The North Coast Resiliency Initiative

Information Session

July 11, 2023

California Public
Utilities Commission

WebEx Logistics

- All attendees are muted on entry by default.

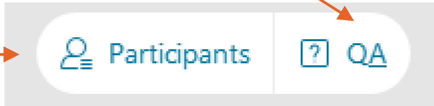
- Please write your questions in the Q&A panel. Questions will be addressed during the Q&A periods of the agenda.

- Comments or Questions can be provided verbally during the Q&A periods 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 Tips

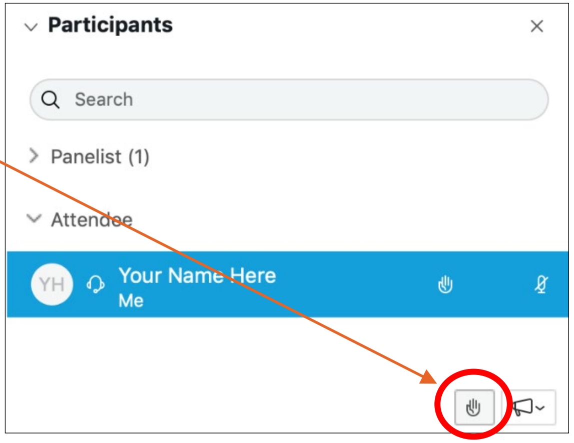
Access the written Q&A panel here

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.



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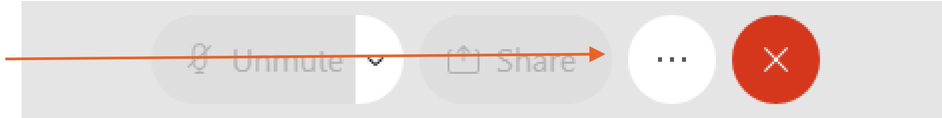


WebEx and Call-In Information

Join by Computer:

https://cpuc.webex.com/weblink/register/rab3da63907d111c895a179130dd2caca

Meeting Number: 2494 025 4774

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.

Opening Remarks

Commissioner Genevieve Shiroma

Agenda

Topic	Duration	Time
Welcome and Opening Remarks	10 min	9:00 to 9:10
Background: Wildfire Risk and PSPS	15 min	9:10 to 9:25
Wildfire Risk, PSPS Impacts, and the North Coast	15 min Presentation 15 min Q&A	9:25 to 9:55
NCRI Introduction	20 min Presentation	9:55 to 10:15
BREAK	10 min	10:15 to 10:25
NCRI Key Findings	20 min Presentation 15 min Q&A	10:25 to 11:00
Problem Solving Framework	15 min Presentation 30 min Q&A and Discussion	11:00 to 11:45
Next Steps and Closing Remarks	15 min	11:45 to 12:00

Objectives

1. Attendees have an improved understanding of Wildfire Risk and Public Safety Power Shutoffs (PSPS) in California.

2. Attendees are aware of the findings from the NCRI for mitigating transmission-level PSPS in the North Coast.

3. Attendees are familiar with the broad framework used in the NCRI, and how it might be applied in the future.

View the full report on the CPUC website here.

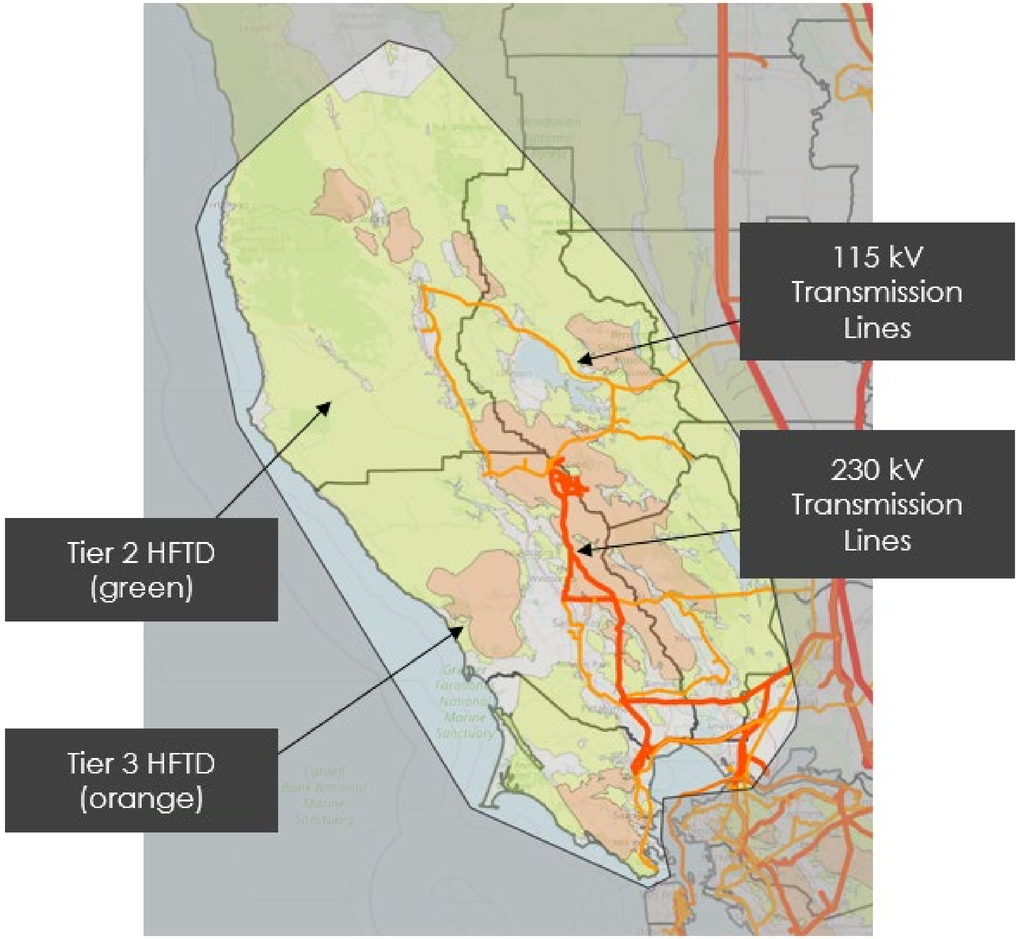
Background: Wildfire Risk and PSPS

Key Terms: Public Safety Power Shutoffs (PSPS)

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.

Key Terms: High Fire Threat Districts (HFTDs)

- Areas where there is a higher risk for power line fires igniting and spreading rapidly, i.e. destructive power line fires.
- There are Tier 2 HFTDs (higher risk) and Tier 3 HFTDs (extreme risk).
- Stricter fire-safety regulations apply to HFTDs.
- The CPUC worked with CAL FIRE and others to develop the Fire-Threat Map of California.*



Map of "North Coast" with HFTDs shown.

*See this website for more information on HFTDs.

Key Terms: Distribution vs Transmission

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.**

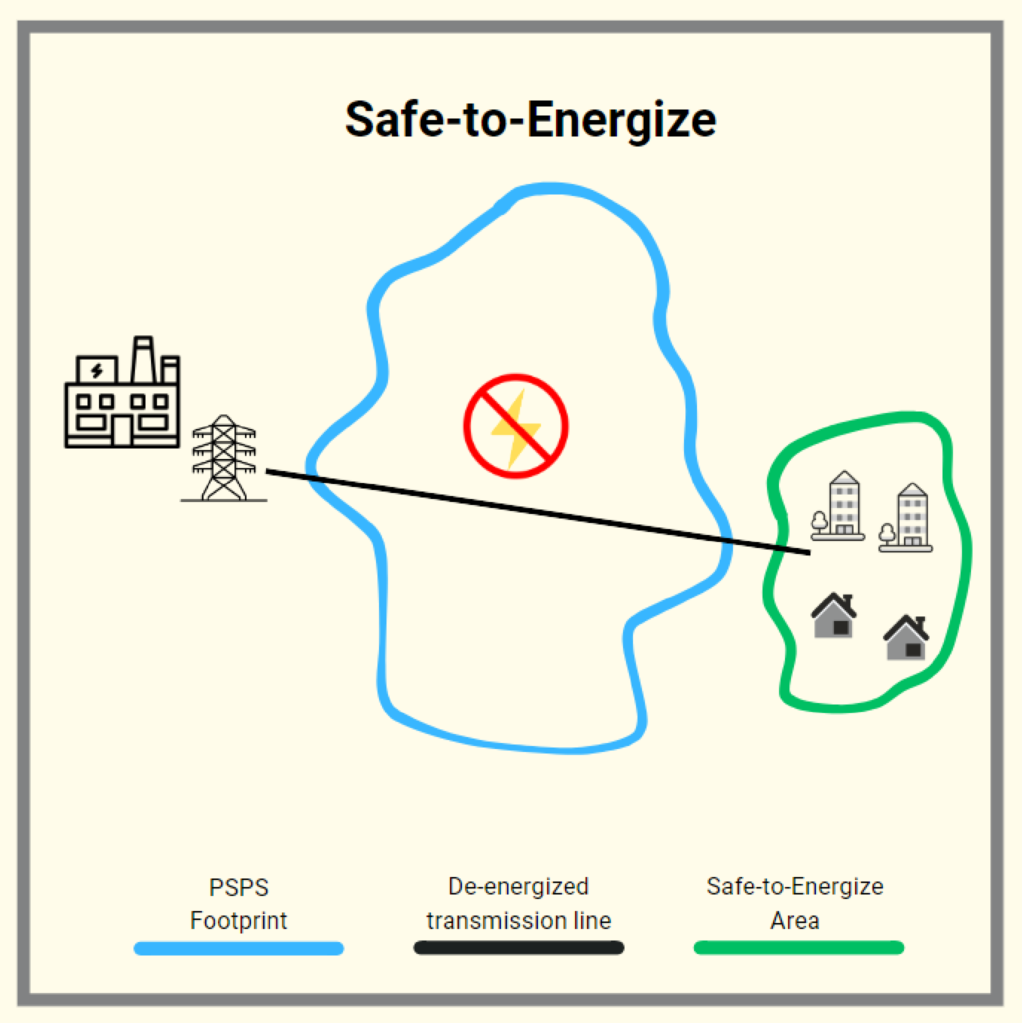
The NCRI only addresses Transmission-level PSPS, various mitigations for Distribution-level PSPS are described in PG&E's Wildfire Mitigation Plan

Key Terms: Safe-to-Energize Customers

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 directly serving them are safe.

