Introduction to the North Coast Resiliency Initiative

May 13, 2022

California Public Utilities Commission

WebEx and Call-In Information

Join by Computer:

https://cpuc.webex.com/cpuc/j.php?RGID=rd7f0716761394a5584e152190a7e583d

Event Password: NCRI (case sensitive)

Meeting Number: 2487 366 0688

Join by Phone:

- Please register using WebEx link to view phone number.

(Staff recommends using your computer's audio if possible.)

Notes:

- This meeting will be recorded.
- Contact Daniel Tutt, daniel.tutt@cpuc.ca.gov, with any additional comments or questions.

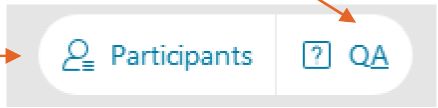
WebEx Logistics

- All attendees are muted on entry by default.
- Please write your questions in the Q&A panel. Some questions will be addressed at the end of each section while others will be answered at the end of the workshop.
- Comments can be provided verbally during the feedback session using the “raise hand” function.
    - The host will unmute you and you will have a maximum of 2 minutes to speak.
    - Please lower your hand after you’ve asked your question by clicking on the “raise hand” again.
    - If you have another question, please “re-raise your hand” by clicking on the “raise hand” button twice.

WebEx Tip

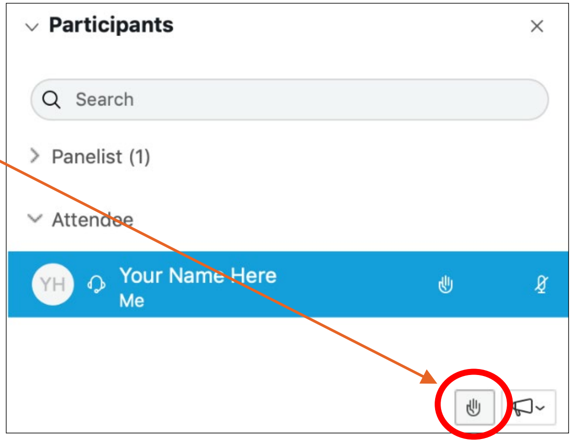
Access the written Q&A panel here

1. Click here to access the attendee list to raise and lower your hand.

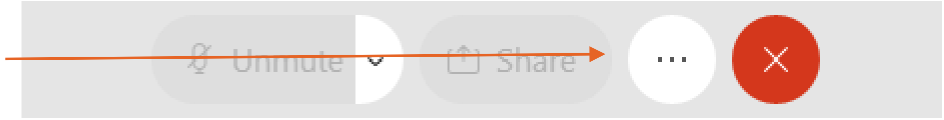


2. Raise your hand by clicking the hand icon.

3. Lower it by clicking again.



Access your meeting audio settings here



Workshop Objectives

1. **Attendees understand purpose and scope of the NCRI.**
   A. NCRI as a pilot framework for resiliency planning more broadly.
   B. How that pilot framework was applied specifically to the North Coast.

2. **Attendees are aware of status, learnings to-date, and next steps of the NCRI**
   A. The 10-year historical lookback analysis.
      - What is it, how are we using it, what does the latest version say? Both generally and for the North Coast specifically.

   B. Direct and indirect PSPS impacts.
      - What causes them? What mitigations are potentially available?

   C. Future plan for the NCRI.

3. **Attendees highlight what we may have missed/overlooked and offer actionable feedback on how to address any gaps.**

Workshop Agenda

Opening Comments & Logistics	15 min
What is the NCRI	10 min
Regional Resiliency Planning Overview	15 min
Defining and Prioritizing the North Coast for Regional Resiliency Planning	20 min
Updated 10-year PSPS Historical Lookback	25 min
Next Steps for the NCRI	15 min
Questions and Comments from the Public	20 min

Opening Comments

Commissioner Shiroma and Commissioner Vaccaro

What is the North Coast Resiliency Initiative?

The North Coast Resiliency Initiative

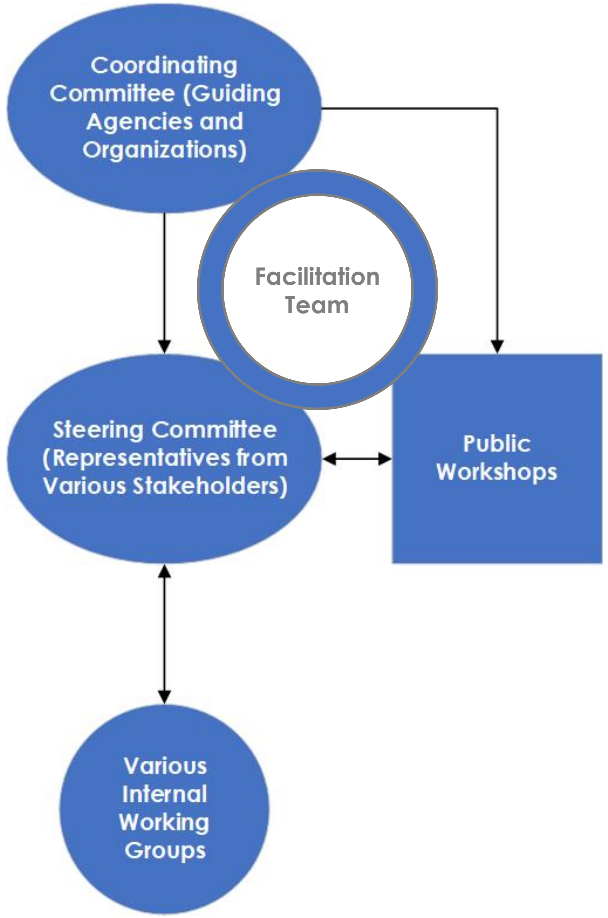
- The North Coast Resiliency Initiative (NCRI) is a state initiative to help identify projects to mitigate transmission-level Public Safety Power Shutoffs (PSPS) in the North Coast area (pictured at right). The initiative will bring together key agencies and stakeholders to develop a comprehensive mitigation plan.
- NCRI intends to accomplish two main objectives by the end of 2022:
    1. Produce a comprehensive regional plan for improving electric resiliency in the North Coast, with a particular focus on transmission-level PSPS mitigation
    2. Provide an overarching framework for regional resiliency planning that others can leverage
- Depending upon mitigations identified (if any), timeline for implementation of mitigations will vary

North Coast Resiliency Initiative Structure

The Initiative consists of:

1. A Coordinating Committee, made up of Commissioners from the CEC and CPUC.
2. A Steering Committee, made up of representatives from MCE, SCP, PG&E, the CAISO, the CEC, and the CPUC.
3. A CPUC and Gridworks Facilitation Team, stewarding the Initiative.

The Coordinating Committee oversees the progress of the initiative and provides direction. The Steering Committee meets regularly to investigate, discuss and propose mitigations for transmission-level PSPS in the North Coast. The Facilitation Team facilitates day-to-day activity.



Presenting the NCRI

Why Resiliency? Why Now?

A Resiliency Initiative in the Abstract

The North Coast Resiliency Initiative

Regional Resiliency Planning Overview

Comprehensive and *Regional* Resiliency Planning

1. What is Electric System Resiliency and Why is it Important?

2. What's Needed for Comprehensive Electric Resiliency Planning?

4. When Does a Resiliency Initiative Make Sense?

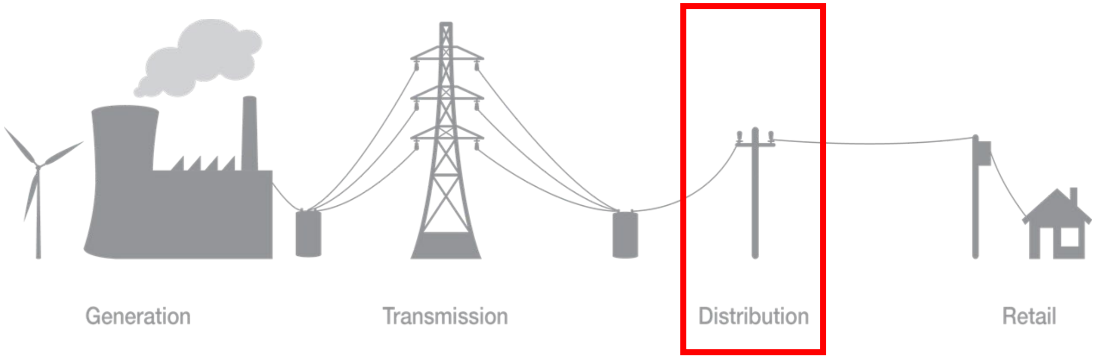
5. How to Choose a 'Region' for the Initiative?

6. Who Should be Involved in a Resiliency Initiative?

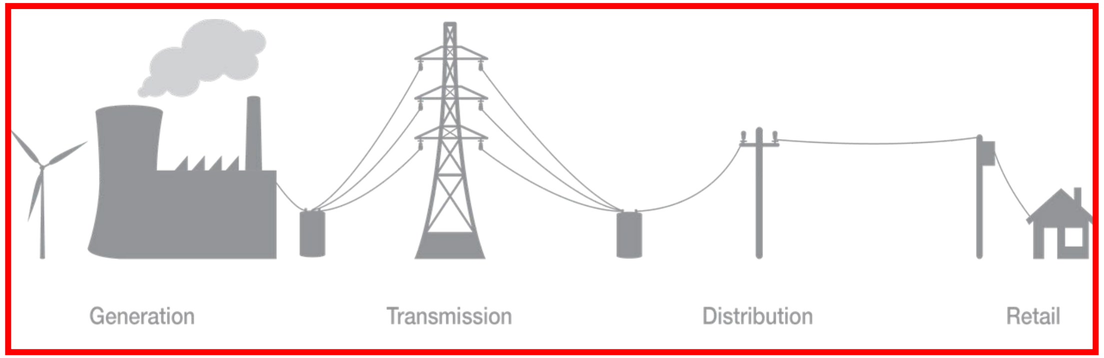
What is Electric System Resiliency and Why is it Important?

- **Electric system resiliency** refers to the ability of the electric grid to withstand, adapt to, and recover from large-scale disruptive events.
- It is a distinct subset of electric system **reliability**, which more broadly refers to the reliable functioning of the electric grid.
- Electric system resiliency is becoming increasingly important due to:
  - Changing environmental conditions that are increasing the risks caused by the grid (i.e. wildfire ignition) and the risks facing the grid (i.e. extreme weather).
  - Evolving maintenance and repair needs for a grid originally designed to operate under very different conditions.
  - Our growing reliance on the grid to decarbonize the building and transportation sectors.
- Climate Change often drives these resiliency needs, at the same time as it requires other dramatic changes to the grid system.

What's Needed for Comprehensive Electric Resiliency Planning?



- The redesign of any single part of a larger system is limited by the larger context.



- A wider scope allows for more creative, innovative, and open systemic planning.

What’s Needed for Comprehensive Electric Resiliency Planning?

Resiliency planning needs to occur in a more comprehensive manner, for example by **involving multiple stakeholders**.

The grid landscape is **fractured**:

- Parts of this grid are managed by PG&E under CPUC regulation,
- Parts are managed by CAISO,
- Local Community Choice Aggregators (CCAs) have a stake in grid management, and
- Customers themselves increasingly play an active part.

The fracturing of the grid may limit the response any single entity can take to address climate change adaptation and mitigation, and it may lead to **conflicting or duplicative measures**.

When Does a Resiliency Initiative Make Sense?

