

Walk-through of long-term utility distribution plans:

Part 2 - Grid modernization plans and plans for high levels of distributed energy resources

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for Mid-Atlantic Region and NARUC-NASEO Task Force on Comprehensive Electricity Planning
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Grid Modernization Planning

With Grid Modernization Examples
from Xcel Energy's Integrated
Distribution Plan (2019-2028)

Xcel's Grid Modernization Goals

- ▶ **Transformed customer experience**
 - ❑ New programs and service offerings
 - ❑ Engaging digital experiences
 - ❑ Enhanced billing and rate options
 - ❑ Timely outage communication

- ▶ **Improved core operations**
 - ❑ Additional monitoring, control, analytics and automation

- ▶ **Facilitation of future capabilities**
 - ❑ Designing for interoperability
 - ❑ In alignment with industry standards and frameworks

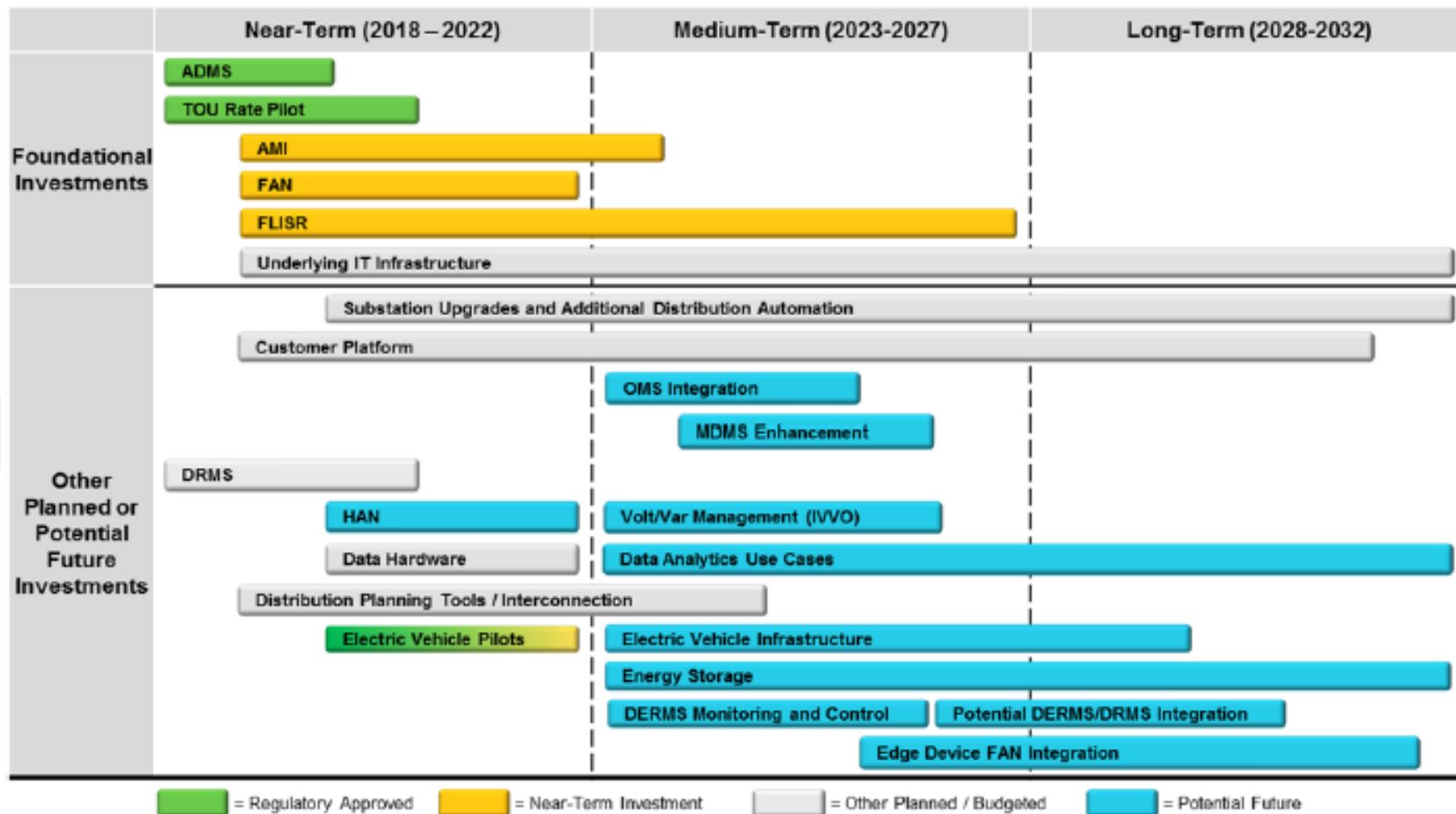
Advanced Grid Intelligence and Security Initiative



The foundational investments of the initiative include:

- ▶ Advanced Metering Infrastructure (AMI)
- ▶ Field Area Network (FAN)
- ▶ Advanced Distribution Management System (ADMS)
- ▶ Fault Location, Isolation, and Service Restoration (FLISR)

Advanced Grid Initiatives Timeline

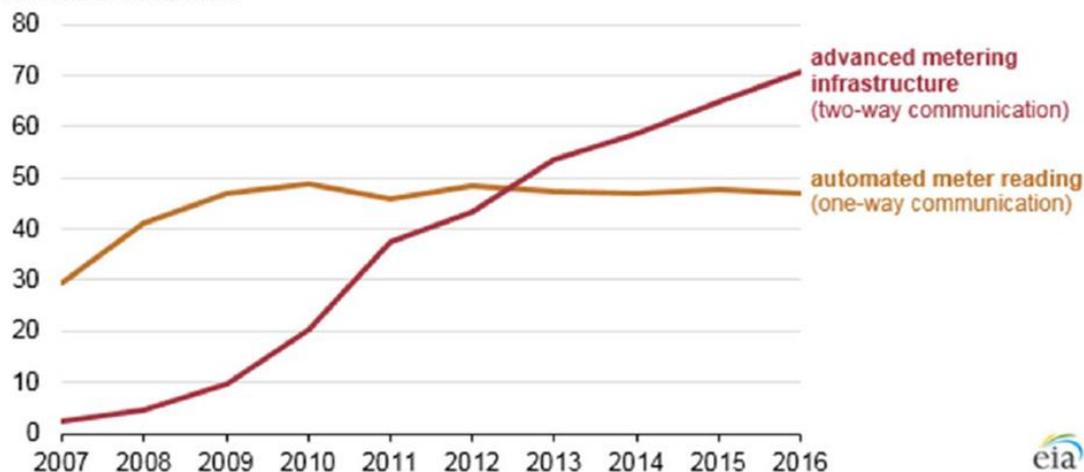


Advanced Metering Infrastructure (AMI)

Motivation: Current AMR system will be discontinued

U.S. advanced electric utility meter adoption (2007-2016)

millions of customers



eia

Budget for both AMI and FAN:

- ▶ Capital Costs:
Between \$450 and \$600 million
- ▶ O&M Costs:
Between \$110 and \$150 million

Timeline:

- ▶ Late 2019:
Limited installation of AMI meters as part of the TOU pilot
- ▶ Between 2020 and 2023:
1.3 million advanced meters deployed

Advanced Metering Infrastructure (AMI)

- ▶ AMI is dependent on:
 - The parallel deployment of the FAN for communication (used to transmit information to and from the meter to the AMI head-end application)

- ▶ The following applications depend on AMI:
 - ADMS
 - Outage management programs (due to its last-gasp functionality)
 - HAN
 - Demand Response Management System (DRMS)

Advanced Metering Infrastructure (AMI)

The collection of interval meter data is the primary capability delivered by AMI



This leads to a number of advantages for both consumers as well as the utility

Advanced Metering Infrastructure (AMI)

Benefits from a customer perspective:

- ▶ Energy usage insights
- ▶ Enhanced rate offerings
- ▶ Targeted DSM program offerings
- ▶ In home interfaces
- ▶ Improved billing features
- ▶ Reduction in customer outage minutes due to faster response capability

Advanced Metering Infrastructure (AMI)

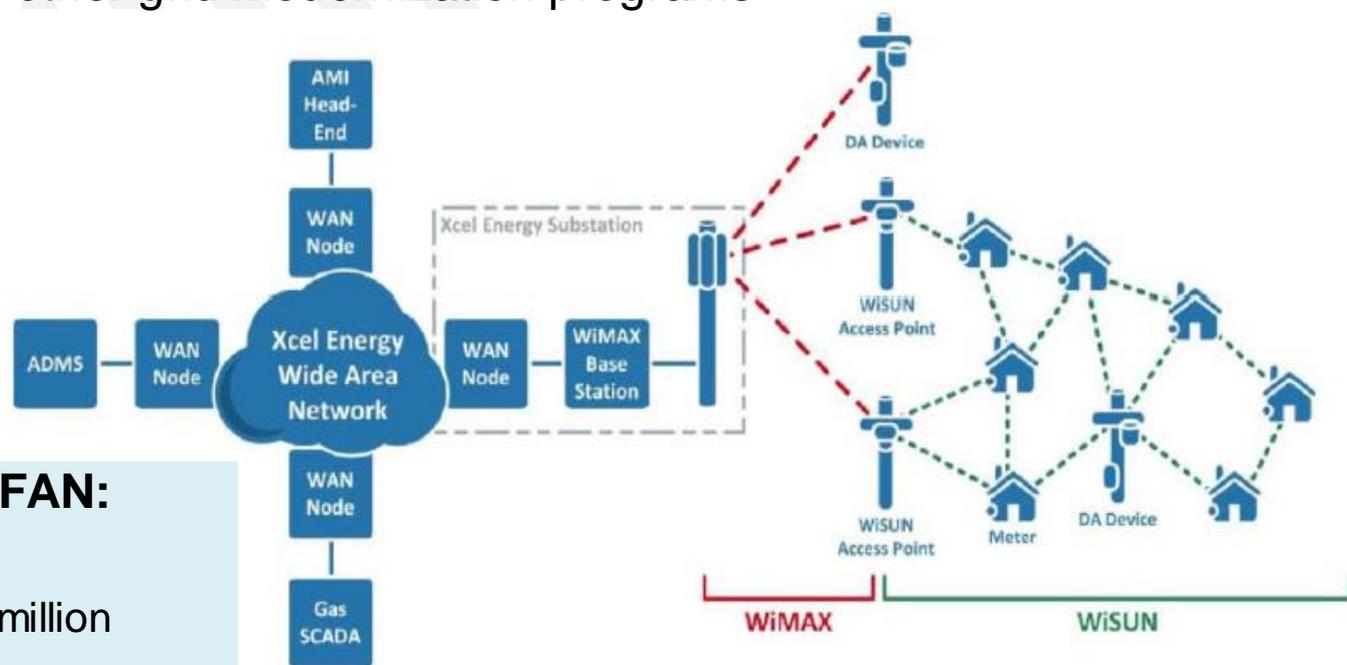
Benefits from a grid perspective:

- ▶ Greater awareness of customer outages
- ▶ Lower meter retirement date due to fewer meter failures
- ▶ Elimination of costs associated with meter reading and meter complaints
- ▶ Easier identification of energy theft and vacated premises
- ▶ Closer alignment of rates with the real time cost of energy:
 - Incentivize load reductions at peak times
- ▶ Distribution System Management Efficiency:
 - AMI information can be used as an input for more granular distribution planning analysis
 - More efficient use of capital dollars to plan and design the system
 - Increased efficiency of distribution maintenance costs

Field Area Network (FAN)

Motivation:

This communication network is necessary for the implementation of most other grid modernization programs



Budget for both AMI and FAN:

- ▶ Capital Costs:
Between \$450 and \$600 million
- ▶ O&M Costs:
Between \$110 and \$150 million

Timeline:

Between 2018 and 2023

Field Area Network (FAN)

The FAN uses two wireless IEEE technology standards:

▶ A WiMAX network

- High-speed connectivity
- Based in Northern States Power's substations
- Point-to-multi-point

▶ A WiSUN network

- Lower speed
- Communicates directly with the AMI infrastructure and the Distribution Automation (DA) field devices
- Mesh network:
 - Allows the network to improve as more devices are brought online and within the FAN, since adding more nodes to the network gives the devices more options to communicate with their access point.