Finding

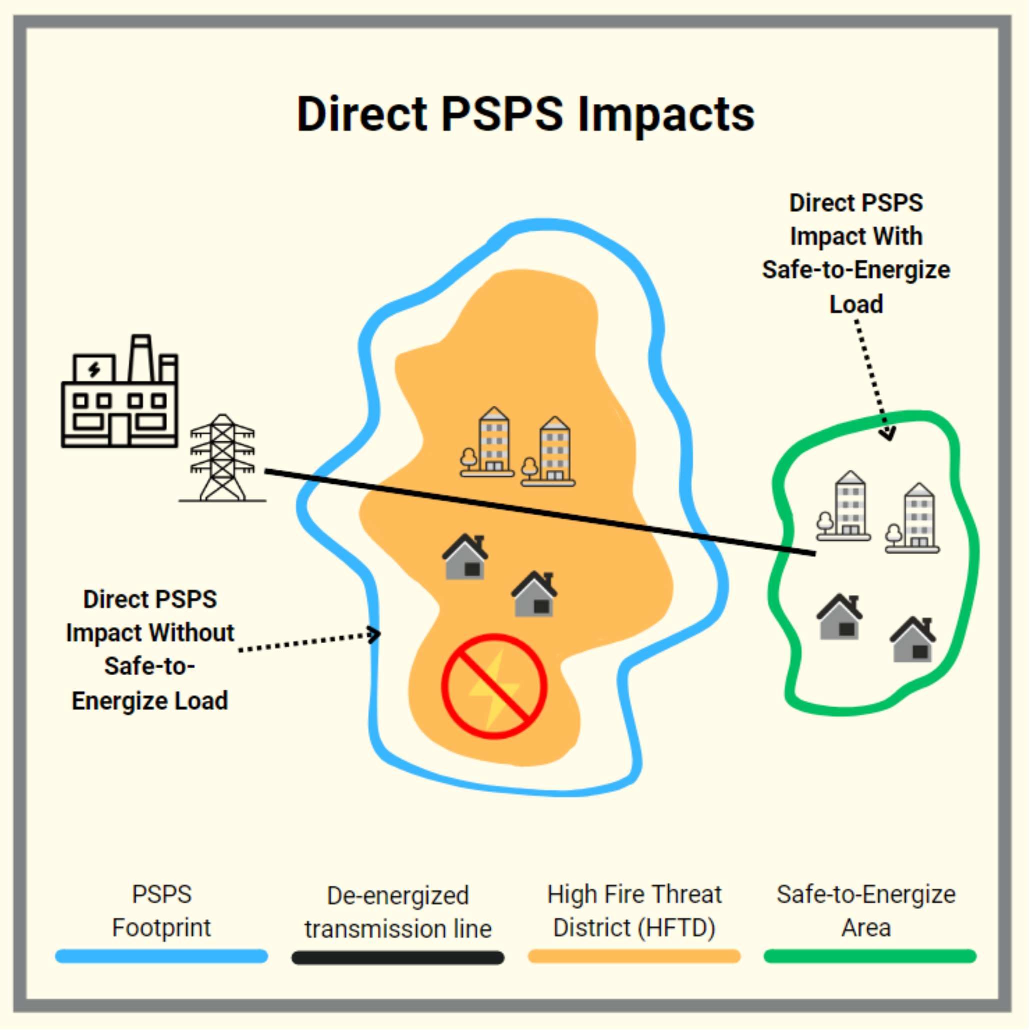
Many customers along the North Coast who are otherwise "safe-to-energize" also lose power during PSPS events. In this case, safe-to-energize refers to **customers who are located outside of the conditions that triggered the need for a PSPS event, but are served by a distribution or transmission line that has been de-energized**. If the grid configuration were different, they would be able to remain online.



Key Terms : Direct vs Indirect PSPS Impacts

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

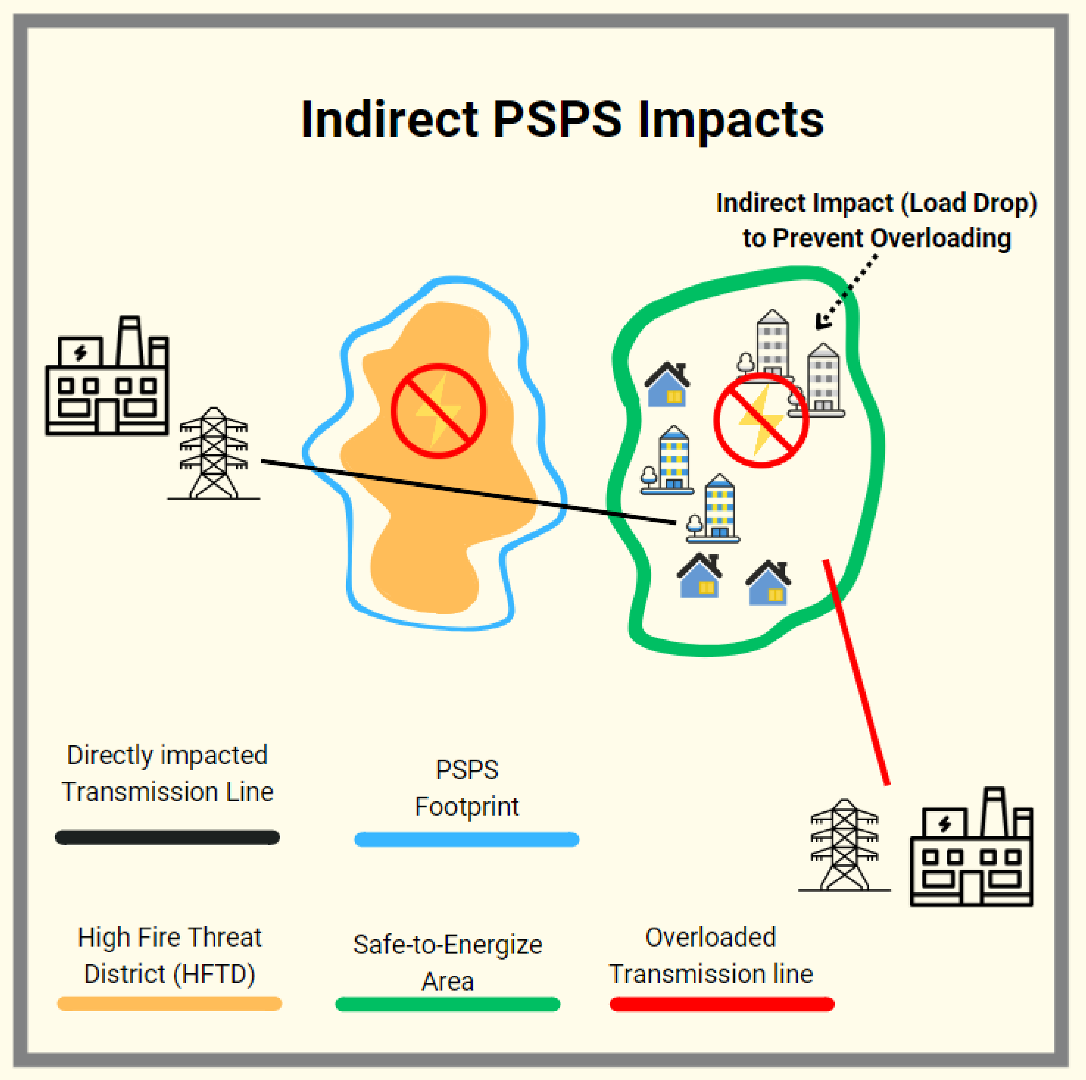
Finding
Transmission lines are impacted by wildfire risk and resulting PSPS events in different ways. These **differences alter the suite of available mitigations and their effectiveness.** Some lines are "**directly impacted**," meaning they are de-energized because they **pass directly through an area experiencing weather conditions** that drive the need for a PSPS event.



Key Terms : Direct vs Indirect PSPS Impacts

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

Finding
Some lines are "**indirectly impacted**," meaning they **become at risk of overloading** (and damage) during PSPS events when they are required to take on the load typically served through other directly impacted transmission lines, requiring load drop.



Key Terms: Historical Lookback Analysis (HLA)

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

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

3. Currently approved PSPS event **scoping framework, protocol, and criteria**

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

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

The HLA examines 10 years of historical weather conditions through the lens of current PSPS de-energization criteria and grid conditions. This enables the HLA to estimate **how many PSPS events would have been triggered during that 10-year historical period if current PSPS criteria and grid conditions had been in effect throughout**.

*Though implications can be drawn from past events, it is important to note that future weather events are not predictable and may present worse or different conditions than what was studied.

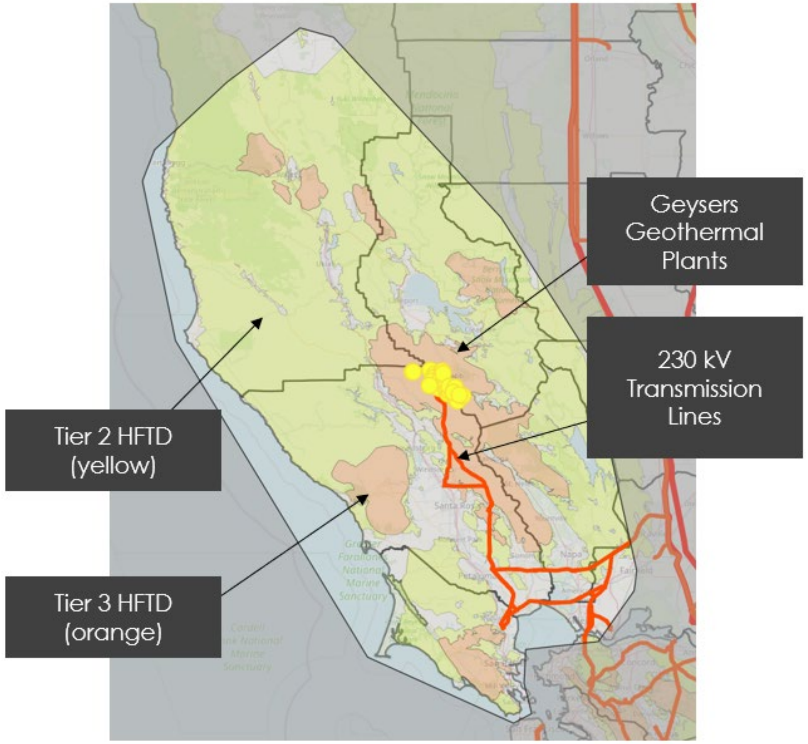
Key Terms

- Public Safety Power Shutoffs (PSPS)
- High Fire Threat Districts (HFTDs)
- Distribution vs Transmission Lines
- Safe-to-Energize Customers
- Direct vs Indirect PSPS Impacts
- Historical Lookback Analysis (HLA)