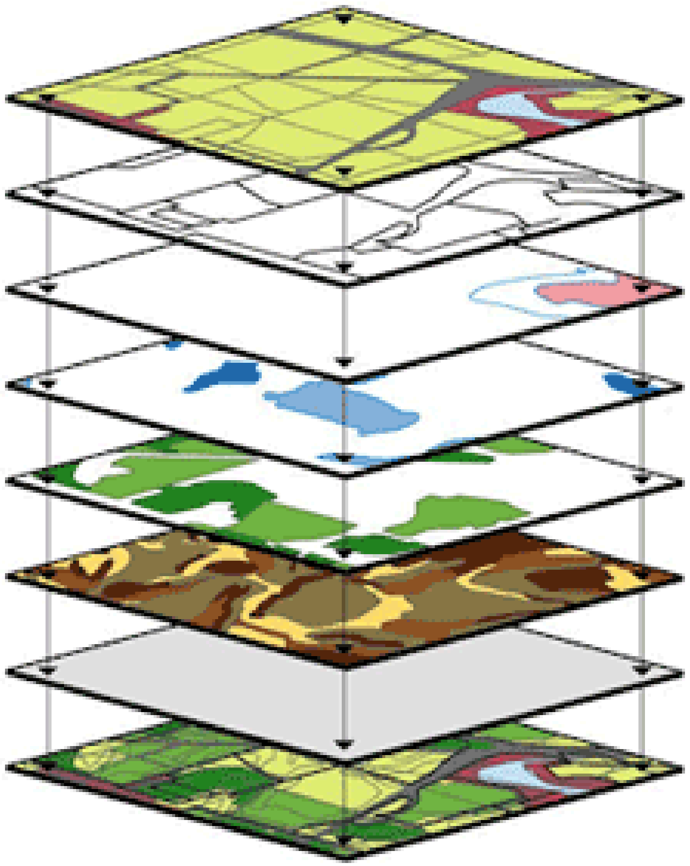
A Resiliency Initiative evolves out of **a specific and concrete problem the grid faces**, often bringing together the following three elements:

1. A changing **environment**, or other climate adaptation need. (i.e. High winds and dry conditions lead to expanded fire risk, in turn leading to power shutoffs.)
2. The general maintenance and replacement of electrical **infrastructure** which may have been designed for different environmental conditions.
3. Changing **expectations** of the electrical grid due to climate mitigation goals. (i.e. transportation and building electrification)

How to Choose a ‘Region’ for the Initiative?

Any specific and concrete problem for the grid also emerges in a specific place, or ‘region.’ A ‘Region’ for a Resiliency Initiative does **not** come pre-defined. Instead, the region indicates where the following factors overlap:

1. Resiliency Need:
   a. Significant Grid Outages.
   b. Other Climate Adaptation Risks (e.g., wildfire, heat, drought, sea-level rise, etc.)
2. Environment:
   a. Existing Environmental Geography.
   b. Scope of Environmental Change.
3. Electrical System:
   a. Structure of the Electrical System (i.e. how the Transmission system currently exists).
   b. Needed Changes to that System.
4. Other Relevant Factors.

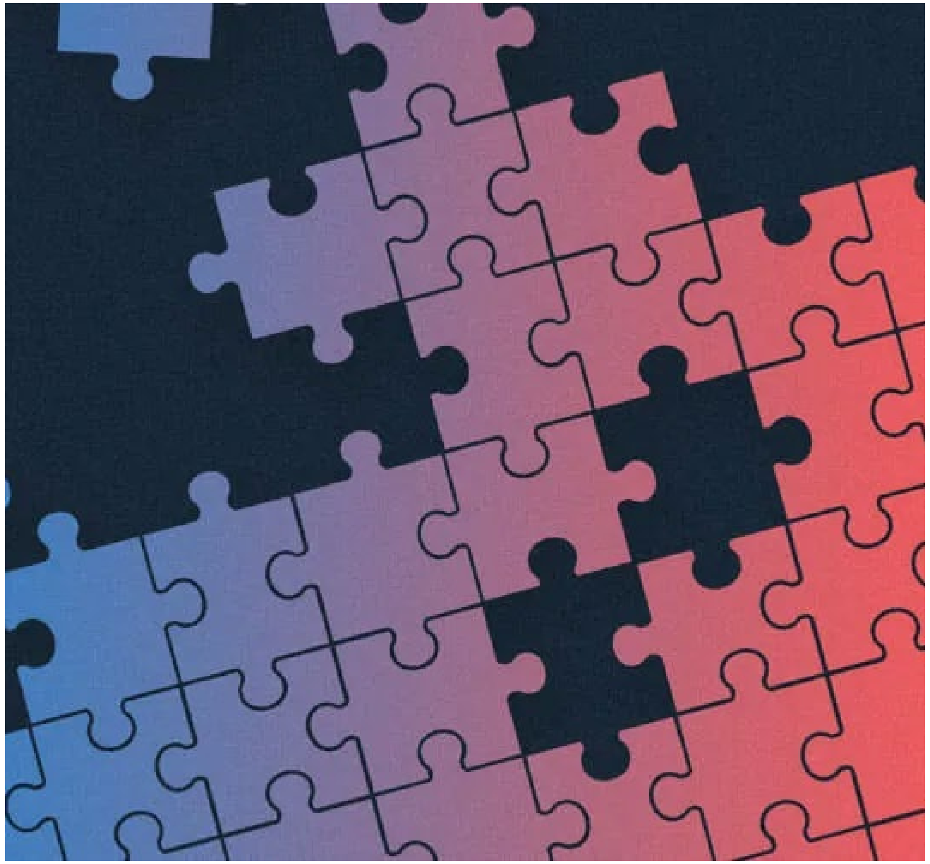


Who Should be Involved in a Resiliency Initiative?

Similarly, the participants in a Resiliency Initiative do not come pre-defined. Instead, participants should include anyone with **a key role in the electric grid** relating to the scope of the problem or it's potential solutions.

1. The **Scope of the Problem** – Does the problem involve the distribution, transmission, generation, or retail aspects of the grid? Which customers/customer types are impacted by the problem? What information is needed to understand the problem?

2. The **Scope of Potential Solutions** – Do potential solutions involve the distribution, transmission, generation, or retail aspects of the grid? Who would be responsible for funding and implementation of mitigations? Who would be impacted by potential mitigations?



Based on the above, different participants may also relate to the initiative in different ways (i.e. heavy or minimal involvement, early or late involvement).

Defining and Prioritizing the North Coast for Regional Resiliency Planning

Key Terms

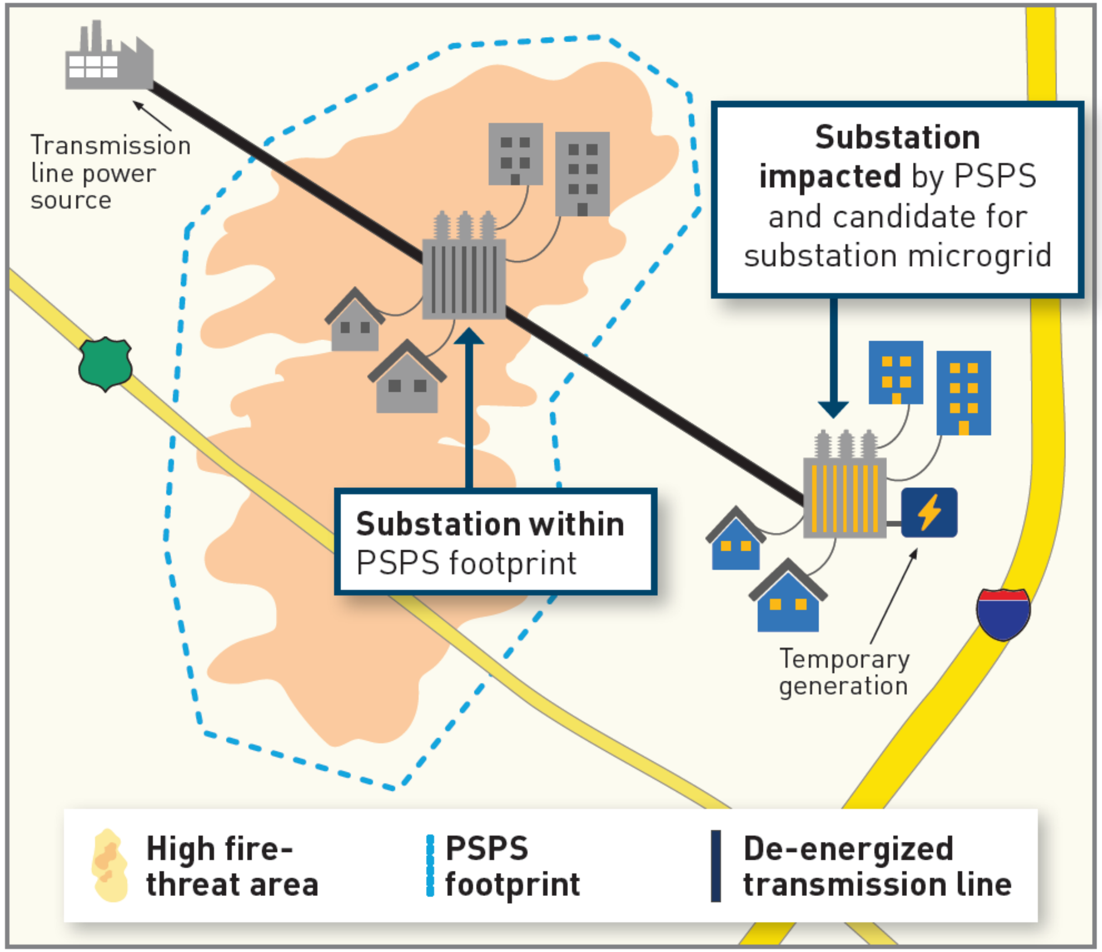
Public Safety Power Shutoff (PSPS): When a utility turns off the power during dry, high-wind periods because the electrical lines have a risk of sparking catastrophic wildfires.

Distribution v. Transmission Lines: Different levels of the electrical system. Distribution lines are lower-voltage lines bringing power to homes and businesses, transmission lines are higher-voltage lines transmitting power across the state. *PSPS can affect either Distribution lines, or Transmission lines, or both.*

Key Terms – ***Transmission-level PSPS***

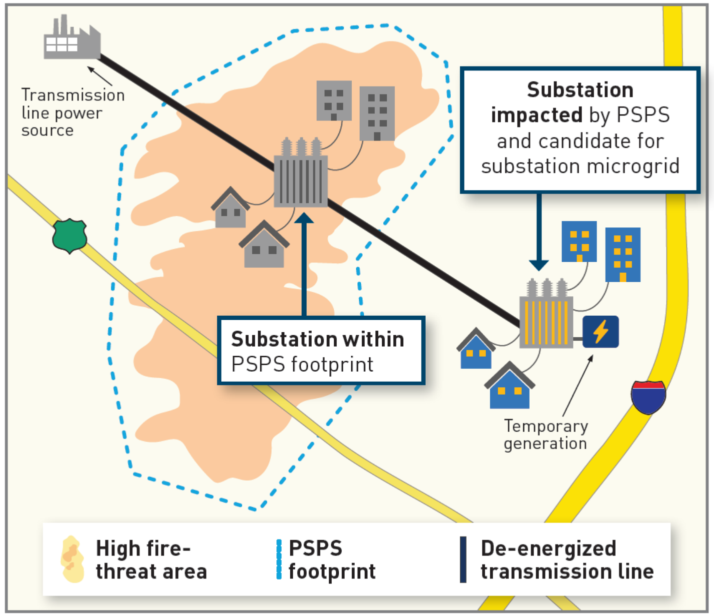
Safe-to-Energize Customers: Customers who lose power during a PSPS event because the *Transmission* line serving them is deenergized, even though the *Distribution* lines serving them are safe.

PSPS Impact with and without Safe-to-Energize Customers.