Advanced Distribution Management System (ADMS)

Motivation:

Provide an integrated operating and decision support system to assist control center operators, field personnel, and engineers

The core software functions include:

- ▶ Distributed Network Modeling
- ▶ Distribution Supervisory Control and Data Acquisition (SCADA) Monitoring and Control
- ▶ Unbalanced Load Flow and Network Topology Processing

Timeline:

Initial rollout by 2020

Fault Location, Isolation, and Service Restoration (FLISR)

Motivation:

Improving distribution system reliability by isolating a faulted segment of a feeder and automatically restoring power to available un-faulted segments.

FLISR is a core application within ADMS

Budget:

Approximately \$66 million

Timeline:

Nine-year deployment timeline

Fault Location, Isolation, and Service Restoration (FLISR)

- ▶ The FLISR application relies on three primary components to operate:
 - ❑ ADMS, for the central control and logic
 - ❑ FAN, for wireless communications to each device
 - ❑ Intelligent field devices (reclosers, overhead switches and pad mount switchgear), to detect faults, isolate where possible and operate when commanded by ADMS.

- ▶ FLISR will involve implementing four principal components:
 - ❑ Reclosers
 - ❑ Automated Overhead Switches
 - ❑ Automated Switch Cabinets
 - ❑ Substation Relaying

Fault Location, Isolation, and Service Restoration (FLISR)

Benefits:

► Real-time situational awareness:

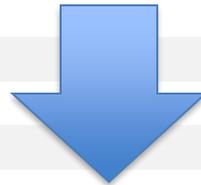
- Ability to see the real-time load across many critical points on the distribution system
- FLISR can be executed even when parts of the distribution system are abnormal
- FLISR can make decisions for the future loading of the system due to ADMS's system loading predictions

► Ability to operate devices remotely:

- Complex switching enabled by automated feeders and remotely controllable devices
- Limited need to manage software on each individual device

► Improved Data for System Planning and Reliability:

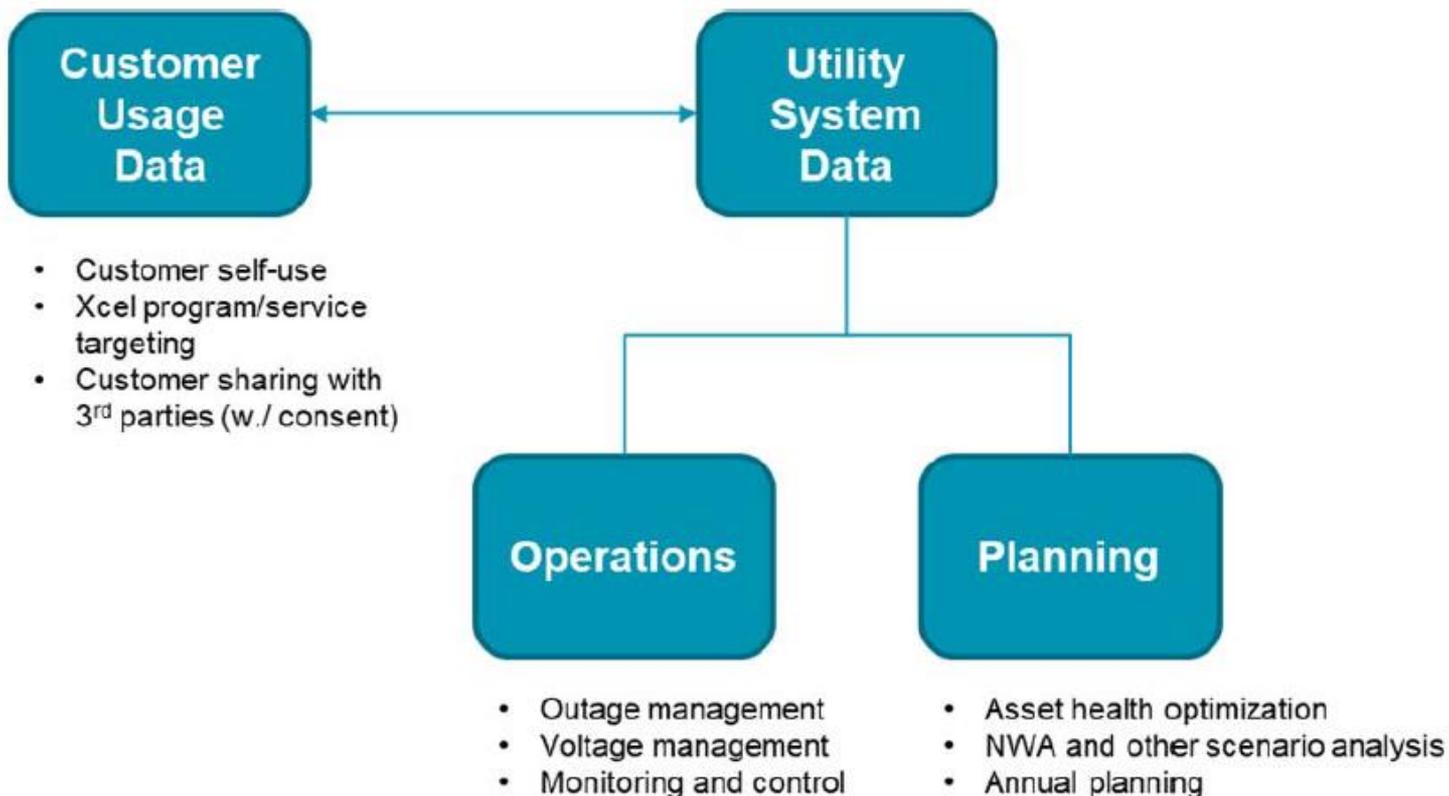
- Key data from FLISR can be used to plan and design the future system



All this done with the goal to reduce outage durations to customers

Customer and Operational Data Management

Xcel's Data Strategy Framework



Customer and Operational Data Management – Potential Tools

For customers

▶ HAN:

- Connects electronic devices, such as thermostats, security systems, energy display devices, and smart appliances, into a common customer network that allows these devices to communicate with each other.

For company operations

▶ Demand Response Management System (DRMS):

- Enables new capabilities for DR

▶ Volt-Var Management (IVVO):

- Automates and optimizes the operation of the voltage regulating devices or VAr control devices on distribution feeders

□ Benefits:

- Reduction of Distribution Electrical Losses
- Reduction of Electrical Demand and Energy Consumption
- Increased Ability to Host DER
- Demand Response

Time-of-Use Rate Pilot

This pilot will provide select residential customers with variable pricing based on the time of day energy is used.

Goal:

Encourage shifting energy usage to daily periods where the system is experiencing low load conditions.

► Implementation area:

- Minneapolis and Eden Prairie
- AMI and FAN technology deployed to 17,5000 residential customers

► Timeline:

- Installation of both FAN and AMI, in connection with the TOU pilot, will begin in 2019. Baseline information will be collected, and the pilot will launch in 2020.

Battery Storage Projects

► Penna Station/Panasonic Battery Demonstration Project

- 1.5 MW of solar installations and a 1 MW/2MWh battery at the Denver airport
- Examining how a battery storage facility can be used to:
 - Facilitate the integration of renewable energy
 - Enhance reliability on the distribution system
 - Assist in providing voltage management and peak reduction
 - Provide power to Panasonic in case of a grid outage by functioning as a microgrid

► Stapleton Battery Storage Project

- 6 in-home batteries and six larger batteries in the Stapleton neighborhood
- Examining how battery storage can be used to:
 - Increase the ability to accommodate more solar energy on the system
 - Manage grid issues such as voltage regulation and peak demand
 - Reduce energy costs

Electric Vehicle Pilots

► Fleet EV Service Pilot

- Xcel would install, own, and maintain EV infrastructure for fleet operators
- Fleet operators participating in the pilot would pay time-of-use rates
- 3 probable fleet customers:
 - Metro Transit
 - Minnesota Department of Administration
 - City of Minneapolis

