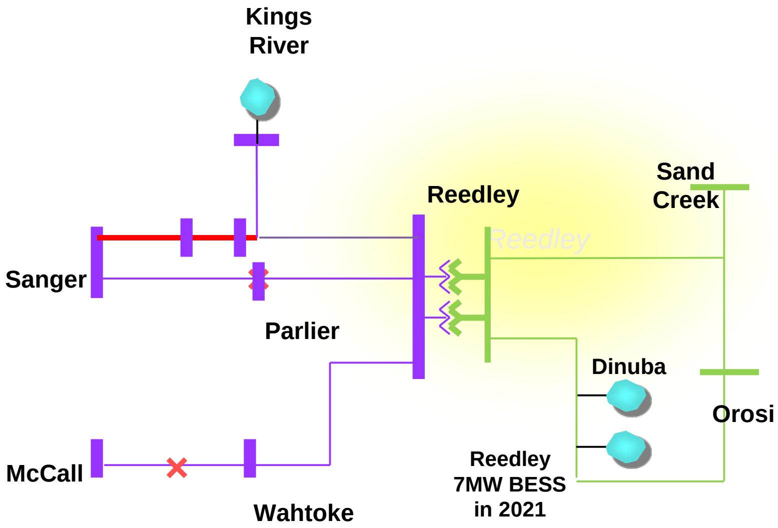


# Borden Sub-Area: Load Profiles



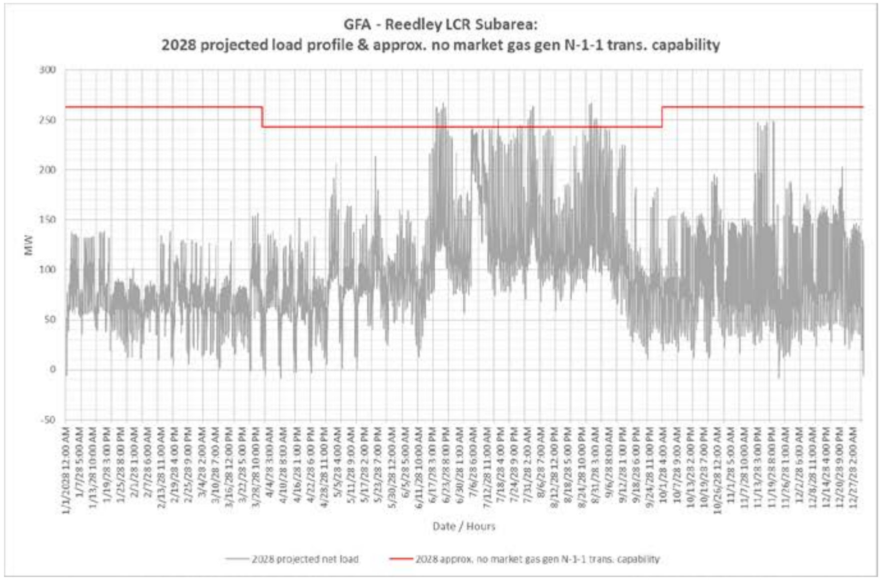



# Reedley Sub-Area Requirements

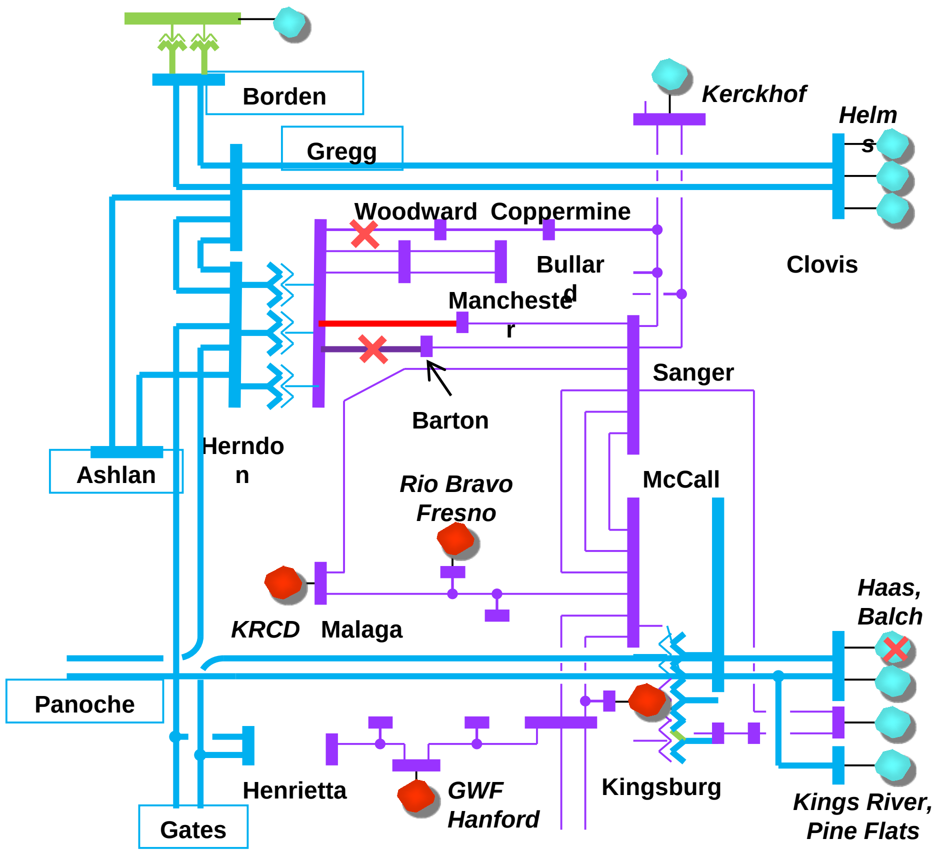



| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | P6 | Kings River-Sanger-Reedley 115kV line | McCall-Reedley 115kV Line & Sanger-Reedley 115kV line | 39 |

# Reedley Sub Area : Load Profiles



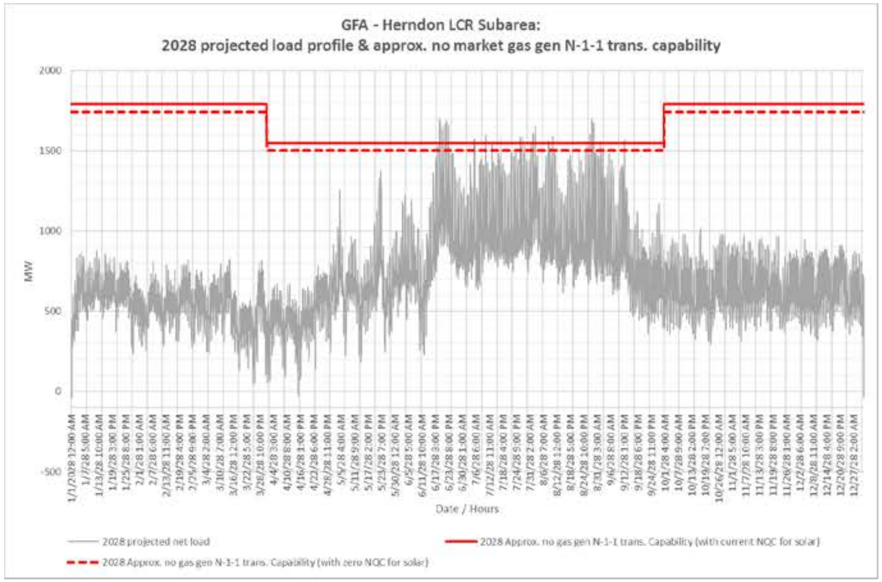

# Herndon Sub-Area Requirements

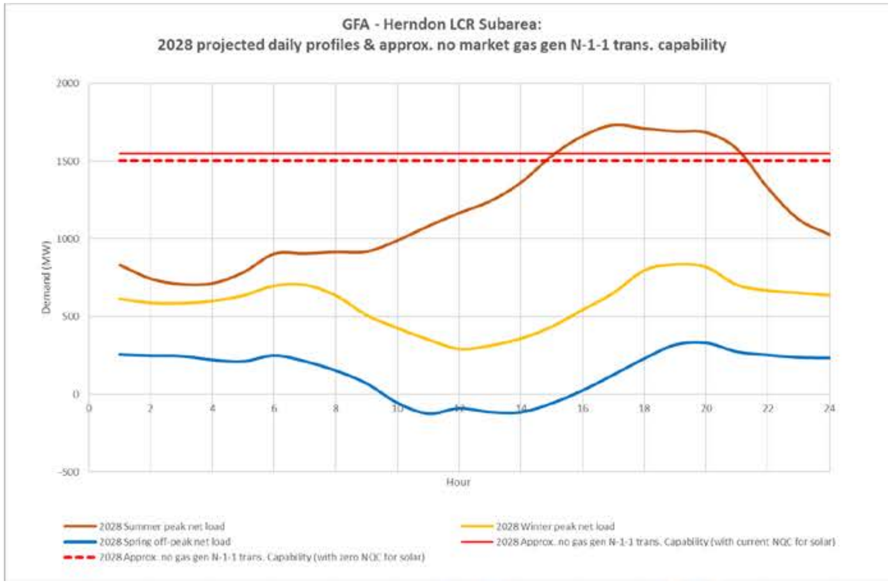


# Herndon Fresno Sub Area : Requirements

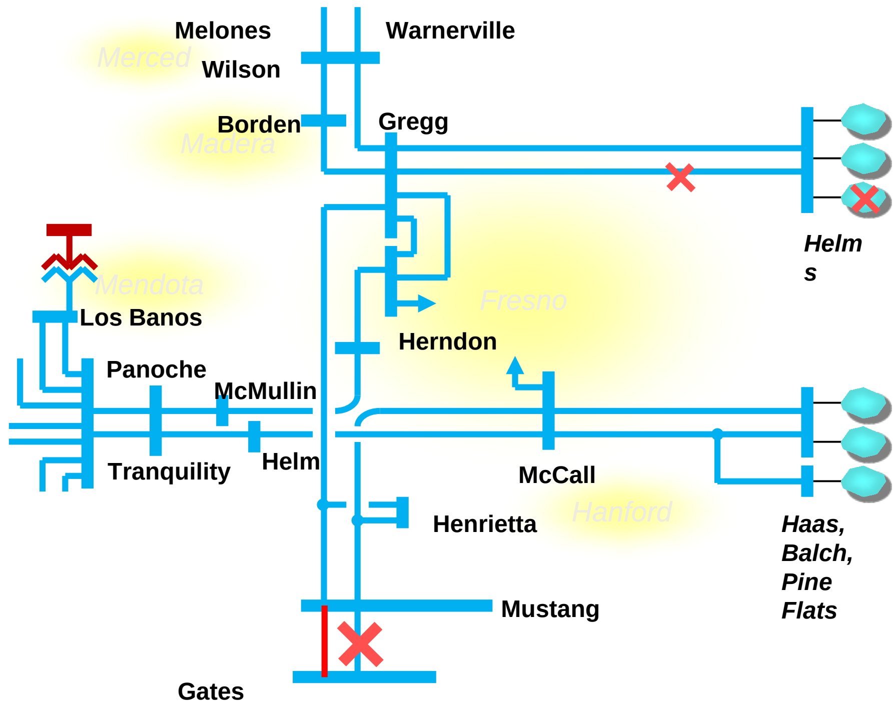
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First limit | P3 | Herndon-Manchester 115kV line | Balch Unit 1 and Herndon-Barton 115kV line | 326 |
| 2028 | First limit | P6 | Herndon-Manchester 115kV line | Herndon-Woodward 115kV line and Herndon-Barton 115kV line | 830 |
| 2028 | Second limit | P6 | Herndon-Barton 115kV line | Herndon-Woodward 115kV line and Herndon-Manchester 115kV line | 655 |

# Herndon Sub Area : Load Profiles



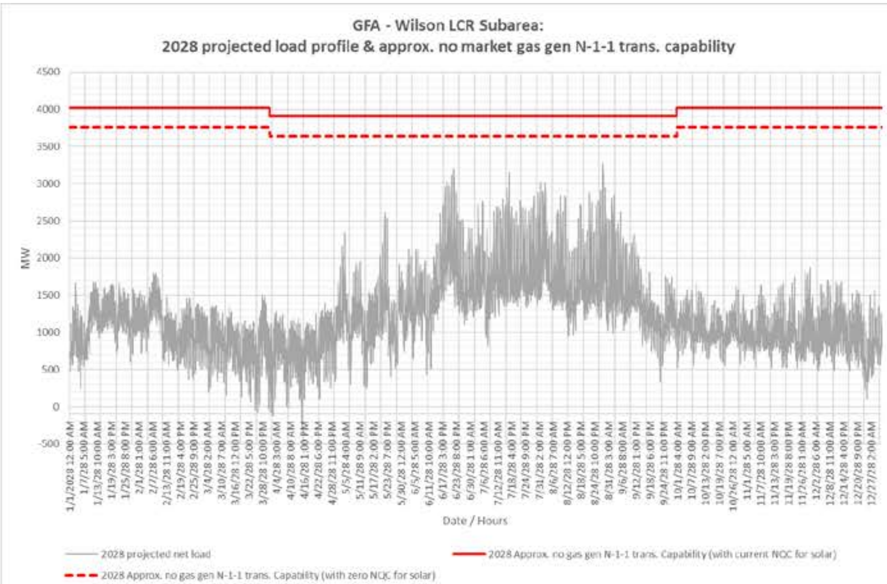
# Overall Sub-Area Requirements

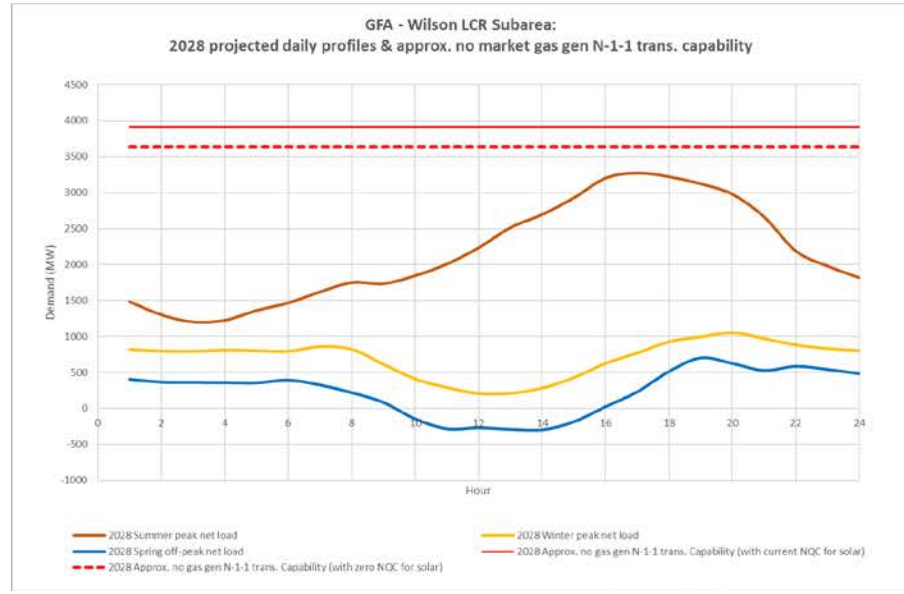


# Overall Fresno Sub Area : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First limit | P3 | Remaining Gates-Mustang 230kV line | Gates-Mustang 230kV #1 or #2 line and one Helms unit out | 1628 |
| 2028 | First limit | P6 | Remaining Gates-Mustang 230kV line | Gates-Mustang 230kV #1 or #2 line and Helms-Gregg 230kV line | 1728 |

# Overall Sub Area : Load Profiles



# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| Hanford | 170.5 | 56 | 186.3 | 107 | 242.5 | 125 |
| Coalinga | 86 | 19 | 85 | 16 | 85 | 17 |
| Borden | 132.6 | 1 | 137.1 | 8 | 152 | 25 |
| Reedley | 237 | 5 | 266 | 12 | 266 | 39 |
| Herndon | 1461 | 792 | 1529 | 821 | 1689 | 830 |
| Overall | 3070 | 1670 | 3231 | 1688 | 3496 | 1728 |

*Note: LCR increases from 2023 to 2028 are all mostly due to load increase*
*Load is Net Load+Losses*

# 2028 Long-Term LCR Study Draft Results Kern Area

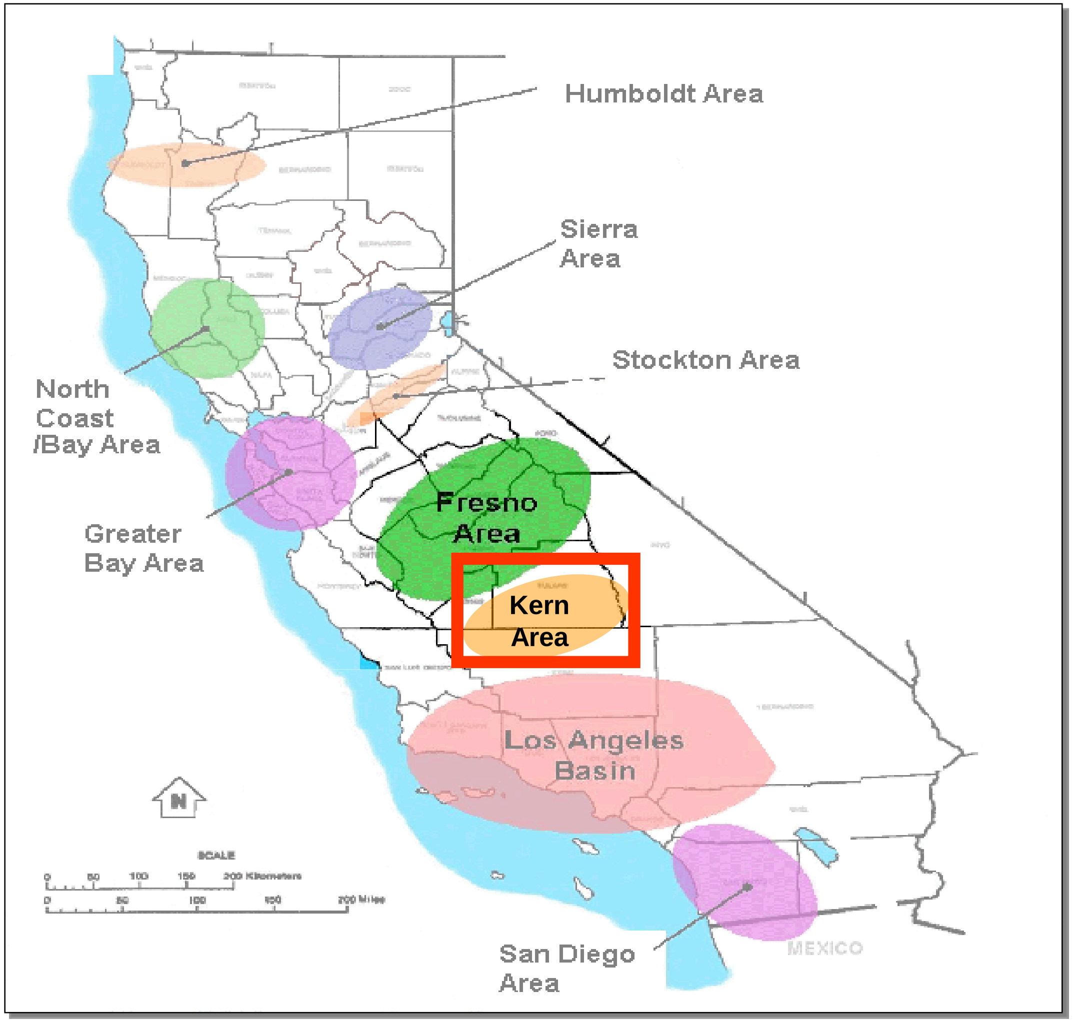
Abhishek Singh

Regional Transmission Engineer Lead

Stakeholder Meeting

September 20-21, 2018

# Kern LCR Area



# New Major Projects

| Project Name | Expected ISD |
|---|---|
| Kern PP 115 kV Area Reinforcement Project | 2028 |
| Wheeler ridge Junction Station Project | 2028 |

No new power plant additions or retirements as compared to 2023.