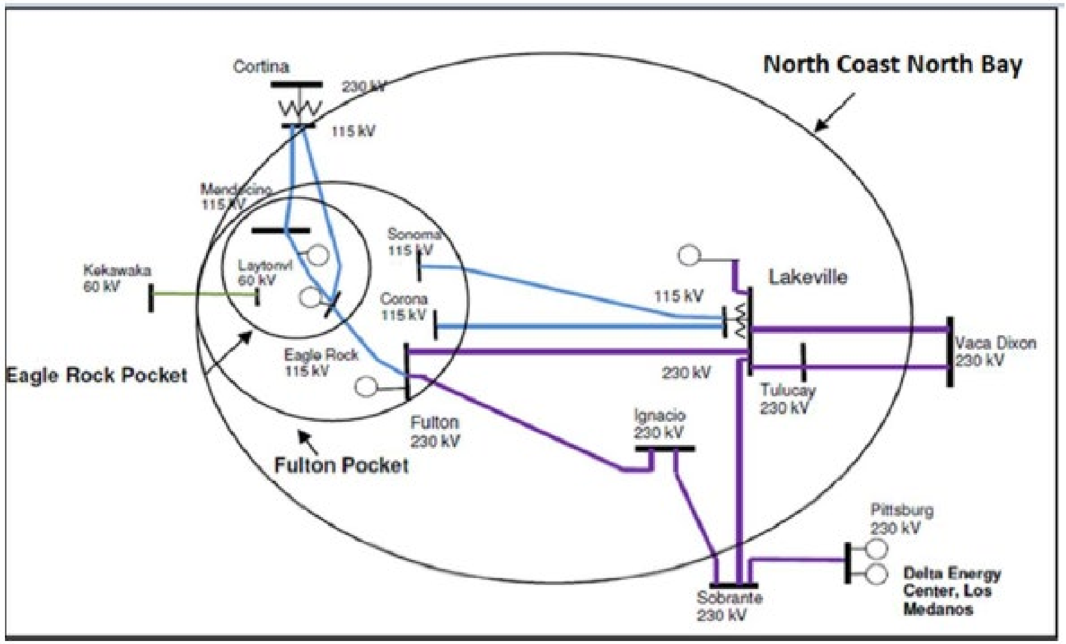
Wildfire Risk, PSPS Impacts, and the North Coast

Unique Grid Conditions in the North Coast

The North Coast Area has Significant Wildfire Risk

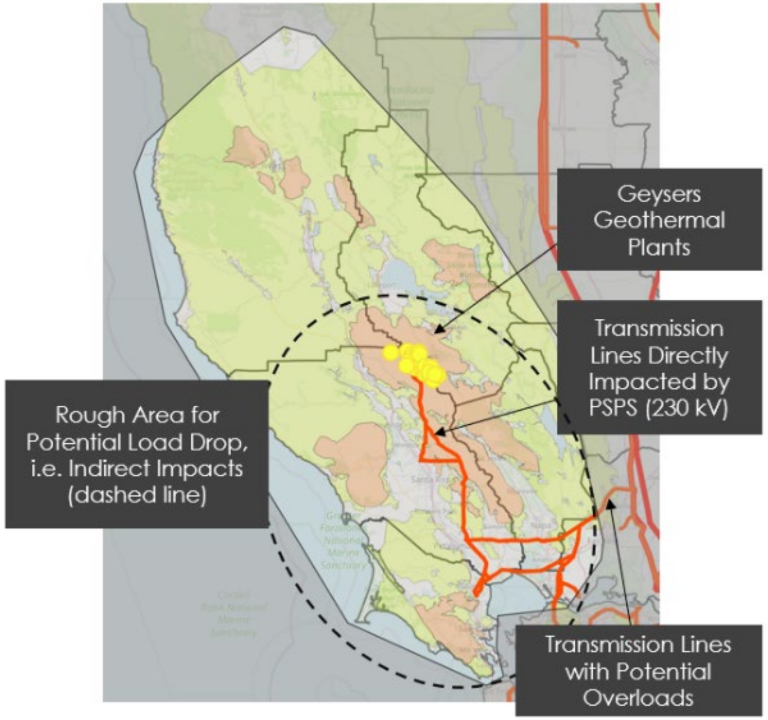


The North Coast Area is Import Constrained, a "Local Capacity Area"