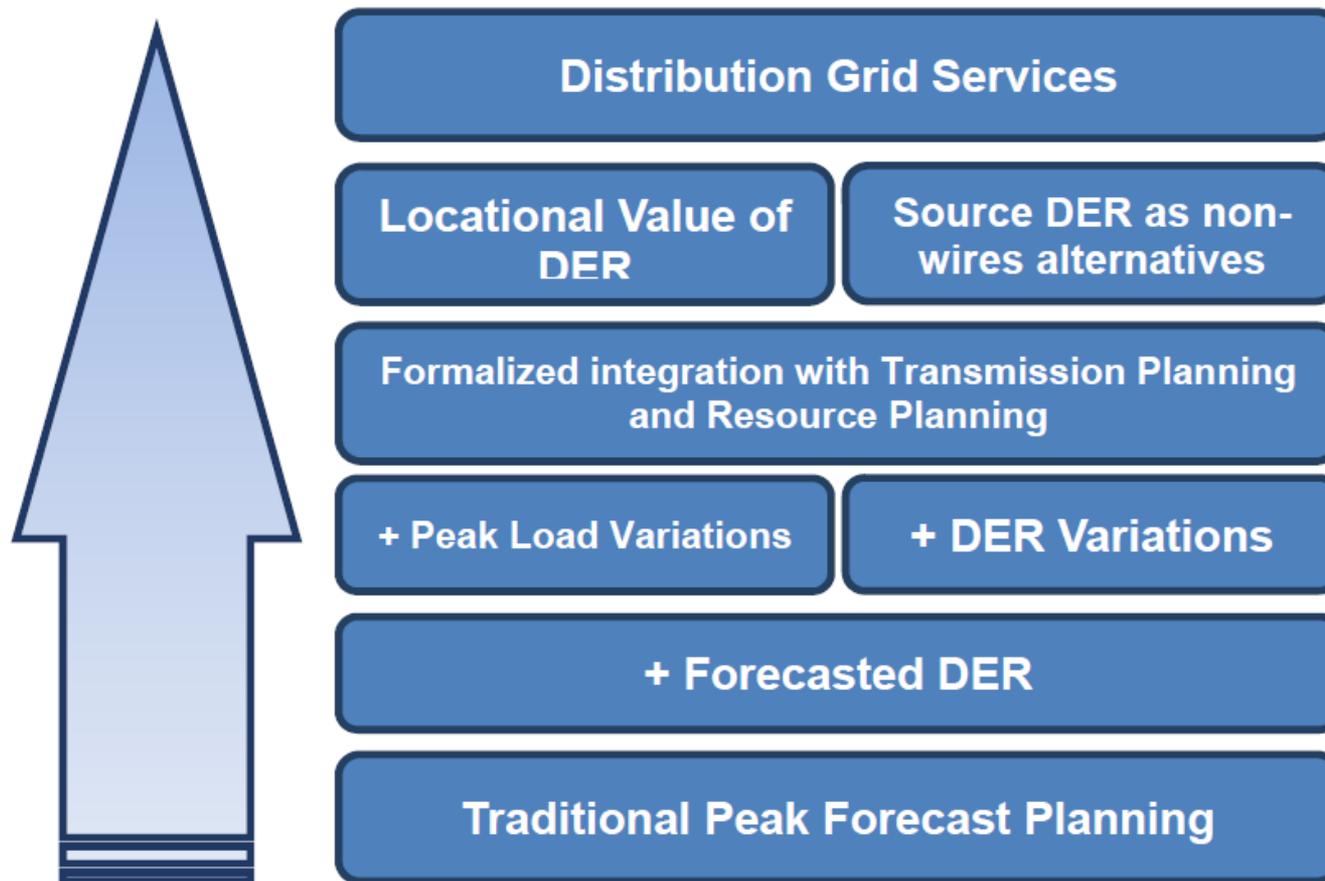
► Public Charging Pilot

- Xcel would install, own, and maintain EV public charging station infrastructure only
- Customers participating in the pilot would pay time-of-use rates
- Increase publicly available charging options to support longer distance driving, address range anxiety, and provide charging solutions for those unable to charge at home
- 2 probable community charging locations:
 - Saint Paul
 - Minneapolis

Potential New EV Pilots

- ▶ *Residential EV Subscription Service Pilot:*
 - Preset monthly subscription fee for dedicated EV charging service during off-peak hours, with additional charges for on-peak charging
- ▶ *Residential Smart Charging Pilot:*
 - Studying how a combination of incentives or rewards encourages smart charging of EVs, enabling the management of EV charging as a demand-response resource
- ▶ *Workplace Smart Charging Pilot:*
 - Studying the provision of workplace EV charging coupled with DER, such as solar generation. The pilot will assess—and explore options to mitigate—the coincidence of workplace charging and system peak.
- ▶ *Vehicle-to-Grid Demonstration with School Buses:*
 - Studying the potential of electric school buses as grid resources. During the school year, daily driving schedules could support off-peak charging during nighttime and weekend hours; during the summer, the buses could operate as grid resources, charging when demand for power is low and discharging power when system demand is high.

Potential Evolution in Planning Practices



Plans for High DER Penetrations:

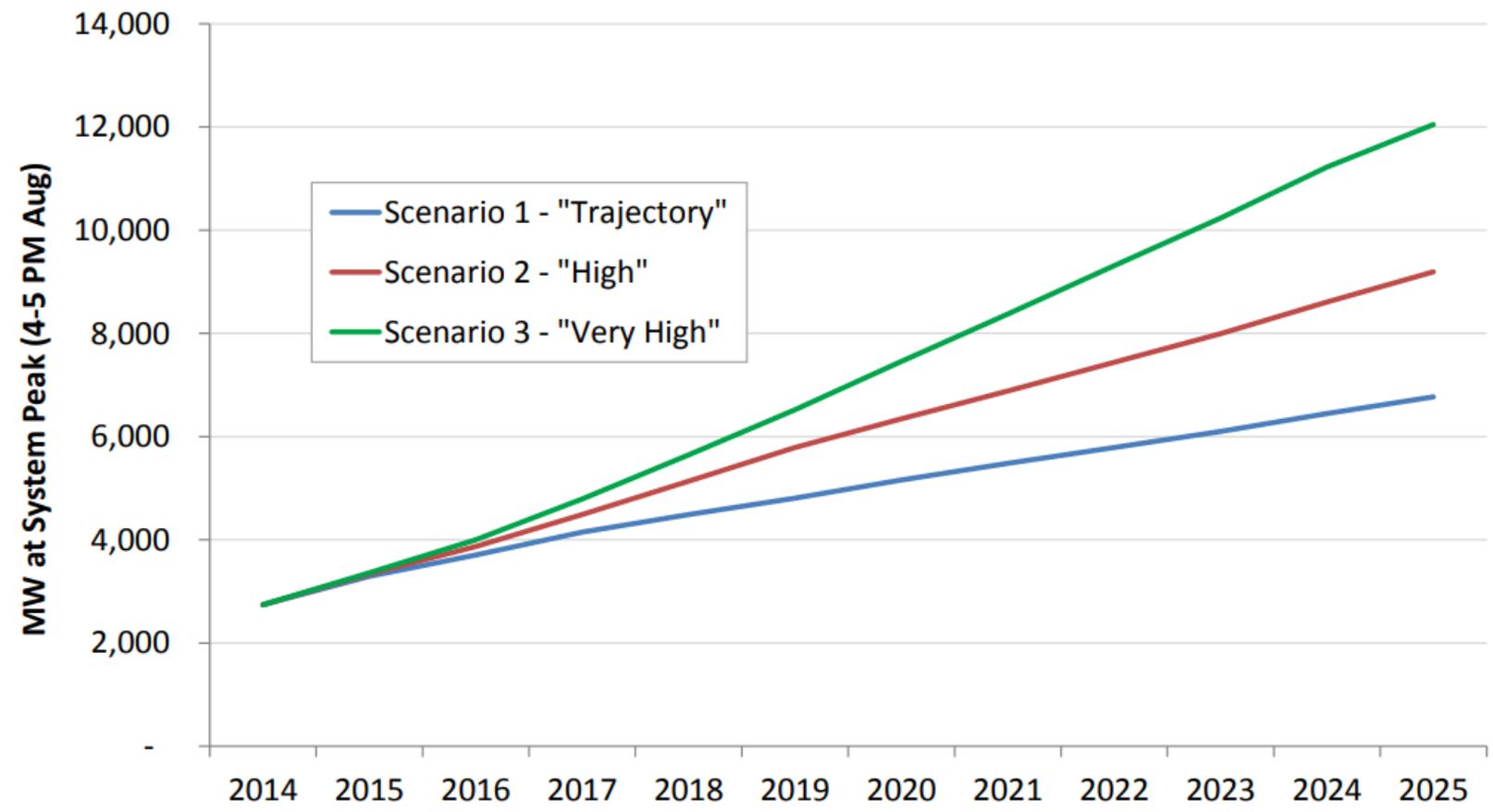
With Examples from PG&E's
Distribution Resources Plan and
Subsequent DRP Working Groups

PG&E Distribution Resources Planning

- ▶ PG&E's traditional distribution planning process includes:
 - Forecasting load and peak demand
 - Power flow modeling to simulate performance to determine needs
 - Identifying and developing capacity additions to meet needs
- ▶ Distribution Resources Plan 2015 - The goal of the DRP is to integrate DERs into the distribution planning process
 - DER Growth Scenarios
 - Integration Capacity Analysis (Hosting capacity)
 - Locational net benefits analysis
- ▶ Distribution Investment Deferral Framework
 - Grid Needs Assessment
 - Candidate deferral projects

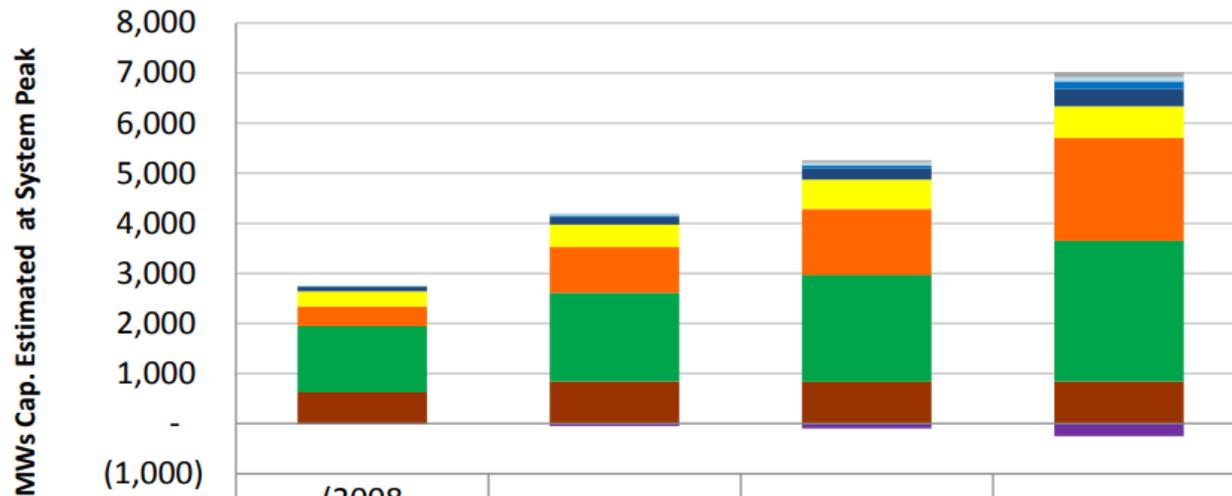
DERs may significantly impact peak load

Estimated DER impacts at current time of PG&E system peak



1. DER Growth Scenarios

Energy efficiency and solar have greatest impact on peak load



	(2008-2014)	2017	2020	2025
■ Distributed Wholesale Energy Storage	6	6	40	97
■ CHP from Feed in Tariffs	9.6	30	50	83
■ Retail Storage	7.4	34	68	156
■ Retail Non-PV DG	92	153	220	347
■ Wholesale DG	302	443	590	631
■ Retail PV	396	916	1,317	2,052
■ Energy Efficiency	1,318	1,770	2,134	2,809
■ Demand Response	627	845	834	841
■ Electric Vehicles	(16)	(48)	(95)	(248)

Impacts depend on DER characteristics and local load profiles



- Variable impact driven by:
 - Coincidence of DER impact with local distribution asset load profile (e.g., evening peaking feeders with high solar deployment)
 - Resource characteristics (e.g., generation profile, associated communications and controls, dispatchability, geographic location, intermittency)
 - Services provided
- Utility currently has limited visibility, operational control and ability to influence geographic location of DER assets
- Deployment is currently optimized on customer economics, not utility cost drivers