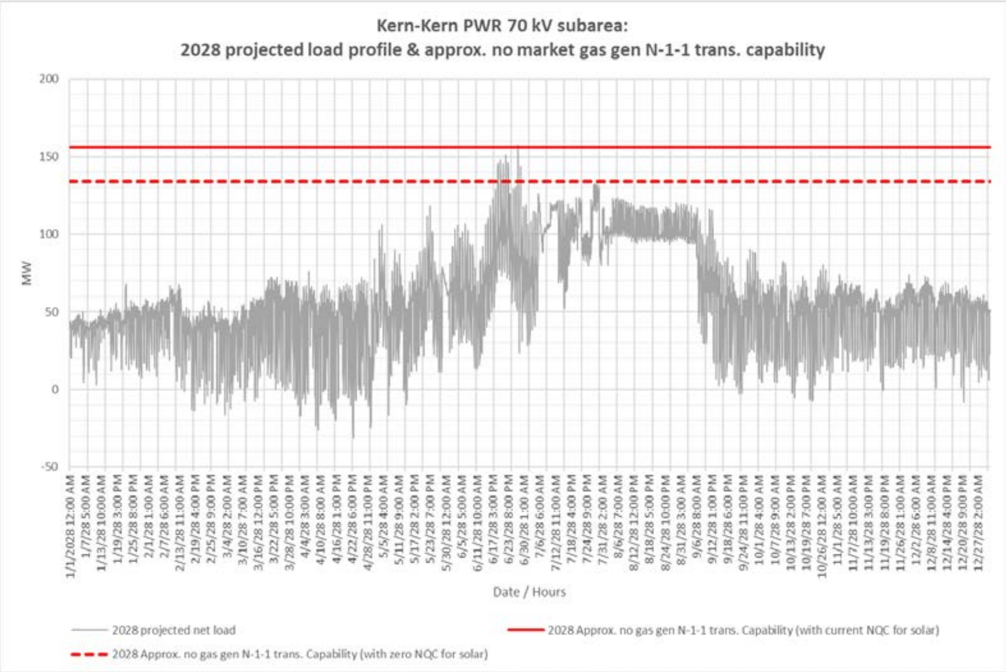
# Load and Resources

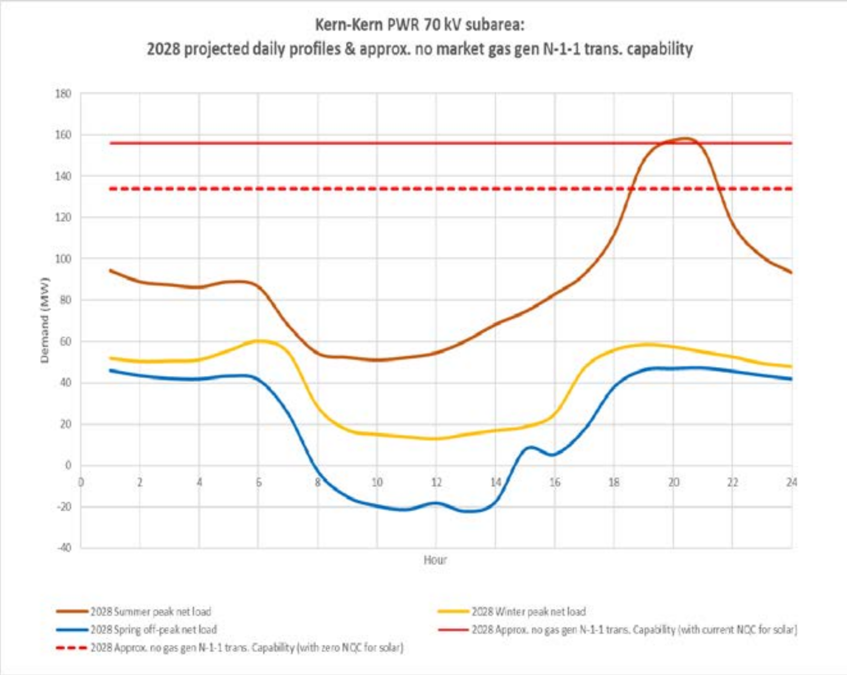
| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 1011 | Market | 491 |
| AAEE | -60 | Wind | 0 |
| Behind the meter DG | 0 | Muni | 0 |
| **Net Load** | **951** | QF | 0 |
| Transmission Losses | 9 | **Total Qualifying Capacity** | **491** |
| Pumps | 0 | | |
| **Load + Losses + Pumps** | **960** | | |

# Kern PP 70 kV Sub Area : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | None |
| 2028 | First Limit | C | Kern PW2 to Kern PW1 70 kV Bus Tie | Kern PW2 115/70 T/F # 1 & Kern-Old River 70 kV line | 31(3) |

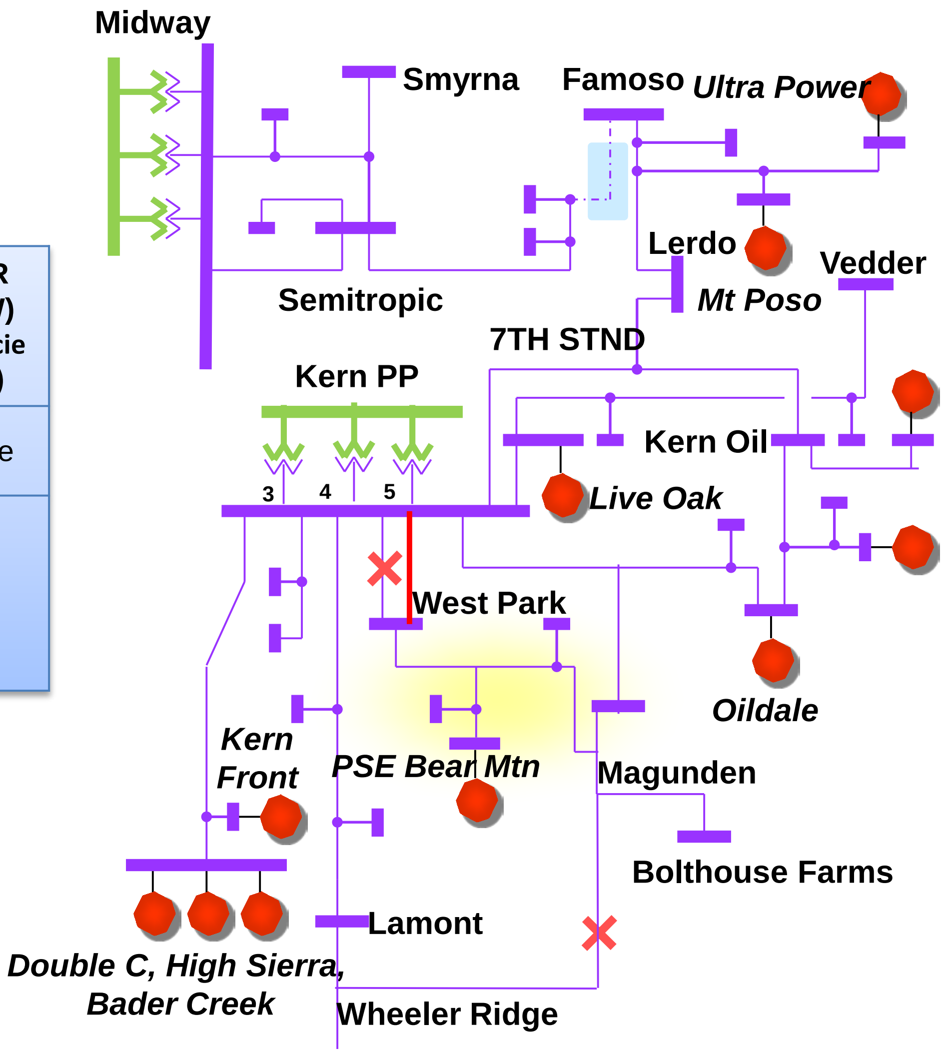
# Kern PP 70 kV Sub Area : Load Profile



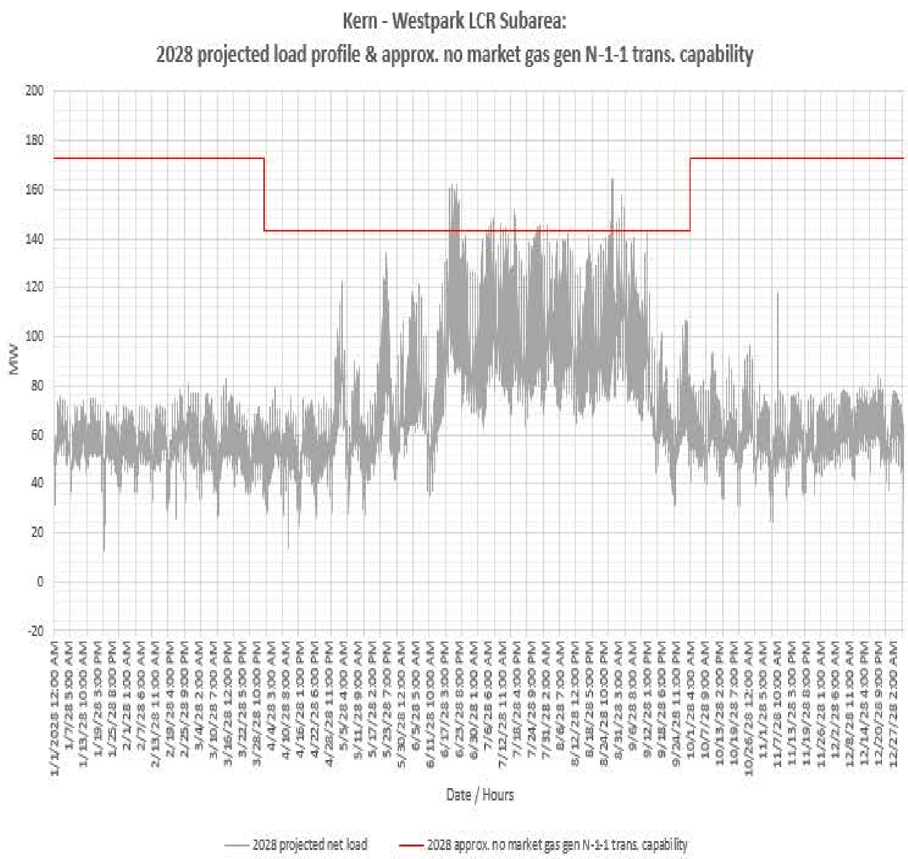



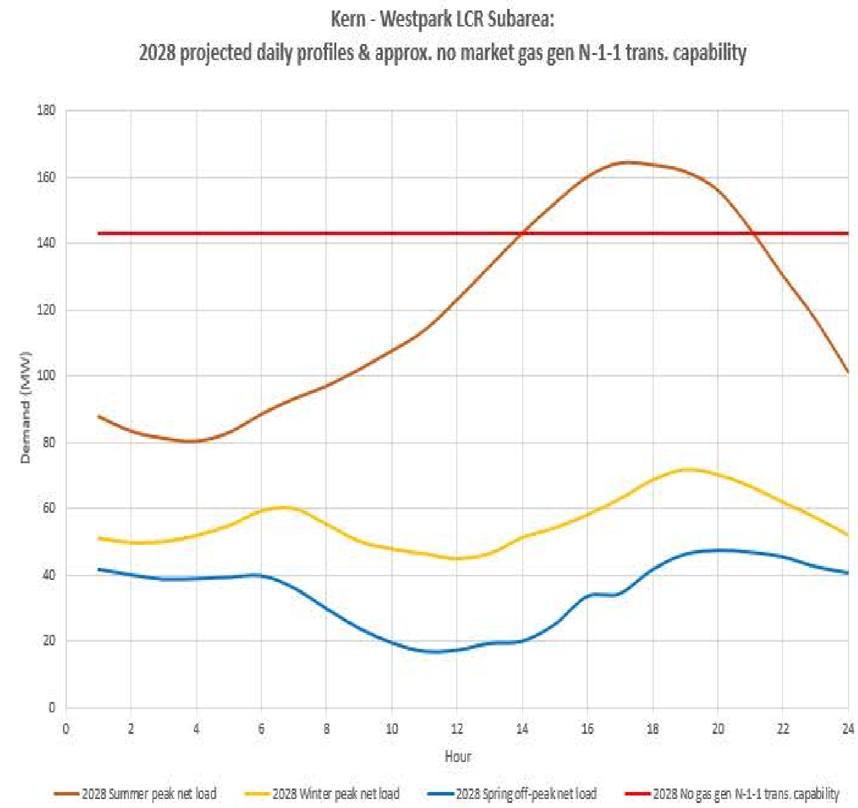
# WestPark Sub Area : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | None |
| 2028 | First Limit | C | Kern-West Park #2 115 kV | Kern-West Park #1 115 kV and Magunden – Wheeler Junction 115 kV | 42 |



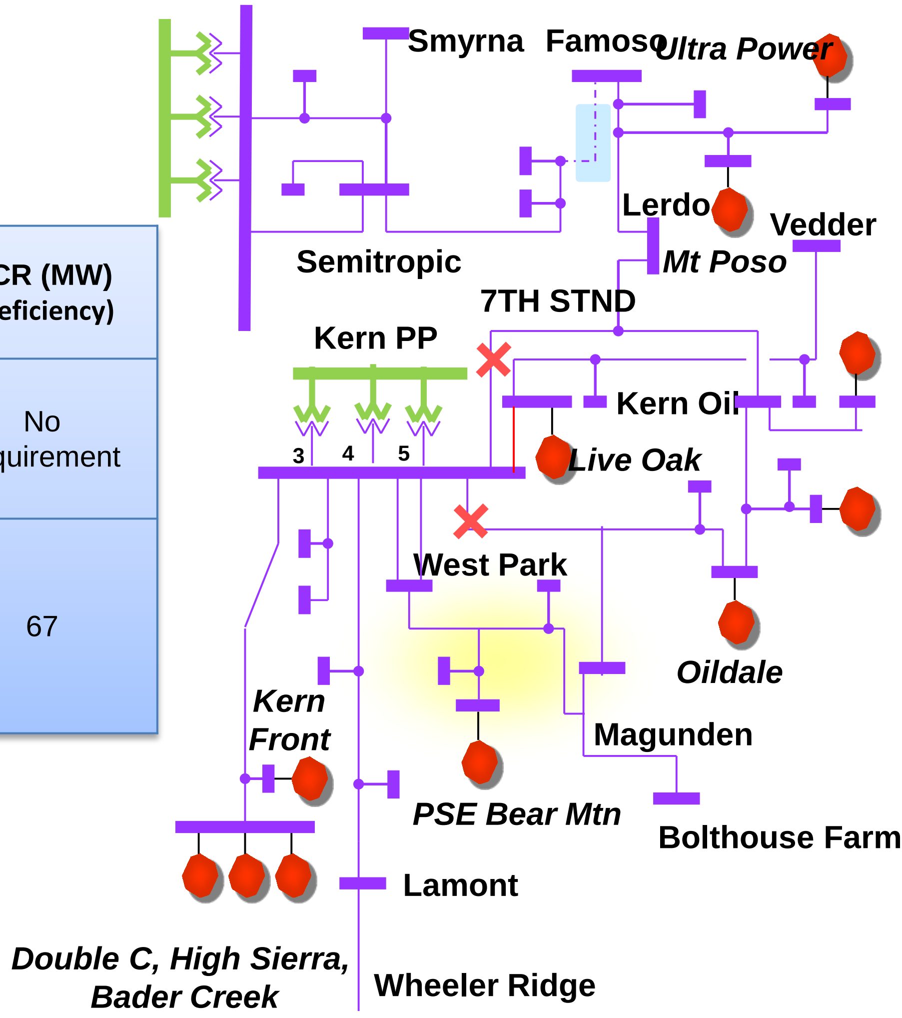
# West Park Sub Area : Load Profiles



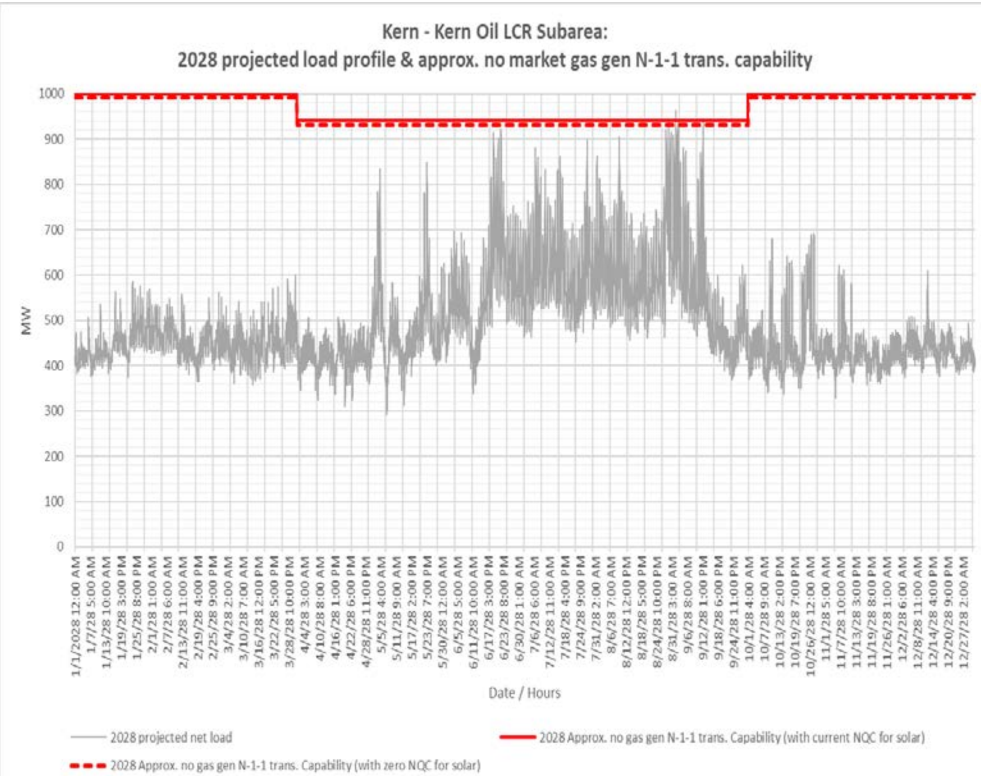



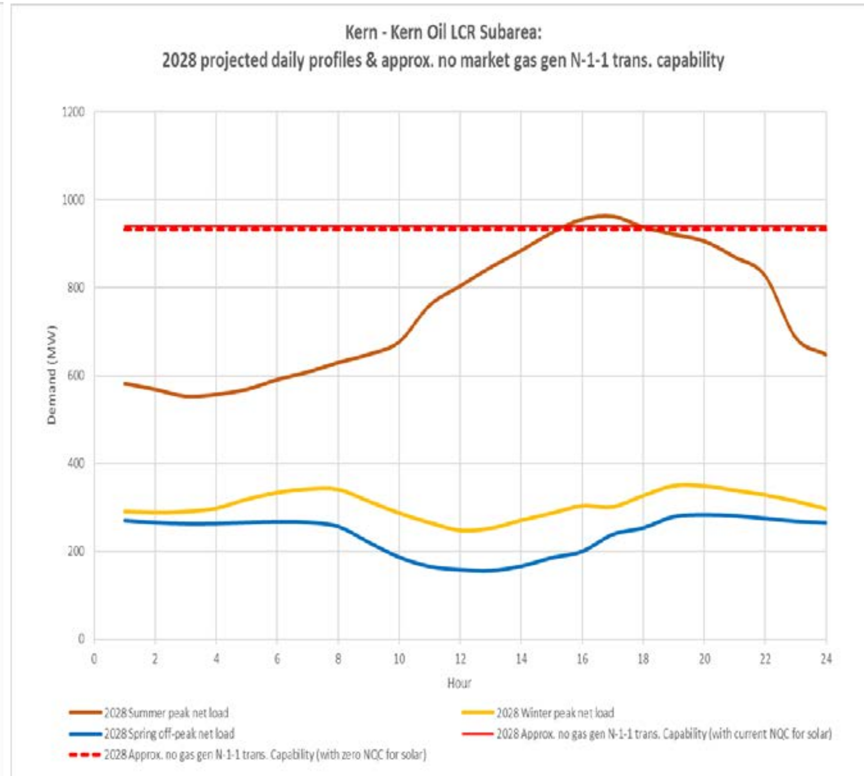
# Kern Oil Sub Area : Requirements

| Year | Limit | Cat | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | B | None | None | No requirement |
| 2028 | First limit | C | Live Oak – Kern Power 115 kV line | Kern-Magunden-Witco and Kern PP-7th Standard 115 kV line | 67 |



# Kern Oil Sub Area : Load Profiles



# Kern Total LCR Need

| 2028 LCR Need | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW Need |
|---|---|---|---|
| Category B (Single) | 0 | 0 | 0 |
| Category C (Multiple) | 137 | 3 | 140 |

South Kern PP Sub Area has been eliminated. Kern Oil sub area drives the requirement for Kern LCR area.

# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| Kern PP 70 kV | NA | NA | NA | NA | 156 | 31* |
| West Park | 151 | 51* | 149 | 51* | 173 | 42 |
| Kern Oil | 684 | 116 | 744 | 131* | 787 | 67 |
| South Kern | 1088 | 472 | 1140 | <131 | 1393 | NA** |
| Kern Overall | 1088 | 478 | 1140 | 182 | 960 | 140* |

*Includes Deficiency
** South Kern sub-area not required in future due to approved transmission projects

*Load is Net Load+Losses*

**Compared to 2023 long-term LCR (May 2018):**

- Kern LCR area definition is smaller due to multiple transmission projects.
- LCR need (140 MW) has decreased by 42 MW vs. 2023 (182MW) – due to multiple Kern Area Transmission projects.