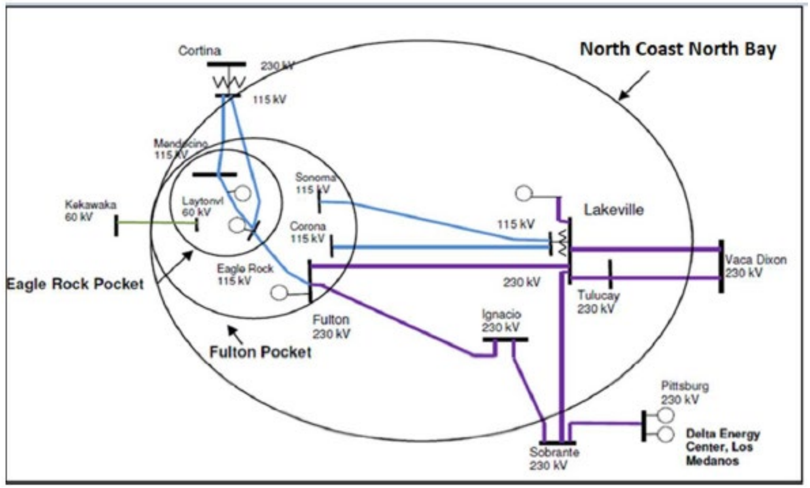


Key Terms – ***Transmission-level PSPS***

Direct PSPS Impact: When deenergized Transmission lines from PSPS cut off the flow of power to a substation.



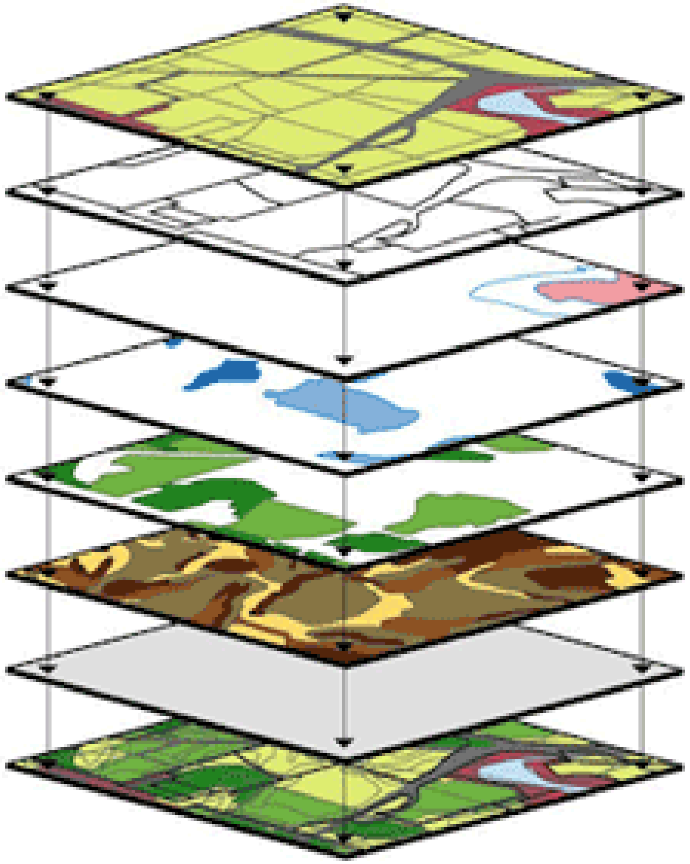
Indirect PSPS Impact: When deenergized Transmission lines from PSPS effect a whole region of the grid, requiring power to be shut off to additional customers (load drop).



Defining the "North Coast Region"

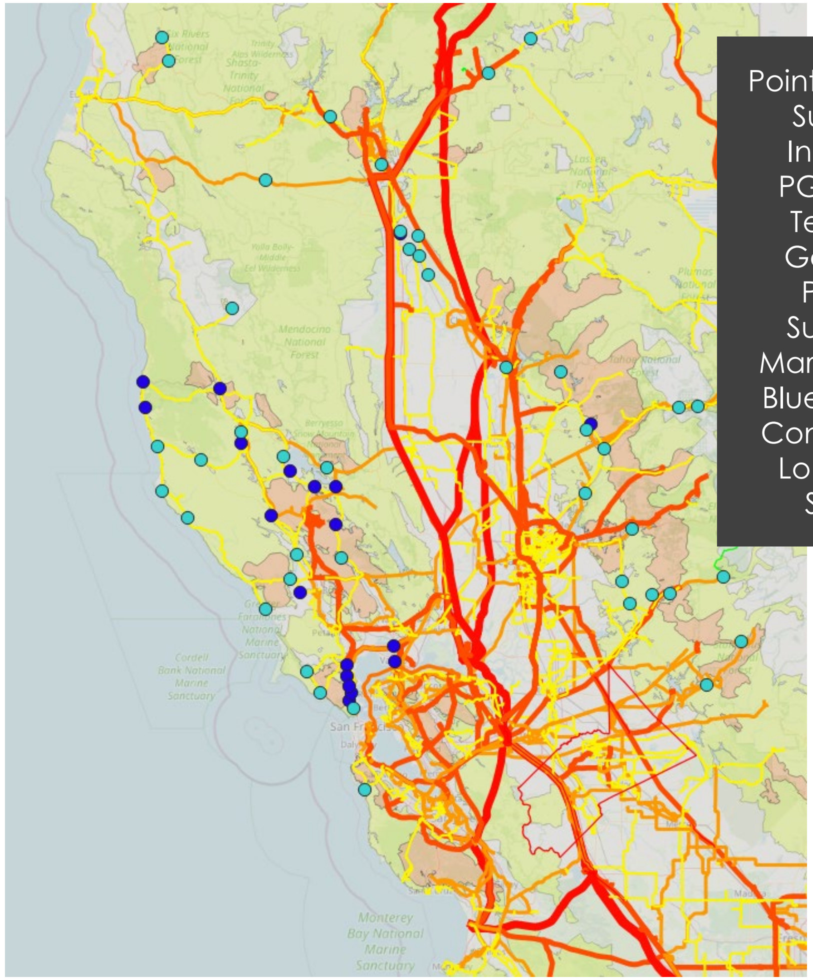
The following elements led to the geographic boundaries of the "North Coast Region" and drove the decision to prioritize resiliency planning there:

1. Resiliency Need:
   a. Significant PSPS Outages in 2019 and forecast of continued impacts
   b. Wildfire Risk from Electrical Infrastructure
2. Environment:
   a. High Fire Risk Environment
   b. Drier Weather, Extreme Winds
3. Electrical System:
   a. Safe-to-energize load
   b. Local Deliverability Constraints
   c. Isolation from Broader Grid
   d. Indirect PSPS Impacts Related to the Regional Grid Configuration
4. Other Relevant Factors
   1. Concerns around PG&E's temporary generation program
   2. North Coast regional demographics are broadly representative of the state overall



Resiliency Need: The Early Years of PSPS

- 2019 PSPS events significantly impacted Northern California
  - Many of these impacts at the transmission-level led otherwise safe-to-energize customers to lose power
- Forecasts for 2020 PSPS events suggested the potential for continued impacts in Northern California, and the North Coast in particular
  - PG&E launched its 2020 temporary generation program which included plans to deploy diesel units at up to 32 substations in the North Coast. PG&E also considered, but did not pursue, longer-term solutions at 17 of these 32 substations.

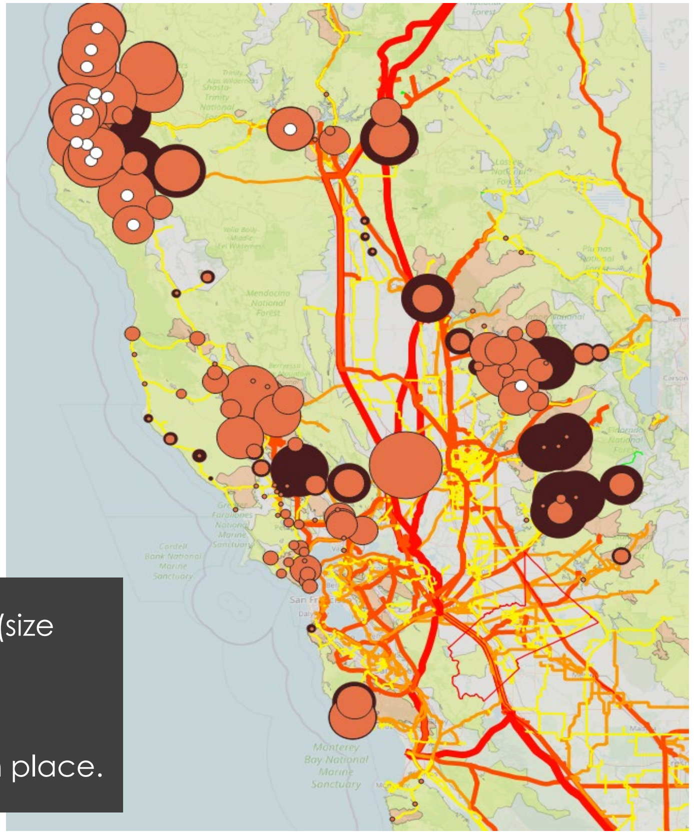


Points Indicate a Substation Included in PG&E's 2020 Temporary Generation Program. Substations Marked in Dark Blue Were Also Considered for Longer-Term Solutions

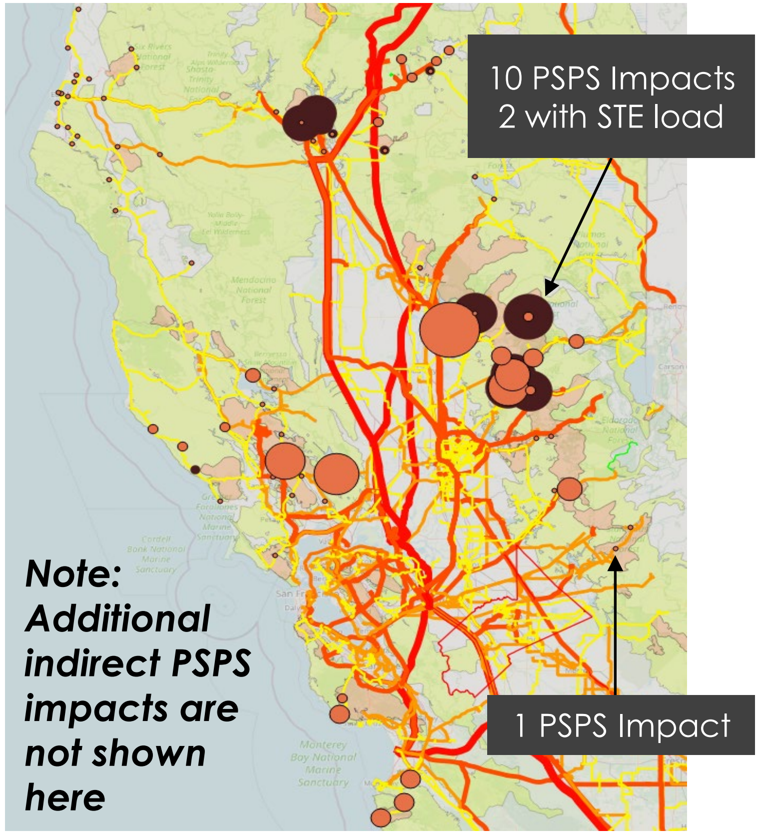
Resiliency Need: Advances in Modeling and Data

- Introduction of the Humboldt Bay Generating Station Island mitigated most *transmission-level* PSPS impacts in the Humboldt area
- Many substations in the Sierras face both transmission-level and distribution-level PSPS. In other words, they have limited safe-to-energize customers.