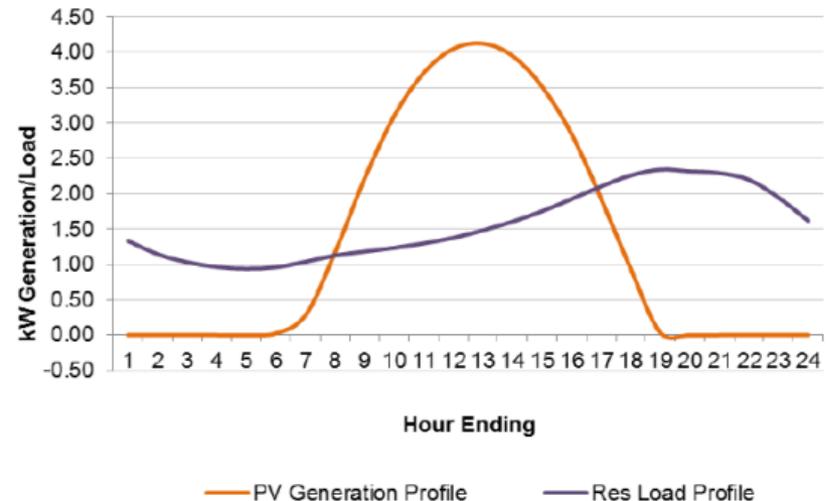
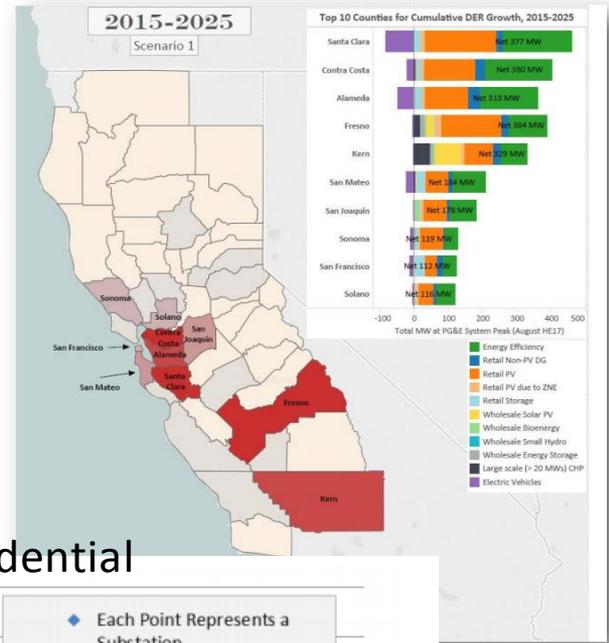


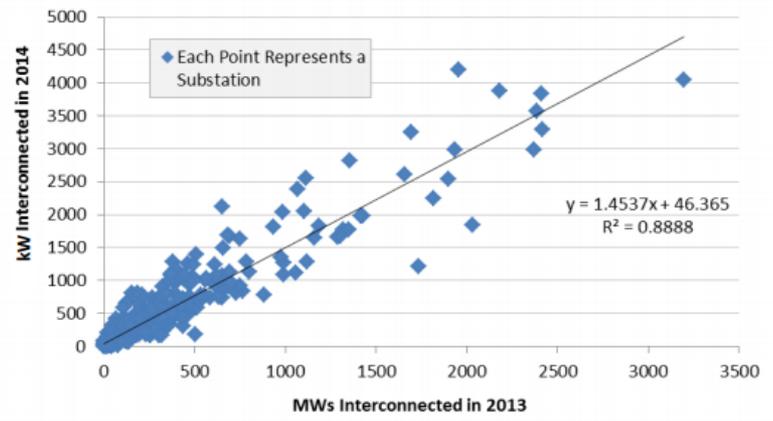
FIGURE 2-28: TYPICAL RESIDENTIAL LOAD PROFILE AND SOLAR GENERATION PROFILE ON AN AUGUST DAY

Other findings from growth scenarios

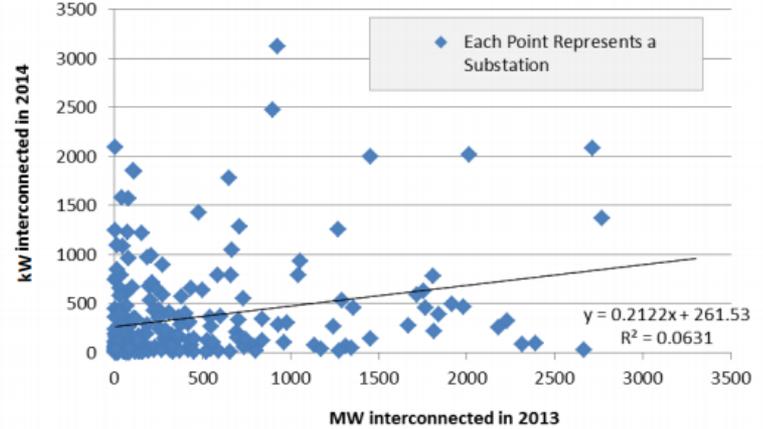
- ▶ DERs likely to cluster
- ▶ To estimate DERs, we need to understand load and adoption patterns
- ▶ Past behavior may not be indicative of future behavior



Residential



Non-Residential



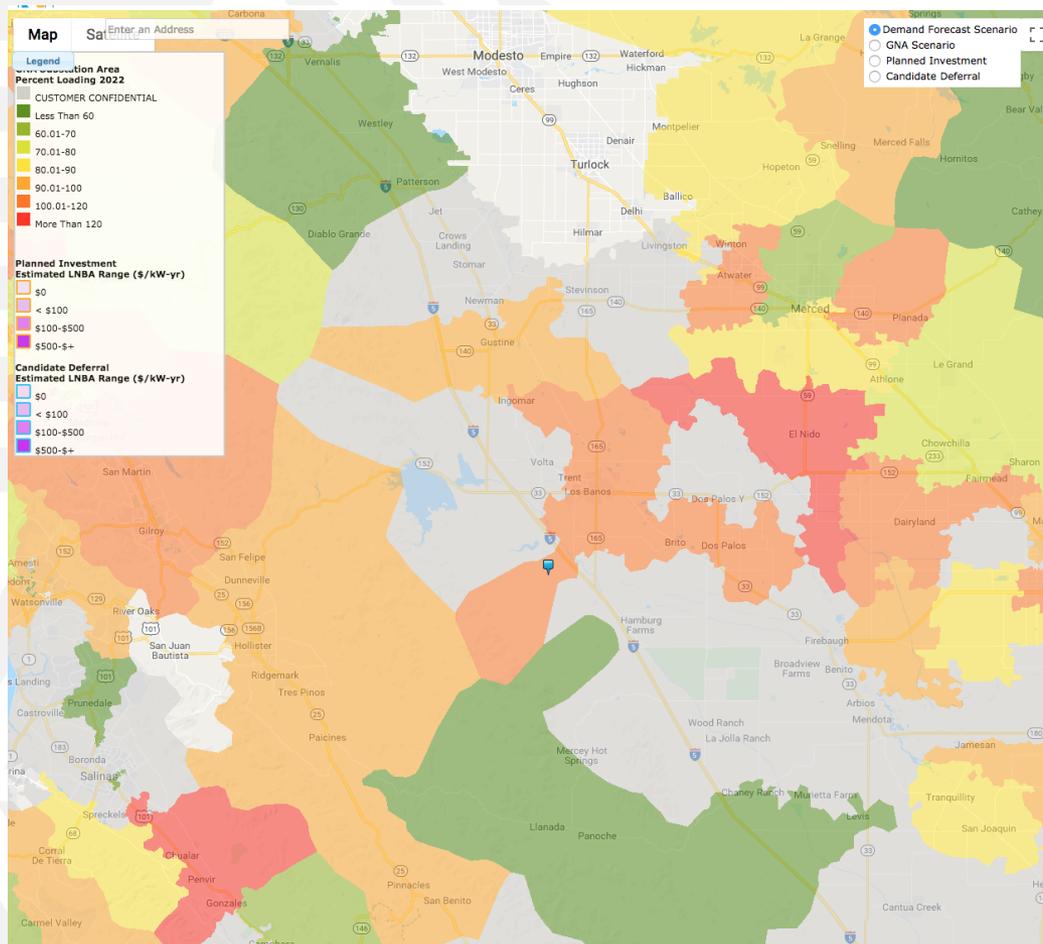


Uncertainty, Impact and Risk

	PV	Electric Vehicles EV	Energy Efficiency AAEE	Energy Storage ES	Demand Response LMDR
IEPR	High	High	High	High	Medium
Method	Medium	Medium	Medium	High	Medium
Shapes/Profile	Low	Med to High	Medium	High	Low
Charge Location	Not Applicable	Medium	Not Applicable	Not Applicable	Not Applicable
Lumpy (NT)*	Low	Medium	Medium	Low	Low
Lumpy (LT)**	High	Medium	Medium	High	Medium
Impact	Large	Medium	Large	Small	Small
Risk	High	Medium	High	Low	Low