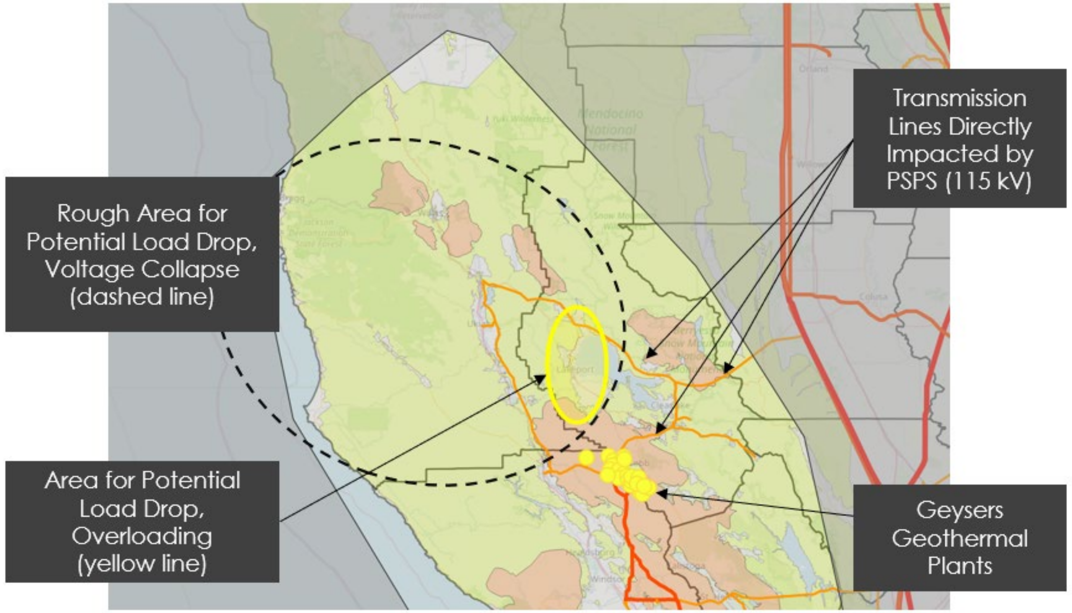


Two Areas for Potential Indirect PSPS Impacts

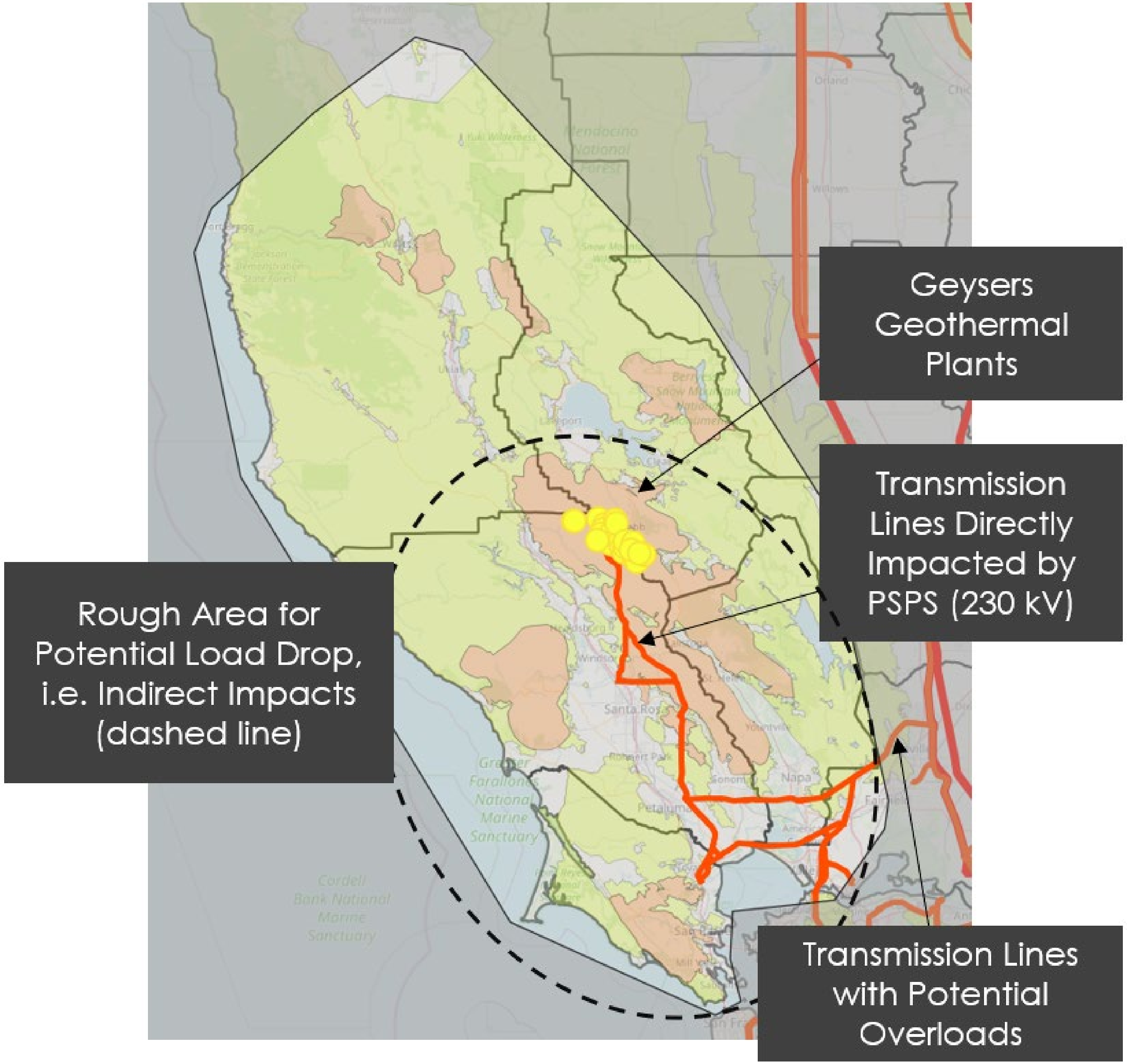
Vaca-Dixon—Lakeville Area



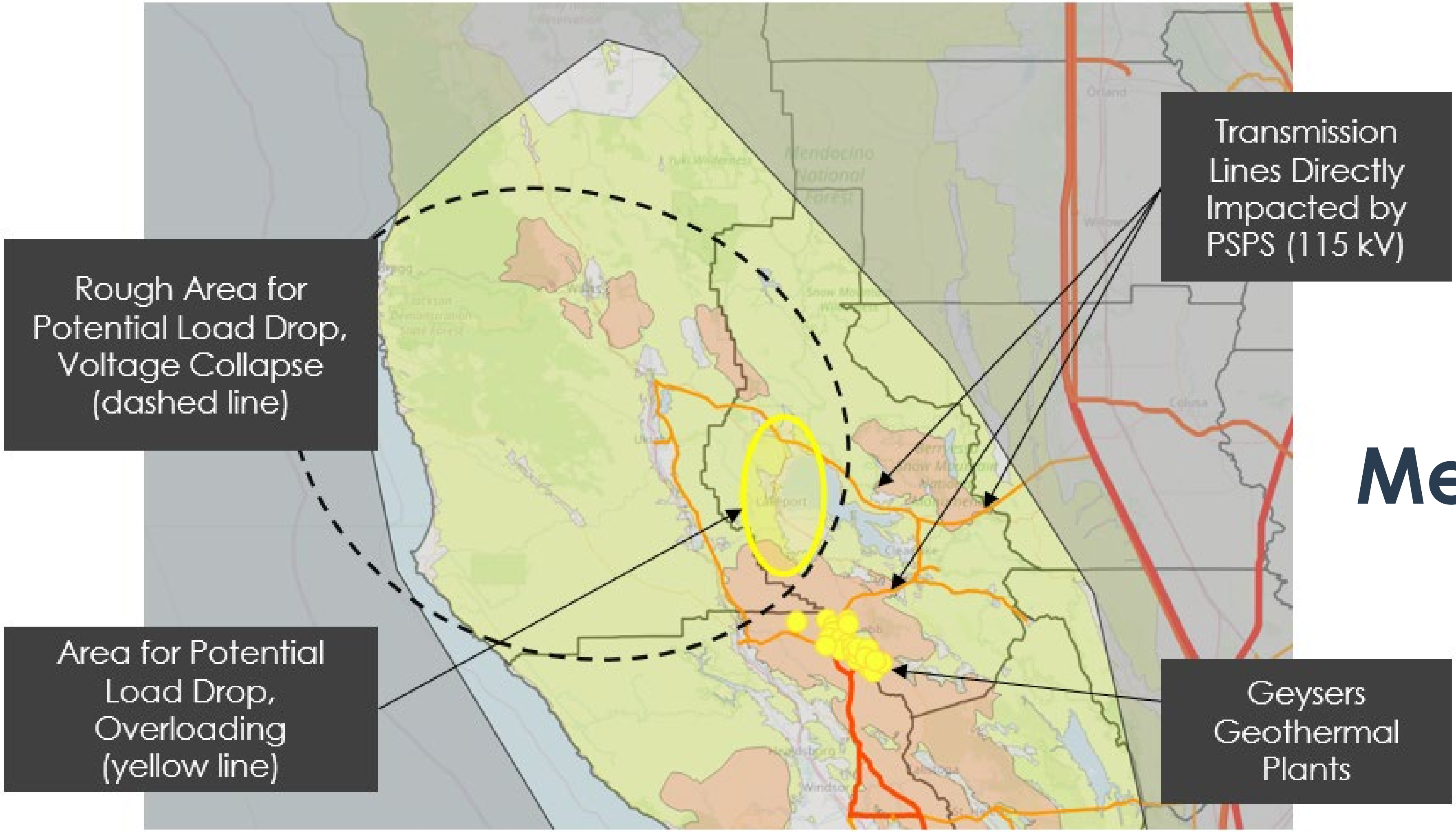
Mendocino Area



Vaca-Dixon—Lakeville Area

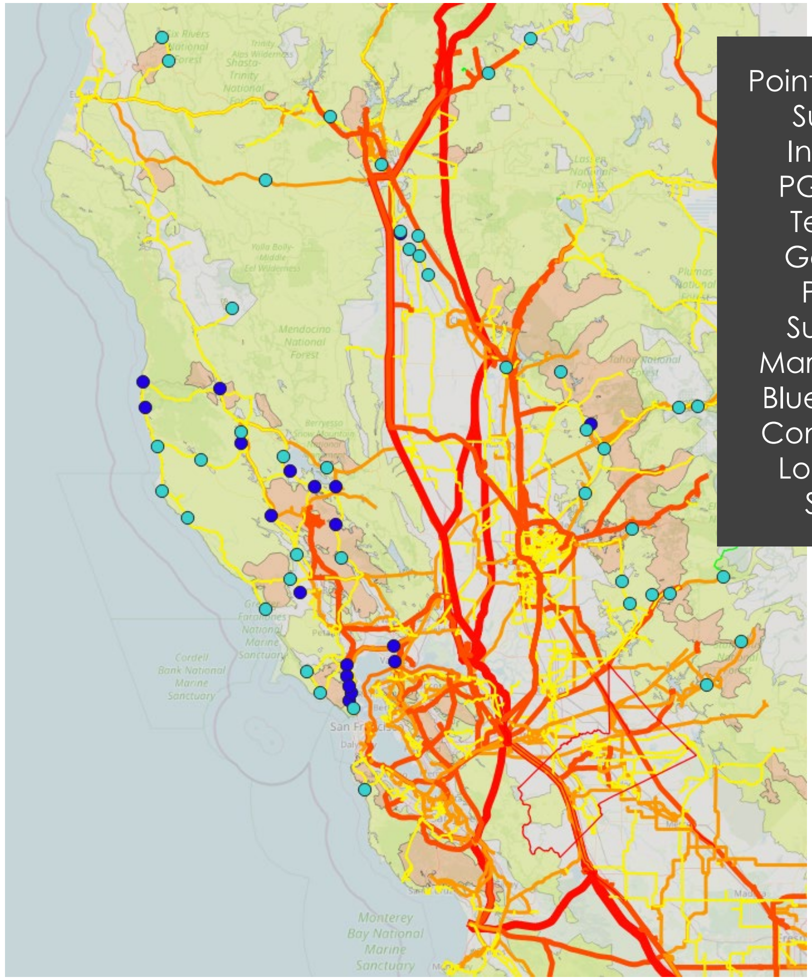


Mendocino Area



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.



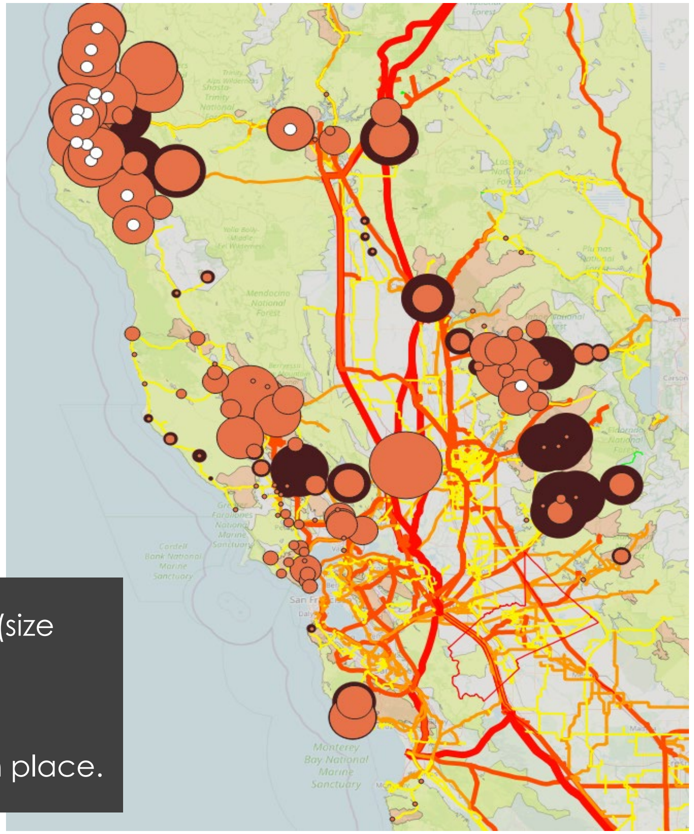
Points Indicate a Substation Included in PG&E's 2020 Temporary Generation Program. Substations Marked in Dark Blue Were Also Considered for Longer-Term Solutions

Resiliency Need: Advances in Modeling and Data

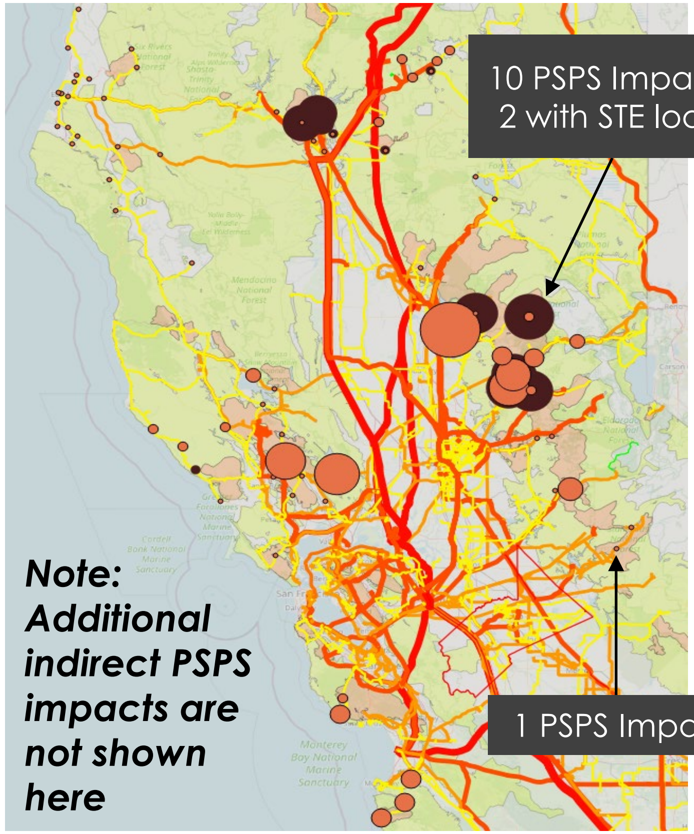
Finding

Improved modeling and asset conditions on PG&E's electric system are driving a **reduction in the frequency and size of transmission-level PSPS events along the North Coast**.