# 2028 Long-Term LCR Study Draft Results North Coast & North Bay Area

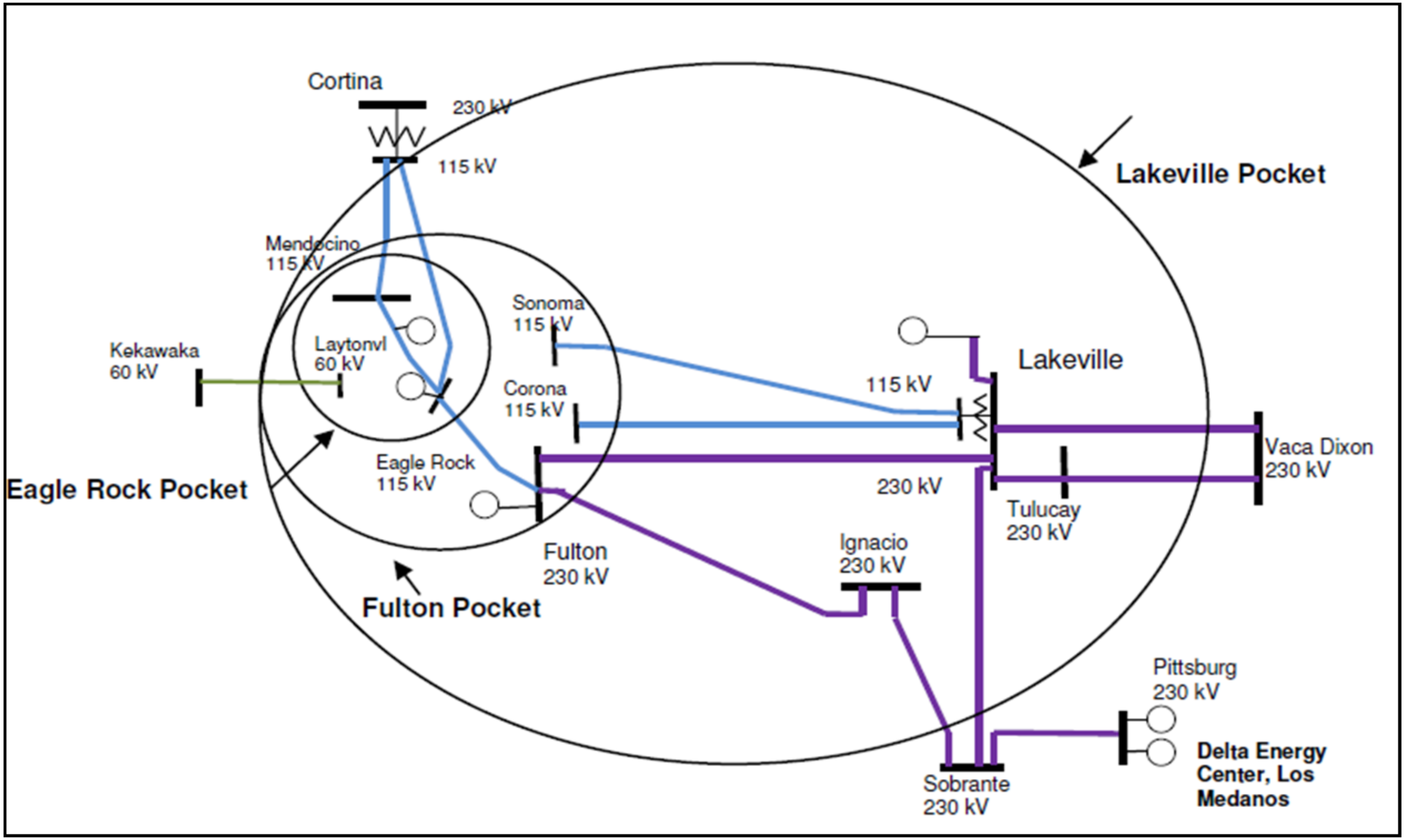
Bryan Fong

Senior Regional Transmission Engineer

Stakeholder Meeting

September 20-21, 2018

# North Coast & Bay Area Transmission System



# New major transmission projects

| Project Name | Expected ISD |
|---|---|
| Fulton-Fitch Mountain 60kV Line Reconductor (Fulton-Hopland 60kv Line) Project – Revised Scope | 2019 |
| Clear Lake 60kV System Reinforcement - Revised Scope | 2023 |
| Ignacio-Alto 60kV Line Conversion - Revised Scope | 2023 |
| Lakeville 60kV Area Reinforcement | 2021 |
| Vaca-Lakeville 230kV Corridor Series Compensation | 2020 |

# Power plant changes

Additions:

- No new resource addition

Retirements:

- None

# Load and Resources

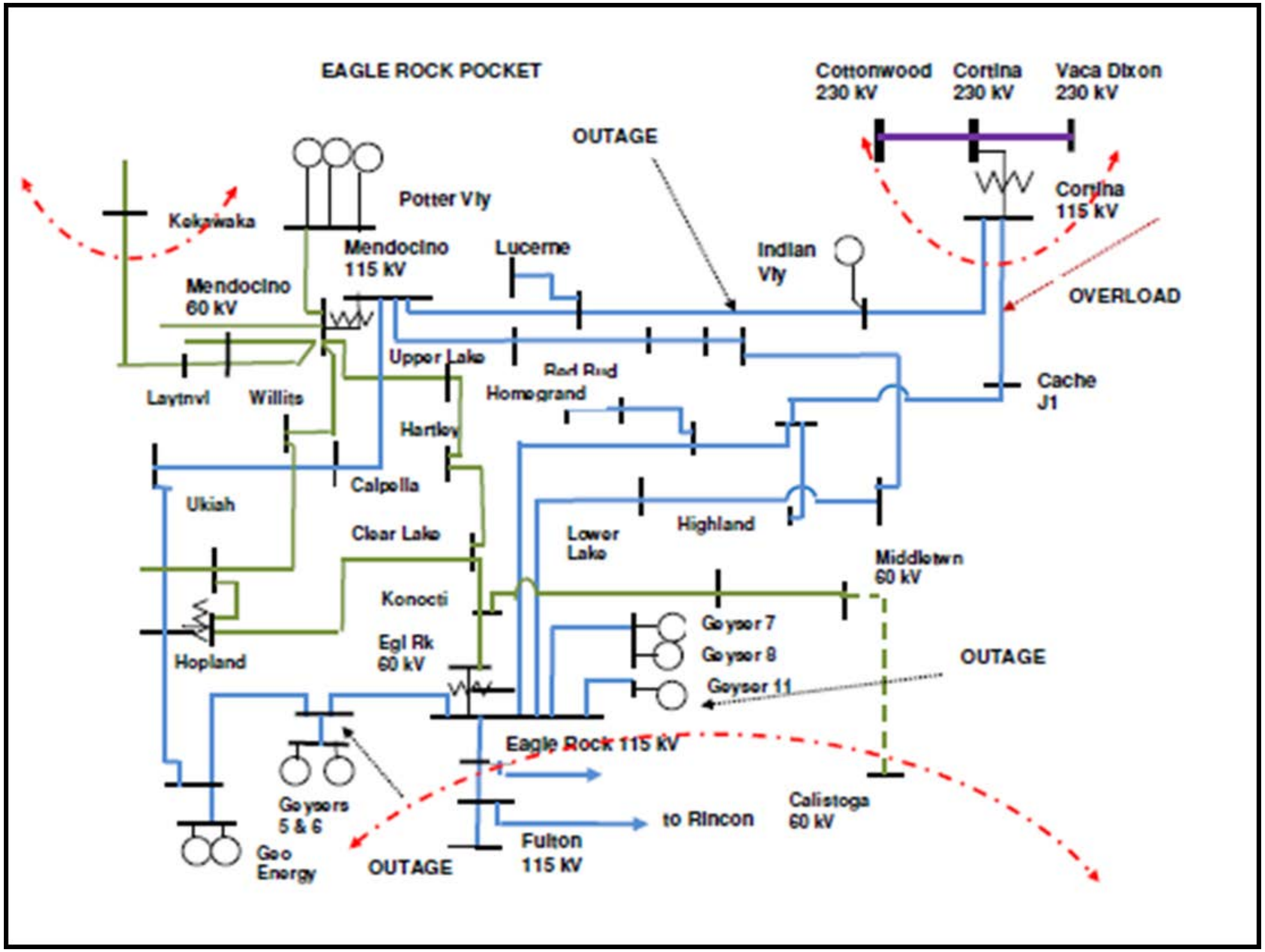
| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 1627 | Market | 736 |
| AAEE | -89 | Wind | 0 |
| Behind the meter DG | 0 | Muni | 114 |
| **Net Load** | **1,538** | QF | 5 |
| Transmission Losses | 49 | **Total Qualifying Capacity** | **855** |
| Pumps | 0 | | |
| **Load + Losses + Pumps** | **1,587** | | |

# Eagle Rock Sub Area : Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | Thermal overload on Eagle Rock-Cortina 115 kV line* | Cortina-Mendocino 115 kV line with Geyser #11 unit out of service | 276 (26) |
| 2028 | First Limit | C | Thermal overload on Eagle Rock-Cortina 115 kV line* | Cortina-Mendocino and Geysers #3-Geysers #5 115 kV lines | 278 (28) |

*Note: With Vaca Dixon-Lakeville and Vaca Dixon-Tulucay 230 kV lines reactors bypassed

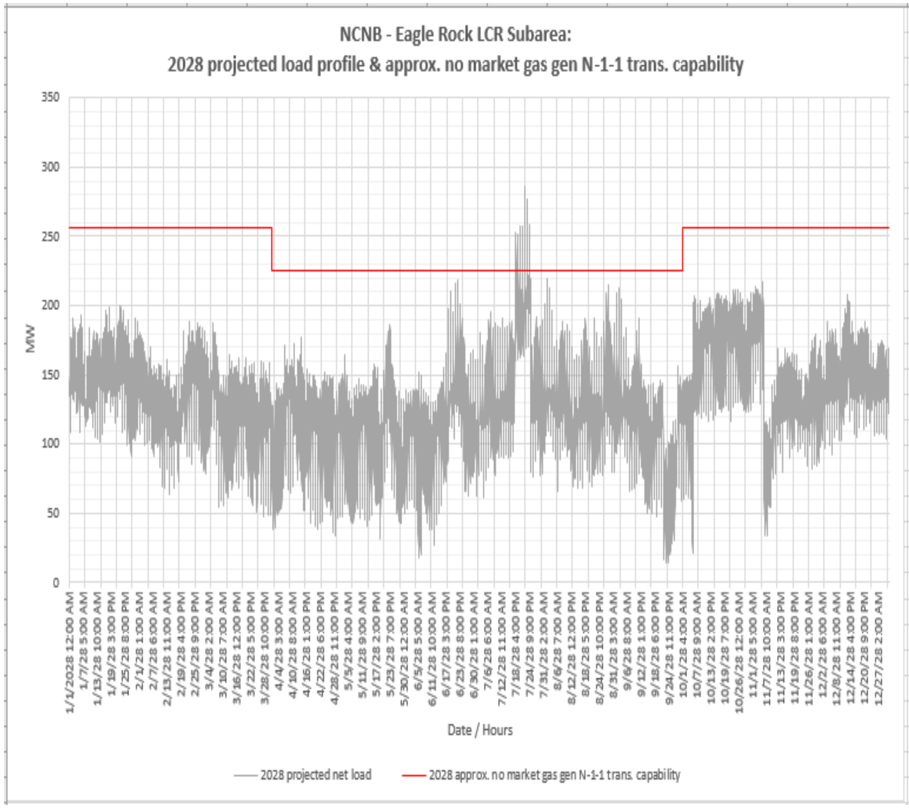
# Eagle Rock Sub Area : Requirements

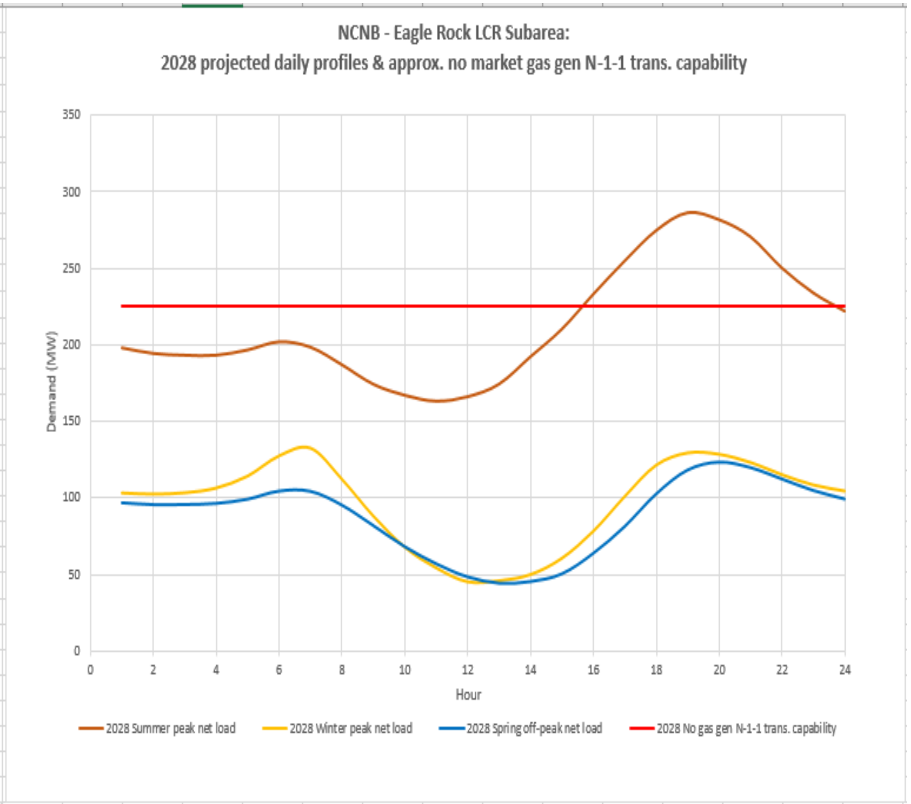



California ISO

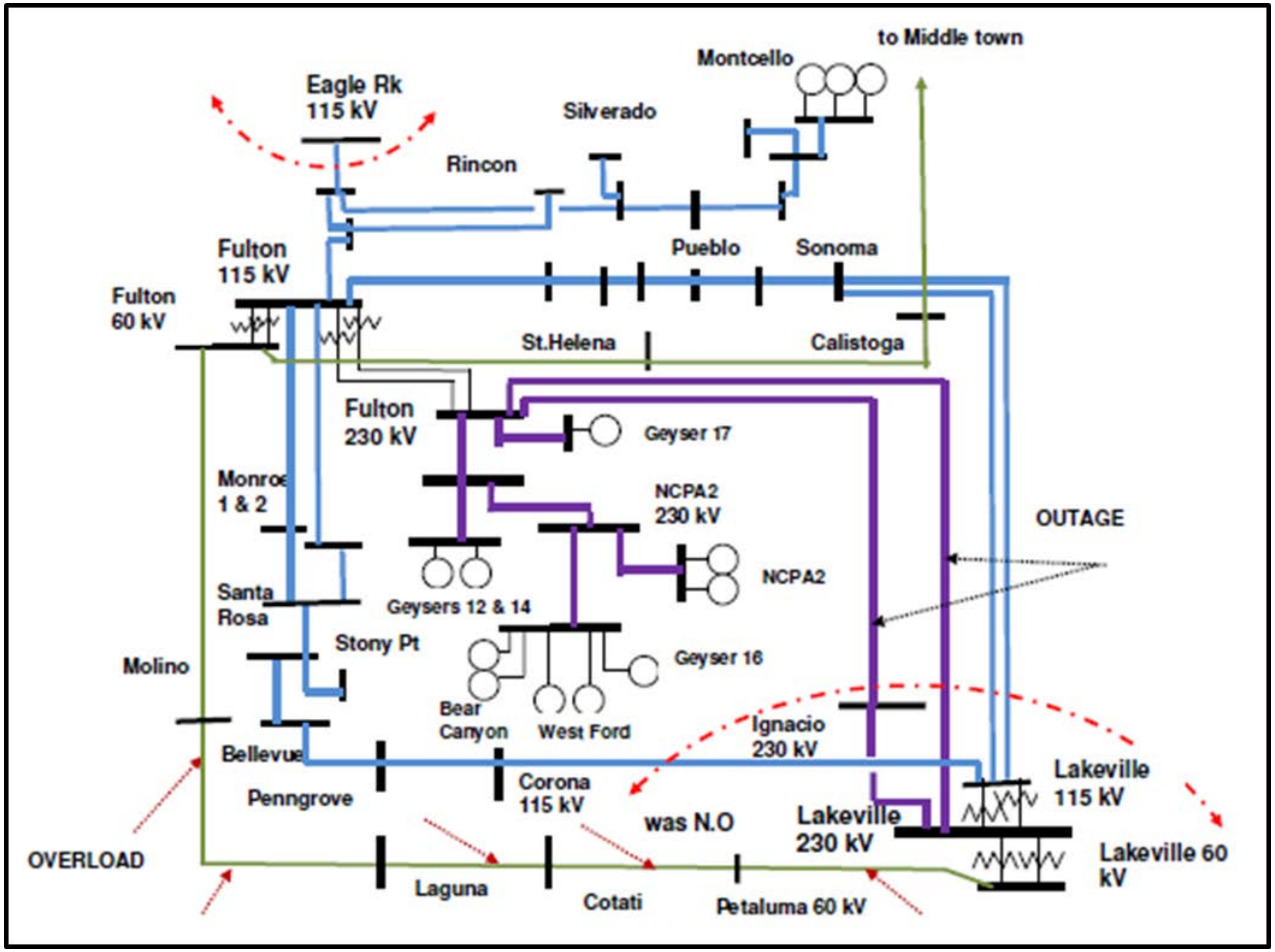
ISO Public

# Eagle Rock Sub Area : Load Profiles



# Fulton Sub Area : Removed



# Fulton Sub Area : Removed

Before

- Contingency: Fulton-Lakeville and Fulton-Ignacio 230 kV lines
- Limiting component: Thermal overload on Lakeville# 2 60 kV line (Lakeville-Petaluma-Cotati 60 kV)

Now - Lakeville# 2 60 kV line - Lakeville-Petaluma-Cotati 60 kV permanently open

- Contingency: Fulton-Lakeville and Fulton-Ignacio 230 kV lines
- Limiting component: Thermal overload on Eagle Rock-Cortina 115 kV line
- Same as Lakeville Pocket

# Lakeville Sub Area : Requirements

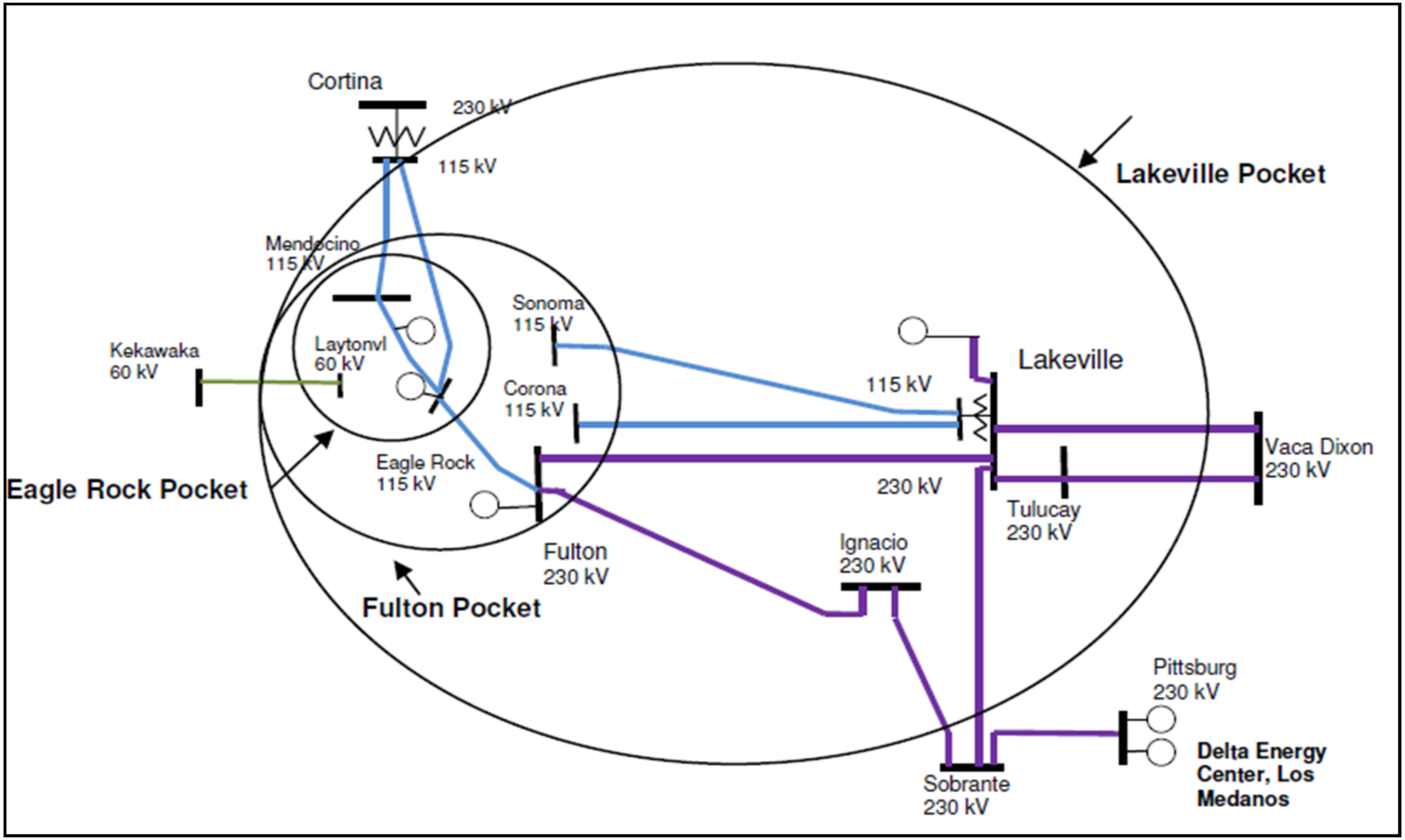
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | Thermal overload on Eagle Rock-Cortina 115 kV line* | Cortina-Mendocino 115 kV line with Geyser #11 unit out of service | 881 (26) |
| 2028 | First Limit | C | Thermal overload on Eagle Rock-Cortina 115 kV line* | Cortina-Mendocino and Geysers #3-Geysers #5 115 kV lines | 883 (28) |