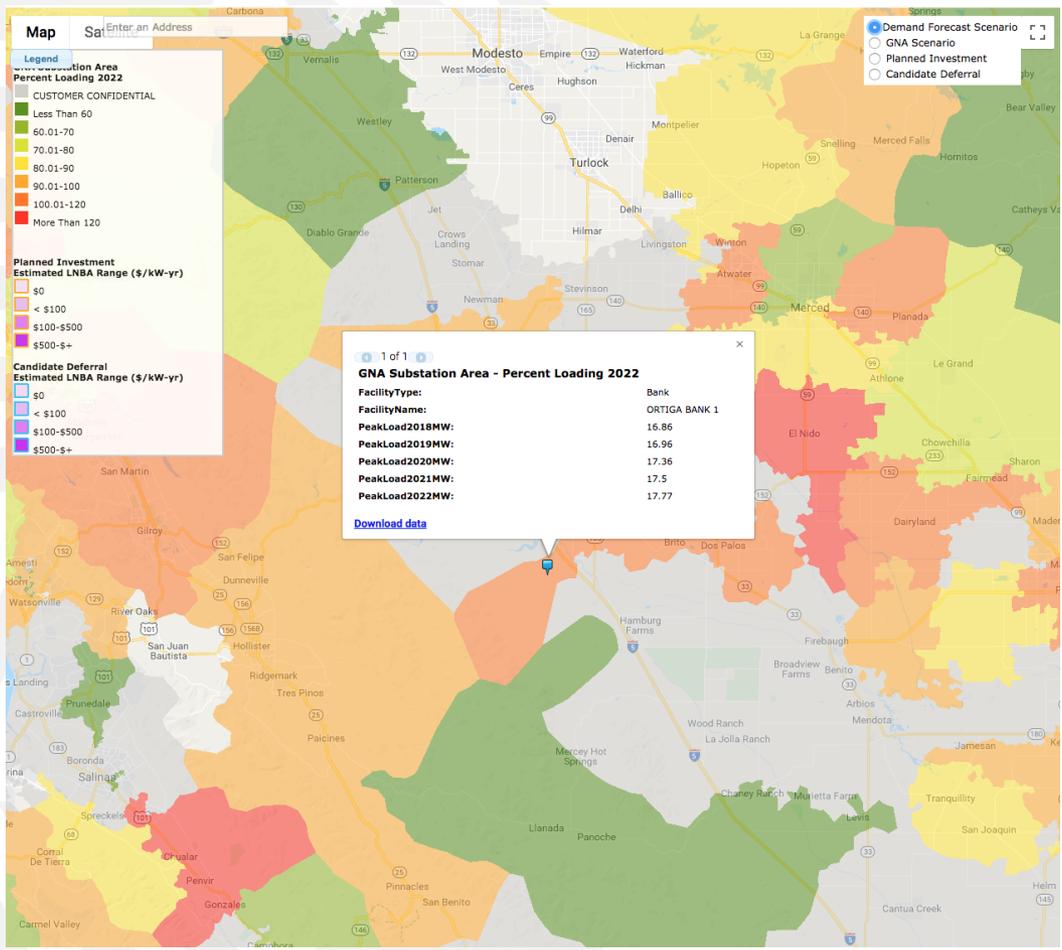
* NT = Near-Term
 ** LT = Long-Term

Example in PG&E service area



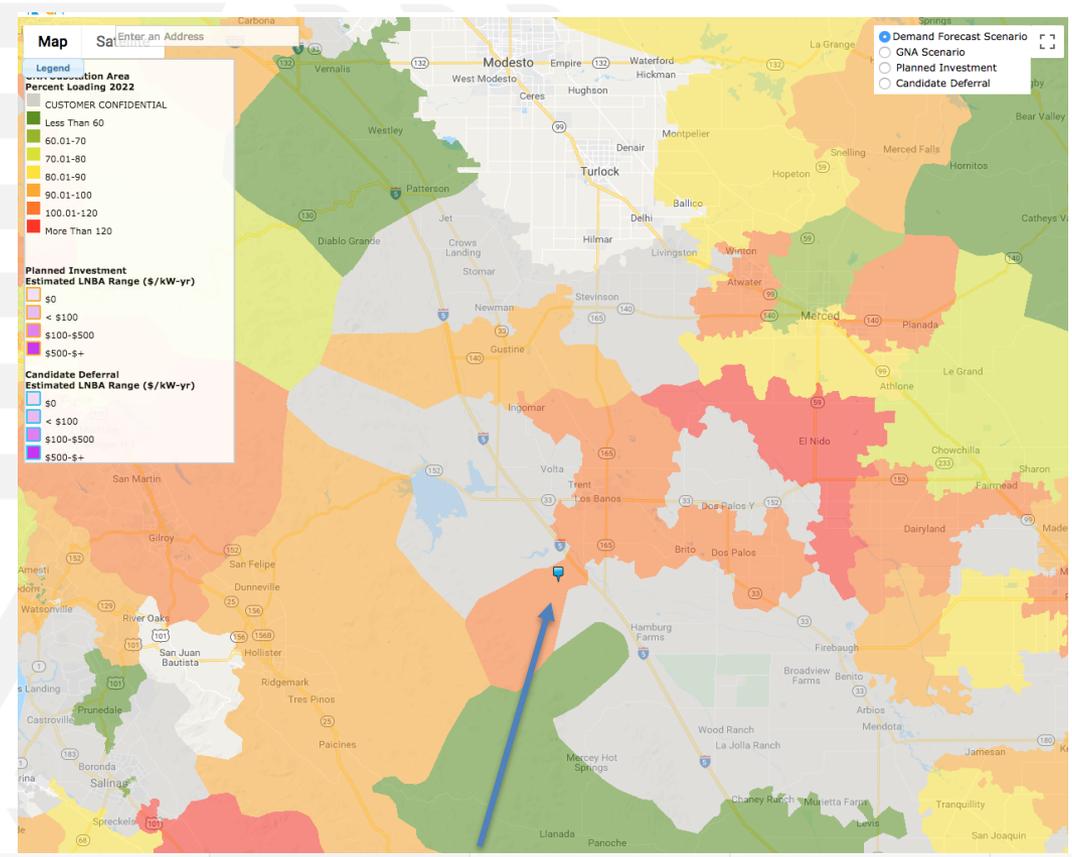
Source: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

Demand Forecast



Source: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

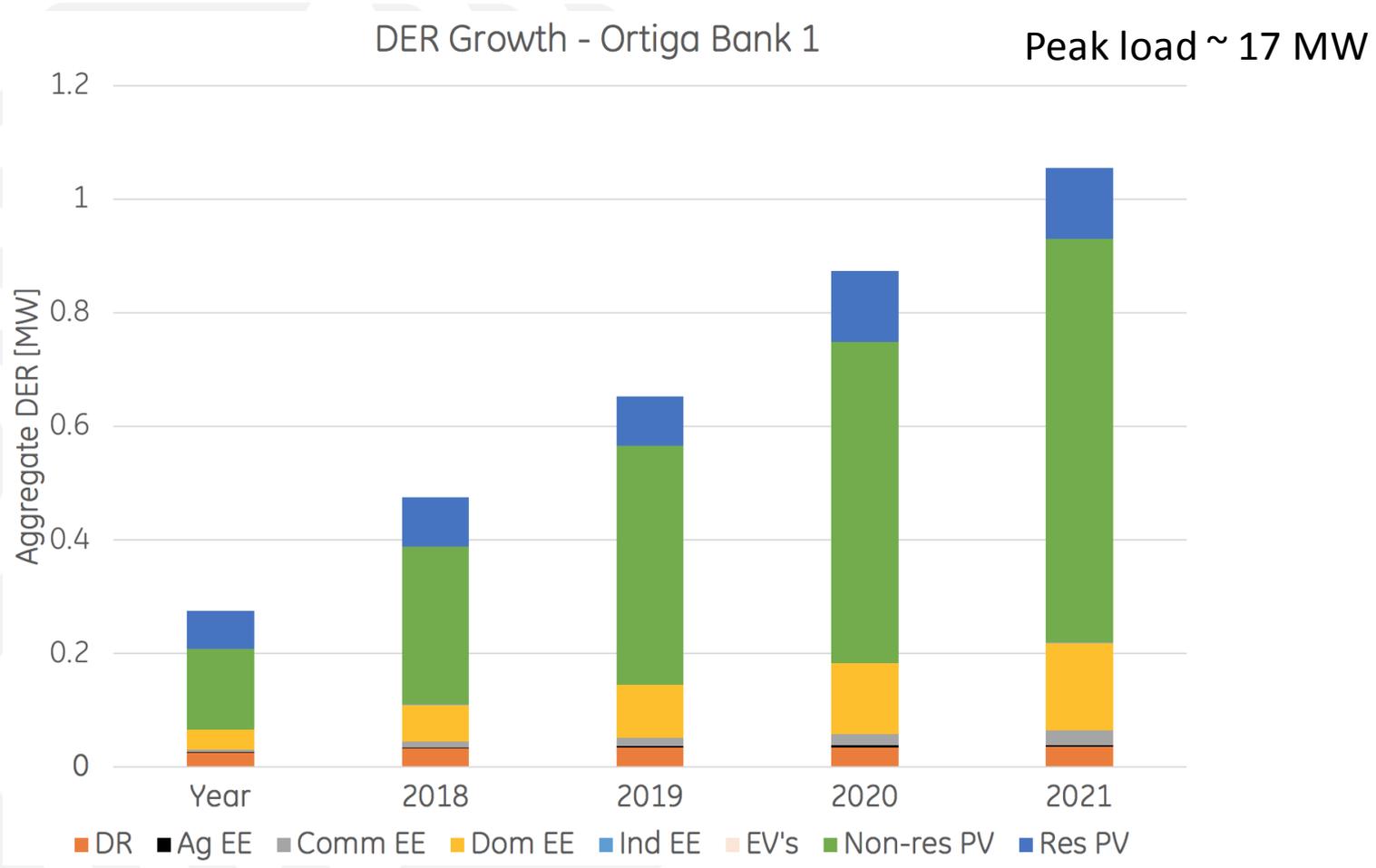
Peak load forecast



Division	Facility Type	Facility Name	Year 2018 Peak Load (MW)	Year 2019 Peak Load (MW)	Year 2020 Peak Load (MW)	Year 2021 Peak Load (MW)	Year 2022 Peak Load (MW)
Yosemite	Feeder	ORTIGA 1105	9.94	9.95	10.01	10.07	10.1
Yosemite	Feeder	ORTIGA 1106	8.33	8.43	8.77	8.86	9.1
Yosemite	Bank	ORTIGA BANK 1	16.86	16.96	17.36	17.5	17.77

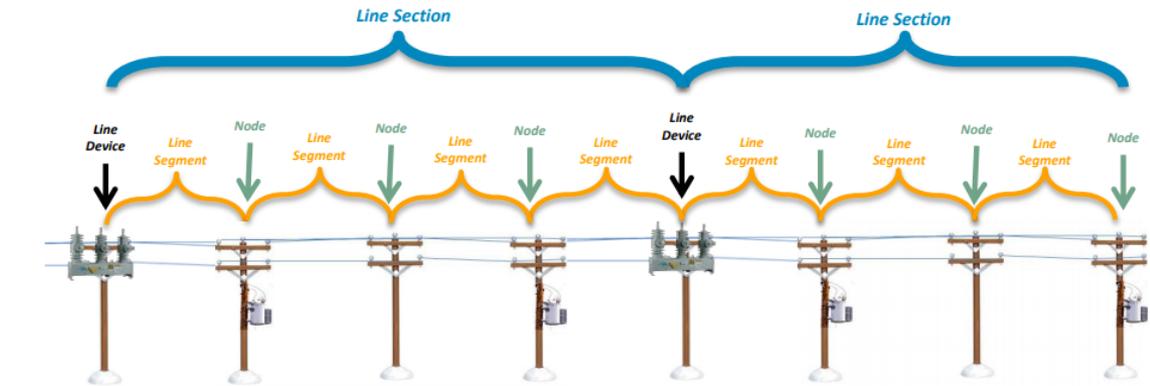


DER Growth Forecast



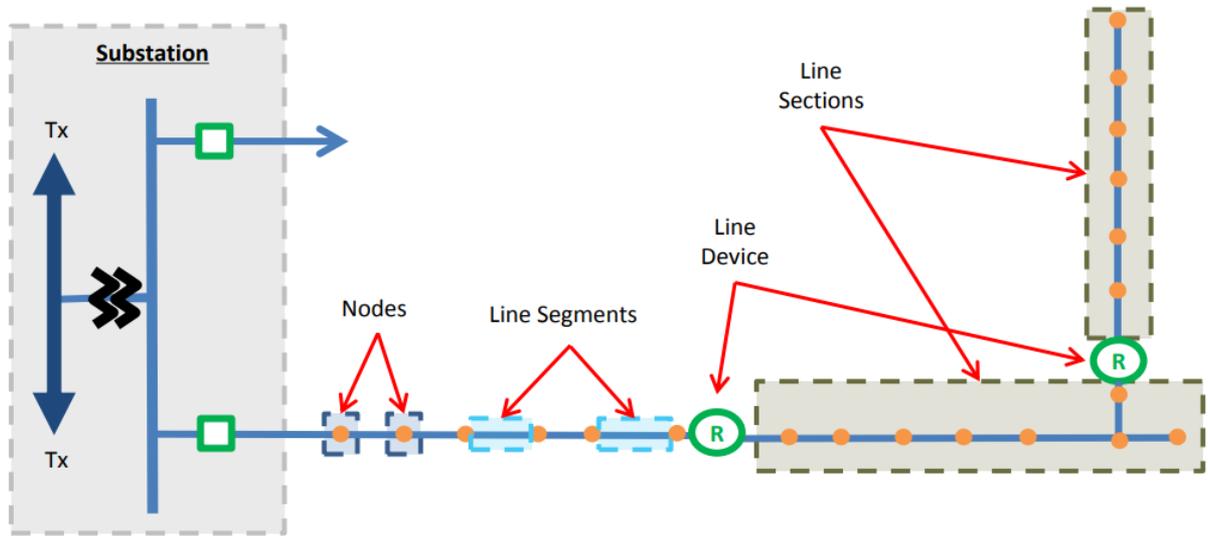
Source: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