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.

Q&A

Introduction to the NCRI

NCRI Problem Statement

Assumptions:

- The North Coast of California has historically been impacted by transmission-level PSPS events to a greater extent than other areas of the state.
- Modeling available at the creation of the NCRI in 2020 indicates the North Coast area may continue to face transmission-level PSPS events affecting otherwise safe-to-energize customers.
- PSPS events are expected to result in de-energizing multiple transmission lines in the region, directly affecting some substations by cutting them off from transmission-level power and others indirectly by exceeding the load-serving capacity of the regional transmission network.

Primary Question:

- **How can transmission hardening, new energy resources, and other measures be used to cost-effectively mitigate transmission level PSPS events in the North Coast area, without utilizing temporary diesel generation?**

Secondary Questions:

- How should the NCRI identify and evaluate these alternatives against each other and diesel temporary generation?
- How should the NCRI evaluate cost-effectiveness of these measures and compare mitigations to one another as well as to the status quo?
- How should an eventual solution or solution set be selected?
- How are vulnerable customers and disadvantaged communities impacted differently by each potential alternative?

NCRI Objectives

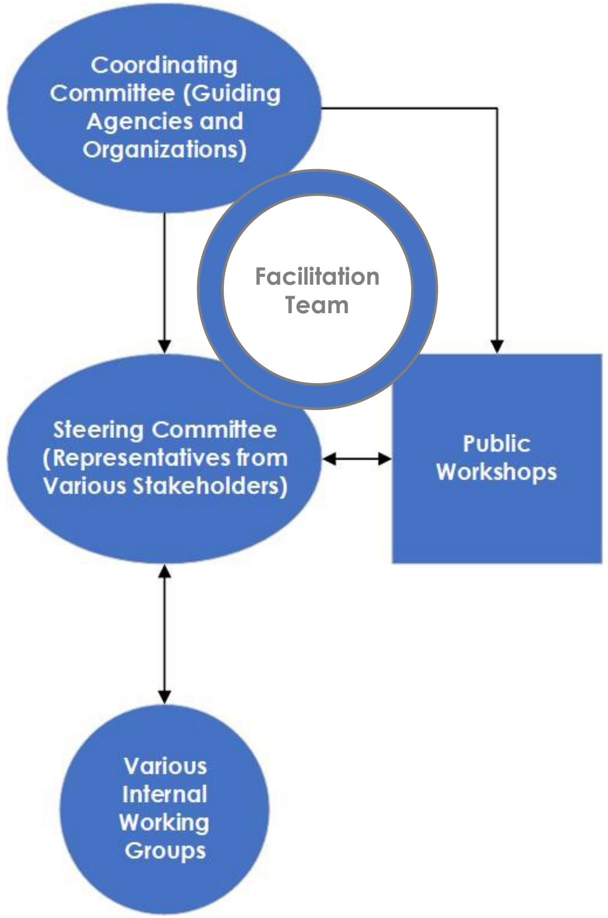
1. **Minimize transmission-level PSPS events through comprehensive regional planning.** Make this region of the grid resilient by minimizing the number of safe-to-energize customers affected by PSPS events in the long term. Specifically, reduce the risk of transmission-level PSPS outages, coordinating distribution hardening or new intra-regional resources with this larger transmission-level plan as needed.
2. **Pilot new grid planning strategies.** Use this initiative to pilot grid planning strategies and grid innovations that could be adopted more widely.
3. **Where reasonable, develop this region of the grid so it contributes to wider grid needs.** Potentially, intra-regional resources could provide PSPS resiliency as well as energy and/or resource adequacy to the larger grid outside of PSPS events.

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.



NCRI Project Phases

Phase 1: Build the Foundation

- Establish governance structure
- Craft problem statement, objectives, and principles

Phase 2: Define the Problem

- Assess potential for future direct and indirect impacts in North Coast, including affected transmission lines and frequency
- Determine root cause(s) of these impacts

Phase 3: Explore and Compare Mitigations

- Identify potential mitigations
- Collect data on costs and impact on customer outages for each mitigation
- Establish methodology for comparing mitigations against one another and the status quo
- Compare mitigations
- Select preferred mitigations

Phase 4: Conduct Comprehensive Regional Planning

- Combine preferred mitigations into a comprehensive regional plan considering the timeline, priority, and impact of these projects
- Identify potential funding sources and implementation owners

NCRI Key Participants

- **CAISO:** Binaya Shrestha, Jeffery Billinton
- **PG&E:** Jeremy Donnell, Madison Hoffacker, Will Dong, Avineet Pannu, Amanda Sweetman
- **Marin Clean Energy:** Jana Kopyciok-Lande, Shalini Swaroop
- **Sonoma Clean Power:** Neal Reardon, Ryan Tracey, Geof Syphers
- **CEC:** Mike Gravely
- **CPUC:** Daniel Tutt, Patrick Saxton, Forest Kaser, Jason Ortego
- **Gridworks:** Claire Halbrook

10 MINUTE BREAK

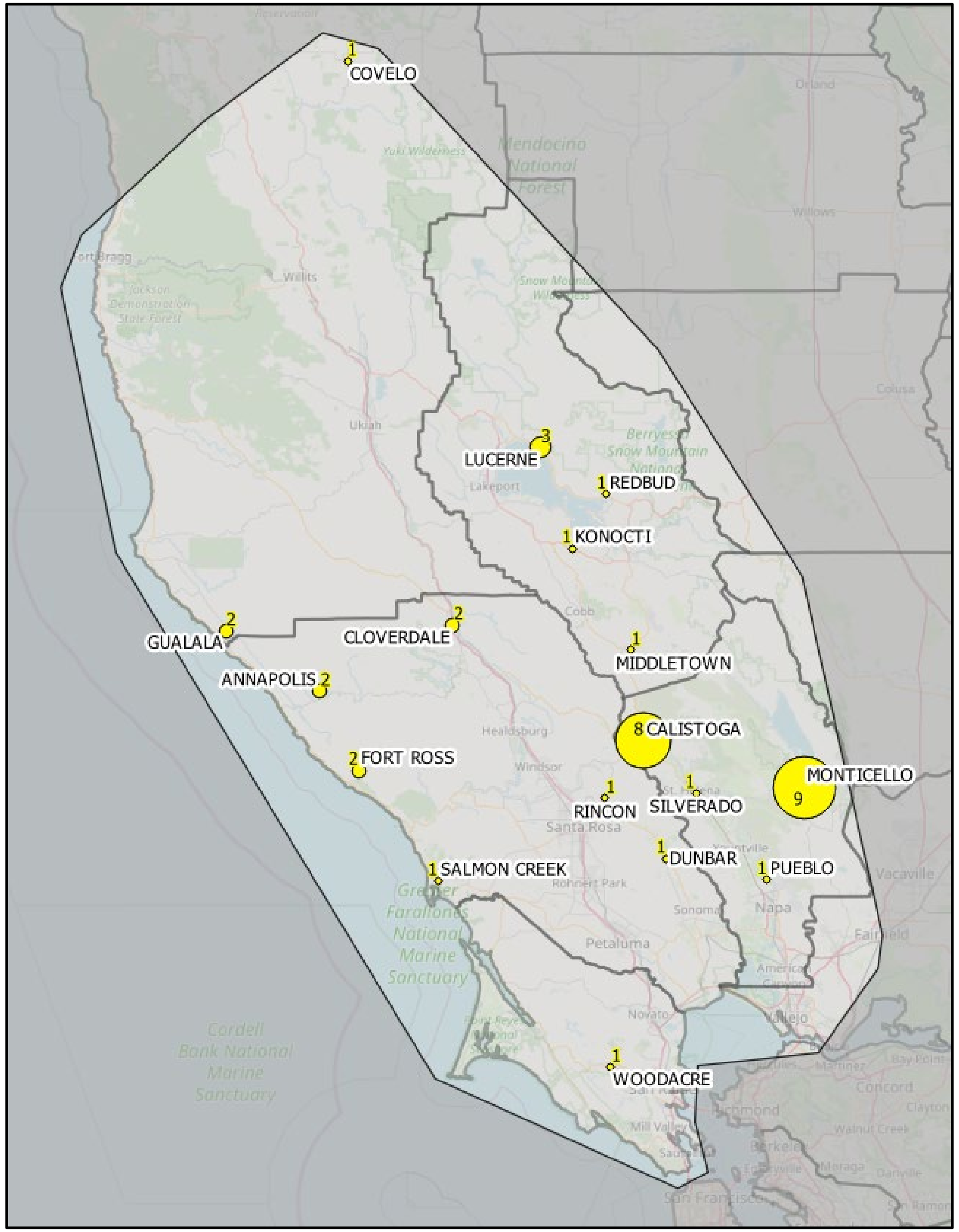
NCRI Key Findings and Lessons Learned

Findings for the North Coast

Direct Impacts in the North Coast (2021 10-Year HLA)

- Calistoga (8 Direct Impacts), Monticello (9 Direct Impacts)
- **Calistoga:** PG&E has an executed and CPUC-approved contract for a green hydrogen and battery-powered microgrid to power Calistoga through PSPS events, expected to be operational by June 1, 2024.
- **Monticello:** Has an existing solution (transmission switching) that would mitigate most of these PSPS impacts.
- With small number of impacts at other substations, direct PSPS impacts need no further study or action from the NCRI

Finding	**Mitigations for** direct transmission-level outages impacting the **Monticello and Calistoga substations are already underway or completed**.