# Associated Ames/Pittsburg/Oakland Area : Requirement

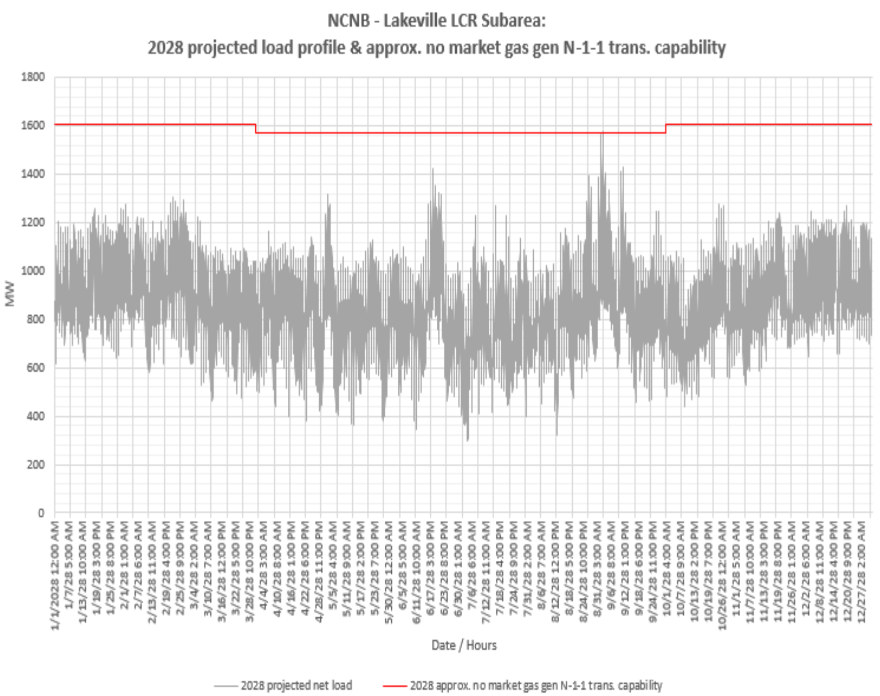
| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First limit | C | Ames-Ravenswood #1 115 kV line | Newark-Ravenswood & Tesla-Ravenswood 230 kV lines | 2022 |
| | | | Moraga-Claremont #2 115 kV line | Moraga-Sobrante & Moraga-Claremont #1 115 kV lines | |

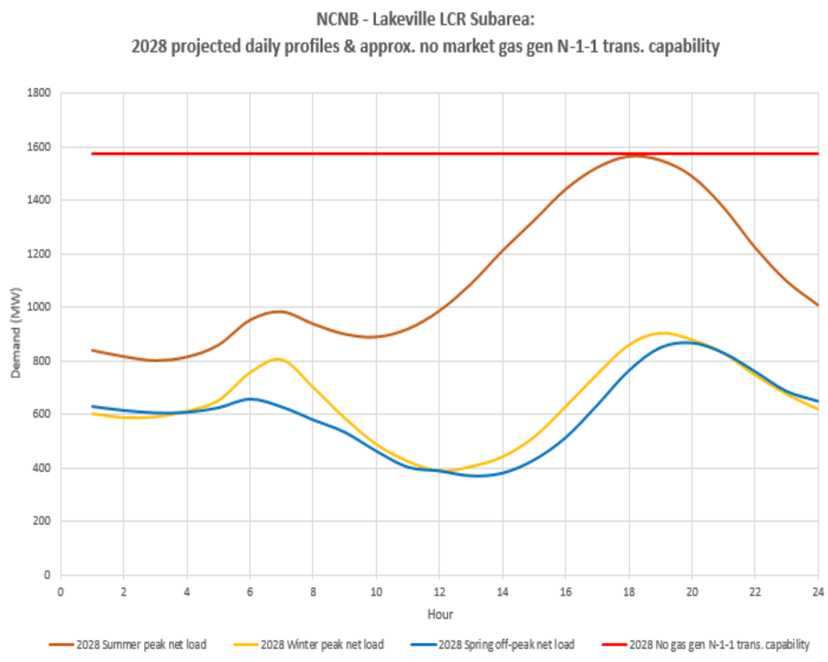
*Note: With Vaca Dixon-Lakeville and Vaca Dixon-Tulucay 230 kV lines reactors bypassed

# North Coast & Bay Area Transmission System



# Lakeville Sub Area : Load Profiles



# North Coast & North Bay Area
# Total LCR Need

| 2028 LCR Need | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW Need |
|---|---|---|---|
| Category B (Single) | 855 | 26 | 881 |
| Category C (Multiple) | 855 | 28 | 883 |

# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| Eagle Rock | 256 | 228 | 262 | 257 | 313 | 278 (28) |
| Fulton | 887 | 525 | 919 | 553 | N/A | N/A |
| Overall | 1465 | 689 | 1524 | 553 | 1587 | 883 (28) |

# 2028 Long-Term LCR Study Draft Results
# Humboldt

Emily Hughes

Regional Transmission Engineer

Stakeholder Meeting

September 20-21, 2018

# Humboldt Area

- Transmission tie lines into the area:
  - Bridgeville-Cottonwood 115 kV line
  - Humboldt-Trinity 115 kV line
  - Willits-Garberville 60 kV line
  - Trinity-Maple 60 kV line

# New major transmission projects

| Project Name | Expected ISD |
|---|---|
| Maple Creek Reactive Support (Install 10 Mvar SVC at Maple Creek Sub) | 2022 |
| Bridgeville – Garberville | On-hold |

# Power plant changes

Additions:

- Maple Creek Reactive Support
- Garberville Reactive Support
- Bridgeville 115/60 kV #1 transformer replacement

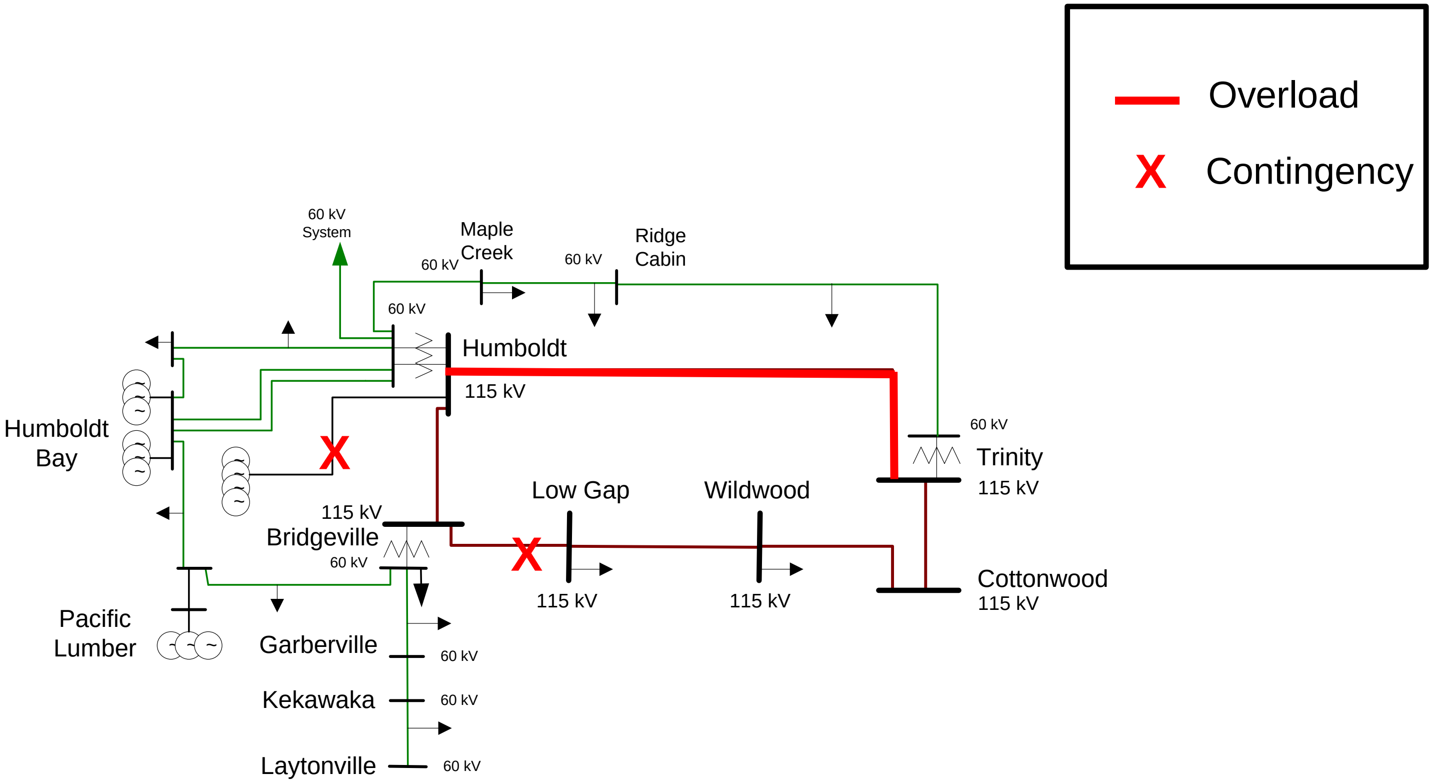
Retirements:

- Blue Lake

# Load and Resources

| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 183 | Market | 201 |
| AAEE | -9 | Wind | 0 |
| Behind the meter DG | 0 | Muni | 0 |
| **Net Load** | **174** | QF | 0 |
| Transmission Losses | 11 | **Total Qualifying Capacity** | **201** |
| Pumps | 0 | | |
| **Load + Losses + Pumps** | **185** | | |

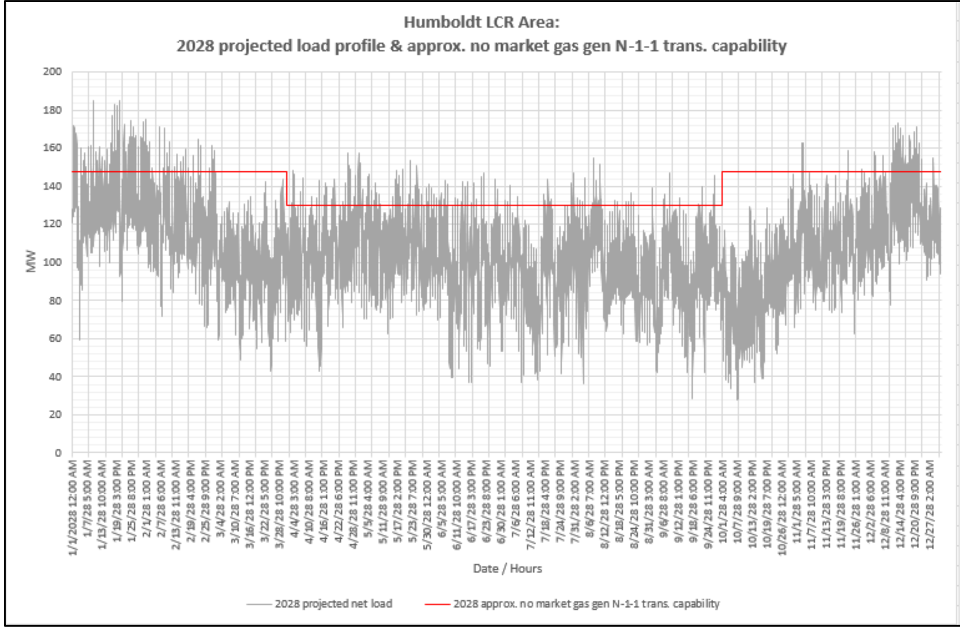
# Humboldt Area: One-line diagram

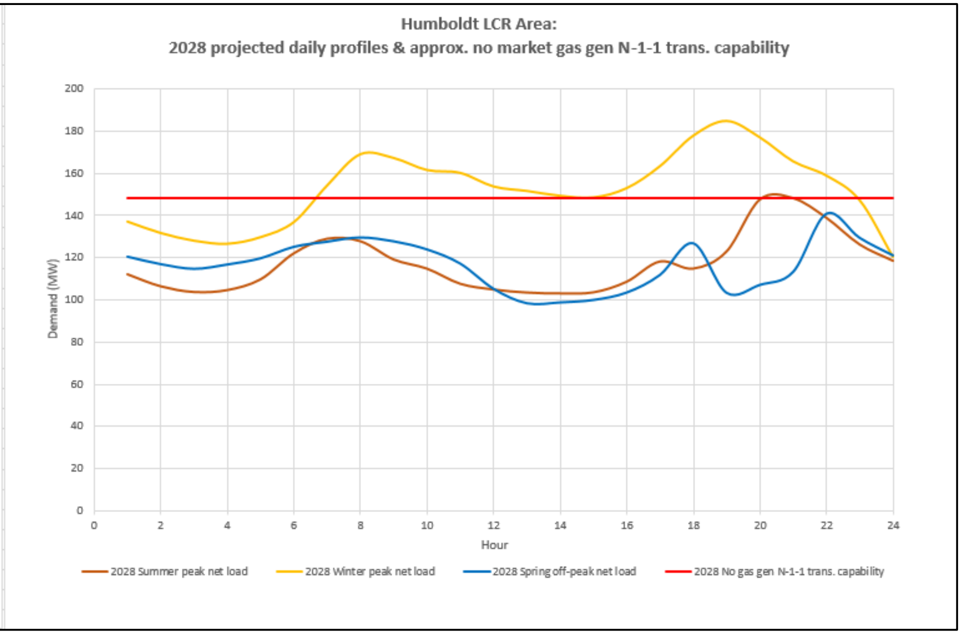


# Humboldt: Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) (Deficiency) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | Thermal overload of Humboldt-Trinity 115 kV | Cottonwood-Bridgeville 115kV line with one of the Humboldt Bay units already out of service. | 117 |
| 2028 | First Limit | C | Thermal overload of Humboldt-Trinity 115 kV | Cottonwood-Bridgeville and Humboldt - Humboldt Bay 115kV line. | 170 |

# Humboldt: Load Profiles



# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| Humboldt | 187 | 165 | 188 | 169 | 185 | 170 |

# 2028 Long-Term LCR Study Draft Results LA Basin and San Diego-Imperial Valley Areas

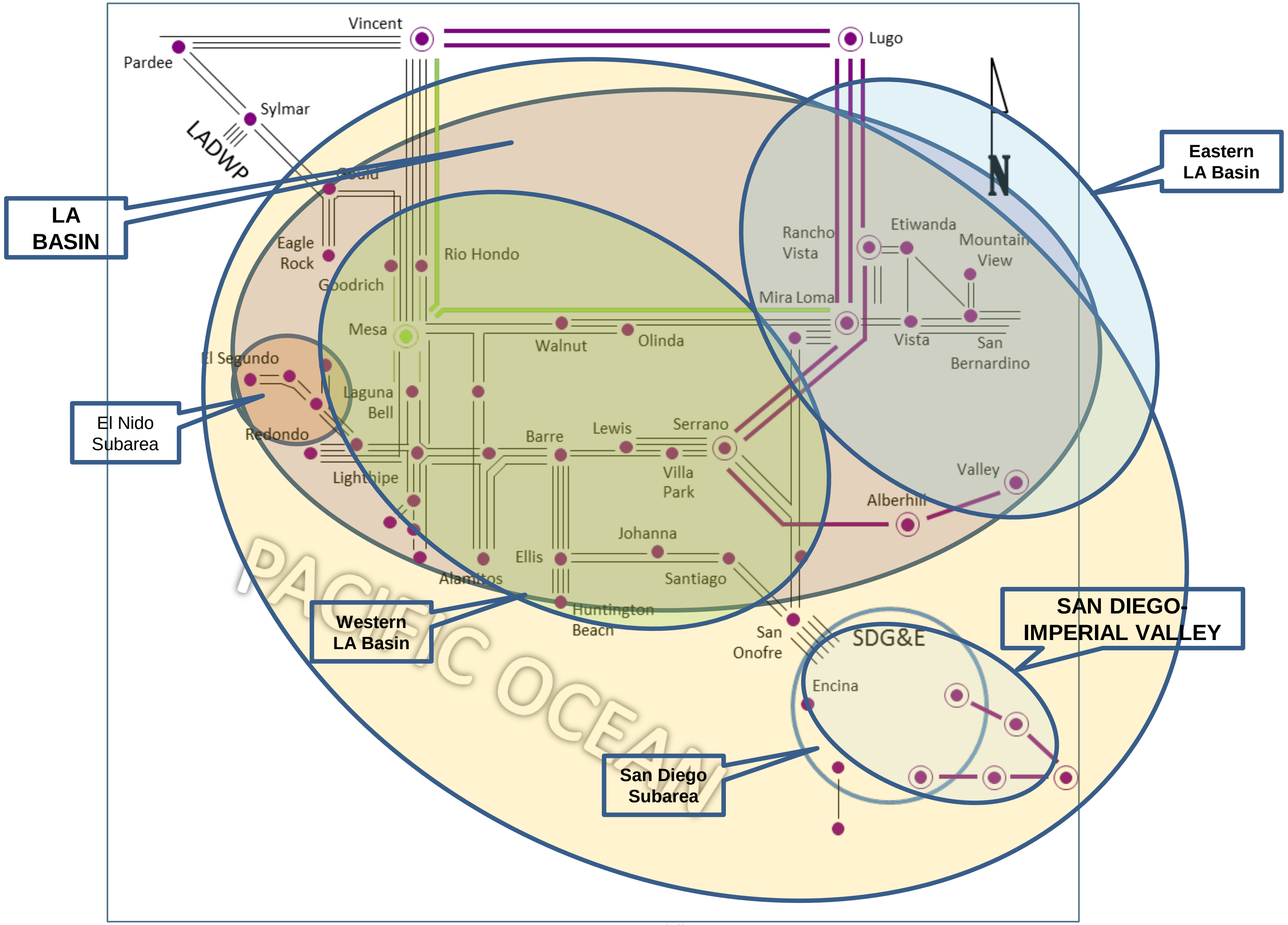
David Le

Senior Advisor - Regional Transmission Engineer

Stakeholder Meeting

September 20 - 21, 2018

# LA Basin and San Diego-Imperial Valley Areas



# New Major Transmission Upgrade Assumptions

- Sycamore – Penasquitos 230kV transmission line (August 2018)
- Bypassing series capacitors on the Imperial Valley – North Gila 500kV line, Sunrise and Southwest Powerlinks
  - Bypassing series capacitors is not a transmission upgrade but rather a major operational procedure assumption for peak load conditions
- Synchronous condensers in southern Orange County and San Diego area (i.e., Santiago, San Onofre, Talega, San Luis Rey and Miguel Substations)
- Mesa 500/230kV loop-in project (currently anticipated March 2022 in-service date)
- Imperial Valley – El Centro 230 kV (“S” line) upgrade (December 2021)

# Major Resource Assumptions

- Encina generation retirement (946 MW)
- Carlsbad Energy Center (500 MW) in-service by Q4 2018 (*CPUC LTPP LCR resource procurement*)
- Use of the existing 20-minute demand response in the LA Basin and San Diego areas
- Implementation of 432 MW of preferred resources (i.e., battery storage, demand response, energy efficiency) via the CPUC long-term procurement plan (LTPP) for the western LA Basin LCR need
- Battery energy storage projects in San Diego area (78 MW)
- Alamitos, Huntington Beach and Redondo Beach gas-fired generation retirement (total of 3,818 MW) to comply with the State Water Board's OTC Policy
- Alamitos and Huntington Beach repowering (1,284 MW) (*CPUC LTPP LCR resource procurement*)
- Stanton Energy Center (98 MW) with 10 MW battery energy storage system (*CPUC LTPP LCR resource procurement*)