Hosting capacity analysis - granularity



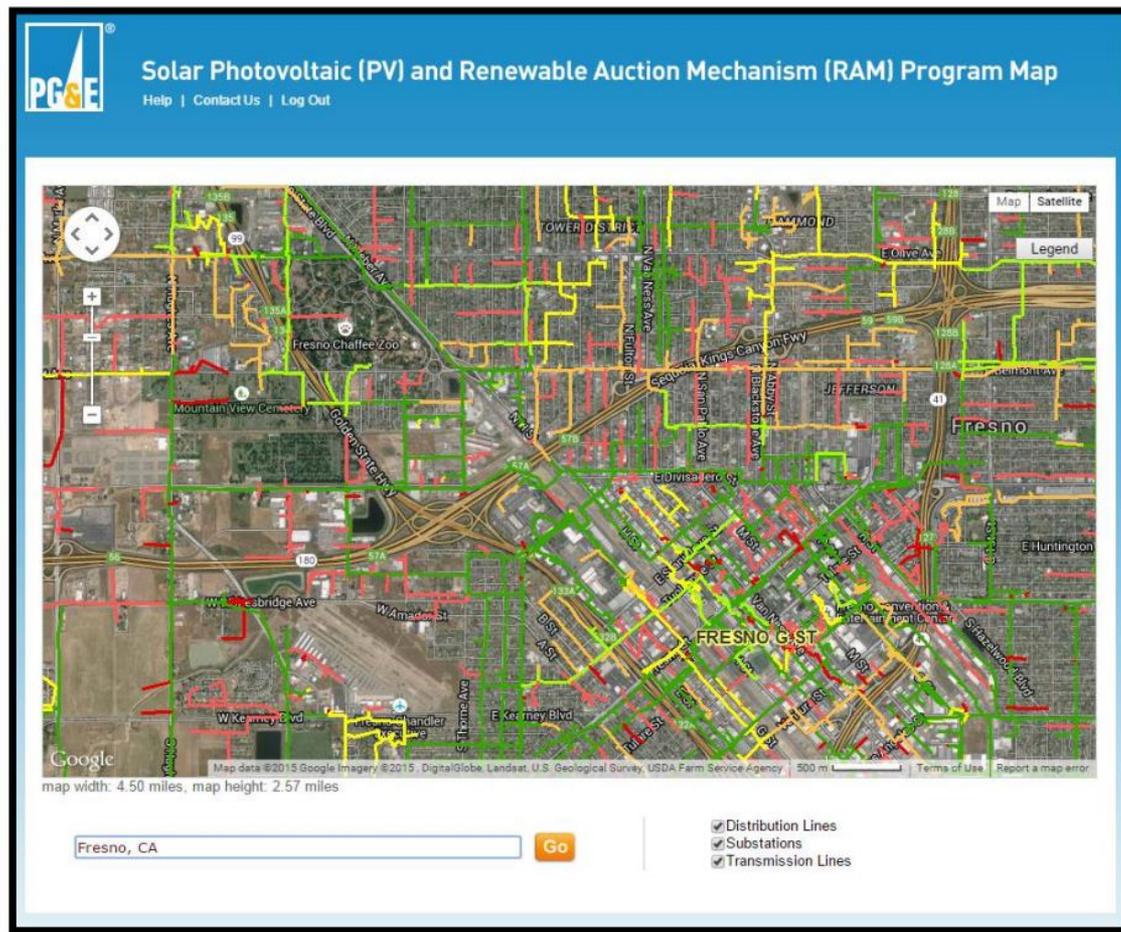
Analysis was granular down to line sections within each feeder

- PG&E was able to perform the analysis down a very granular level on specific line sections within each distribution feeder
- This is very important to be able to capture the limiting aspects of the tapered radial distribution system design
- Industry studies and analyses typically only consider or have the ability to do this analysis at the substation level



2. Integration Capacity Analysis

PG&E analyzed 102,000 line sections within >3,000 circuits

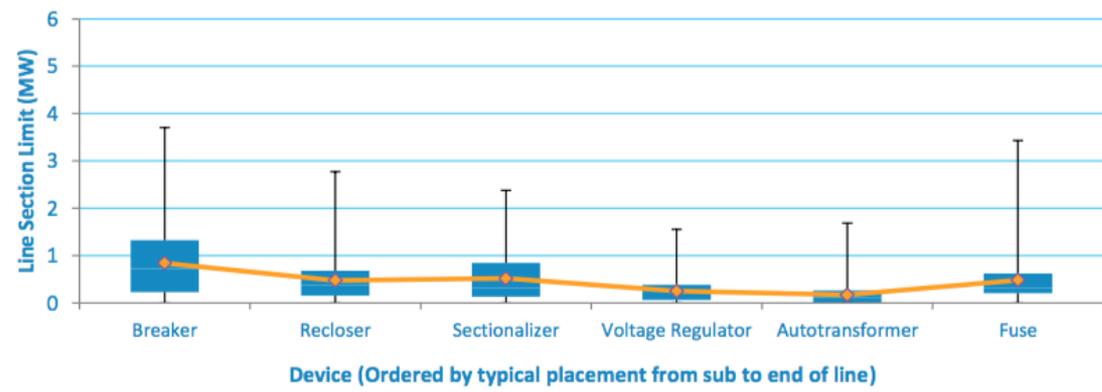
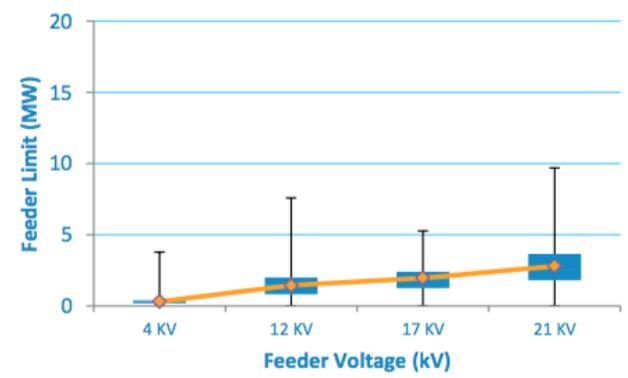
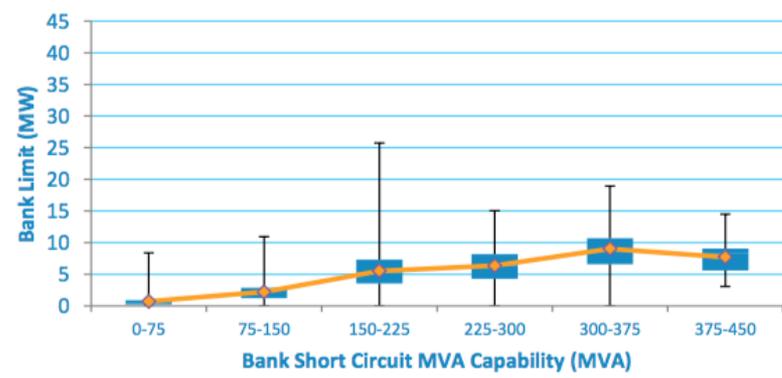


PG&E analyzed all three phase line sections for all the 3,000+ distribution circuits

- Results for approx. 102,000 line sections
 - Average of 34 line sections per feeder
 - Largest number of line sections for one feeder was found to be 310
- Locational results published by each DER type
- Granular down to fuse devices
- Initially colored by PV Results
 - Line Section IC / Feeder IC
 - Red, Amber, Green color scheme with green being higher capacities

Hosting capacity analysis for Hydro/Biogas in PG&E

Typical DER Use Case: Hydro, Bio-Gas, and other DER with constant full output using machinery



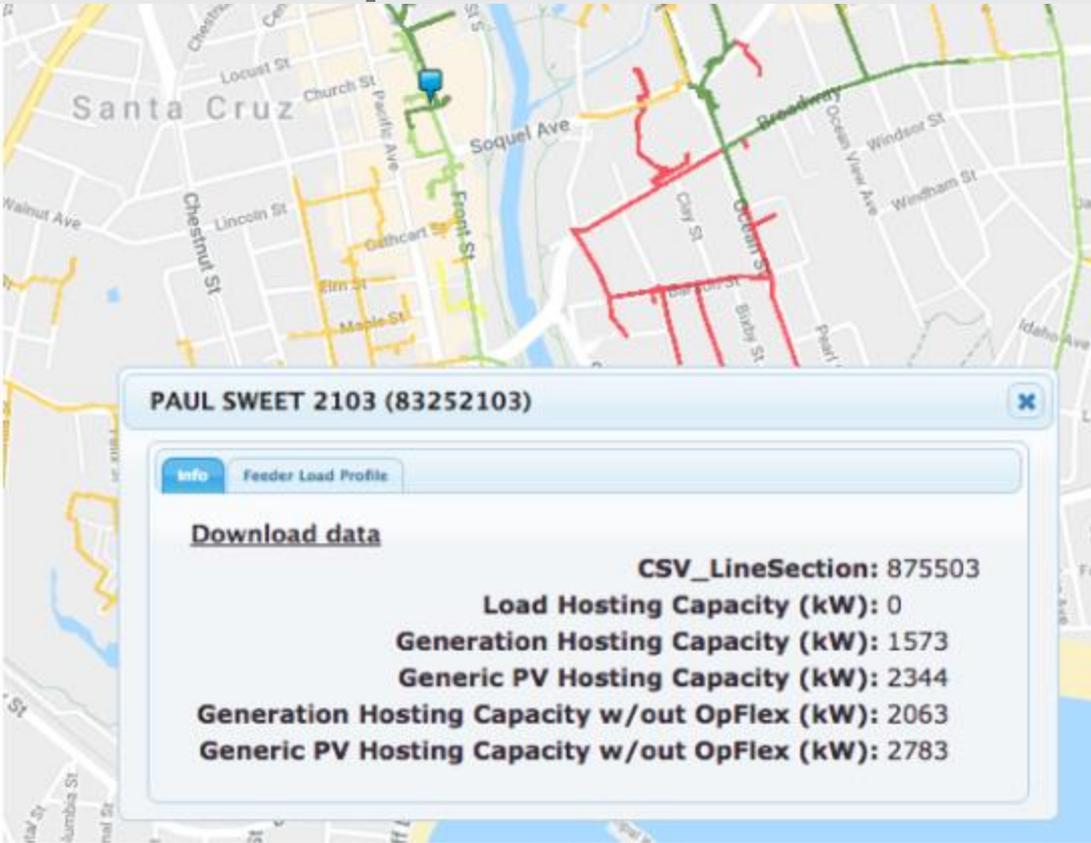
NOTE: Results based on July 1 2015 ICA data