Late 2020: First Round of New PSPS Modelling Data



Late 2021: Second Round of New PSPS Modelling Data



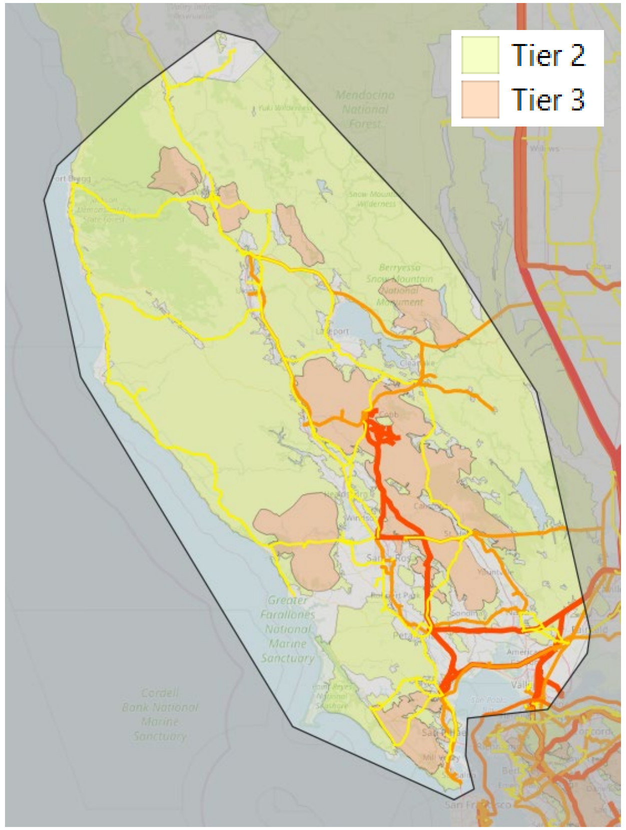
Note: Additional indirect PSPS impacts are not shown here

Substation with modeled transmission-level PSPS Impacts (size indicates number of impacts). Orange indicates safe-to-energize (STE) load. Brown indicates no STE load.

White point indicates PG&E already has a likely solution in place.

Environment: The North Coast has Many Transmission Lines Going Through High Fire Threat Districts

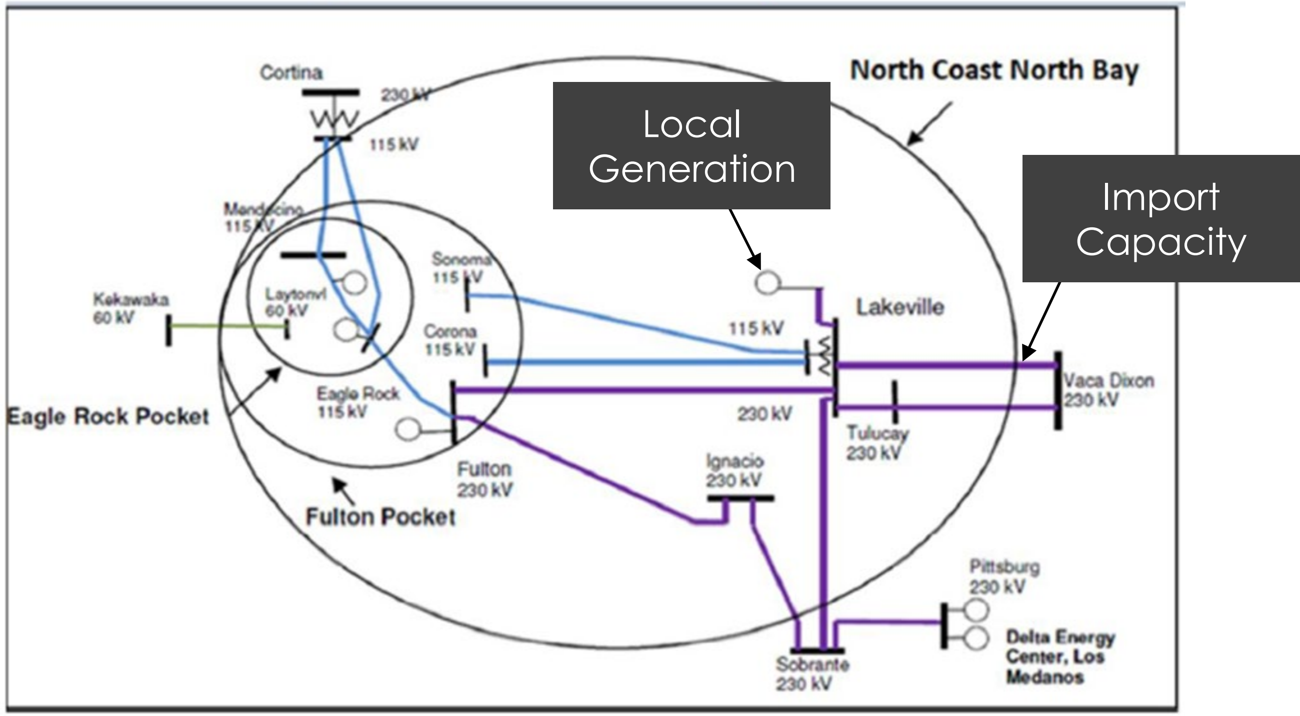
- Most of the North Coast Area is designated either Tier 2 or Tier 3 High Fire Threat District (HFTD).
- Many transmission lines travel long distances through HFTD.
- The Geyser's Geothermal Plant – a key energy resource for the North coast – is in the center of Tier 3 HFTD.
- The loss of the Geyser's Generation leads to larger issues in the regional grid because of import constraints which limit access to other generating resources that could compensate for this loss.



Electrical System: The North Coast is Relatively Isolated from the Wider Grid

- The North Coast is considered a "Local Capacity Area," meaning it is dependent on local generation to reliably serve load. The CAISO studies the North Coast to ensure that local load can be met with a combination of local generation and energy imports.
- Because of this unique grid configuration, the North Coast:
  1. Has limited import capability, and
  2. Is vulnerable to *indirect PSPS impacts (see next slide)*

Grid Configuration in North Coast North Bay Region, Showing Key Generators and Transmission Lines

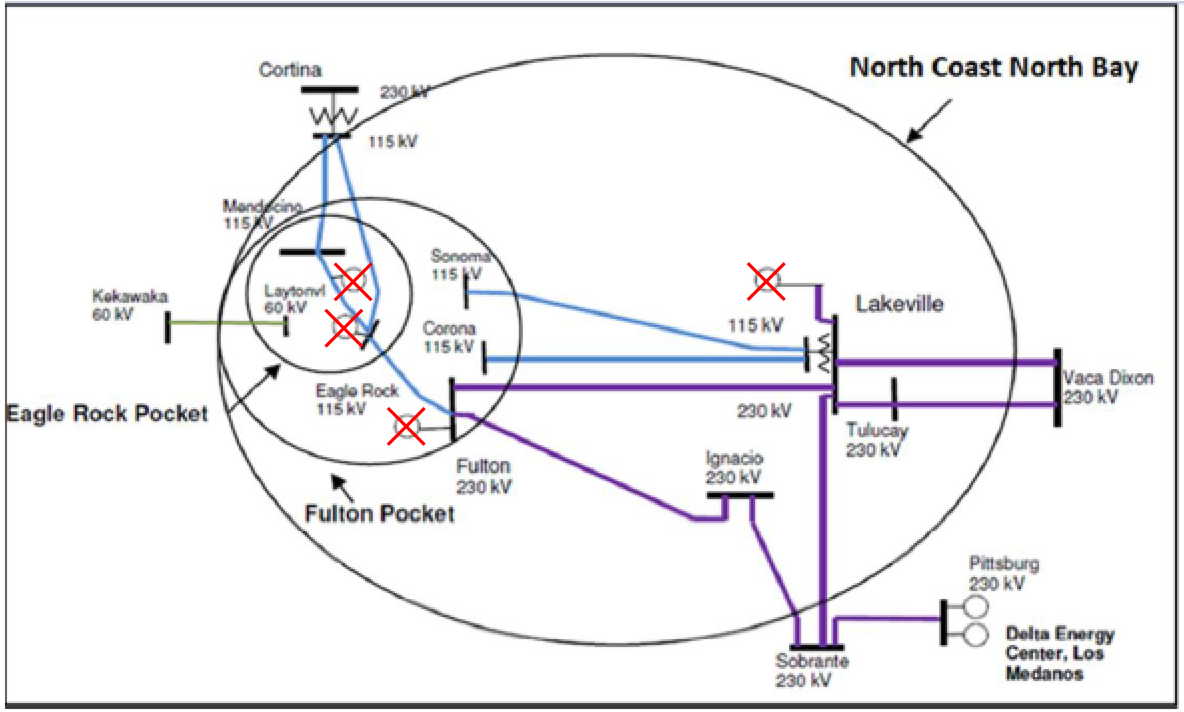


Base diagram from CAISO 2021 Local Capacity Technical Study.

Electrical System: Indirect PSPS Impacts facing the North Coast

- Indirect Impacts occur when local energy resources, and the capacity to import energy from the larger grid, are inadequate for serving local load. The operational response to these reliability concerns will be load drop.
- Indirect effects are relatively common in the North Coast, because it is relatively isolated from the larger grid and heavily affected by PSPS.
- PG&E will discuss indirect impacts in more depth later.

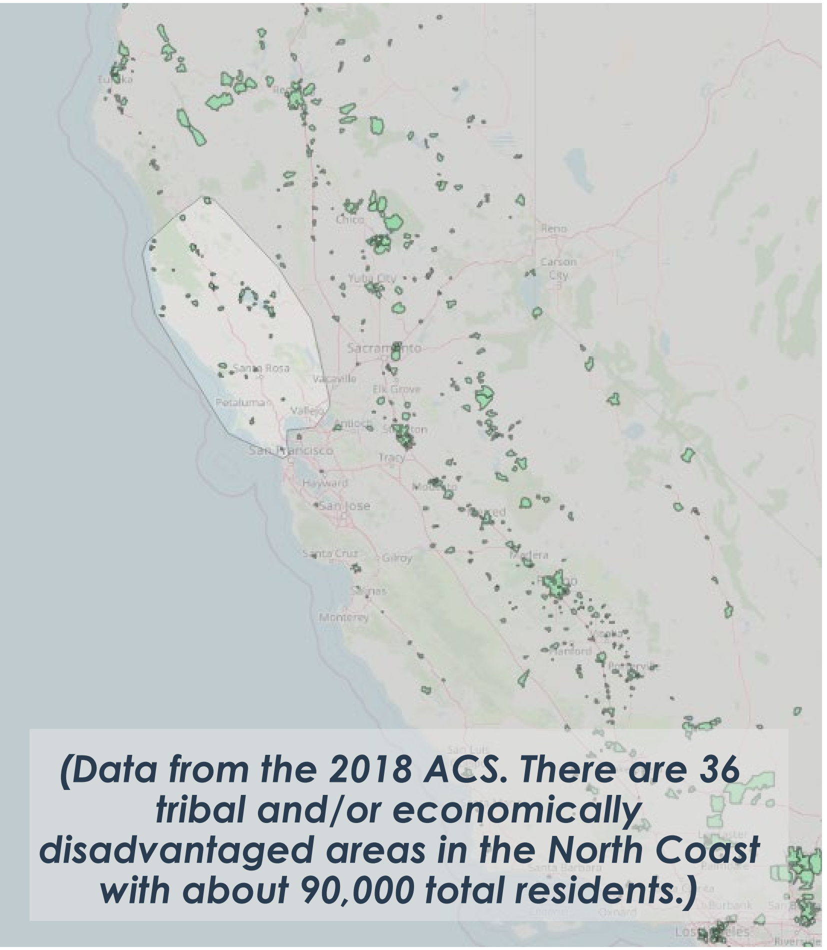
Grid Configuration in North Coast North Bay Region, Showing Key Generators and Transmission Lines



Base diagram from CAISO 2021 Local Capacity Technical Study, red Xs reflect potential PSPS event.