# Loads and Resources
# LA Basin Area

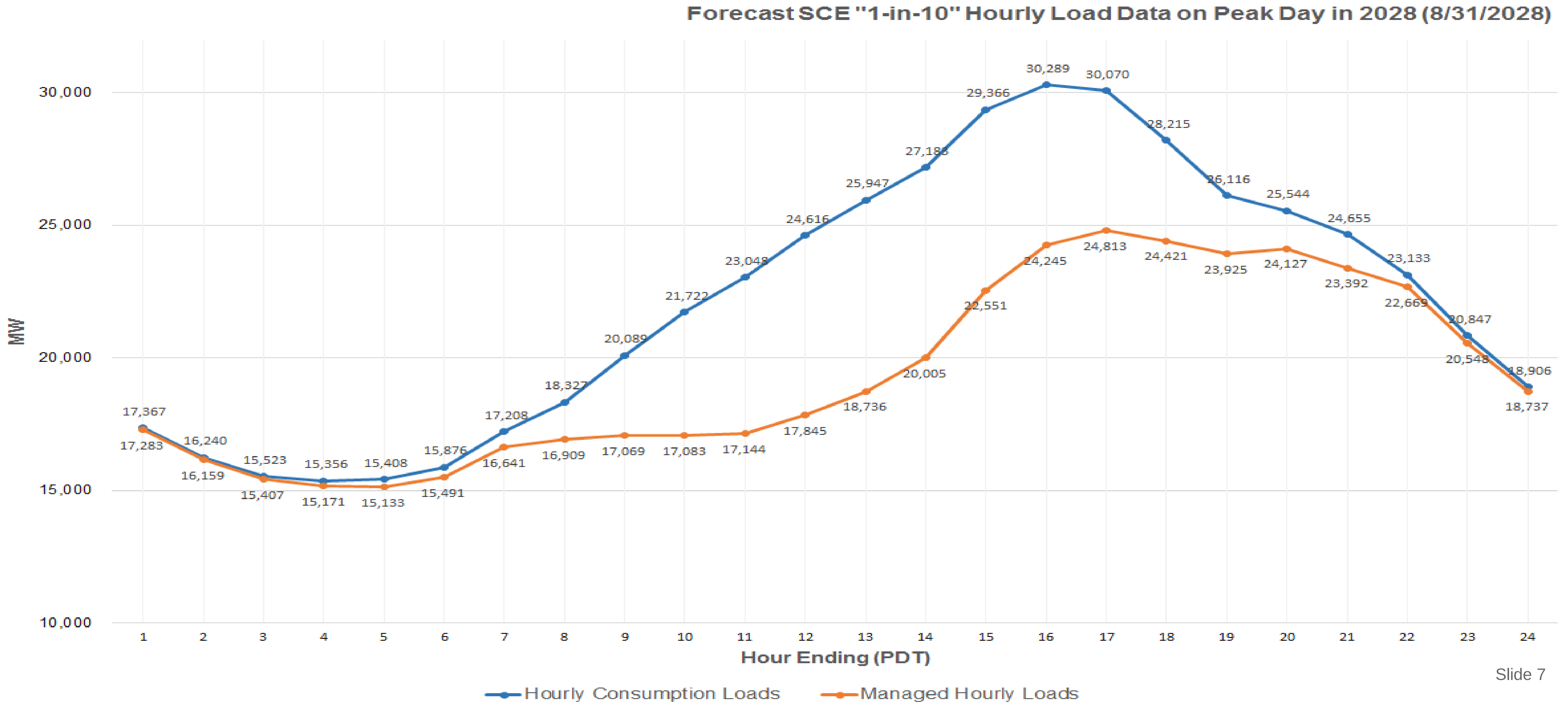
| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 23,604 | Market | 5,556 |
| AAEE + AAPV | -2,145 | Wind | 124 |
| Behind the meter DG (production) | -2,207 | Muni | 1,164 |
| **Net Load** | **19,252** | QF | 279 |
| Transmission Losses | 351 | LTPP Preferred Resources | 432 |
| Pumps | 22 | Existing 20-minute Demand Response | 294 |
| **Loads + Losses + Pumps** | **19,625** | Mothballed | 435 |
| | | **Total Qualifying Capacity** | **8,284** |

# Loads and Resources
# San Diego-Imperial Valley Area

| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 5,752 | Market (including solar generation) | 4,299 |
| AAEE + AAPV | -362 | Wind | 185 |
| Behind the meter DG (production) | -853 | Muni | 0 |
| **Net Load** | **4,537** | QF | 106 |
| Transmission Losses | 134 | Future preferred resource assumptions (EE, DR) | 23.64 |
| **Loads + Losses** | **4,671** | Existing 20-Minute Demand Response | 16 |
| | | Total battery energy storage procurement to date | 117 |
| | | **Total Qualifying Capacity** | **4,747** |

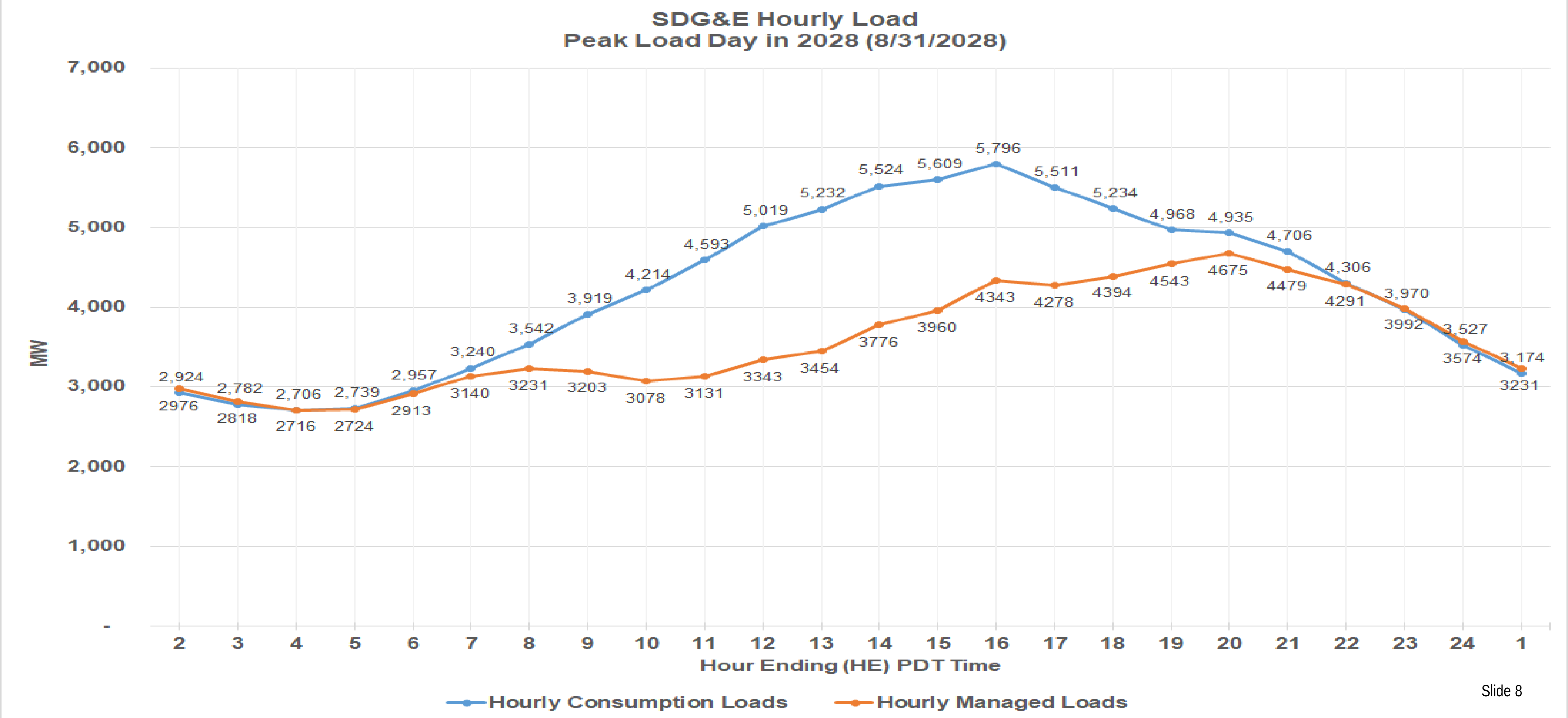
# SCE Service Area Load Profile

Hourly demand forecast for SCE service area on the peak day in 2028
(projected 1-in-10 load based on CEC 1-in-2 load forecast profile for peak day)



# SDG&E Load Profile

Hourly demand forecast for SDG&E service area on the peak day in 2028
(projected 1-in-10 load based on CEC 1-in-2 load forecast profile for peak day)



# Estimated factors to calculate simultaneous loads between SCE and SDG&E at each other's respective peak load hours

| Year | SCE peak demand | | | SDG&E @ SCE peak demand | | | SDG&E peak demand | | | SCE @ SDG&E peak demand | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Date/time (PDT)* | Hourly Managed Peak Demand (MW) from hourly plot | LSE/BA Table peak demand forecast (MW)** | Date/time (PDT)* | Hourly Managed Demand (MW) from hourly plot | % of own peak demand (from hourly managed demand plot) | Date/time (PDT)* | Hourly Managed Peak Demand (MW) from hourly plot (MW) | LSE/BA Table peak demand forecast (MW)** | Date/time (PDT)* | Hourly Managed Demand from hourly plot (MW) | % of own peak demand (from hourly managed demand plot) |
| **2028** | 8/31/2028 17:00 hr. | 24813 | 24716 | 8/31/2028 17:00 hr. | 4278 | 91.51% | 8/31/2028 20:00 hr. | 4675 | 4681 | 8/31/2028 20:00 hr. | 24127 | 97.24% |

Notes:

* All hour expressed in PDT hour ending (HE)

**Peak demand from the CEC posted 2017 CED Revised Forecast for LSE/BA Table for Mid Demand Level (1-in-10) with Low AAEE and AAPV

# El Nido Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | Thermal loading on La Fresa-La Cienega 230kV line | La Fresa – El Nido #3 & 4 230kV lines | 400 MW*^ |
| 2028 | N/A | B | None | Various contingencies | No requirements |
| 2023 (Informational) | First Limit | C | Thermal loading on La Fresa-La Cienega 230kV line | La Fresa – El Nido #3 & 4 230kV lines | 439 MW**^ |

Notes:

*This includes LTPP-procured preferred resources (21.6 MW of behind-the-meter storage, 18.4 MW EE, 1 MW DR) and 10.4 MW of existing 20-minute DR.

**This is a corrected value which includes LTPP-procured preferred resources (21.6 MW of behind-the-meter storage, 18.4 MW EE, 1 MW DR) and 12.5 MW of existing 20-minute DR.

^All procured resources in the El Nido subarea are also used toward meeting the western LA Basin LCR need.

# Western LA Basin Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | Thermal loading on the Mesa-Laguna Bell #1 230kV line | Mesa – Redondo #1 230 kV line, followed by Mesa - Lighthipe 230 kV line, or vice versa | 3,912* |
| 2028 | N/A | B | None-binding | Multiple combinations possible | N/A |
| 2023 (Informational) | First Limit | C | Thermal loading on the Mesa-Laguna Bell #1 230kV line | Mesa – Redondo #1 230 kV line, followed by Mesa - Lighthipe 230 kV line, or vice versa | 3,970** |

Notes:

*This includes 153.8 of existing 20-minute DR, 431.7 MW of CPUC-approved LTPP Track 4 preferred resources (i.e., DR, EE, BESS), 105 MW of PRP (DR and BESS) and 12 MW of existing BESS)

**This includes 162 MW of existing DR and 432 MW of CPUC-approved LTPP preferred resources for LCR need

# Eastern LA Basin Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | Post-transient voltage stability | Serrano-Valley 500kV line, followed by Devers – Red Bluff 500kV #1 and 2 lines | 2,678* |
| 2028 | N/A | B | None-binding | Multiple combinations possible | N/A |
| 2023 (Informational) | First Limit | C | Post-transient voltage stability | Serrano-Valley 500kV line, followed by Devers – Red Bluff 500kV #1 and 2 lines | 2,702** |

Notes:

*This includes 140.6 MW of existing 20-minute demand response and 50 MW of existing BESS.

**This includes 159 MW of existing 20-minute demand response.

# Combined Overall LA Basin and San Diego-Imperial Valley LCR Assessment

# San Diego Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | Thermal loading concern on the remaining Sycamore-Suncrest 230 kV line | N-1/N-1 ECO-Miguel 500 kV line, system readjustment, followed by one of the Sycamore-Suncrest 230 kV lines | 2,362* |
| 2028 | N/A | B | None-binding | Multiple combinations possible | N/A |
| 2023 (Informational) | First Limit | C | Thermal loading concern on the remaining Sycamore-Suncrest 230 kV line | N-1/N-1 ECO-Miguel 500 kV line, system readjustment, followed by one of the Sycamore-Suncrest 230 kV lines | 2,731** |

Notes:

*This includes 79.5 MW of procured BESS, 16 MW existing DR MW existing DR, 4.6 MW future DR, 19 MW future EE (beyond AAEE), 77.5 MW of existing BESS

- The 2028 LCR need is projected to be lower due to curtailment of generation connected to Imperial Valley 230kV switchyard (part of the recently approved RAS for Sycamore-Suncrest 230kV lines).
- The new RAS includes curtailment of approximately total of 1,800 MW of gas-fired and renewable generation connecting to Imperial Valley and vicinity substations. This is needed to reduce loading on the identified 230kV line.

**This includes 77.5 MW of BESS

# Overall San Diego – Imperial Valley Area

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | B/C | El Centro 230/92 kV transformer thermal loading | G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1) | 3,908 MW* |
| 2023 (Informational) | First Limit | B/C | El Centro 230/92 kV transformer thermal loading | G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1) | 4,132 MW** |

Notes:

*This includes 79.5 MW of procured BESS, 16 MW of existing DR, 4.6 MW future DR, 19 MW future EE (beyond AAEE), 77.5 MW of existing BESS

- The 2018 ELCC/NQC for grid-connected solar generation is modeled due to unavailability of ELCC/NQC for long-term study
- Potential lower ELCC/NQC to reflect peak shift to later timeframe will affect the study results

**This includes 77.5 MW of existing BESS

# Overall San Diego – Imperial Valley Total LCR

| 2028 LCR Need | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total LCR (MW) |
|---|---|---|---|
| Category B (Single) | 3,908 | 0 | 3,908 |
| Category C (Multiple) | 3,908 | 0 | 3,908 |

Notes:

- 2028 load forecast is higher by 127 MW compared to 2023 load forecast.
- However, LCR need is decreased by 224 MW due to addition of resources in the effective locations for the most limiting contingency.
- An important assumption is the continued use of the 2018 NQC (technology factor) for grid-connected solar generation due to unavailability of ELCC/NQC for long-term study. If this assumption changes, it will affect the LCR for the overall San Diego-Imperial Valley area.

# Overall LA Basin LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | Mesa – Laguna Bell #1 230 kV line | N-1 of Mesa – Redondo 230 kV line, system readjustment, followed by N-1 of Mesa - Lighthipe 230 kV line out | 6,590* |
| 2028 | First Limit | B | El Centro 230/92 kV transformer thermal loading | G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1) | 5,526 MW** |
| 2028 | Second Limit | B | Mesa – Laguna Bell #1 230kV line | G-1 of Huntington Beach CCGT, followed by N-1 of Mesa – Laguna Bell #2 230kV line | 5,326 MW* |
| 2023 (Informational) | First Limit | C | Mesa – Laguna Bell #1 230 kV line | N-1 of Mesa – Redondo 230 kV line, system readjustment, followed by N-1 of Mesa - Lighthipe 230 kV line out | 6,634*** |

Notes:

*This includes 294 MW of 20-minute DR, 432 MW of CPUC-approved LTPP LCR preferred resources, 62 MW of existing BESS, 45 MW PRP DR, 60 MW PRP BESS

- The 2028 LCR need is lower than the need for 2023, primarily due to lower demand forecast

**This includes 294 MW of 20-minute DR, 432 MW of CPUC-approved LTPP LCR preferred resources, 62 MW of existing BESS, 45 MW PRP DR and 60 MW PRP BESS

***This includes 321 MW of 20-minute DR and 432 MW of CPUC-approved LTPP LCR preferred resources

# Overall LA Basin LCR

| 2028 LCR Need | Existing Resource Capacity Needed (MW) | Deficiency (MW) | Total LCR (MW) |
|---|---|---|---|
| Category B (Single) | 5,526 | 0 | 5,526 |
| Category C (Multiple) | 6,538 | 0 | 6,590 |

<u>Notes:</u>

- 2028 load forecast is lower by 509 MW compared to 2023 load forecast
- LCR need has decreased by 44 MW due to lower demand forecast
- However, the LCR decrease is modest due to the following:
  - ❖ Lower LCR for the overall San Diego – Imperial Valley area (achievable due to addition of resources in effective locations even with slightly higher load forecast for San Diego area)
  - ❖ Note that 2018 NQC for grid-connected solar is assumed for this study due to unavailability of ELCC/NQC for long-term study
- The available resources in the western LA Basin area are highly utilized to meet local capacity needs after retirements of once-through-cooled coastal gas-fired generation

# Changes Compared to Previous LCR Requirements

| Subarea/Area | 2019 | | 2023 | | 2028 | | Comments |
|---|---|---|---|---|---|---|---|
| | Loads + Losses (MW) | LCR* (MW) | Loads + Losses (MW) | LCR* (MW) | Loads + Losses (MW) | LCR* (MW) | |
| El Nido Subarea | 1,611 | 421 | 1,614 | 439 | 1,466 | 400 | Lower LCR (2018) due to lower load forecast |
| Western LA Basin Subarea | 11,635 | 3,993 | 11,681 | 3,970 | 11,141 | 3,912 | Lower LCR due to lower load forecast; however, there are less resources dispatched in S/D area. |
| Eastern LA Basin Subarea | 7,390 | 2,956 | 7,428 | 2,702 | 7,371 | 2,678 | Lower LCR due to lower load forecast and implementation of new transmission project (Mesa loop-in project) |
| Overall LA Basin | 20,075 | 8,116 | 20,072 | 6,793 | 19,625 | 6,590 | See above comments |
| San Diego Subarea | 4,412 | 2,417 | 4,535 | 2,731 | 4,671 | 2,362 | Implementation of recently approved RAS |
| Overall San Diego-Imperial Valley Area | 4,412 | 4,026** | 4,535 | 4,132** | 4,671 | 3,908** | More resources materialize in effective area |

Notes:

*Maximum value from Category C or B requirements.

**Solar generation 2018 NQC values are modeled. Long-term NQC values are not yet available.

# Sensitivity Assessment for the Absence of Solar Generation for Evening Peak Load Hour

# Overall San Diego – Imperial Valley Area

| Year | Limit | Category | Limiting Facility | Contingency | LCR | Deficiency |
|---|---|---|---|---|---|---|
| 2028 | First Limit (No Solar) | B/C | El Centro 230/92 kV transformer thermal loading | G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1) | 4,110 MW* | -133 MW* |
| 2028 | First Limit (No Solar) | B/C | El Centro 230/92 kV transformer thermal loading | G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1) | 3,977 MW** | 0 MW |
| 2028 | First Limit (Solar modeled at 2018 NQC) | B/C | El Centro 230/92 kV transformer thermal loading | G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1) | 3,908 MW* | 0 MW |

Notes:

*This includes 79.5 MW of procured BESS, 16 MW of existing DR, 4.6 MW future DR, 19 MW future EE (beyond AAEE), 77.5 MW of existing BESS and 133 MW of deficient resources at effective location in San Diego – Imperial Valley area

- A total of 893 MW of preferred resources (i.e., DR, EE, BESS) in the LA Basin was also utilized for mitigating this thermal loading concern

**Additional LA Basin resources (284 MW), in addition to 893 MW of preferred resources, were dispatched to help mitigating resource deficiency for the San Diego-Imperial Valley area

# Overall LA Basin LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit (No Solar) | B/C | El Centro 230/92 kV transformer thermal loading | G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1) | 6,874 MW* |

Notes:

- *This includes 294 MW of 20-minute DR, 432 MW of CPUC-approved LTPP LCR preferred resources, 62 MW of existing BESS, 45 MW PRP DR, 60 MW PRP BESS.
- The additional resources in the LA Basin are dispatched to provide mitigation to cure deficiency for the San Diego-Imperial Valley area under the “No Solar” scenario for peak load shifting to evening timeframe (i.e., 8 p.m.).

# THANK YOU

**Your comments and questions are welcome.**

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

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# 2028 Long-Term LCR Study Draft Results
# Big Creek – Ventura Area

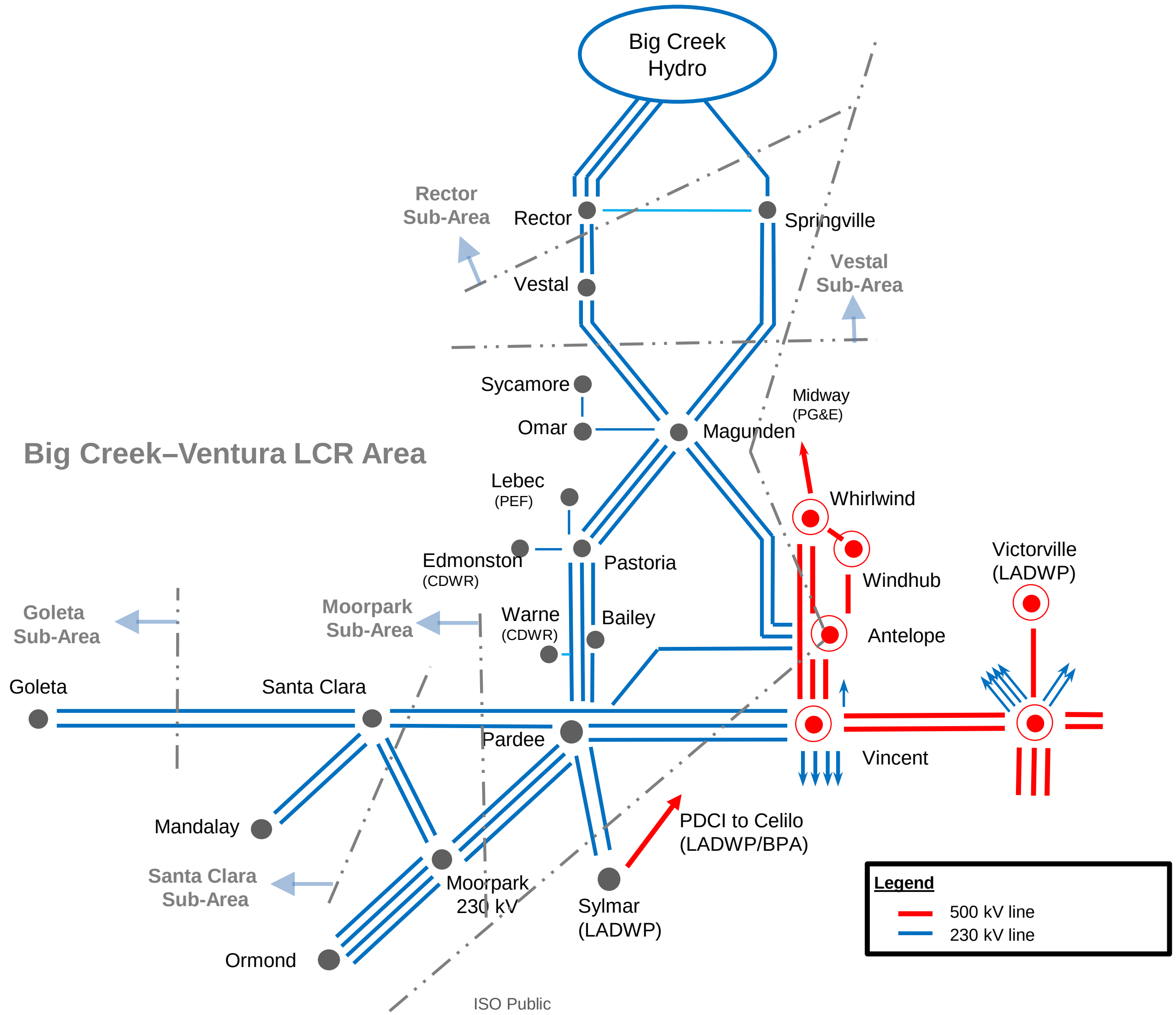
Nebiyu Yimer

Regional Transmission Engineer Lead

Stakeholder Meeting

September 20-21, 2018

# Bic Creek - Ventura Area Transmission System



# New major transmission projects

- Big Creek Corridor Rating Increase Project
- Pardee-Moorpark No. 4 230 kV Transmission Project

# Resource Assumptions

- Mandalay, Ormond Beach and Ellwood retired (total of 2100 MW)

- The Las Flores Canyon Cogeneration Facility (EXGEN) has been OOS since 2015 and is assumed to be unavailable.