Hosting Capacity Analysis in California: Integration Capacity Analysis - ICA



- ▶ Since 2015 ICA 1.0 was used only as a rough guide to developers for avoiding locations that require upgrades.
- ▶ In September 2017 CPUC ruled on the final ICA methodology (“ICA 2.0”) for interconnection case and ordered IOUs to provide maps by July 2018:
 - IOUs to implement ICA across their **entire distribution systems**, using the **iterative method** to meet the **interconnection** use case.
 - Criteria to be considered: thermal overloads, voltage violations, protection, and safety limitations.
 - Hosting capacity to be determined for three DER types (generation, PV, load) and two operational flexibility scenarios (no reverse flow, reverse flow up to substation).
- ▶ In Sep. 2018 IOUs closed public access to their ICA 1.0 maps due to confidentiality, physical and cyber-security. After CPUC asked IOUs to make ICA maps publicly available again, IOUs reopened portals with ICA 2.0 maps on 12/28/18.
- ▶ ICA 2.0 maps include detailed, **576-hour** power flow modeling down to **every circuit, line section, and node** on the grid, with **monthly updates**.
- ▶ ICA 2.0 built on the same input data used for Locational Net Benefits Analysis and Distribution Deferral Opportunity Reports.

ICA 2.0 Maps Published December 2018



Example of ICA 2.0 maps, showing color-coded capacity and detailed information for the specific identified point, as well as circuit load profiles with 576 hourly values

<http://clean-coalition.org/news/ica-press-release-january-2019/>

ICA 2.0 Lessons Learned

► PG&E

- ❑ Long ICA processing time: determining HC for a single feeder using iterative method and CYME software can take from several hours to several weeks depending on feeder complexity. PG&E had to increase number of CYME licenses 10 times for their ~3,000 circuits.
- ❑ Load-flow convergence issues: small percentage of circuit did not converge in CYME tool

► SCE

- ❑ ICA processing time: average time of 10.50 hours per circuit. SCE developed a node reduction methodology.
- ❑ Input Data: SCE had to use CYME Gateway tool for data extraction from SCE's network, AMI and SCADA datasets
- ❑ Operation of voltage regulation devices: SCE had to develop an enhanced ICA calculation engine to account for capacitors and voltage regulators

► SDG&E

- ❑ System-wide ICA implementation cost: Approximate estimate \$450,000 (SDG&E has ~3.3 million consumers through ~1.4 million electric meters). Costs include ongoing administration and updates, associated IT and licensing.

ICA Working Group – Summary of Recommendations



- ▶ ICA Working Group monitors and provides consultation to the IOUs on the development and refinements of the ICA methodology. December 2016: IOUs submitted their final Demo A reports. March 2017: ICA Working Group submitted Final ICA WG Report (short-term refinements report).
- ▶ March 2018: Final ICA WG Long-Term Refinements Report
 - ❑ WG agrees that additional evaluation of ICA methodologies is required.
 - ❑ Planning use case – No final recommendation on methodology. The challenge is how to integrate load and DER growth projections. CPUC guidance needed on timing of implementation and exact planning use case definition
 - ❑ DER Spatial Modeling – interconnection case: at each node; planning case: at locational granularity supported by accurate DER forecast
 - ❑ Smart inverter functions - Additional IOU testing and WG review needed
 - ❑ Operational flexibility (allows utilities to make operational decisions in emergency situations) - Real-time visibility of DER needed for same HC levels
 - ❑ Queued DER projects – WG Consensus about inclusion
 - ❑ Data Sharing – Recommendation for common data APIs
 - ❑ Voltage Regulating Devices and Load shape methodology – Additional IOU work and WG Review

ICA 3.0 Plans

- ▶ Current ICA maps pertain to just the distribution grid. ICA 3.0 will add **constraints related to the transmission grid** that could affect interconnection — for example, other projects being proposed for that part of the transmission grid.
- ▶ ICA 2.0 maps model each circuit, but they do not show how a circuit may affect neighboring circuits. ICA 3.0 will dynamically model **multiple circuits and their impact on one another**.
- ▶ ICA 3.0 will aim to update the **maps in real-time**, to ensure that the results are never out of date.



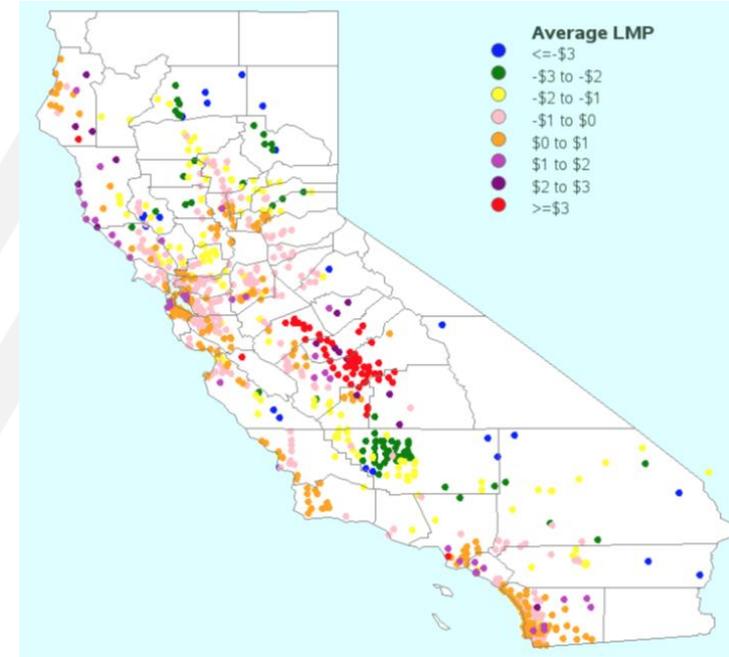
Locational Net Benefits Analysis

- ▶ Start with CPUC/E3 cost-effectiveness calculator and add location-specific values and additional avoided cost components
- ▶ Applications of LNBA
 - 2 use cases for LNBA – project deferrals
 - LNBA Public Tool and Heat Map to provide information for candidate distribution deferral opportunities
 - Prioritizing candidate distribution deferral opportunities
 - 3rd use case – cost-effectiveness; incorporate DER integration costs. Develop location-specific T&D avoided cost values to input into DER Avoided Cost Calculator (DERAC)

Help developers find potential project sites

Avoided energy

- ▶ Originally DERAC calculator used NP-15 price for PG&E and SP-15 price for SCE/SDGE
- ▶ Move to DLAP (default load aggregation point) price because IOU pays this price to serve load
- ▶ How to forecast DLAP?
 - Historical or forecasted hourly DLAP energy prices; modify heat rates using CPUC/E3 capacity expansion RESOLVE model to reflect future resource mix
 - Hourly production cost model – higher resolution, more accurate, but waiting for IRP proceeding which is developing hybrid resource adequacy/production cost model

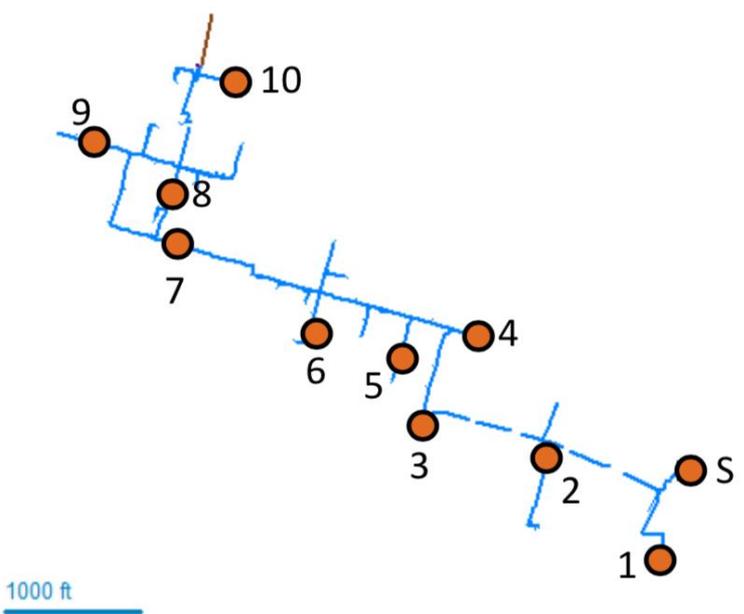


3. Locational net benefits

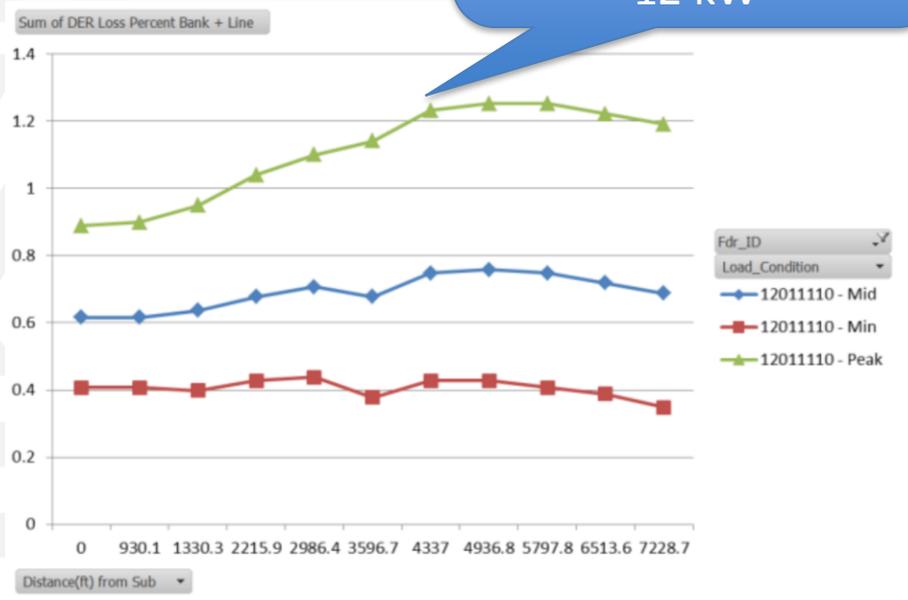
Avoided losses: Urban feeders have low losses; not location-sensitive