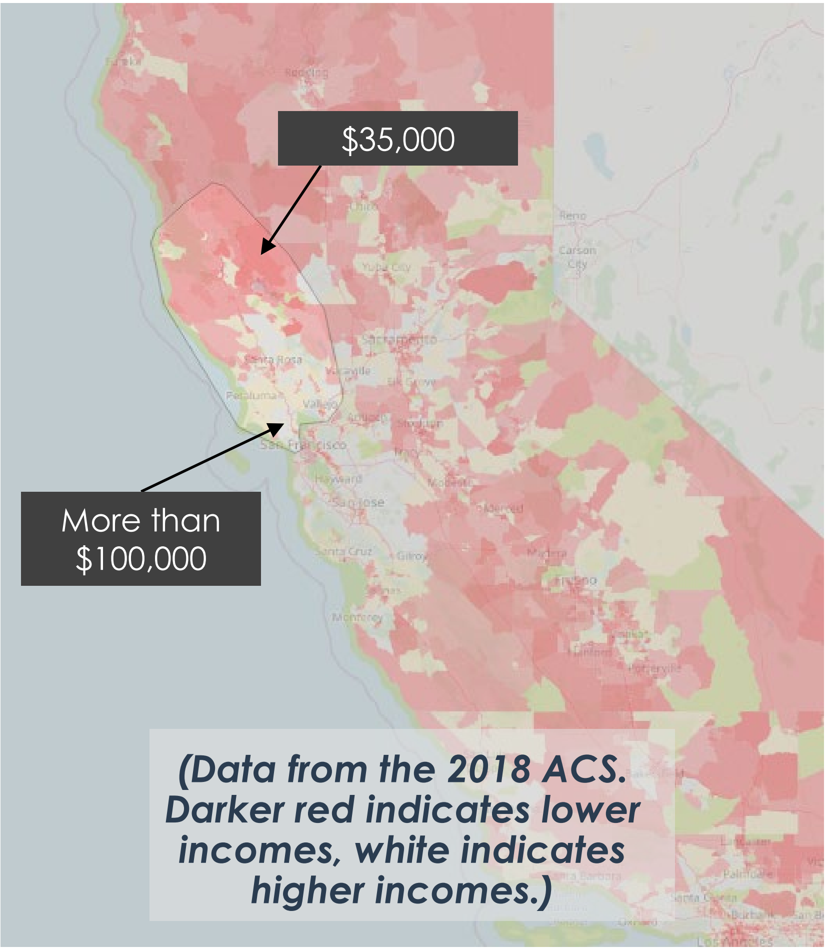
Other Relevant Factors: North Coast Regional Demographics are Broadly Representative of the State Overall

DACs and Tribal Communities in the North Coast



(Data from the 2018 ACS. There are 36 tribal and/or economically disadvantaged areas in the North Coast with about 90,000 total residents.)

Median Household Income in the North Coast



(Data from the 2018 ACS. Darker red indicates lower incomes, white indicates higher incomes.)

2021 10-Year Historical Lookback

PG&E

Overview of PG&E’s transmission PSPS lookback analysis

Public Webinar 13 May, 2022

Together, Building a Better California

Purpose and Agenda

Webinar objective:

Present a summary of and provide an opportunity for questions re:
PG&E's transmission PSPS lookback analysis (filed 12/17/2021)

Agenda

Summary presentation

Q & A discussion

PSPS Lookback – Overview and Direct Impact

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Overview of Lookback Framework

Transmission PSPS Risk Projection – Transmission PSPS Lookback Data Development

1. Historical **weather and environmental conditions** – most recent 10 years[1]

2. Current **system conditions** (e.g., transmission asset[2] and trees) – best available snapshot

3. Approved 2021 PSPS event **scoping framework, protocol, and criteria**

4. **Transmission lines to de-energize for PSPS** due to Vegetation, Asset, Behavior[3], or combination of risks

5. **Power flow analysis**[4] performed to identify directly impacted (Direct), or indirectly impacted (Indirect) Substations

[1]For example, 2021 historical lookback uses weather and environmental data from 2011 to 2020
[2]Asset condition is based on probability of failure using PG&E's transmission Operability Assessment
[3]Catastrophic wildfire behavior (e.g., how quickly a wildfire fire can spread and be contain)
[4]Power Flow studies are computer simulations that account for electric grid equipment, generation, and loading. They are based on electric circuit theory and physical parameters and are used for compliance, operational studies, and investment decisions.

Transmission Line Scoping Categories

Asset Health

2020

Large Fire Probability

- Product of the Fire Potential Index (FPI)[1] and probability of failure from the transmission Operability Assessment (OA)[2].
- Calculation can be done on a granular structure level

2021

Catastrophic Fire Potential Transmission- Asset

- Same product of the FPI and probability of failure from the Operability Assessment
- Utilizes a higher threshold determined by additional years worth of data.
- Calculation can be done on a granular structure level

Vegetation

2020

Vegetation Risk

- Lines that meet a minimum FPI and high veg risk (contains 1 or more fall in risk trees ranked in the 99.7% or 50 in the 95%.)
- Calculation associated to entire line/line segment

2021

Catastrophic Fire Potential Transmission-Vegetation

- A risk assessment of the probability of fire ignitions due to vegetation failure combined with the probability of catastrophic fires. It is the 2021 Transmission Tree Strike Model combined in space and time with the Fire Potential Index (FPI).
- Calculation can be done on a granular structure level instead of presence of vegetation somewhere along the line

Consequence

2020

Black Swan[3]

- Consequence based on when FPI, wind, and dry fuel moisture exceed guidance a structure would be reviewed to be in scope on weather alone.

2021

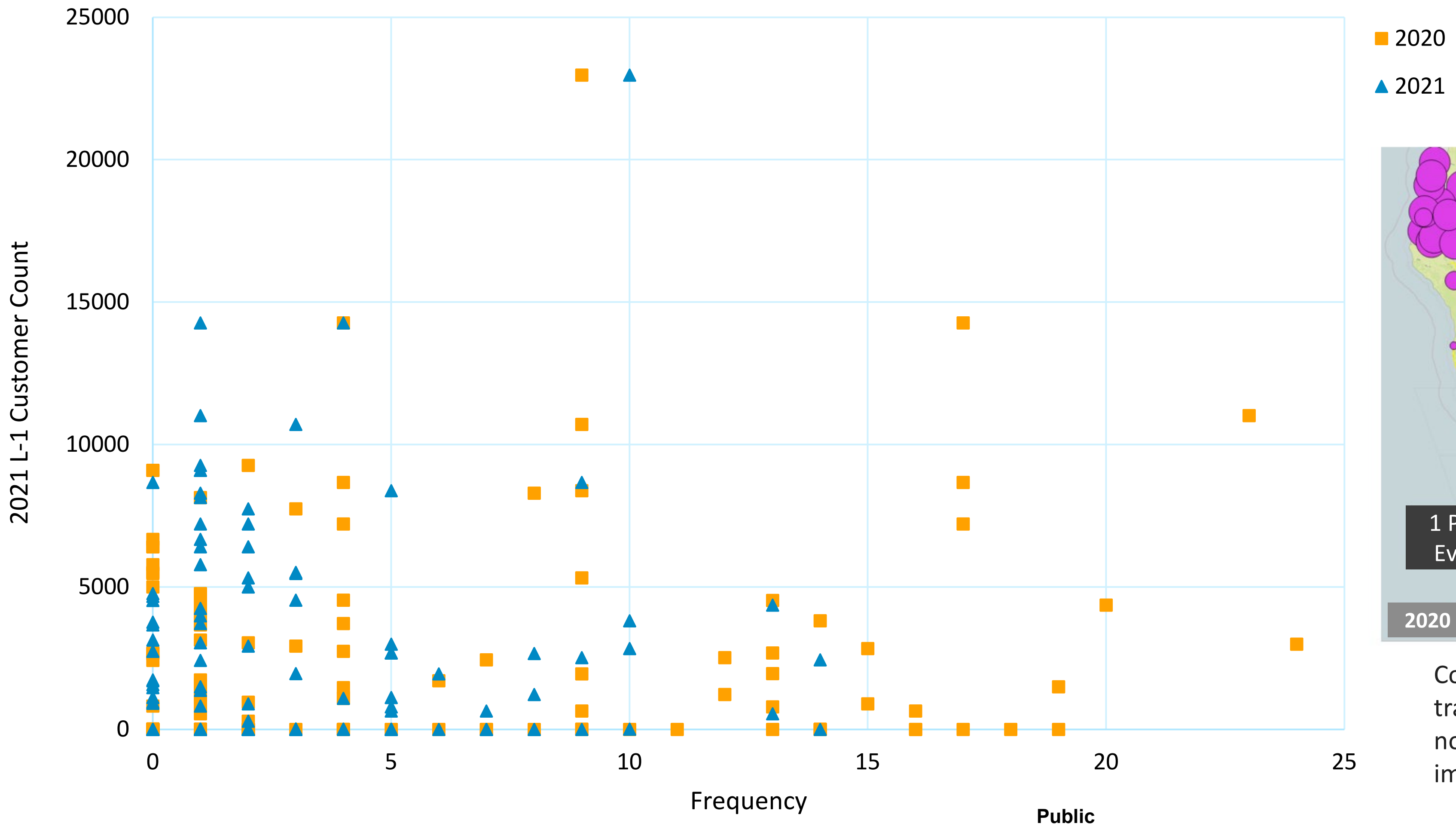
Catastrophic Fire Behavior

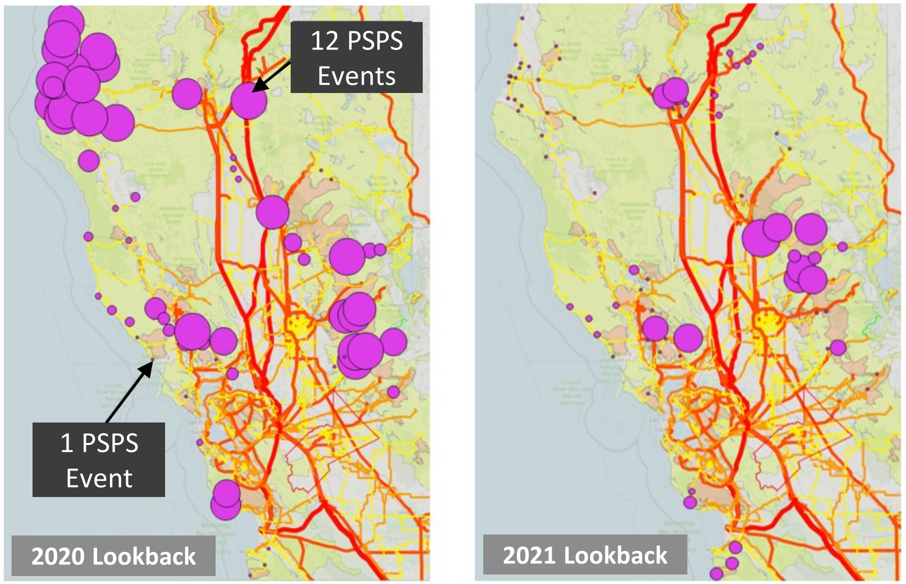
- Where **Technosylva's** fire spread modeling indicates catastrophic fire behavior is possible (intense, fast spreading fires).