# Load and Resources

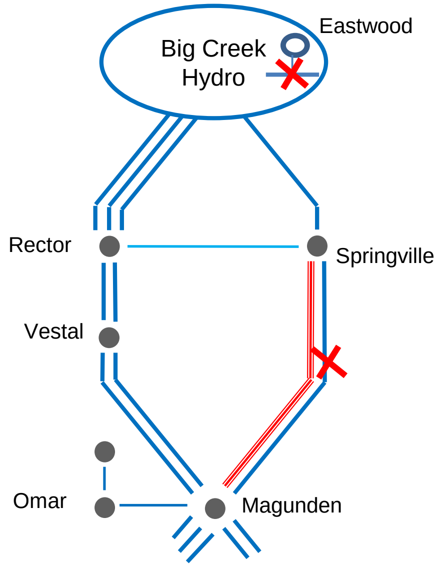
| Load (MW) | | Generation (MW) | |
|---|---|---|---|
| Gross Load | 5456 | Market | 2975 |
| AAEE | -301 | Pref. Res & ES | 112 |
| Behind the meter DG | -609 | Muni | 372 |
| **Net Load** | **4547** | QF | 52 |
| Transmission Losses | 105 | **Total Qualifying Capacity** | **3511** |
| Pumps | 379 | | |
| **Load + Losses + Pumps** | **5031** | | |

# Rector Sub-Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | LCR for Rector is satisfied by the LCR of the larger Vestal sub-area | | | | |

# Vestal Sub-Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | B/C | Magunden–Springville #2 230 kV line | Magunden–Springville #1 230 kV line with Eastwood out of service | 465 |
| 2028 | Second Limit | B/C | Magunden–Vestal #1 or #2 230 kV line | One Magunden–Vestal 230 kV line with Eastwood out of service | 453 |

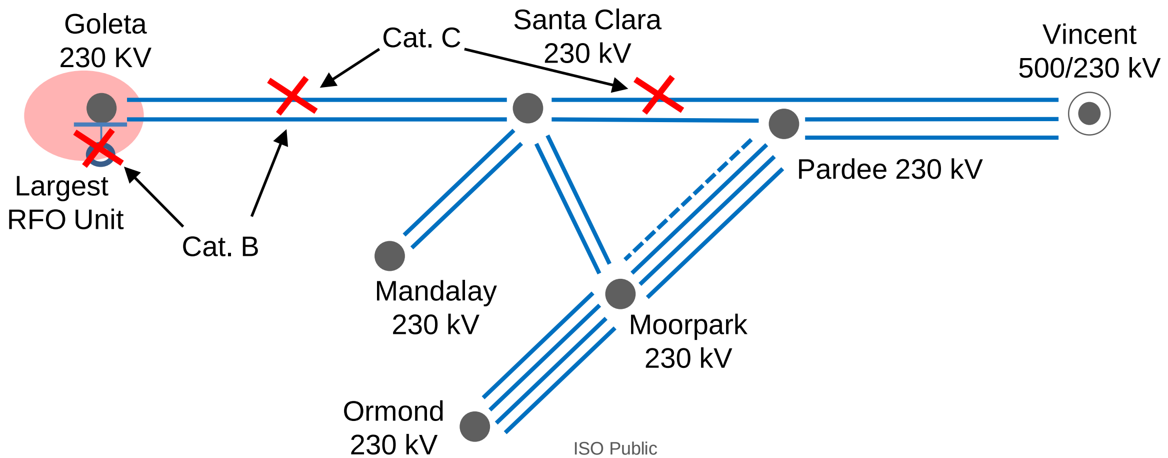


# Goleta Sub-Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | Goleta 230 kV bus (Low voltage) | Santa Clara–Goleta 230 kV line with largest resource at Goleta out of service | 32 MW plus largest resource at Goleta(1) |
| 2028 | First Limit | C | Goleta 230 kV bus (Low voltage) | Overlapping outage of Santa Clara–Goleta and Vincent–Santa Clara 230 kV lines(2) | 42 MW(1) |

(1) Generic resources with reactive capability are assumed at Goleta to meet the local capacity deficiency.

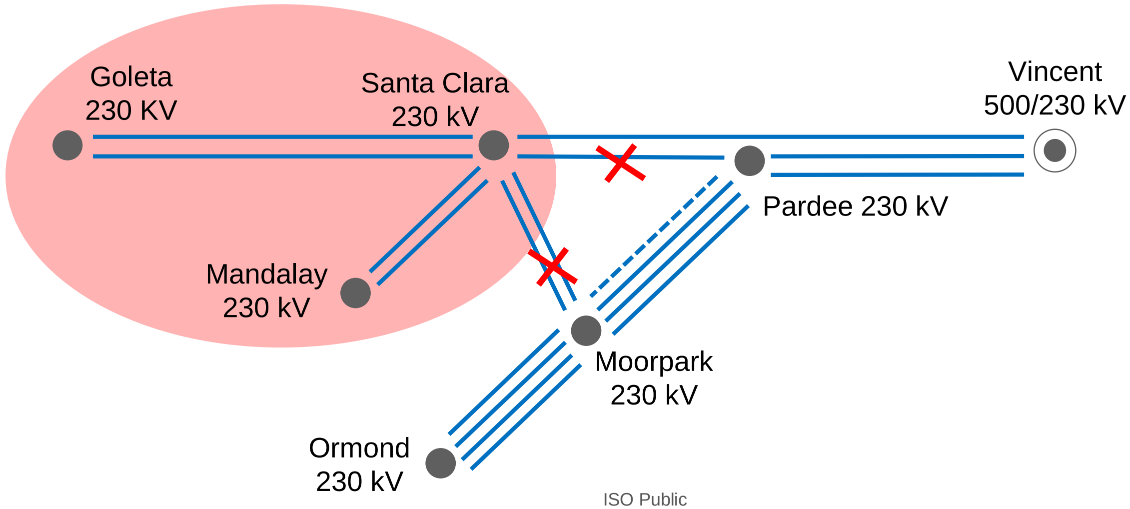
(2) The worst TPL 001-4 (Category P6) contingency is overlapping outage of Santa Clara shunt capacitor and the Santa Clara–Goleta 230 kV line. This would require 67 MW of local capacity. However, this contingency is not an LCR criteria contingency.



# Santa Clara Sub-Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | None | None | No requirement |
| 2028 | First Limit | D | Voltage Collapse | Pardee–Santa Clara 230 kV line followed by Moorpark–Santa Clara #1 and #2 230 kV DCTL | 318(1) |

(1) 120 MW of generic resources with reactive capability are assumed at Goleta to meet the local capacity deficiency. For locational and reactive power effectiveness information, see http://www.caiso.com/Documents/2023LocalCapacityTechnicalAnalysisfortheSantaClaraSub-Area.pdf



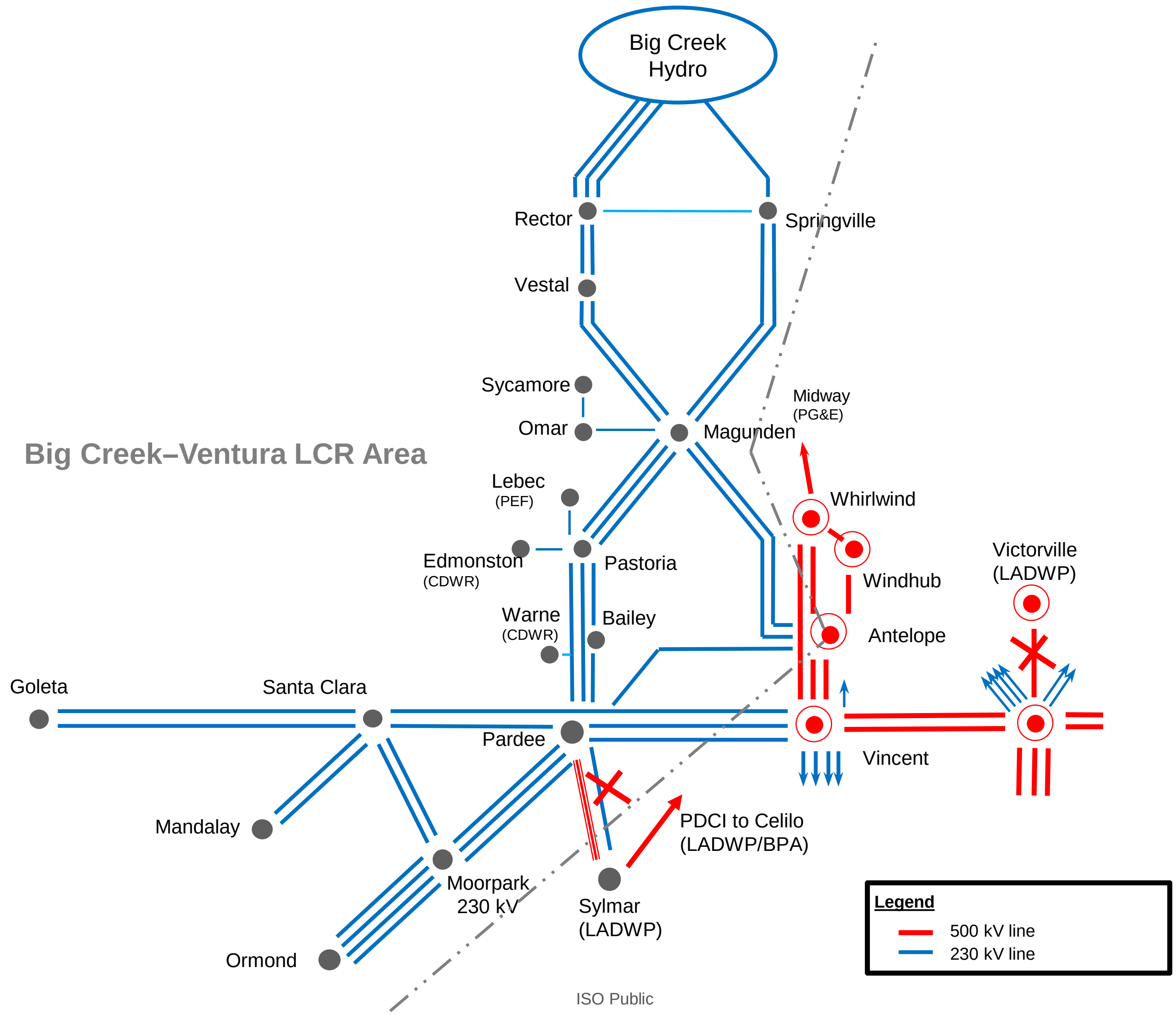
# Moorpark Sub-Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | No requirement due to the Pardee–Moorpark No. 4 230 kV Transmission Project | | | | |

# Overall Big Creek-Ventura Area Requirements

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | B | Sylmar–Pardee #1 or #2 230 kV line | One Sylmar–Pardee 230 kV line with Pastoria combined cycle module out of service. | 2,095 |
| 2028 | First Limit | C | Sylmar-Pardee #1 or #2 230 kV line | Overlapping outage of Lugo–Victorville 500 kV line and one Sylmar–Pardee 230 kV line | 2,251 |

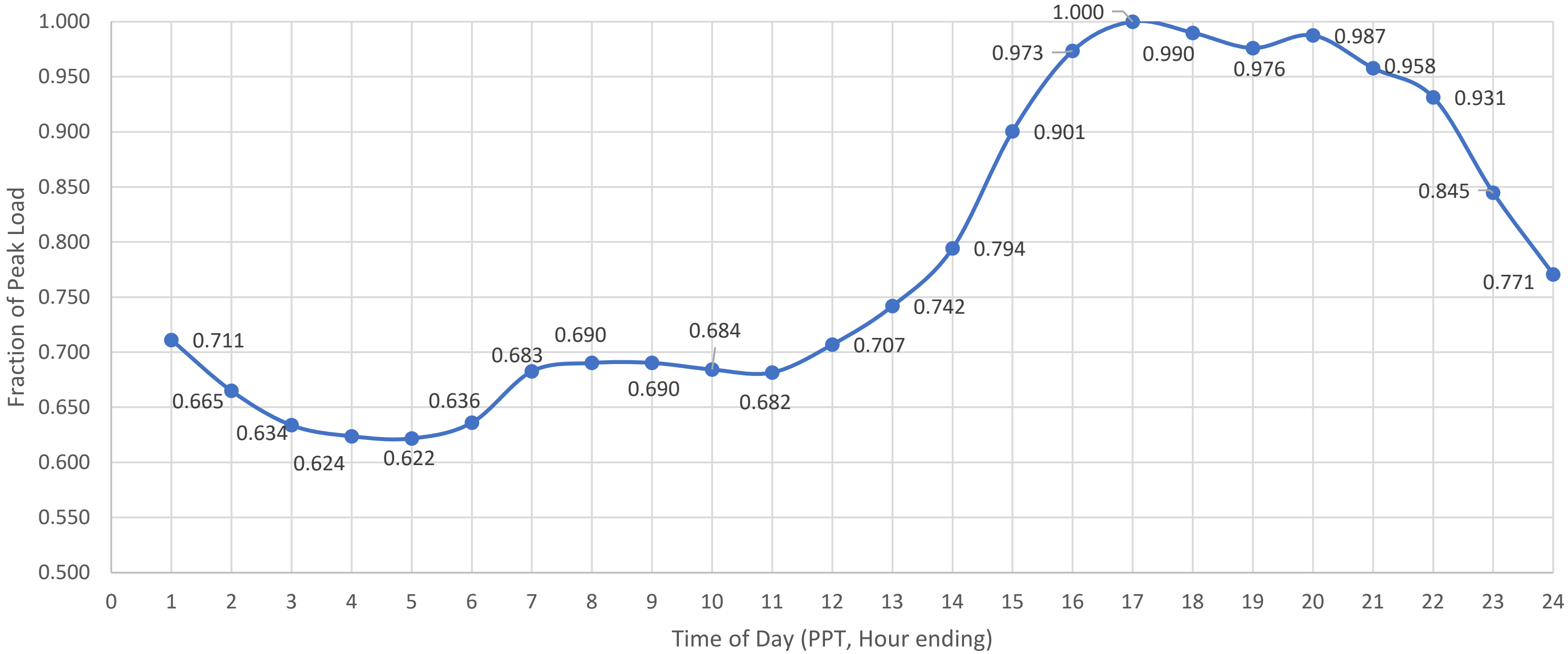
# Overall Big Creek-Ventura Area Constraints



# Big Creek Area Total LCR Need

| 2028 LCR Need | Existing Generation Capacity Needed (MW) | Deficiency (MW) | Total MW Need |
|---|---|---|---|
| Category B (Single) | 2,095 | 0 | 2,095 |
| Category C (Multiple) | 2,131 | 120 | 2,251 |

# 2028 SCE Area Load Profile (CEC)




| 2028 Peak LCA and Sub-Area Load, MW (includes losses) | | | | | |
|---|---|---|---|---|---|
| Rector | Vestal | Goleta | Santa Clara | Moorpark | BCV |
| 834 | 1,352 | 308 | 875 | 1,754 | 5,031 |

# Changes Compared to Previous LCR Results

| Sub-Area | 2019 | | 2023 | | 2028 | | Reason for LCR Change |
|---|---|---|---|---|---|---|---|
| | Load (MW) | LCR (MW) | Load (MW) | LCR (MW) | Load (MW) | LCR (MW) | |
| Rector | 900 | N/A | 887 | N/A | 834 | N/A | N/A |
| Vestal | 1520 | 621 | 1481 | 621 | 1352 | 465 | Load decrease |
| Goleta | 360 | N/A | 346 | N/A | 308 | Larger of 42 MW or 32 MW plus largest RFO unit | New sub-area |
| Santa Clara | 864 | 237 | 927 | 295-316 | 875 | 318 | Reactive power representation of generic DG resources |
| Moorpark | 1740 | 433 | 1768 | 0 | 1754 | 0 | Pardee–Moorpark Project |
| Overall Big Creek Ventura | 5162 | 2,614 | 5169 | 2,690 | 5031 | 2251 | Load decrease and other system changes |

# 2028 Long-Term LCR Study Draft Results
# San Diego-Imperial Valley Non-Bulk Subareas

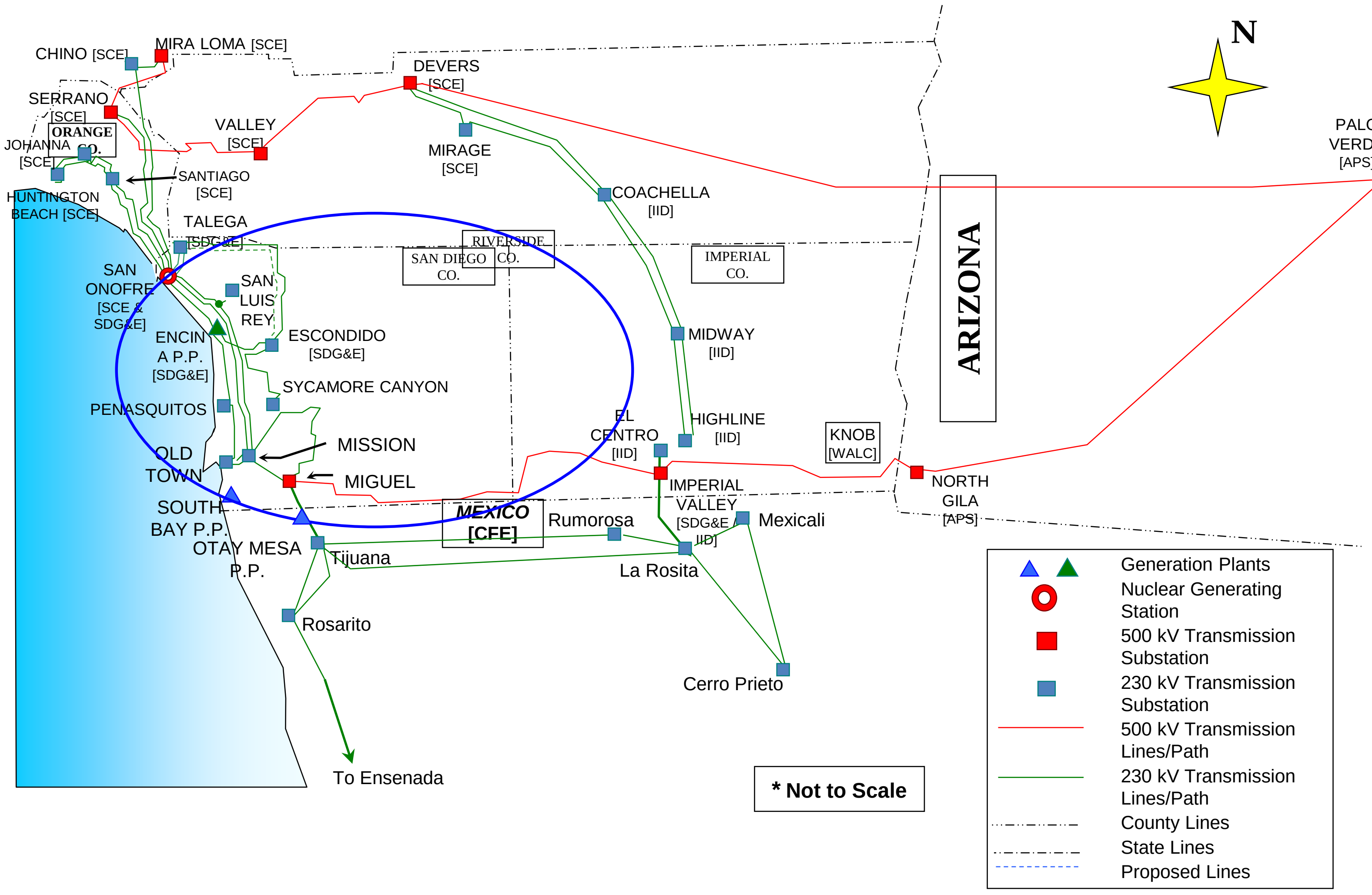
Meng Zhang

Senior Regional Transmission Engineer

Stakeholder Meeting

September 20 - 21, 2018

# San Diego-Imperial Valley LCR Area



# New Major Transmission Upgrade Assumptions

1. Ocean Ranch 69 kV substation
3. Mesa Height TL600 Loop-in
4. Re-conductor of Mission-Mesa Heights 69 kV
4. Re-conductor of Kearny-Mission 69 kV line
5. TL6906 Mesa Rim rearrangement
6. Upgrade Bernardo - Rancho Carmel 69kV line
7. Re-conductor of Japanes Mesa–Basilone–Talega Tap 69 kV lines
8. 2nd Miguel–Bay Boulevard 230 kV line
9. Sycamore–Penasquitos 230kV line
10. 2$^{nd}$ Mission 230/69 kV bank
11. Suncrest SVC project
12. By-passing 500 kV series capacitor banks on SWPL and SPL
13. Encina generation retirement
14. Carlsbad Energy Center (5x100 MW)
15. Battery energy storage projects (total of 78 MW)