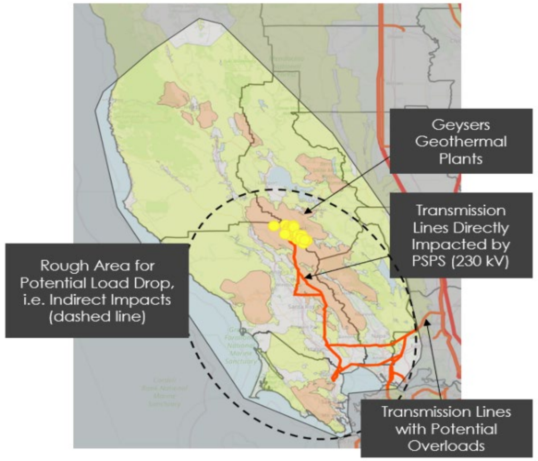
Direct Impacts - Changes in the 2022 10-Year HLA

- Fewer modelled events at the Calistoga substation (5).
- More modelled events at the Lucerne substation (5). **In four of those 5 events, there are fewer than 100 safe-to-energize customers connected to the substation**. PG&E currently has a distribution microgrid able to serve some safe-to-energize customers in the Lucerne area during PSPS events.
- More modelled events at the Redbud substation (4). **In one of those events there are fewer than 100 safe-to-energize customers connected to the substation.**
- Conclusion drawn based on 2021 data holds, direct PSPS impacts need no further study or action from the NCRI. No new substation is close to 10 or more impacts with safe-to-energize load, a threshold set by the CPUC in D.22-11-009.

Substation Name	Number of Impacts (2021 10-Year HLA)	Number of Impacts (2022 10-Year HLA)
Monticello	9	**9**
Calistoga	8	**5**
Lucerne	3	**5**
Redbud	1	**4**
Covelo	1	**1**
Dunbar	1	**1**
Salmon Creek	1	**1**
Woodacre	1	**1**
Middletown	1	**1**
Annapolis	2	**0**
Gualala	2	**0**
Konocti	1	**0**
Fort Ross	2	**0**
Cloverdale	2	**0**
Pueblo	1	**0**
Rincon	1	**0**
Silverado	1	**0**

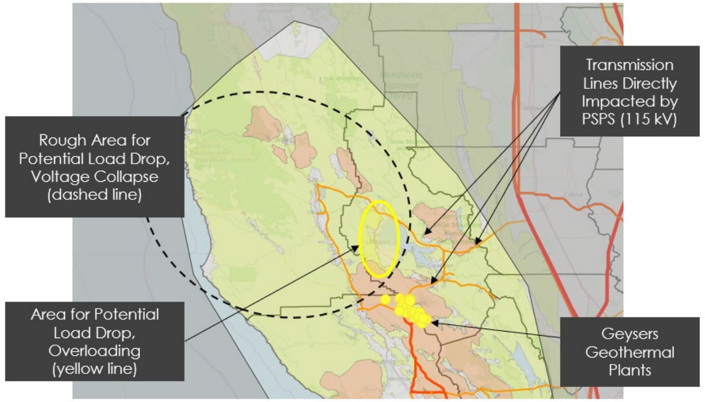
Indirect Impacts in the North Coast (2022 10-Year HLA)

Vaca-Dixon—Lakeville Area



9 indirect impacts over 10 years, affecting an estimated 10-30 percent of regional load.

Mendocino Area



12 indirect impacts over 10 years, most small but with 3 impacts leading to potential voltage collapse

Indirect Impacts – Changes After Resolving Tag Issues

PG&E inspects its lines and occasionally issues corrective action or maintenance tags when a component needs repair or replacement in the near- or medium-term. Addressing open tags on key transmission lines would reduce the number of modeled indirect impacts significantly.

Vaca-Dixon—Lakeville Area

- Impacts **reduced from 9 to 3** in the 2022 10-Year HLA

Mendocino Area

- Impacts **reduced from 12 to 5** in the 2022 10-Year HLA
- Modelling improvements lead to a **further reduction from 5 to 3**

Finding

Repairing or replacing several components on transmission lines in the North Coast could reduce the impact from projected indirect transmission-level PSPS events in the North Coast by 80%.

Transmission Maintenance Tags can greatly Reduce PSPS impacts

PG&E’s PSPS scoping process is heavily informed by transmission inspection records and the maintenance work assigned to assets.

Transmission Assets inspected and assigned “condition scores”

Maintenance Tags created based on conditions determined during inspection*

Maintenance Tag information fed into PG&E’s transmission models

PG&E’s transmission models used to scope PSPS events

Granular data from model used to identify if completing maintenance would allow the structure model score to drop below the threshold

PG&E and the CPUC utilized this stage of the process to determine a handful of repairs to structures that could have positive impacts on the historical frequency of PSPS impacts in the North Coast/North Bay

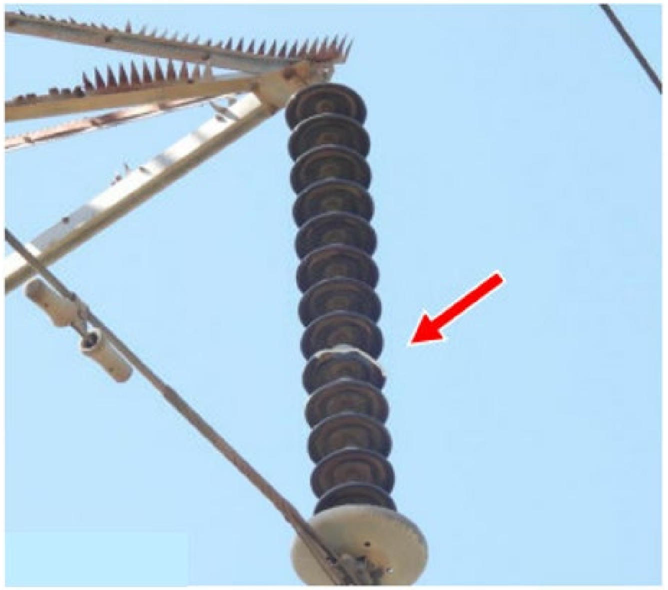
*Maintenance tags can also be created during routine and non-routine patrols, or whenever a condition is discovered.

What do conditions look like?

There are various conditions that can exist on transmission assets depending on many factors. Here are examples* of conditions inspectors may encounter in the field.


>1/16” crack reaching stub


Paint Deteriorating


Single broken insulator bell

*These are not specific examples pertaining to this analysis, rather generic photos to demonstrate what kind of conditions could potentially exist.

Current Status of Maintenance Tags Identified for Mitigation in 2023

PG&E determined, by completing a certain set of these maintenance tags on the lines that feed the North Bay pocket, the historical impact would lessen*.

Transmission Line Name	Number of Deenergizations due to Wildfire Risk, 10-Year Period (Before Mitigation)	Number of Deenergizations due to Wildfire Risk, 10-Year Period (After Mitigation)
Geysers #9 - Lakeville	9	3
Geysers #12 - Fulton	5	1
Fulton - Ignacio #1	1	0

***Table**: Change in Deenergizations for Key North Coast Transmission Lines Causing Indirect Impacts: Before and After Hardening Lines by Removing Tags.*

Specifically, there were approximately 9 structures spanning across 3 transmission lines identified in this analysis.

Of these identified structures, 6 have been completed and 3 are still pending maintenance before end of year.

*Though implications can be drawn from past events, it is important to note that future weather events are not predictable and may present worse or different conditions than what was studied.

All Findings and Lessons Learned

On the methodology and structure of the initiative…

1. Initiative Structure: The NCRI’s structure contributed significantly to its successful identification of a timely and cost-effective solution. Steering Committee members expressed that the **collective knowledge gained and trust built** over the course of this initiative will also **enable productive future dialogue**.
    a. The **informal nature** of the initiative allowed participants to comfortably exchange draft documents and share interim thinking in a way that **facilitated productive conversations**.
    b. The **absence of hard deadlines provided the Steering Committee the time it needed** to explore the drivers of the problem in depth, ensure all participants had a shared understanding of key information, and allow PG&E’s PSPS modeling to evolve.
    c. The Steering Committee **included the organizations and people** needed to gather the necessary information, conduct analyses, and implement solutions. The group’s small size eased coordination.

On the methodology and structure of the initiative…

2. Applicable Framework: While the NCRI did not need to complete all of the steps in its four-phase problem solving framework, **others could still use the framework to address regional energy challenges they face**.

3. Facilitation and Engagement: The NCRI was a small part of most participants' work duties, and occurred outside any standard leadership structure. This situation led to the possibility of low engagement and incomplete work, and made it more difficult to build and maintain the technical knowledge required to carry out analyses. **The initiative required strong facilitation, with the facilitation team consistently completing draft work, providing technical summaries, and checking in with Steering Committee members to keep the initiative on track.**

On PSPS and wildfire risk…

1. Safe-to-Energize Customers: Many customers along the North Coast who are otherwise "safe-to-energize" also lose power during PSPS events. In this case, safe-to-energize refers to **customers who are located outside of the conditions that triggered the need for a PSPS event, but are served by a distribution or transmission line that has been de-energized**. If the grid configuration were different, they would be able to remain online.

2. Line Impacts: Transmission lines are impacted by wildfire risk and resulting PSPS events in different ways. These **differences alter the suite of available mitigations and their effectiveness**.
   a. Some lines are "**directly impacted**," meaning they are de-energized because they **pass directly through an area experiencing weather conditions** that drive the need for a PSPS event.
   b. Some lines are "**indirectly impacted**," meaning they **become at risk of overloading** (and damage) during PSPS events when they are required to take on the load typically served through other directly impacted transmission lines, requiring load drop.

On PSPS and wildfire risk…

3. Substation Effectiveness: For indirect impacts, **substations vary in their ability to relieve overloading conditions** on a transmission line during a PSPS event. Dropping load from one substation may have a greater impact than dropping the same amount of load from another substation within the same region due to a variety of factors.

4. Investment Decision-making Processes: PSPS impacts are complicated, driven by many factors each with different mitigations. As a result, **investments in PSPS mitigations must be carefully considered over time.** Hasty decision-making, common in emergency situations, can result in unnecessary spending and adverse outcomes.

On PSPS in the North Coast region…

1. System and Modeling Improvements: Improved modeling and asset conditions on PG&E's electric system are driving a **reduction in the frequency and size of transmission-level PSPS events along the North Coast**.

2. Direct Impact Mitigations: **Mitigations for** direct transmission-level outages impacting the **Monticello and Calistoga substations are already underway or completed**.

3. Indirect Impact Mitigations: **Repairing or replacing several components on transmission lines in the North Coast** could reduce the impact from projected indirect transmission-level PSPS events in the North Coast by 80%.