[1]Fire Potential Index (FPI) is used to assess the probability of a small fire becoming a large fire based on weather and fuel data
[2]Operatability Assessment (OA) assesses the probability of failure of transmission line assets at a specific windspeed
[3]Black Swan is extreme weather and environmental conditions (e.g., exceedingly high winds combined with low moisture content) leading to de-energization

2020 Historical Lookback and 2021 Historical Lookback Comparison

Overall, the number of lines impacted by transmission PSPS for the 2021 10-year historical lookback has slightly increased. However, the frequency in which those lines would have been scoped as direct impacts has significantly decreased for the 2021 historical lookback.





Comparing 2020 and 2021 10-Year Lookback analyses of transmission PSPS impacts on substations within PG&E's northern service territory (size of point represents PSPS direct impact count)

PSPS Lookback – Indirect Impact

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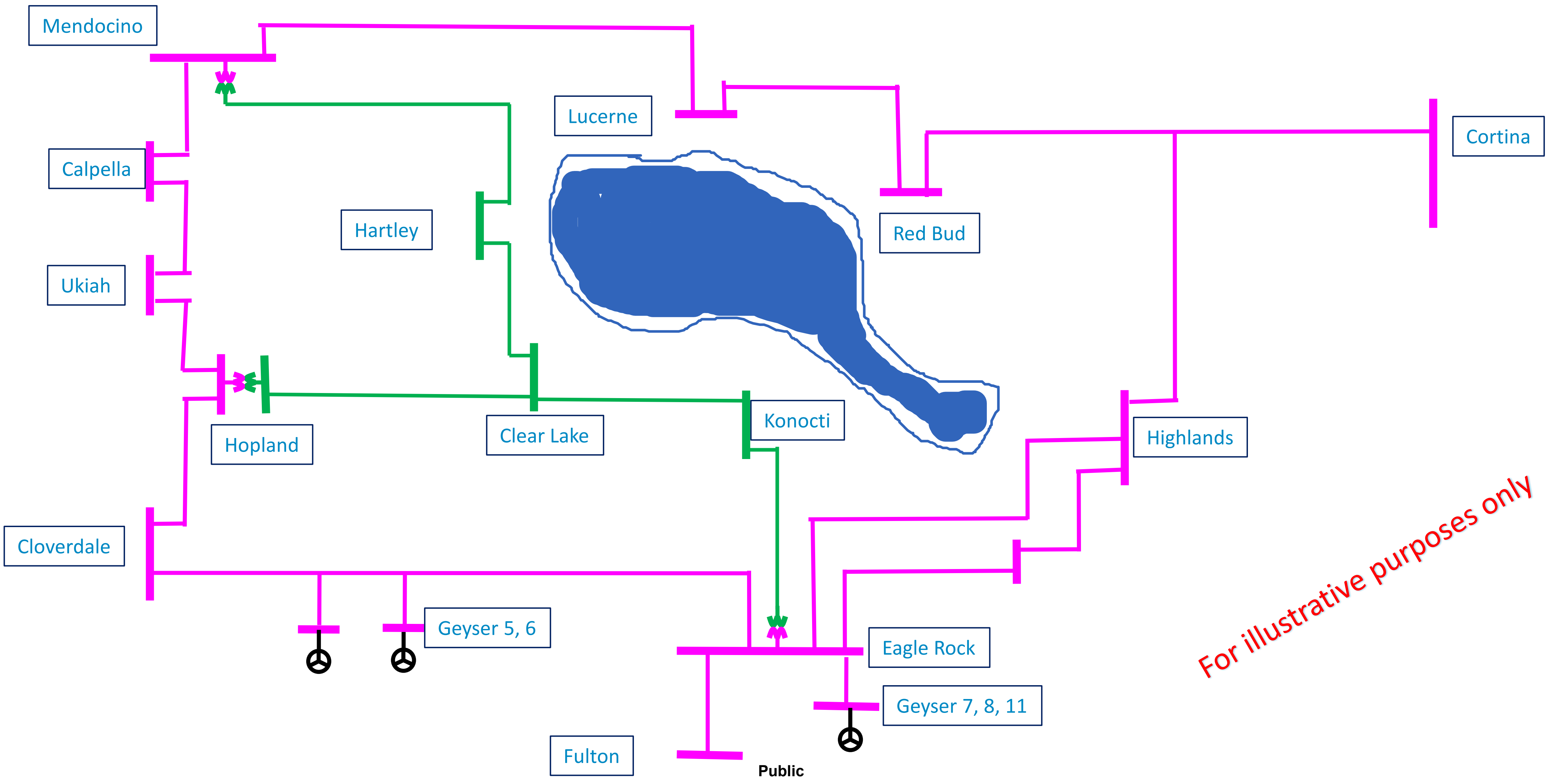
Indirect Impact – What is it again?

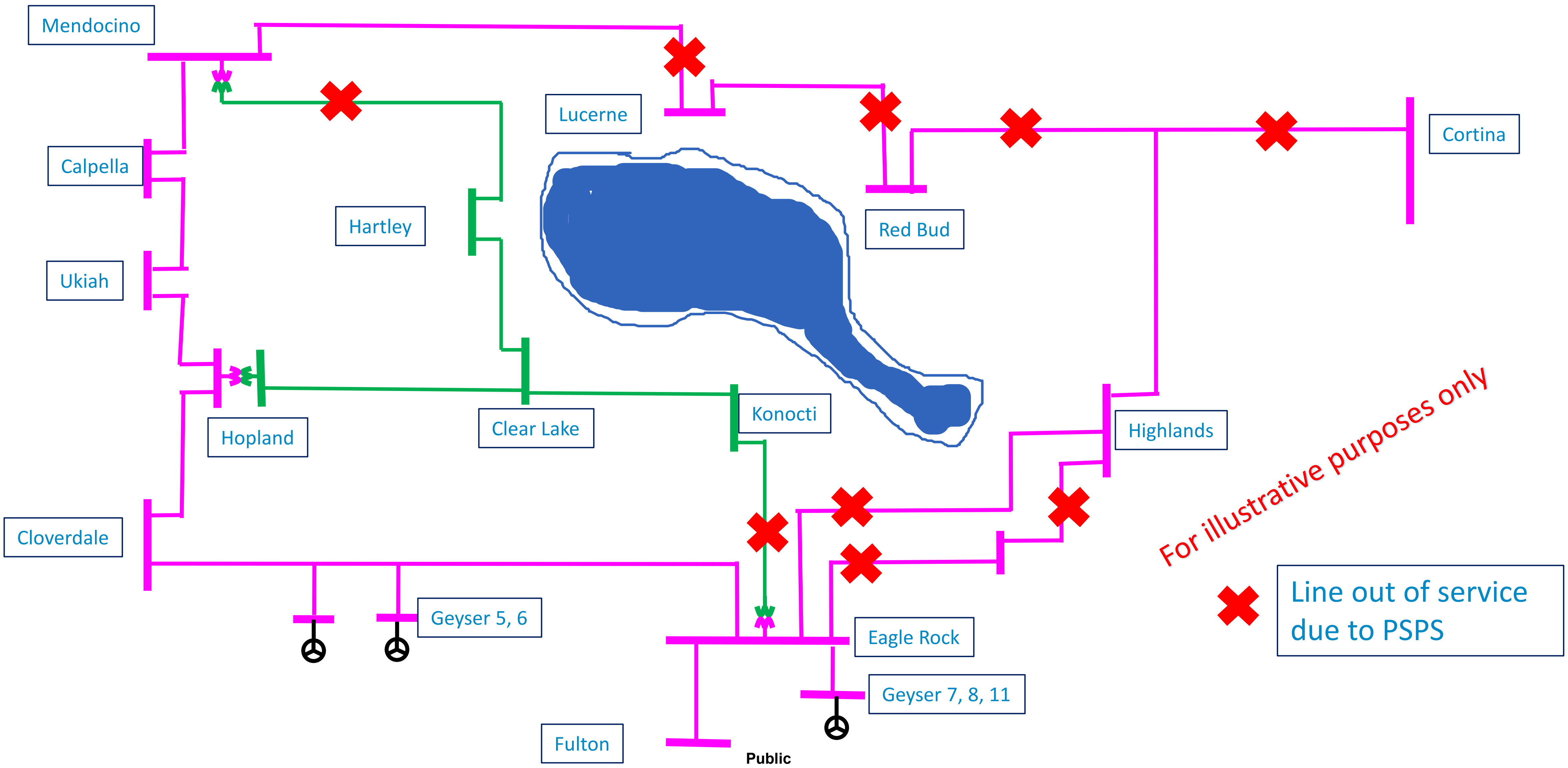
- Electrical connection may remain, but transmission system exceeds a reliability limit[1] (e.g., thermal overload or voltage instability)
- Due to numerous transmission lines scoped to be de-energized the remaining system may not be designed to support the load that is still connected
  - NERC Transmission Planning (TPL) reliability standards require N-1-1 criteria, PSPS may be N-10 or N-20
- Absent a long-term capital solution (e.g., transmission upgrades, in area generation, etc) the remaining operational solution to mitigate transmission impacts may be to drop load (i.e., de-energize a selection of customers)

[1]Operating above a reliability limit can lead to grid instability and outages

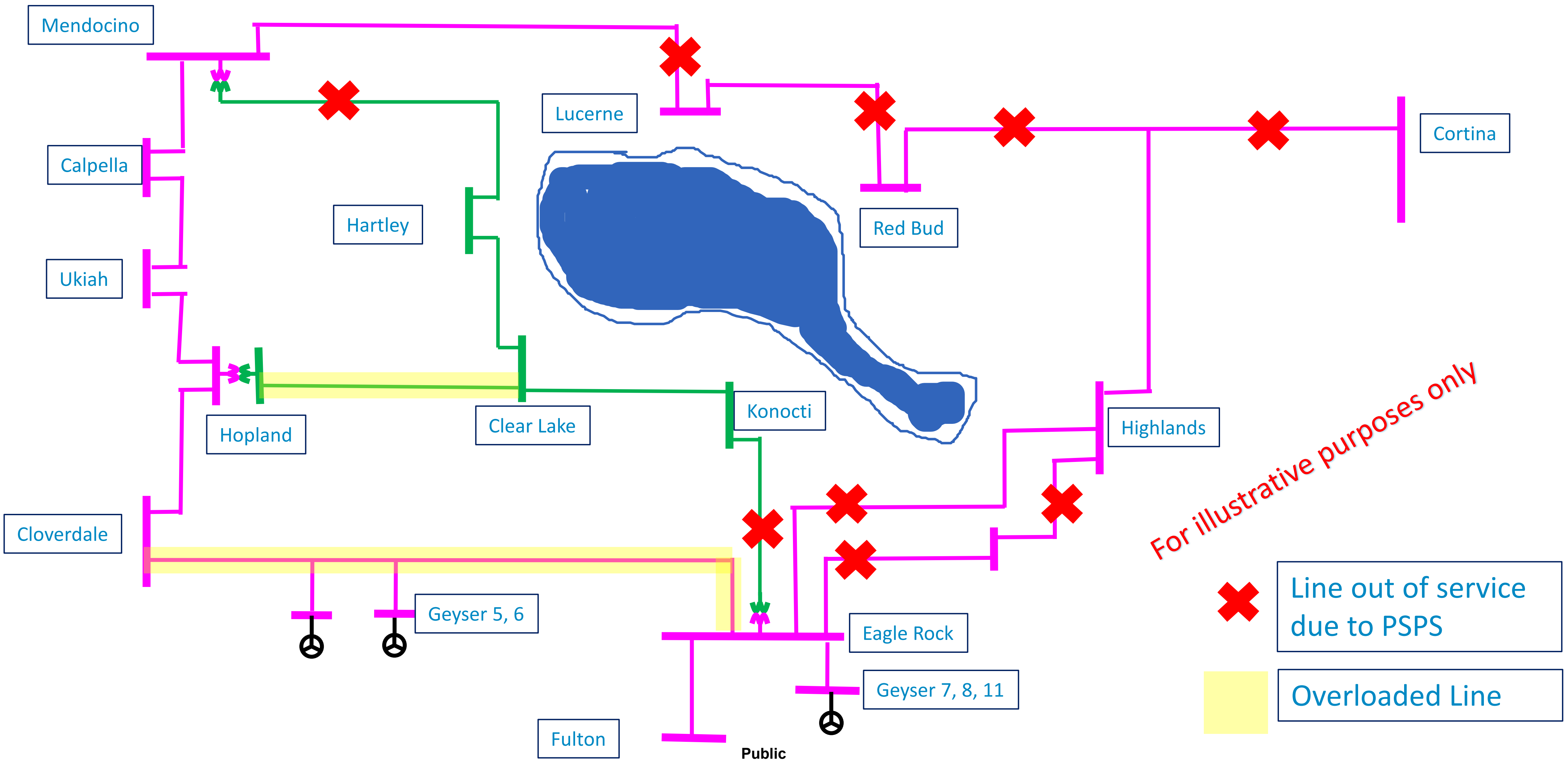
Eagle Rock – Mendocino Pocket System Normal