# Continued…

16. TL632 Granite loop-in and TL6914 reconfiguration
17. 2nd San Marcos–Escondido 69kV line
18. Reconductor of Stuart Tap–Las Pulgas 69 kV line (TL690E)
19. 2nd Poway–Pomerado 69 kV line
20. Artesian 230 kV expansion with 69kV upgrade
21. South Orange County Reliability Enhancement
22. Imperial Valley bank #80 replacement

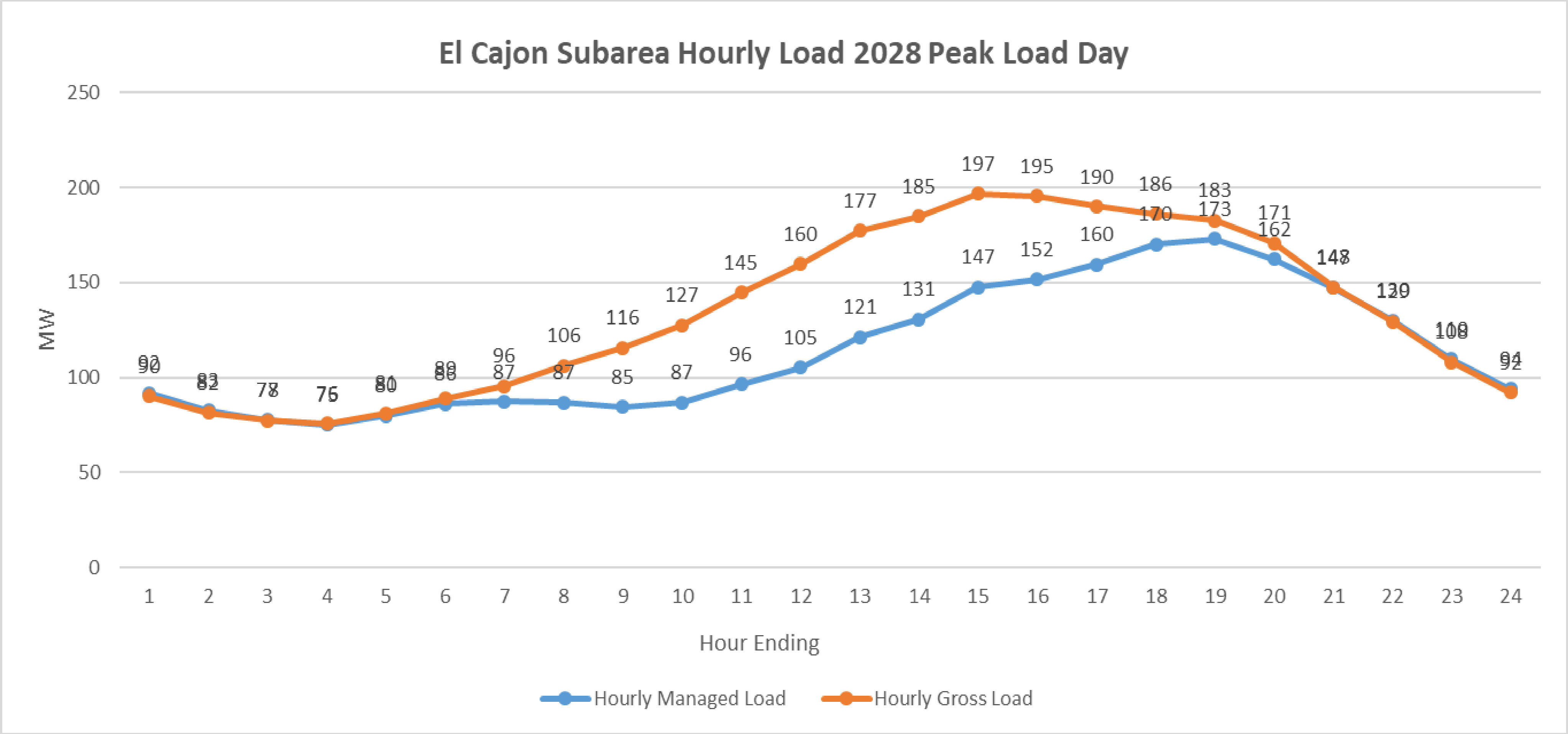
## Subareas Studied:

El Cajon sub-area
Esco sub-area
Pala sub-area
Border sub-area
Mission sub-area
Miramar sub-area

# El Cajon Subarea Loads and Resources

| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 177 | Market (including solar generation) | 93.52 |
| AAEE + AAPV | -6 | Wind | 0 |
| Behind the meter DG (production) | 0 | Muni | 0 |
| **Net Load** | **171** | QF | 0 |
| Transmission Losses | 2 | Future preferred resource assumptions (EE, DR) | 2.5 |
| **Loads + Losses** | **173** | Existing 20-Minute Demand Response | 4.28 |
| | | Total battery energy storage procurement to date | 7.5 |
| | | **Total Qualifying Capacity** | **107.8** |

# El Cajon Subarea Load Profile



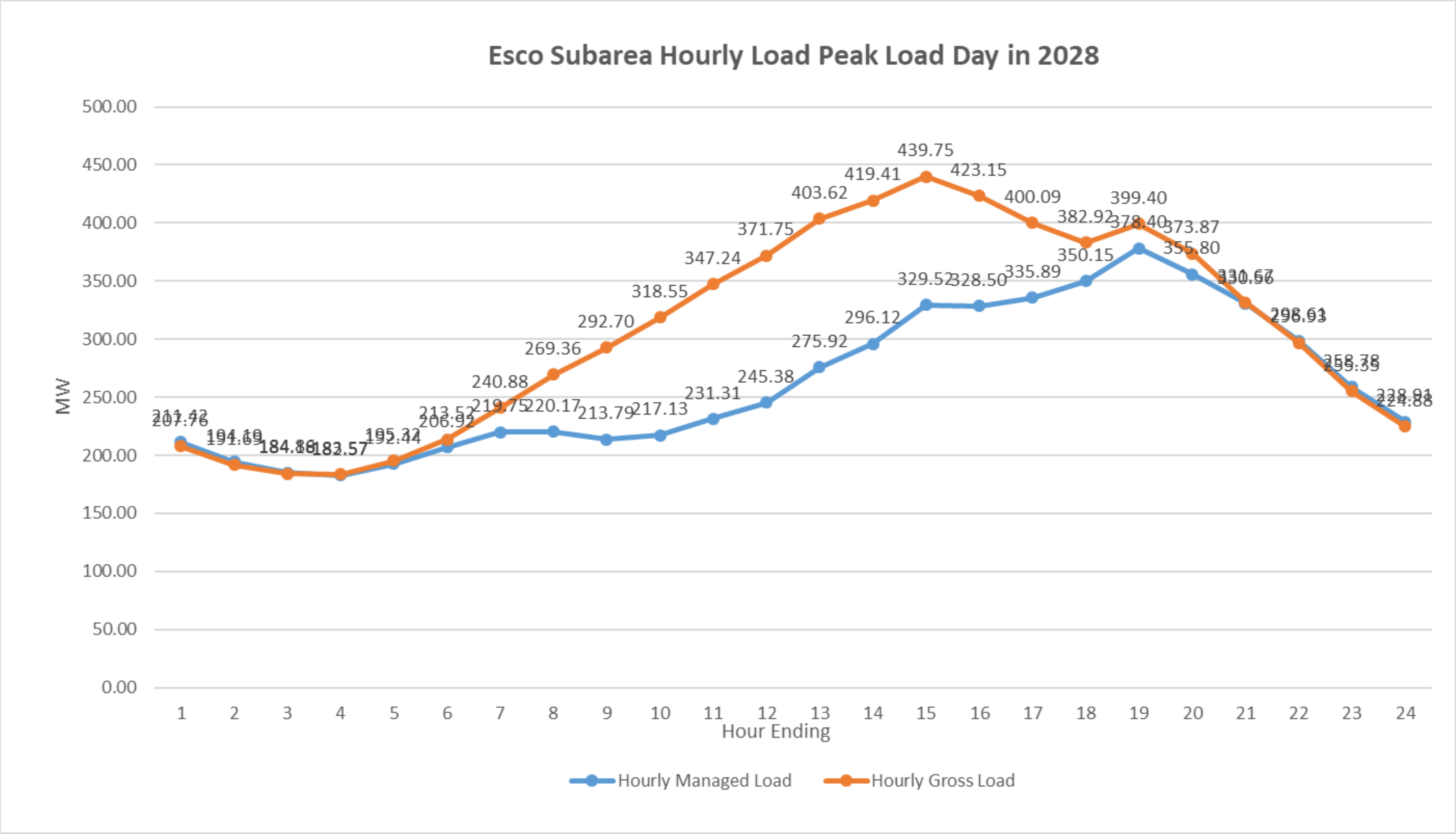
# El Cajon Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | El Cajon-Los Coches 69kV line (TL631) | Granite-Los Coches 69kV Nos.1&2 lines | 76MW |
| 2023 (Informational) | First Limit | C | El Cajon-Los Coches 69kV line (TL631) | Granite-Los Coches 69kV Nos.1&2 lines | 35MW |

# Esco Subarea Loads and Resources

| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 399.2 | Market (including solar generation) | 133.12 |
| AAEE + AAPV | -21.8 | Wind | 0 |
| Behind the meter DG (production) | 0 | Muni | 0 |
| **Net Load** | **377.4** | QF | 0 |
| Transmission Losses | 1 | Future preferred resource assumptions (EE, DR) | 1.08 |
| **Loads + Losses** | **378.4** | Existing 20-Minute Demand Response | 2.14 |
| | | Total battery energy storage procurement to date | 70 |
| | | **Total Qualifying Capacity** | **206.34** |

# Esco Subarea Load Profile




![California ISO]

ISO Public

# Esco Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | None | N/A | None | None | 0* |
| 2023 (Informational) | First Limit | C | The remaining Sycamore-Pomerado 69kV line | One of the two Sycamore-Pomerado 69kV lines (TK6915 or TL6924) and Artesian 230/69kV bank | 20MW |

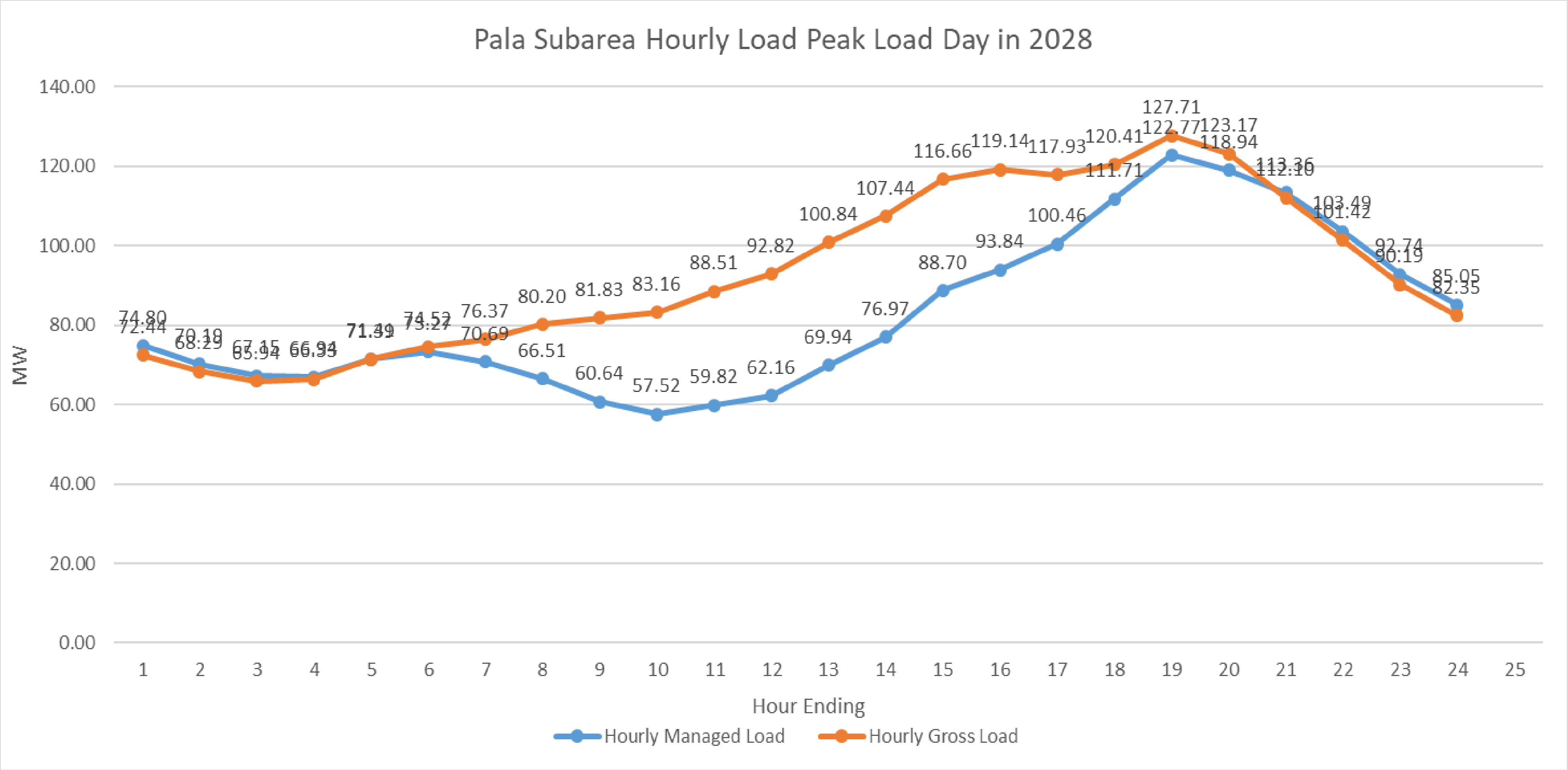
Notes:

* All three Palomar units are on-line in 2028 LCR case. If only one unit is on-line (same as assumption as 2023 LCR study), the LCR requirement would be 80MW.

# Pala Subarea Loads and Resources

| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 128.92 | Market (including solar generation) | 100.04 |
| AAEE + AAPV | -7.84 | Wind | 0 |
| Behind the meter DG (production) | 0 | Muni | 0 |
| **Net Load** | **121.08** | QF | 0 |
| Transmission Losses | 1.69 | Future preferred resource assumptions (EE, DR) | 0 |
| **Loads + Losses** | **122.77** | Existing 20-Minute Demand Response | 0 |
| | | Total battery energy storage procurement to date | 0 |
| | | **Total Qualifying Capacity** | **100.04** |

# Pala Subarea Load Profile



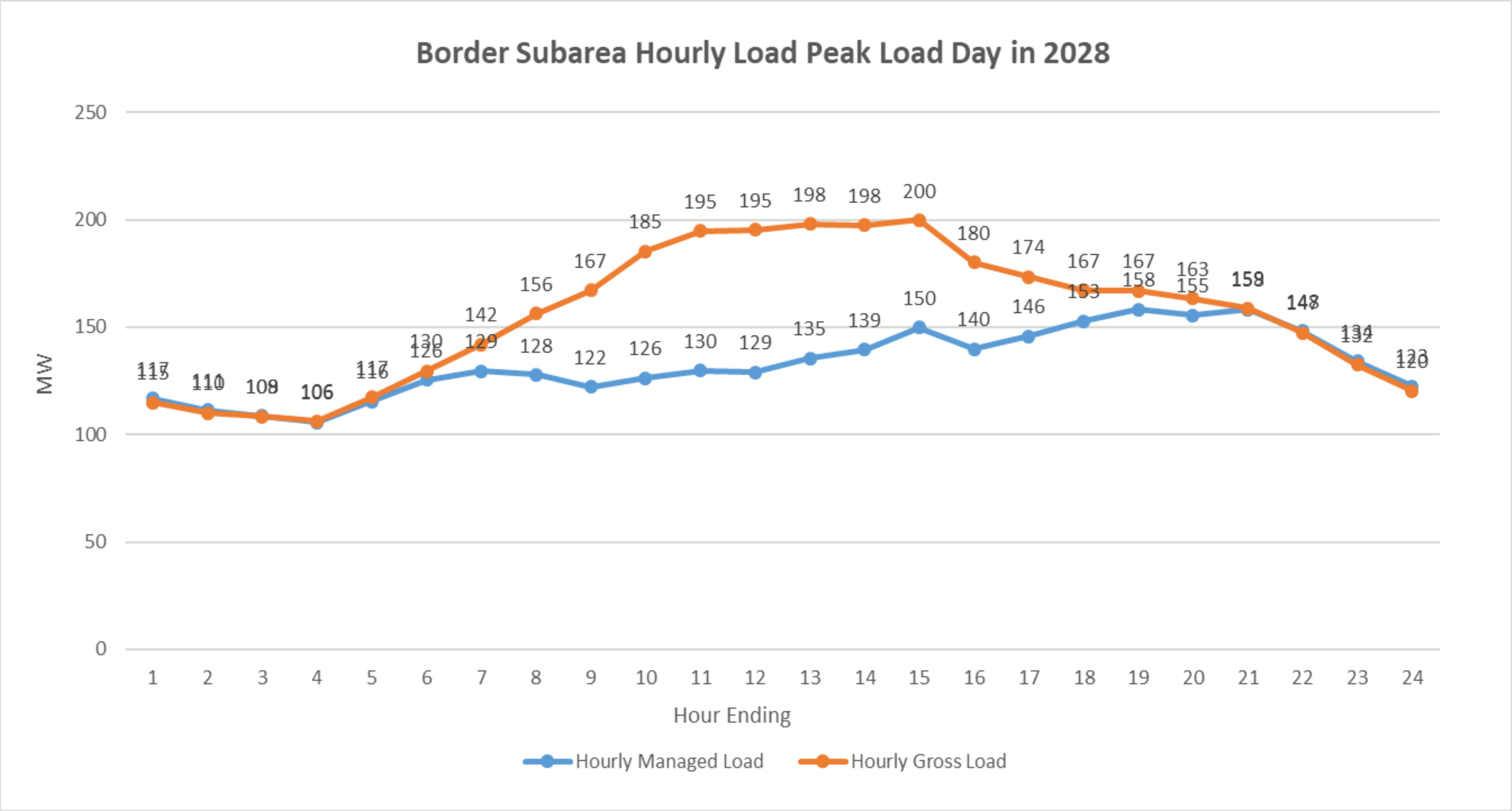
# Pala Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | Melrose-Morro Hill Tap-Monstrate 69kV line (TL694) | Pendleton-San Luis Rey 69kV (TL6912) and Lilac-Pala 69kV (TL698) lines | 26 |
| 2023 (Informational) | First Limit | C | Melrose-Morro Hill Tap 69kV line (TL694) | Pendleton-San Luis Rey 69kV (TL6912) and Lilac-Pala 69kV (TL6908) lines | 10 |

# Border Subarea Loads and Resources

| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 175.14 | Market (including solar generation) | 177.66 |
| AAEE + AAPV | -17.3 | Wind | 0 |
| Behind the meter DG (production) | 0 | Muni | 0 |
| **Net Load** | **157.84** | QF | 1.78 |
| Transmission Losses | 0.46 | Future preferred resource assumptions (EE, DR) | 0 |
| **Loads + Losses** | **158.3** | Existing 20-Minute Demand Response | 0 |
| | | Total battery energy storage procurement to date | 0 |
| | | **Total Qualifying Capacity** | **179.44** |