Modelled PSPS Impacts that Remain*

- **Remaining Direct Impacts at Substations:** Redbud, and other substations with a single impact.
- **Remaining Indirect Impacts:** Three modelled impacts in the 10-year HLA remain, for both the Vaca-Dixon—Lakeville and Mendocino Areas.
- **Remaining Distribution Impacts:** The NCRI did not address distribution-level PSPS impacts. The initiative only covered transmission-level impacts.

*Though implications can be drawn from past events, it is important to note that future weather events are not predictable and may present worse or different conditions than what is modelled.

Q&A

Problem Solving Framework

4-Step Framework for Addressing Grid Issues

Phase 1
Build the Foundation

1. Craft **objectives** and **principles**
2. Identify initial **participants** and clarify their **roles** and responsibilities
3. Determine your **governance** structure

Phase 2
Define the Problem

1. Craft the **problem statement**
2. Determine **root cause(s)** of the problem
3. Document the **implications** of the problem
4. Identify **current efforts**

Phase 3
Explore and Compare Mitigations

1. Identify **potential mitigations**
2. Collect **data**
3. Establish a **comparison methodology**
4. **Compare** mitigations
5. **Select** preferred mitigation(s)

Phase 4
Conduct Comprehensive Regional Planning

1. **Integrate** mitigations
2. Identify **implementation** pathways

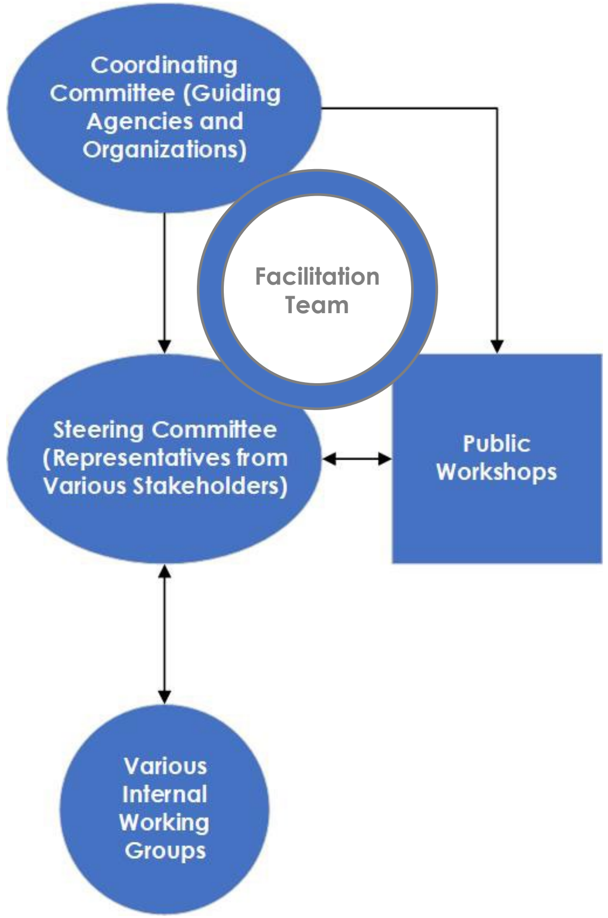
Source: Gridworks, 2023

Using the NCRI as an Example
Step 1: Build the Foundation

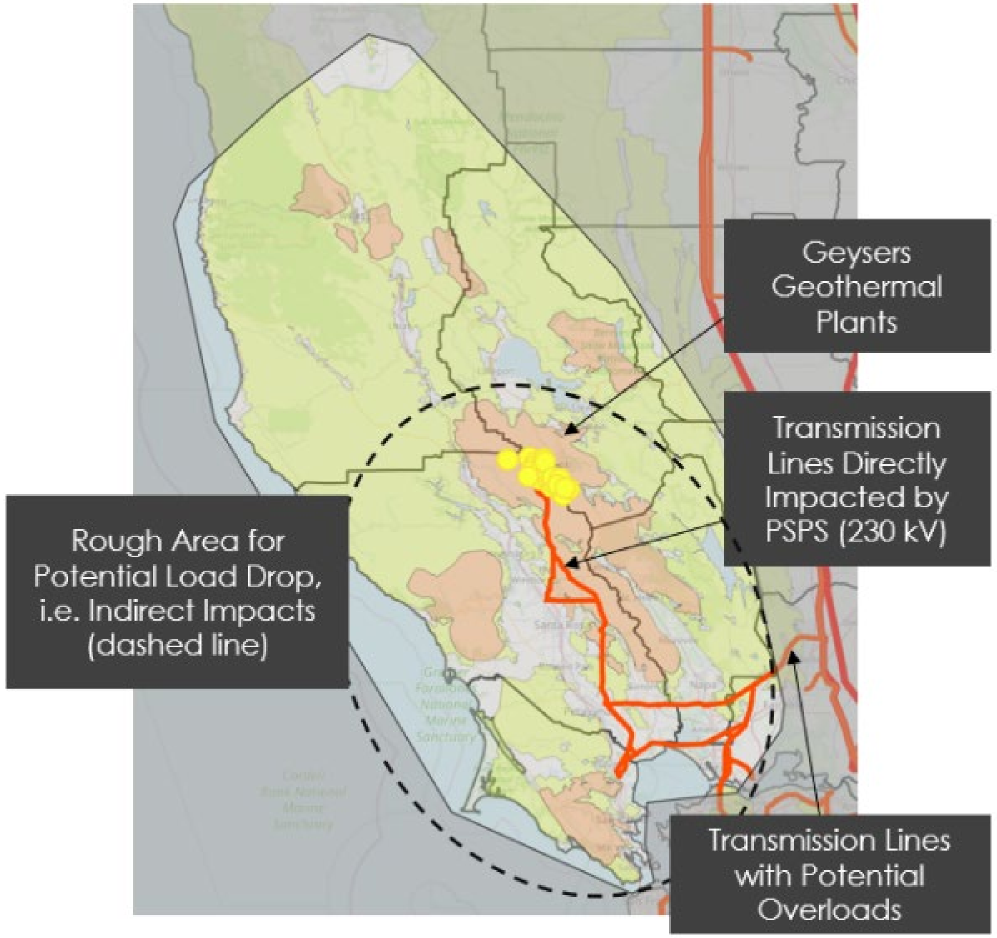
The Initiative consists of:

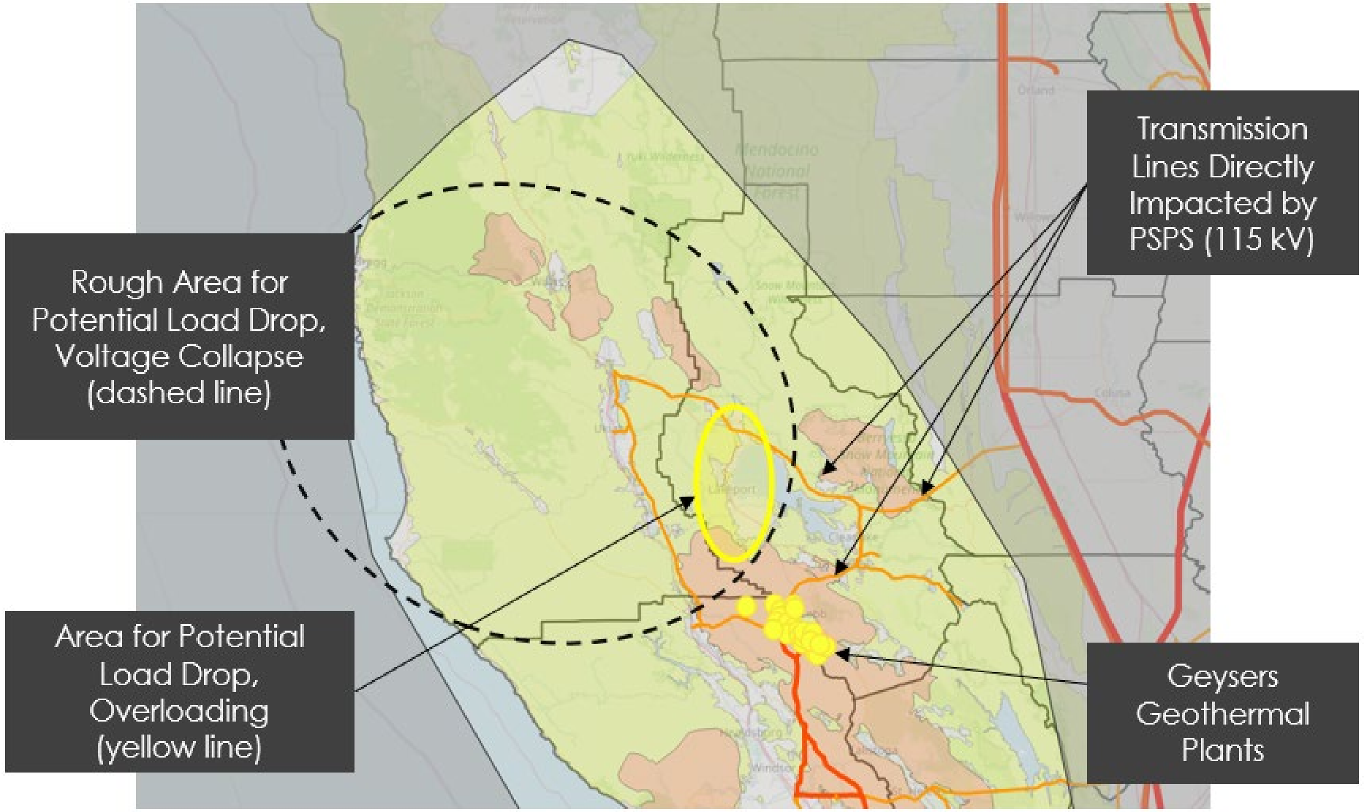
1. A Coordinating Committee, made up of Commissioners from the CEC and CPUC.
2. A Steering Committee, made up of representatives from MCE, SCP, PG&E, the CAISO, the CEC, and the CPUC.
3. A CPUC and Gridworks Facilitation Team, stewarding the Initiative.

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.