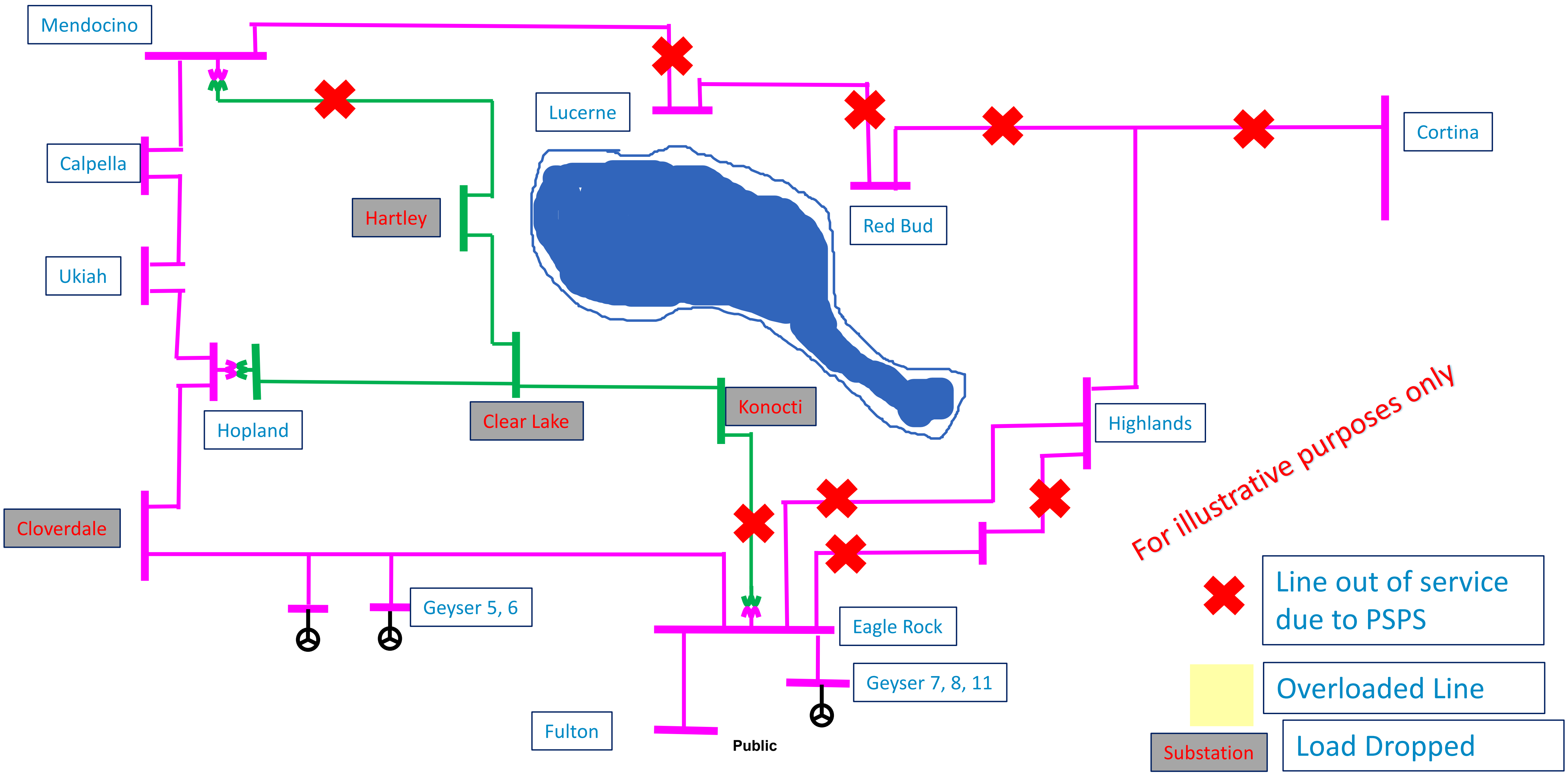
Eagle Rock – Mendocino Pocket PSPS Scope 10-09-2019 [Lookback]



Eagle Rock – Mendocino Pocket Affected Facilities



Eagle Rock – Mendocino Pocket Substations dropped (Indirect)



Q & A

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Thank you!

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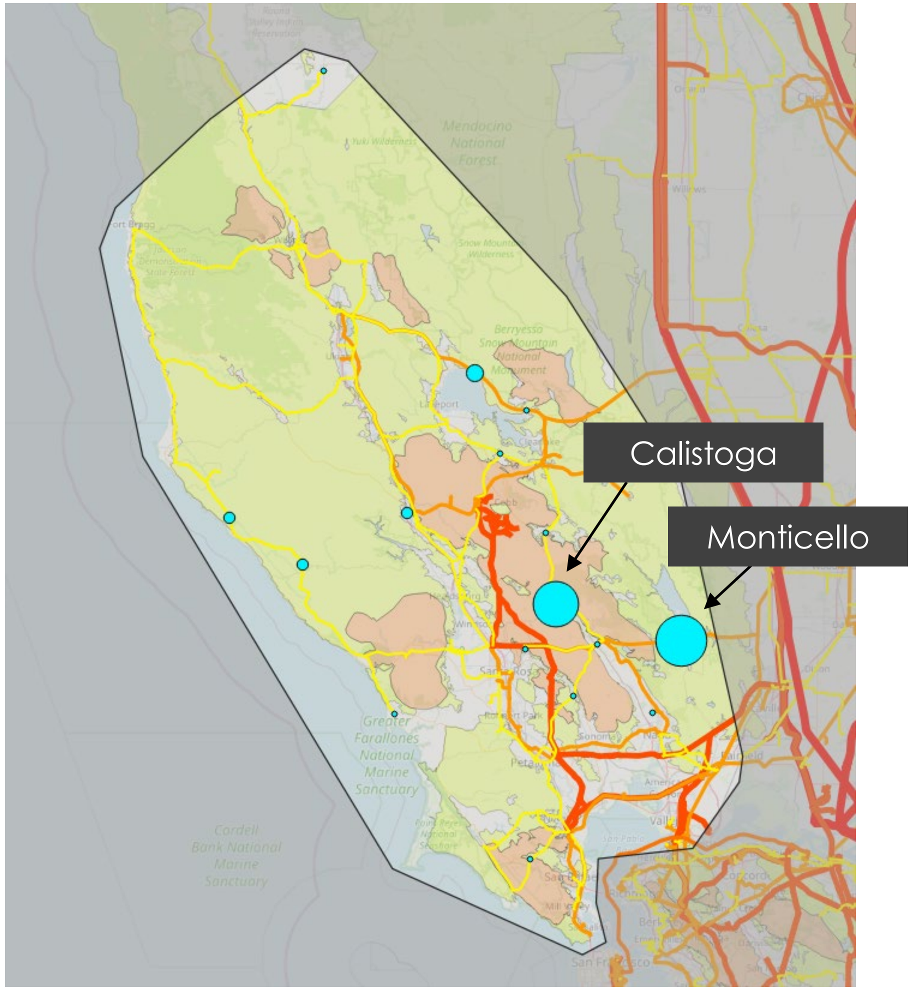
Implications of Lookback for the North Coast

Direct Impacts in the North Coast

- Calistoga (8 Direct Impacts), Monticello (9 Direct Impacts)
- <u>Calistoga: </u>Currently has a large distribution microgrid and PG&E has an open RFO to expand that to a clean substation microgrid.
- <u>Monticello: </u>Likely has an existing solution (transmission switching) that would mitigate most of these PSPS impacts.
- Direct PSPS Impacts likely need no further study or action from the NCRI

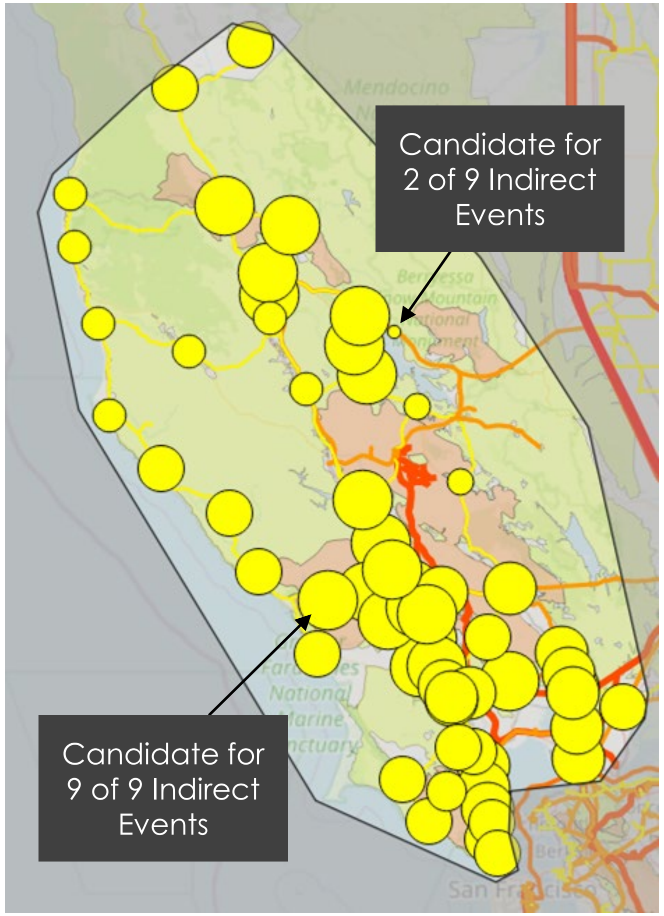


Direct Impacts with 100+ Safe-to-Energize Customers; Size of circle represents number of times the substation is impacted

Potential Indirect Impacts in the North Coast

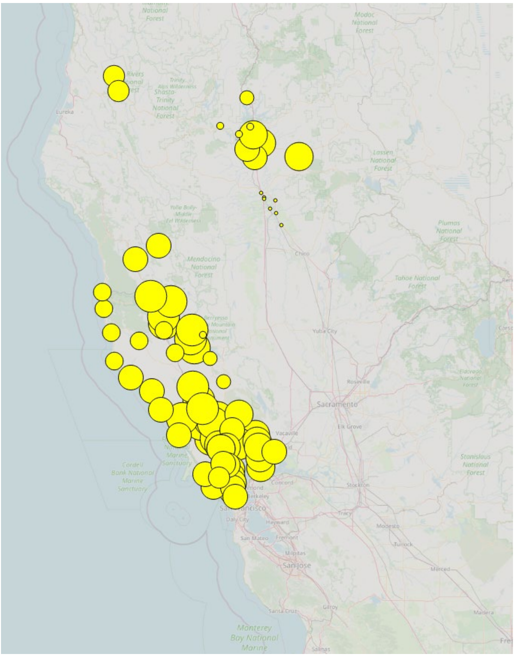
- All substations that *could* be deenergized as part of an indirect PSPS impact are shown as "candidate" substations.
- In any given event, only a subset of the substations would *actually* incur indirect impacts.
- The yellow bubbles show that load could be dropped at any one of these points throughout the North Coast region.
- About 40 substations are candidates for 7-9 indirect impact events in the North Coast.