# Border Subarea Load Profile



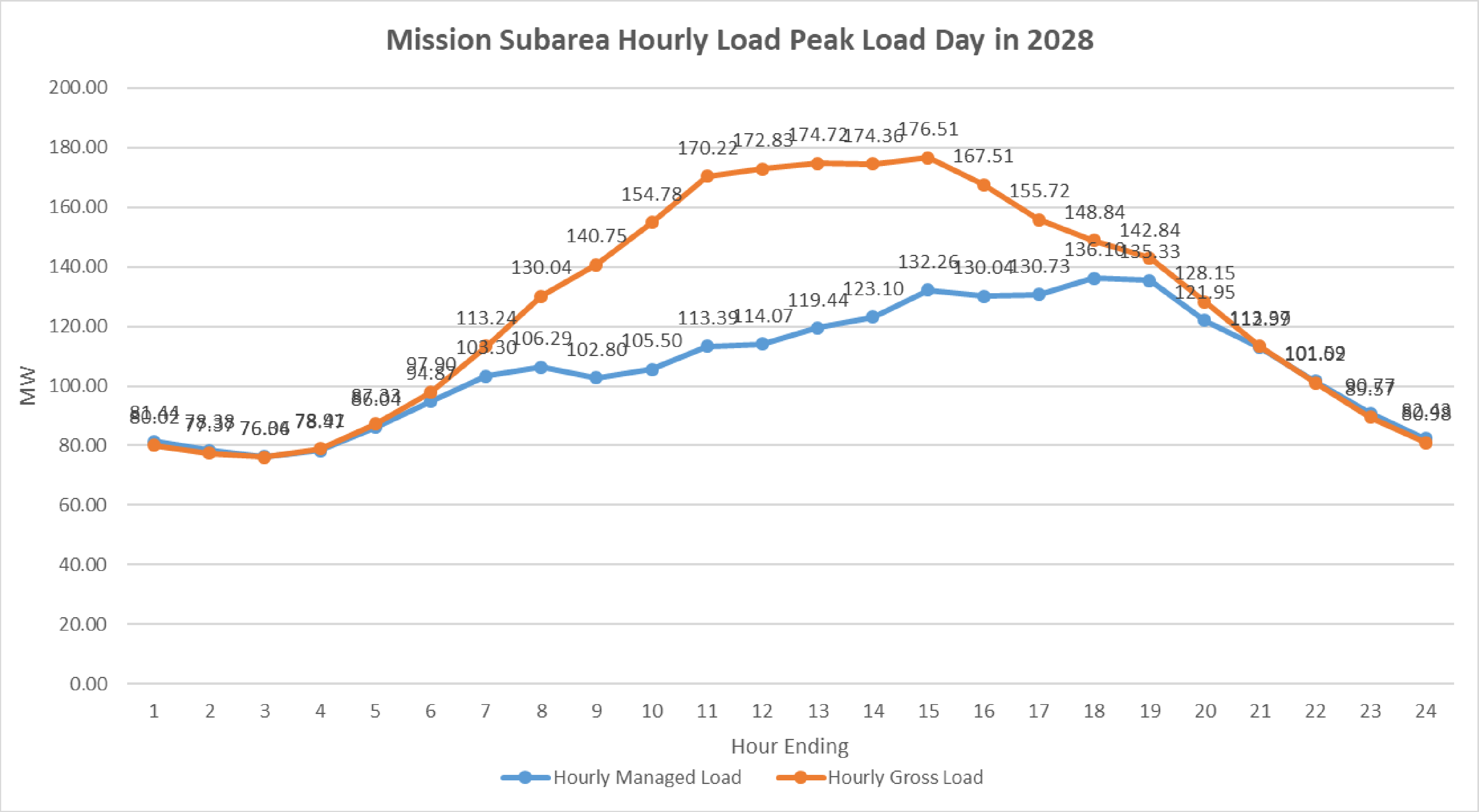
# Border Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | First Limit | C | Imperial Beach-Bay Boulevard 69kV line (TL647) | Loss of Bay Boulevard-Otay 69kV Nos.1&2 lines (TL645 and TL646) | 70 |
| 2028 | First Limit | B | Otay-Otay Lake Tap 69kV line (TL649) | Miguel-Salt Creek 69kV line (TL6964) | 14 |
| 2023 (Informational) | First Limit | C | Imperial Beach-Bay Boulevard 69kV line (TL647) | Loss of Bay Boulevard-Otay 69kV Nos.1&2 lines (TL645 and TL646) | 108 |

# Mission Subarea Loads and Resources

| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 146.72 | Market (including solar generation) | 4.42 |
| AAEE + AAPV | -10.67 | Wind | 0 |
| Behind the meter DG (production) | 0 | Muni | 0 |
| **Net Load** | **136.05** | QF | 0 |
| Transmission Losses | 0.05 | Future preferred resource assumptions (EE, DR) | 0 |
| **Loads + Losses** | **136.1** | Existing 20-Minute Demand Response | 0 |
| | | Total battery energy storage procurement to date | 0 |
| | | **Total Qualifying Capacity** | **4.42** |

# Mission Subarea Load Profile




California ISO

# Mission Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | None | N/A | None | None | 0* |
| 2023 (Informational) | None | N/A | None | None | 0* |

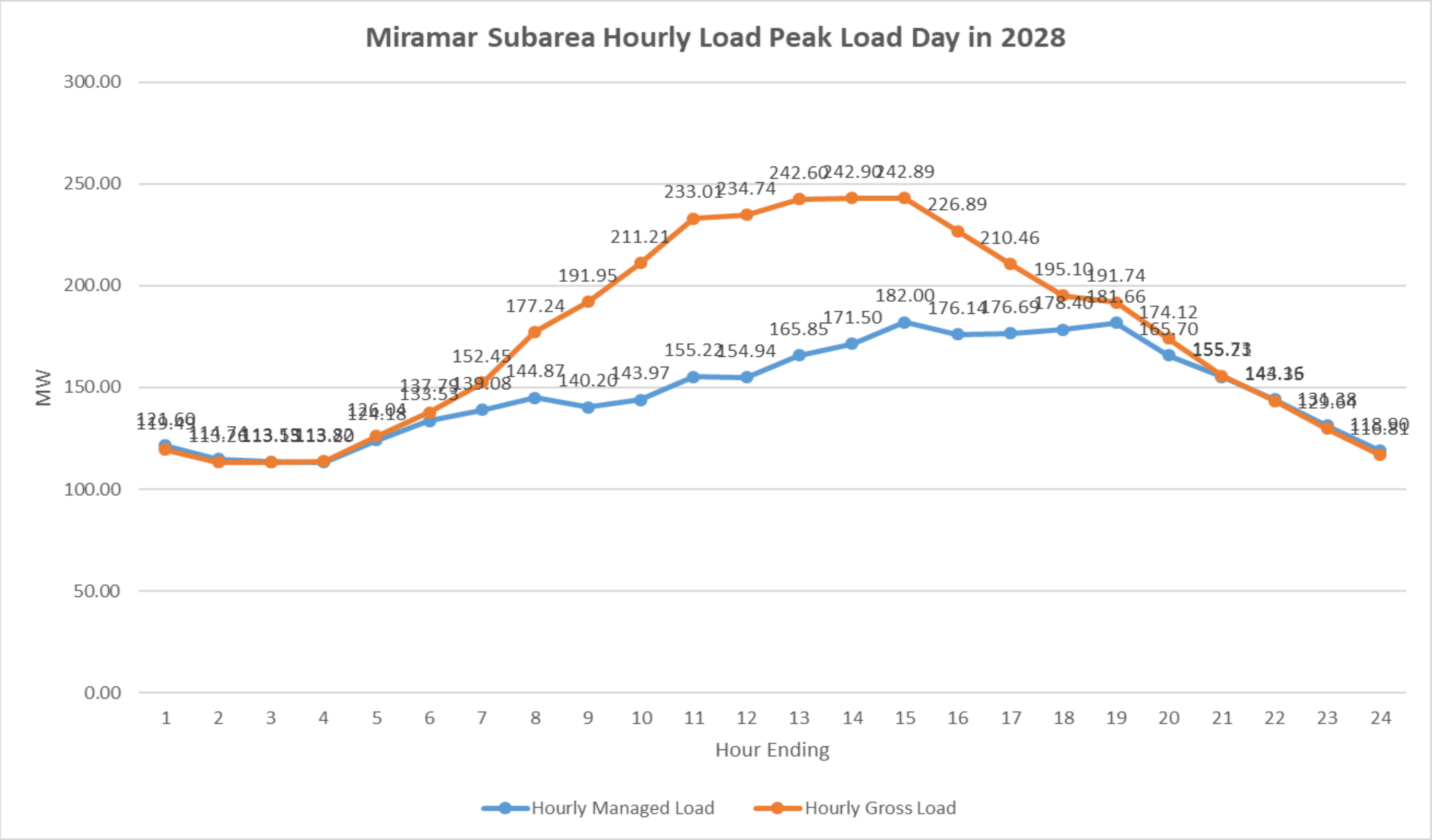
Notes:

*LCR need for the Mission subarea is eliminated with the completions of the TL600 Mesa Heights 69kV loop-in and the TL676 Mission-Mesa Heights 69kV reconductoring project

# Miramar Subarea Loads and Resources

| Loads (MW) | | Resources (MW) | |
|---|---|---|---|
| Gross Load | 196.4 | Market (including solar generation) | 95.9 |
| AAEE + AAPV | -15.1 | Wind | 0 |
| Behind the meter DG (production) | 0 | Muni | 0 |
| **Net Load** | **181.3** | QF | 0 |
| Transmission Losses | 0.7 | Future preferred resource assumptions (EE, DR) | 1.08 |
| **Loads + Losses** | **182.0** | Existing 20-Minute Demand Response | 2.14 |
| | | Total battery energy storage procurement to date | 0 |
| | | **Total Qualifying Capacity** | **99.12** |

# Miramar Subarea Load Profile



# Miramar Subarea LCR

| Year | Limit | Category | Limiting Facility | Contingency | LCR (MW) |
|---|---|---|---|---|---|
| 2028 | None | N/A | None | None | 0* |
| 2023 (Informational) | None | N/A | None | None | 0* |

Notes:

*LCR need for the Miramar subarea is eliminated with the addition of the Sycamore-Penasquitos 230kV line

# Changes Compared to Previous LCR Requirements

| Subarea | 2019 | | 2023 | | 2028 | |
|---|---|---|---|---|---|---|
| | Load | LCR | Load | LCR | Load | LCR |
| El Cajon | 158 | 88 | 158 | 35 | 173 | 76 |
| Esco | 324 | 0 | 360 | 20 | 378 | 0 |
| Pala | 101 | 10 | 103 | 10 | 123 | 26 |
| Border | 168 | 100 | 178 | 108 | 158 | 70 |
| Mission | 145 | 0 | 145 | 0 | 136 | 0 |
| Miramar | 179 | 0 | 183 | 0 | 182 | 0 |
| Overall | 1045 | 198 | 1127 | 173 | 1150 | 172 |

# THANK YOU

**Your comments and questions are welcome.**

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

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# Economically valuing local resource adequacy capacity requirements in local capacity areas


Jeff Billinton

Manager, Regional Transmission - North

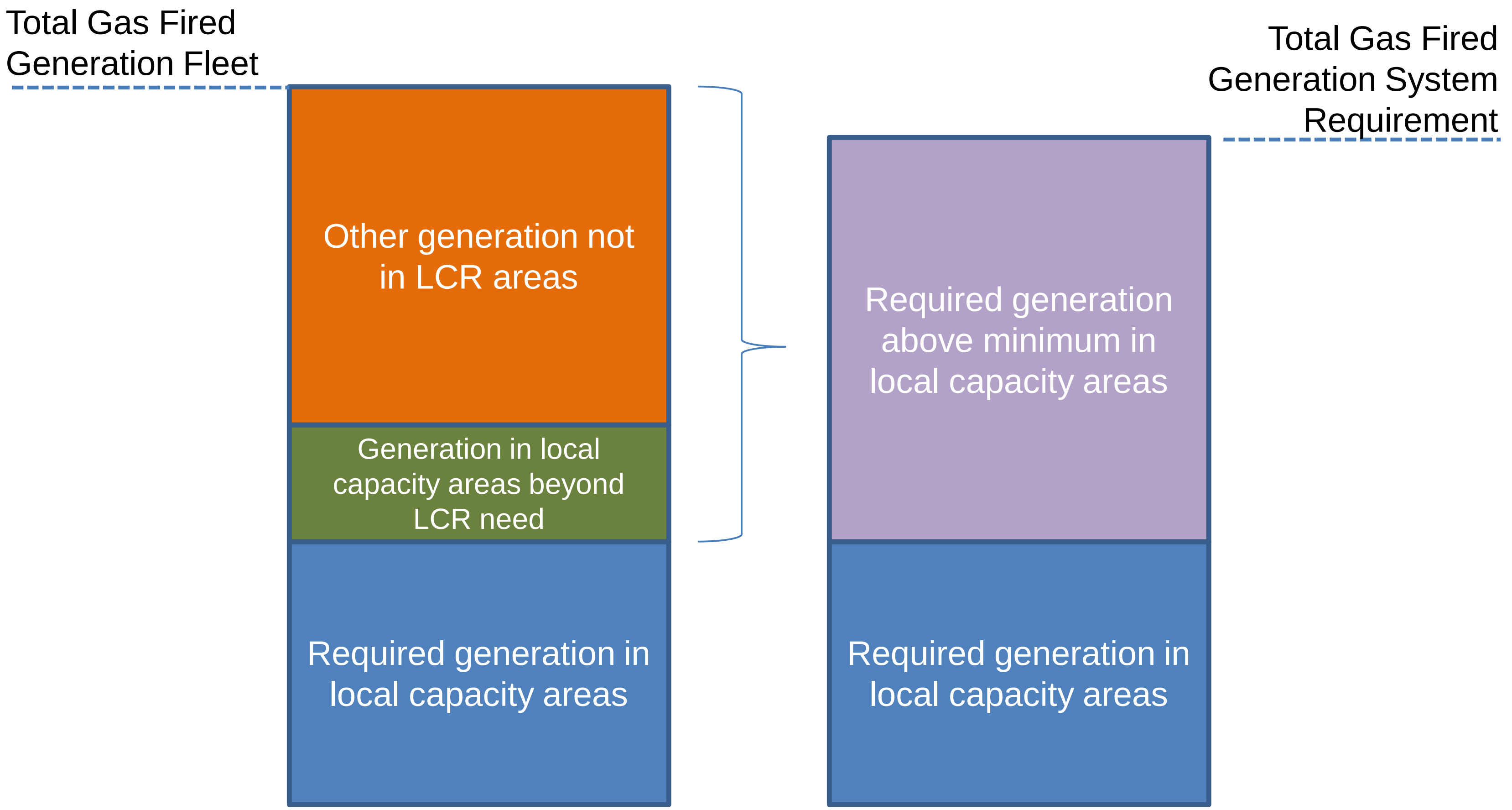

2018-2019 Transmission Planning Process Stakeholder Meeting

September 20-21, 2018

# The ISO wants to revisit how to assess the capacity value of local capacity requirement reductions

- The ISO is reviewing potential alternatives as means to reduce or eliminate local capacity requirements as potential economic driven projects
  - Note that there is no specific policy framework driving these reductions at this time
- Given the role certain generation can play in providing system, flexible, and local capacity, careful consideration needs to be given to valuing – as an economic driver – a potential reduction in local capacity requirements, e.g.:
  - Does reducing local capacity requirements truly benefit ratepayers if the generation is required for system purposes in any event?
  - Is the “lowest cost” local capacity the best value if higher cost local capacity can also provide flexible capacity?

# System requirements more than surpass local requirements, so is the generation providing the “best” value being retained if local requirements are reduced?



# A number of concepts are being considered for the economic benefit of local capacity requirement reductions

- A price differential between system and local capacity may be the appropriate value to consider 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 full cost of service of the resource may be the appropriate cost comparison if there is only one (newer) generator in the area, and essentially no competition for providing local RA capacity
- The CPM soft offer cap may be appropriate if there is only one older unit in the area that is heavily depreciated
- If there are a number of generators in an area, but they are ALL required to meet the local capacity requirement, the situation becomes even more complex. Sensitivities can help understand the situation, but not necessarily help inform a defensible decision

# Other considerations

- Possible data sources:
  - Would the CPUC's weighted average price for local, non-CPM/RMR capacity
  - Known (filed) RMR and CPM costs?
- "Supply" curves in each area would require resource specific contract information – could proxies suffice?
- Note the 2017-2018 planning decisions are not informative – the benefits in the two cases in that cycle were overwhelming, even if heavily discounted

# At this time…for the 2018-2019 cycle:

- The ISO is looking for feedback on the methodologies to value local capacity reductions – input will be considered in preliminary results that will be discussed in November
- The evaluation of alternatives in this cycle is useful regardless of “economic driven” decision-making outcomes, to potentially inform future policy decisions or improve preparedness for generation retirements
- We will need to consider the other factors beyond local area cost/benefit comparisons
  - The ISO is updating its previous analysis regarding reliance on the existing gas-fired generation fleet for system and flexible needs

# Informational Study: Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California

Ebrahim Rahimi
Lead Regional Transmission Engineer

2018-2019 Transmission Planning Process Stakeholder Meeting
September 20-21, 2018

# Background and Objective:

- 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
- The request included an assessment of the role the AC and DC interties can play in displacing generation whose reliability is tied to Aliso Canyon
- An informational special study was included in the 2018-2019 transmission planning cycle

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

# Study Plan

- Draft Study Plan posted on April 12, 2018
- Stakeholder call on Draft Study Plan on April 18
- Stakeholder comments submitted by April 25
- Final Study Scope posted on May 23

http://www.caiso.com/Documents/FinalStudyScopeforTransfersbetweenPacificNorthwestandCalifornia.pdf

California ISO

2018-2019 Transmission Planning Process

Study Scope for

Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California Informational Study

May 23, 2018

Final

ISO Market and Infrastructure Development Division May 23, 2018

# Study Scope:

- To evaluate the impact of the following on Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California:
  - Increase transfer capacity of AC and DC interties
  - Increase dynamic transfer limit (DTC) on COI
  - Implementing sub-hourly scheduling on PDCI
  - Assigning RA value to firm zero-carbon imports or transfers

# Near-term and Long-term Assessments

- Near-term assessment (year 2023)
  - To assess the potential to maximize the utilization of existing system
    - Identify minor upgrades that may be required

- Longer-term assessment (year 2028)
  - To use production simulation to assess the potential benefits of increased transfer capabilities
    - If production simulation results determine that higher capacity on AC and DC interties are beneficial beyond existing path ratings, snapshots to test alternatives to increase the capability will be developed
  - Effective hydro modeling is critical to the study

# Increase transfer capacity of AC and DC interties in Near-term

- In the North to South direction the objective is to test COI flow at 5,100 MW under favorable conditions in the following scenarios:
  - Energy transfer in Summer late afternoon
  - Resource shaping in Spring late afternoon
- In the South to North direction the objective is to test PDCI flow at 1,500 MW or higher. PDCI is currently operationally limited to around 1000 MW in the S-N direction.
  - Energy transfer in Fall late afternoon
  - Resource shaping in Spring mid-day

# Increase transfer capacity of AC and DC interties Longer-Term Assessment

- Hydro Assumptions in Production Simulation Model
  - WECC Anchor Data Set (ADS) will be used for the production simulation analysis
    - ABB Gridview software
  - Hydro assumptions in ADS are based on historical hydro output from 2008/2009
  - Outreach with the Planning Regions and the hydro owners to review modeling and make updates as required
    - The ISO will receive information on typical, high, and low hydro scenarios from NWPCC and BPA
    - Gridview study with updated hydro assumptions will provide an insight to potential benefits of higher intertie capacity in the long term

# Increase DTC on COI and Sub-hourly scheduling on PDCI

- The DTC on NWACI has increased from 400 MW to 600 MW effective 7/1/2018 *.
  - The CAISO will assess the benefits to California system of going beyond 600 MW and any potential requirements on the ISO controlled grid.

- The LADWP and BPA are evaluating the feasibility and requirements of implementing sub-hurly scheduling (15-minute scheduling) on PDCI
  - The CAISO will assess the benefits to California system of PDCI 15-minute scheduling and any potential requirements on the ISO controlled grid.

* https://www.bpa.gov/transmission/Doing%20Business/bp/Redlines/Redline-DTC-Operating-Scheduling-Reqs-BP-V08.pdf

# Assigning RA value to firm zero-carbon imports or transfers

- Historical Maximum Import Capability (MIC) allocation to COI and PDCI to be compared with historical monthly RA showings.

- Comparison of Real time flows on COI and PDCI with MIC allocation and RA showings.

# Next Steps

- November 16 stakeholder meeting
  - Provide preliminary study results for near-term assessment
  - Provide preliminary production simulation results for longer-term assessment
- January 31, 2019 post draft Transmission Plan
  - Detailed analysis and potential alternatives
- February 7, 2019 stakeholder meeting on draft Transmission Plan

# *Day 2 - Wrap-up*
# Reliability Assessment and Study Updates

*Jody Cross*
*Stakeholder Engagement and Policy Specialist*

*2018-2019 Transmission Planning Process Stakeholder Meeting*
*September 20-21, 2018*

# Request Window Submissions for Reliability Assessment

- Request Window closes October 15
  - Request Window is for alternatives in the reliability assessment
  - Stakeholders requested to submit comments to: requestwindow@caiso.com
  - ISO will post Request Window submission on the market participant portal

# Stakeholder Comments

- Stakeholder comments to be submitted by October 5
  - Stakeholder comments are to include potential alternatives for economic LCR assessment
  - 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