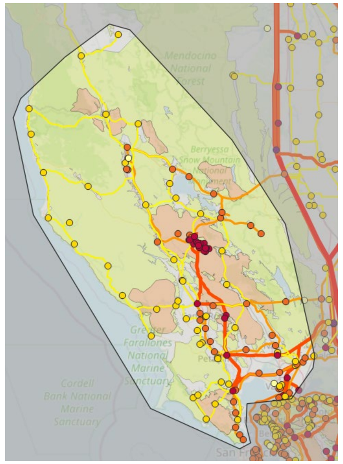


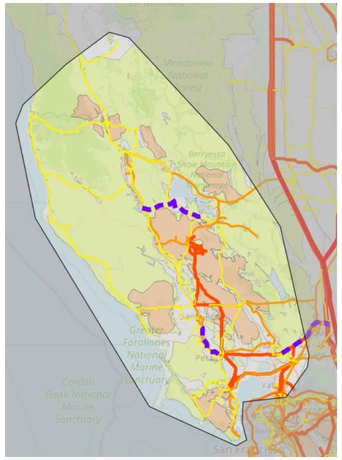
Using the NCRI as an Example
Step 2: Define the Problem

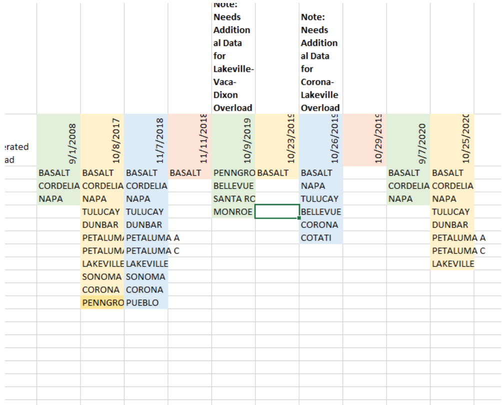




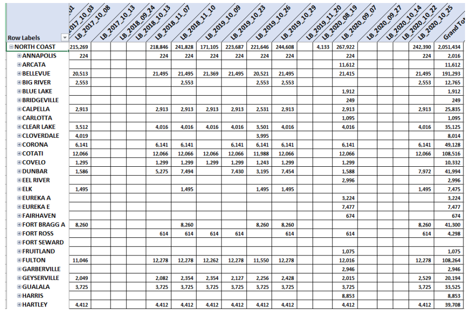
Using the NCRI as an Example
Step 2: Define the Problem







					Note: Needs Additional Data for Lakeville-Vaca-Dixon Overload		Note: Needs Additional Data for Corona-Lakeville Overload			
erated ad	9/1/2008	10/8/2017	11/7/2018	11/11/2018	10/9/2019	10/23/2019	10/26/2019	10/29/2019	9/7/2020	10/25/2020
	BASALT	BASALT	BASALT	BASALT	PENNGRO	BASALT	BASALT		BASALT	BASALT
	CORDELIA	CORDELIA	CORDELIA		BELLEVUE		NAPA		CORDELIA	CORDELIA
	NAPA	NAPA	NAPA		SANTA RC		TULUCAY		NAPA	NAPA
		TULUCAY	TULUCAY		MONROE		BELLEVUE			TULUCAY
		DUNBAR	DUNBAR				CORONA			DUNBAR
		PETALUMA	PETALUMA A				COTATI			PETALUMA A
		PETALUMA	PETALUMA C							PETALUMA C
		LAKEVILLE	LAKEVILLE							LAKEVILLE
		SONOMA	SONOMA							
		CORONA	CORONA							
		PENNGRO	PUEBLO							



Row Labels	LB_2017_10_08	LB_2017_10_13	LB_2018_09_24	LB_2018_10_13	LB_2018_11_07	LB_2018_11_10	LB_2019_10_09	LB_2019_10_23	LB_2019_10_26	LB_2019_10_29	LB_2019_11_20	LB_2020_08_19	LB_2020_09_07	LB_2020_09_27	LB_2020_10_14	LB_2020_10_22	LB_2020_10_25	Grand Total
NORTH COAST	215,269				218,846	241,828	171,105	223,687	221,646	244,608		4,133	267,922				242,390	2,051,434
ANNAPOLIS	224				224	224	224	224	224	224			224				224	2,016
ARCATA													11,612					11,612
BELLEVUE	20,513				21,495	21,495	21,369	21,495	20,521	21,495			21,415				21,495	191,293
BIG RIVER	2,553					2,553			2,553	2,553							2,553	12,765
BLUE LAKE													1,912					1,912
BRIDGEVILLE													249					249
CALPELLA	2,913				2,913	2,913	2,913	2,913	2,531	2,913			2,913				2,913	25,835
CARLOTTA													1,095					1,095
CLEAR LAKE	3,512				4,016	4,016	4,016	4,016	3,501	4,016			4,016				4,016	35,125
CLOVERDALE	4,019								3,995									8,014
CORONA	6,141				6,141	6,141		6,141	6,141	6,141			6,141				6,141	49,128
COTATI	12,066				12,066	12,066	12,066	12,066	11,988	12,066			12,066				12,066	108,516
COVELO	1,295				1,299	1,299	1,299	1,299	1,243	1,299			1,299					10,332
DUNBAR	1,586				5,275	7,494		7,430	3,195	7,454			1,588				7,972	41,994
EEL RIVER													2,996					2,996
ELK	1,495					1,495			1,495	1,495							1,495	7,475
EUREKA A													3,224					3,224
EUREKA E													7,477					7,477
FAIRHAVEN													674					674
FORT BRAGG A	8,260					8,260			8,260	8,260							8,260	41,300
FORT ROSS					614	614	614	614		614			614				614	4,298
FORT SEWARD																		
FRUITLAND													1,075					1,075
FULTON	11,046				12,278	12,278	12,262	12,278	11,550	12,278			12,016				12,278	108,264
GARBERVILLE													2,946					2,946
GEYSERVILLE	2,049				2,082	2,354	2,354	2,127	2,256	2,428			2,015				2,529	20,194
GUALALA	3,725				3,725	3,725	3,725	3,725	3,725	3,725			3,725				3,725	33,525
HARRIS													8,853					8,853
HARTLEY	4,412				4,412	4,412	4,412	4,412	4,412	4,412			4,412				4,412	39,708

#

Estimate Area Load

Area Load Greater than Critical Loading Level

→ Overload on Key Lines

List of Substations Dropped to Mitigate Overloads, Using Effectiveness Figures

Total STE Customers at the Dropped Substations

Estimated Outage-Minutes from PSPS Indirect Impacts

Using the NCRI as an Example
Step 3: Explore and Compare Mitigations

A. Wildfire Hardening

- Hardening the directly impacted lines so they no longer need to be deenergized
- Includes hardening of individual structures (i.e. fixing tags) and hardening of entire lines (i.e. undergrounding)

B. Line Upgrades

- Upgrading the overloaded lines so they can carry more power into the region, for example by reconductoring

C. Energy Resources

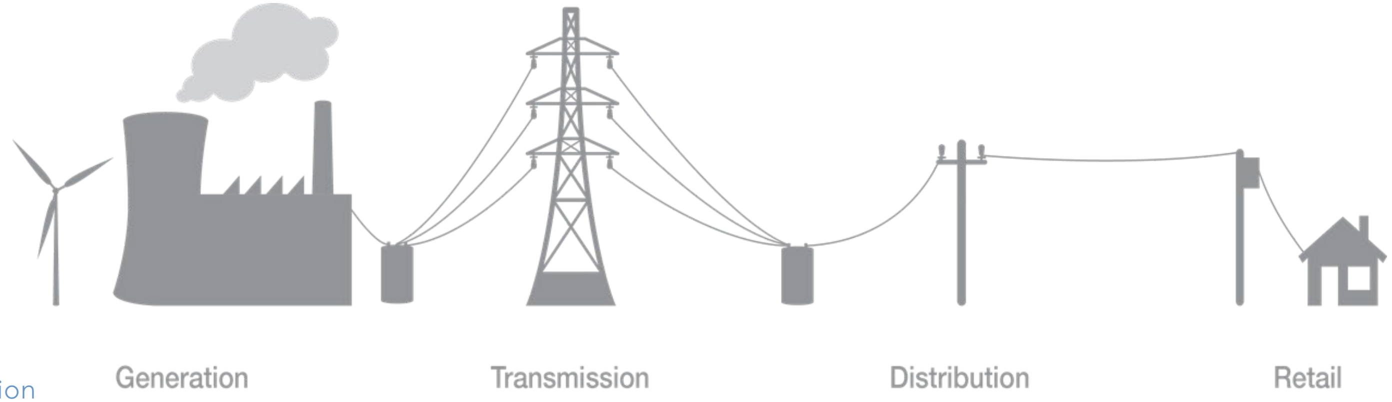
- Using new or existing local energy resources to meet local demand
- Local resources have the same effect on the regional grid as load drop
- Considering storage, solar + storage, etc.

D. Operational Changes

- These are mitigations that would reduce or redistribute PSPS impacts, including deenergizations for only part of the day, rotating deenergization, targeted deenergization, etc

Using the NCRI as an Example Hypothetical Step 4

1. Evaluate whether transmission upgrades to increase regional deliverability are reasonable and cost effective based on any new energy resources proposed as a result of the work in Step 3, as well as any other plans for energy resources in the region.
2. Combine the projects proposed in Step 3 into a comprehensive regional plan considering the timeline, priority, and impact of these projects.
3. Evaluate the extent to which PSPS mitigation projects can contribute to regional or wider grid needs, including with the incorporation of local or regional control systems.



Q&A

Discussion: Leveraging the Problem Solving Framework

How might this problem-solving framework be applied to other regional energy challenges that require multijurisdictional collaboration?

1. What existing or potential *technical* regional grid challenge would be a good fit for the NCRI's problem-solving framework? Why?
2. What region would be in scope here? Why?
3. What might happen if this challenge goes unaddressed?
4. Which entities would need to work together to better understand and address this problem? (Think of federal, state, local and tribal government entities with relevant jurisdiction as well as utilities, CCAs, and other stakeholder groups.)
5. By when does the challenge need to be addressed? Why?

Next Steps

Next Steps after the NCRI

- **Indirect PSPS Impacts:** Recommend incorporating the evaluation methodology used in the NCRI into PG&E's existing substation microgrid framework.
  - PG&E plans to file a Petition for Modification to D.22-11-009 to incorporate the NCRI into their framework without the need for a separate application.

- **Future Grid Challenges:** The CPUC may launch similar initiatives in the future to address other regional grid challenges.

Closing Remarks

Commissioner Genevieve Shiroma

For More Information

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