North Coast Indirect Impacts in Lookback Analysis



Candidate Substation for Indirect Impacts; Size indicates number of times the substation is a potential candidate

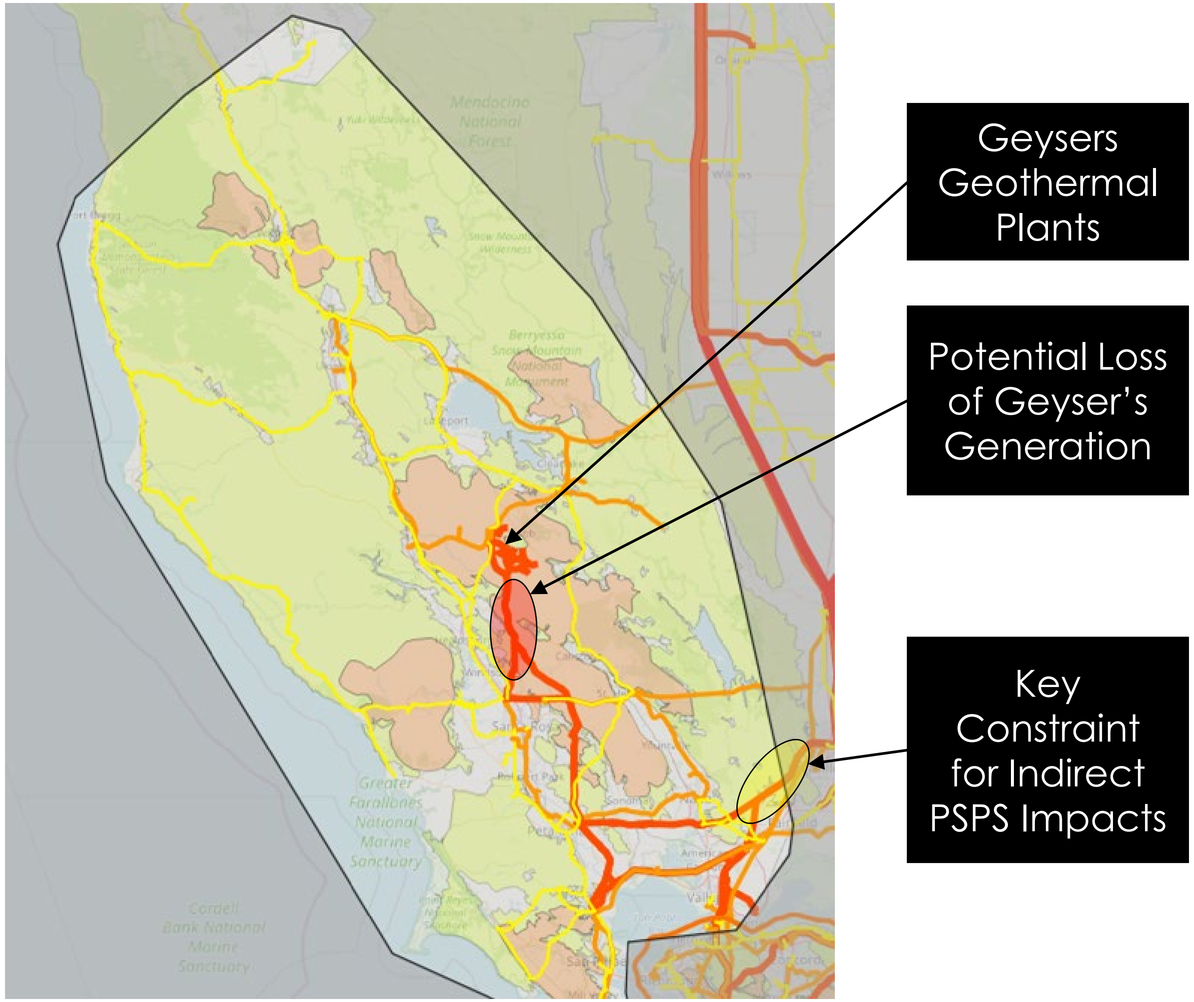
All Indirect Impacts in Lookback Analysis



Potential Indirect Impacts in the North Coast

- In the past 10 years, the lookback analysis showed **9 indirect impacts** in the North Coast region. These events roughly following the same pattern, shown on the right.

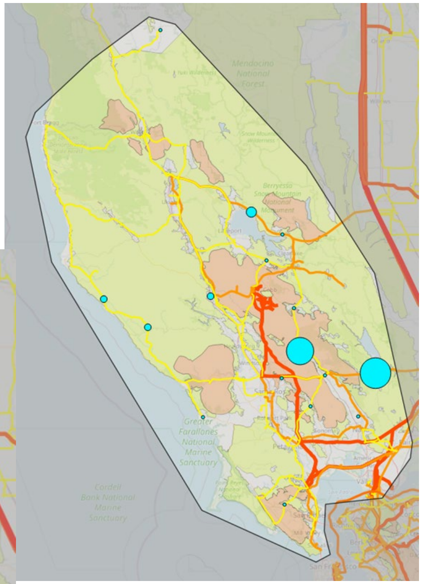
- For each indirect impact, an estimated **10-30 percent of regional load** may need to be dropped.

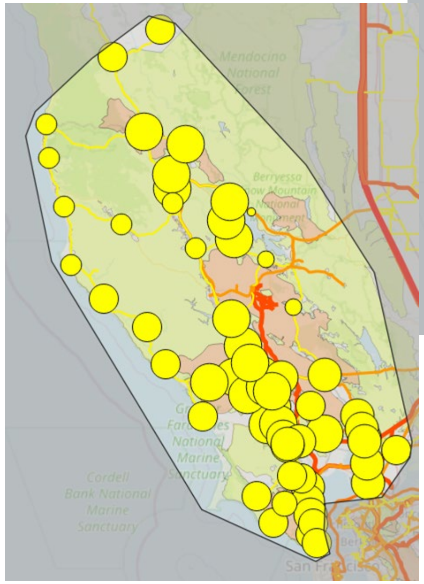


Next Steps for the NCRI

Study Indirect Impacts and Identify Mitigations

- Direct PSPS Impacts likely need no further study or action from the NCRI.
- By contrast, for indirect impacts, the NCRI plans to continue studying:
  - The likely scope of these impacts in the future.
  - The factors that combine to cause these impacts.
  - Detailed information on when and where these impacts may occur.
  - The potential mitigations for these impacts.





Establish an Evaluation Methodology for Indirect Impact Mitigations

10-Year Historical Lookback

Used to define the scope and focus of the NCRI study:

- Direct Impacts - Calistoga and Monticello
- North Coast Indirect Impacts - Geysers Drop and Potential Vaca-Dixon Overload
- Additional Indirect Impacts – Clearlake

NCRI “Resiliency Standard”

- Used to judge and prioritize between mitigation projects that come up within the NCRI study.
- The NCRI Steering Committee has not finalized an evaluation methodology, it is an ongoing effort.
- This methodology would *only* apply to the NCRI.

Build a Comprehensive Regional Plan

1. Combine mitigations considered in NCRI study into a comprehensive regional plan.
2. Evaluate whether transmission upgrades to increase regional deliverability are reasonable and cost-effective based on this comprehensive plan, also considering other relevant factors.
3. Consider the extent to which other state, regional or local policy goals or initiatives may fit into the NCRI comprehensive plan.

Propose Mitigations and Funding Mechanisms

To the extent the NCRI Steering Committee identifies preferred mitigation projects for transmission-level PSPS in the North Coast:

- Identify potential sources of funding (existing and/or new).
- Identify already-existing planning processes (i.e. the CAISO TPP) that may relate to the projects.
- Build preliminary buy-in for the proposed mitigations.

Develop a Broader Regional Planning Framework

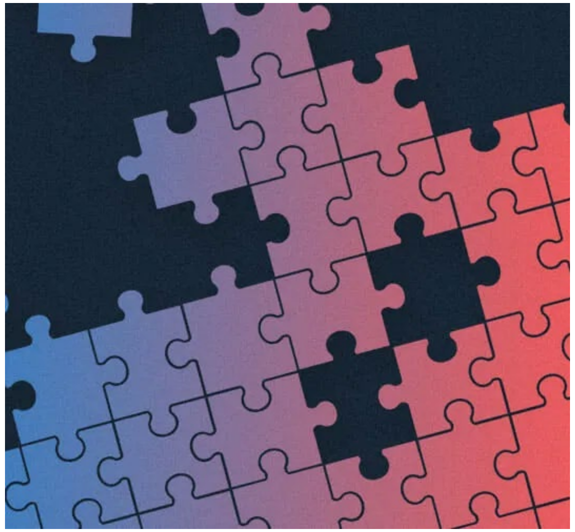
The NCRI will also issue a report including:

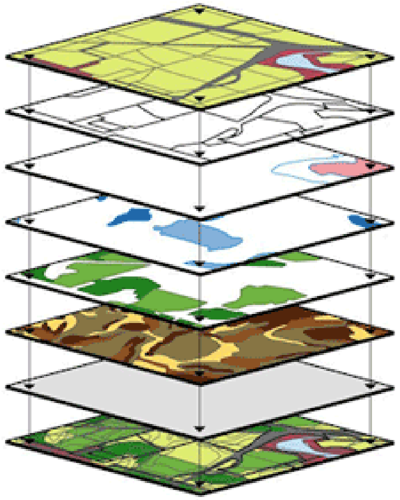
(1) An overarching description of the course of the initiative, including any outcomes or conclusions, and

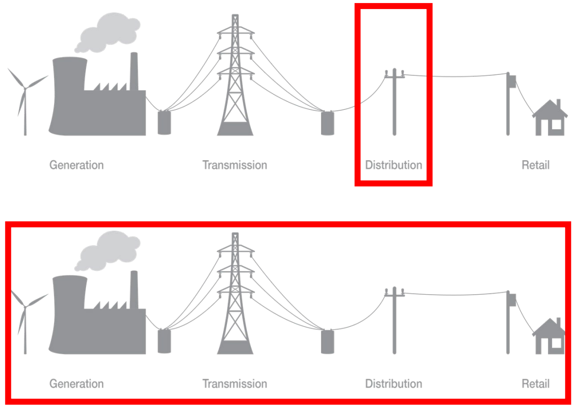
(2) A proposed broader comprehensive regional planning processes.

When the Draft Report is issued, we will hold another public workshop and take feedback.

If you have additional feedback, feel free to email Daniel Tutt at **daniel.tutt@cpuc.ca.gov**







Q&A and Feedback from Attendees

Feedback: Questions for Consideration

1. What about your understanding of resiliency planning changed as a result of today's presentation?
2. What resiliency issues are you experiencing/do you anticipate in your area?
3. How well does this framework suit your resiliency planning needs? What else might you need?
4. What do you think we have overlooked?

For more information:

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Appendix

Representation of Indirect Impact – 2021 Approach

- **How best to assign indirect impact to substations within a load pocket?**
  - 2020 approach: mapping impact to specific substations within a sub-area
    - Based on heuristics (e.g., effectiveness, size of Substation load, historic PSPS de-energization actuals)
  - 2021 consideration: representing impact at all effective substations within a sub-area
    - Reflecting the operational reality that a broader set of substations can also be selected
    - This is the menu of stations that can be impacted but need not be all of them. This will depend on the system need for the event