Oakland C 1110, 12 kV, Urban, Peak Load



1.2% losses means that 1 MW DER reduces line losses by 12 kW

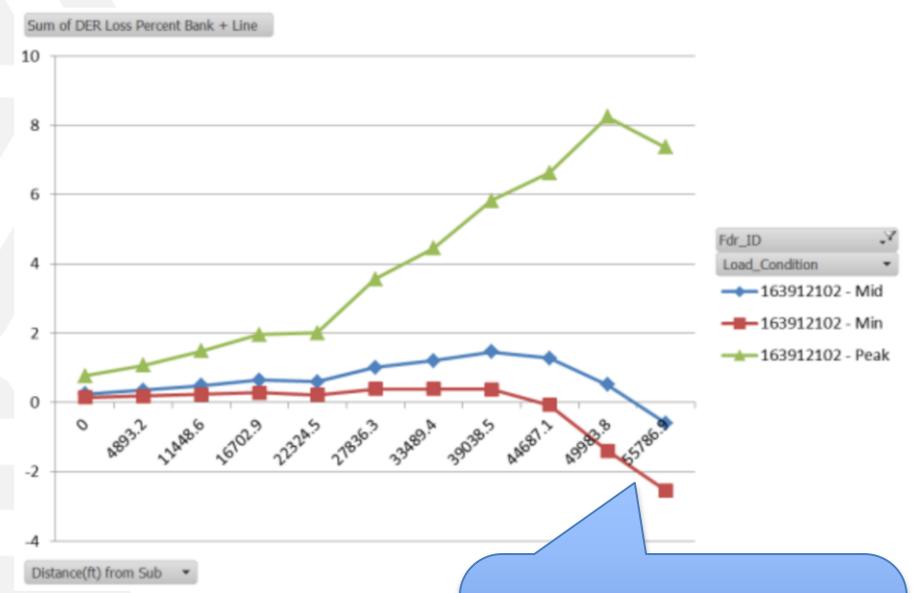
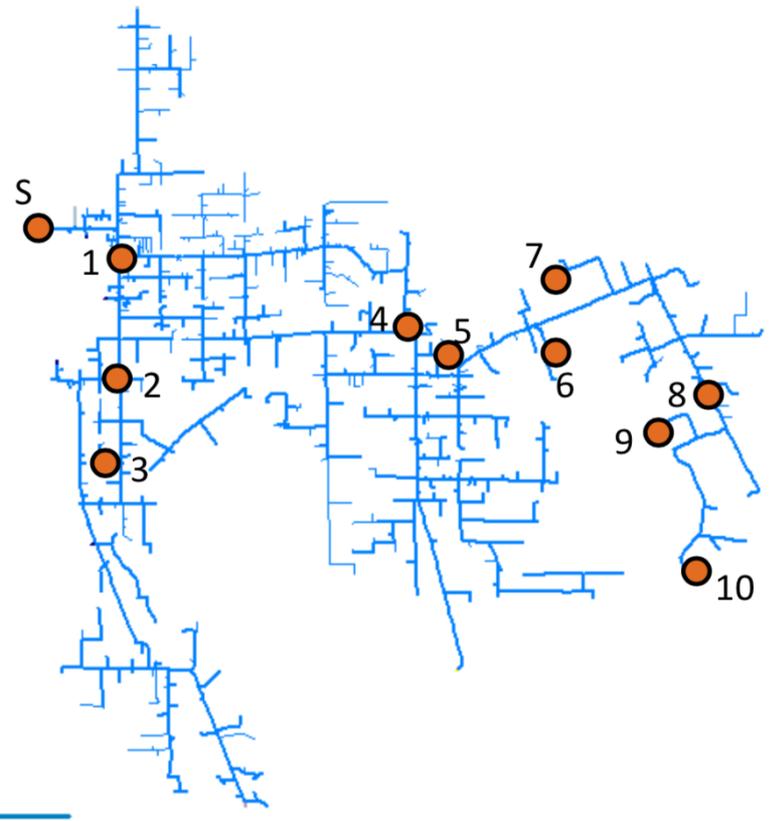


3. Locational net benefits



Rural feeders are longer and more location-sensitive

Corning 1104, 12 kV, Rural, Peak Load



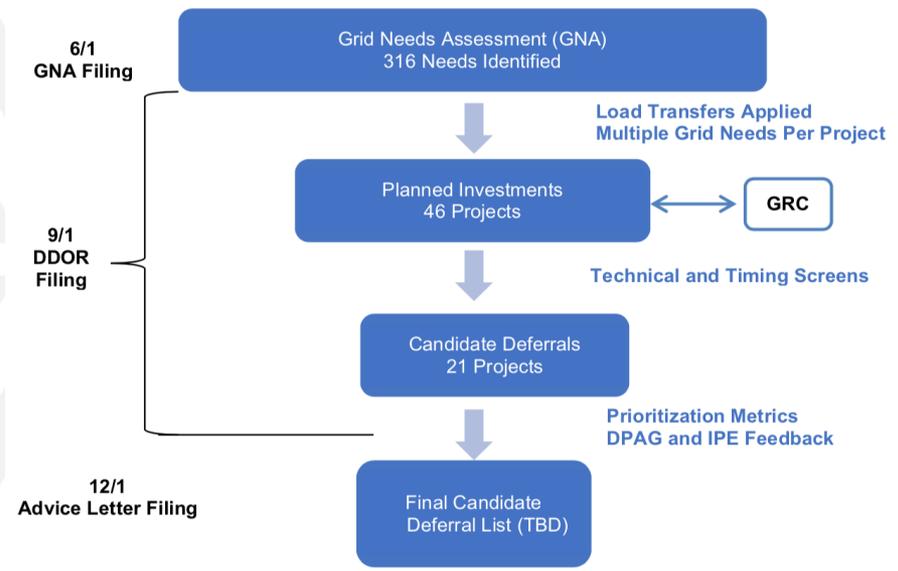
Reverse power flow causes losses to *increase*

Avoided losses

- ▶ For deferral framework and heat map tool use cases, use locational differentiation of losses
- ▶ For cost-effectiveness DERAC use case, don't change until granular line loss factors are available
- ▶ Reactive power/voltage support capabilities
 - Utilities need to develop methodology to calculate hourly VAR requirement profile. Tools being developed in ICA work. Use this to determine upgrade deferrals. Waiting for Rule 21 proceeding to determine reactive power requirements and power factor assumptions
- ▶ Conservation Voltage Reduction
- ▶ Situational Awareness

Distribution Investment Deferral Framework (DIDF)

- ▶ Transparent process to create candidate deferral shortlist, grid mod investments, & proactive hosting capacity upgrades to accommodate forecasted DER growth
- ▶ 5 year planning horizon
- ▶ Grid Needs Assessment (GNA)
- ▶ Investment projects
- ▶ Technical and timing screens
 - ❑ Capacity, reactive power, voltage, reliability (backtie), resiliency (microgrid)
 - ❑ Can DER provide required service?
 - ❑ Operating date 2021-2022
- ▶ Prioritization metrics
 - ❑ Cost Effectiveness
 - ❑ Forecast Certainty
 - ❑ Market Assessment



Grid Needs Assessment

► GNA

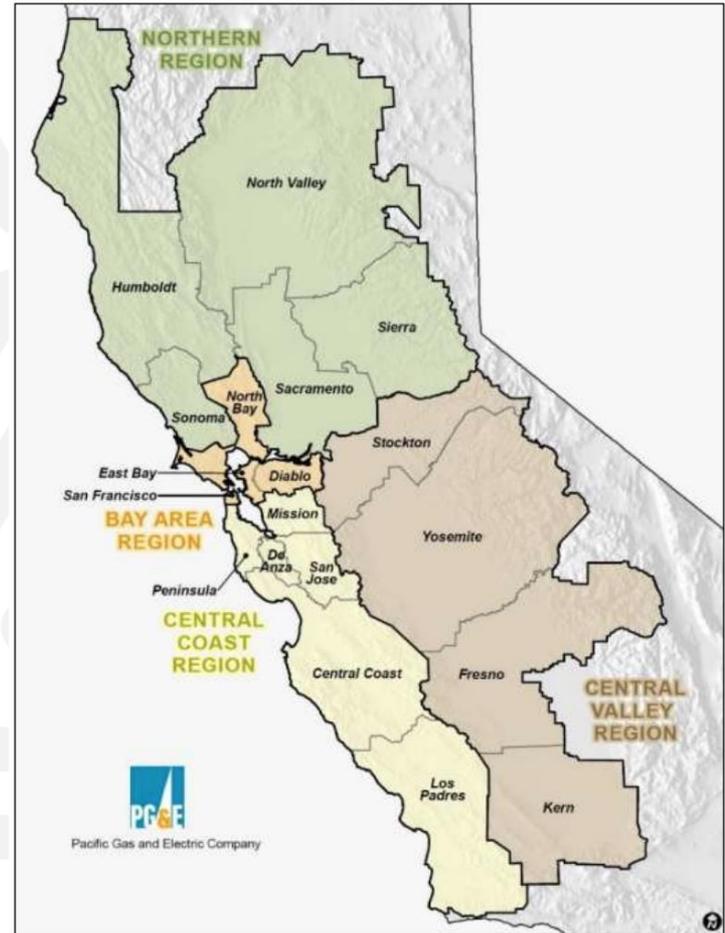
- Location
- Distribution service required
- Date needed
- Equipment/Facility rating
- Forecasted deficiency over 5 years
- What mitigation options are possible? Can they be mitigated through distribution switching and load transfers?

► Bay Area Distribution Planning Region (DPR) overview:

- 4453 MW peak demand, 90% residential
- 549 MW of DG (81% is inverter-based)
- 659 circuits; 242 substations

► Bay Area DPR grid needs & mitigation:

- 37 needs for distribution capacity
 - 29 could be met through switching/transfers
 - 8 needed investments
- 7 needs for reliability reasons
 - None could be met through switching/transfers
 - All needed investments





Examples of planned investments

Division	Facility Type	Proposed Work	In-Service Date	Distribution Service Required	Estimated LNBA Range (\$/kW-yr)	Deficiency (MW)	DER Service Eligible (Y/N)
Central Coast	Bank	Install new bank at Substation	5/1/21	Capacity	\$100-\$500	3.99	Y
Central Coast	Bank	Replace Bank #3	5/1/21	Capacity	\$100-\$500	2.00	Y
Central Coast	Feeder	Installation to reduce the number of customers on nearby feeder	5/1/22	Reliability / Other	\$100-\$500	1.00	Y
Central Coast	Distribution Line	Replace recloser and booster to transfer and reduce number of customers	12/1/22	Reliability / Other	\$0-\$100	2.23	Y
Diablo	Feeder	Install new feeder to reduce load on 2 other feeders	5/1/21	Reliability / Other	\$0-\$100	5.78	Y

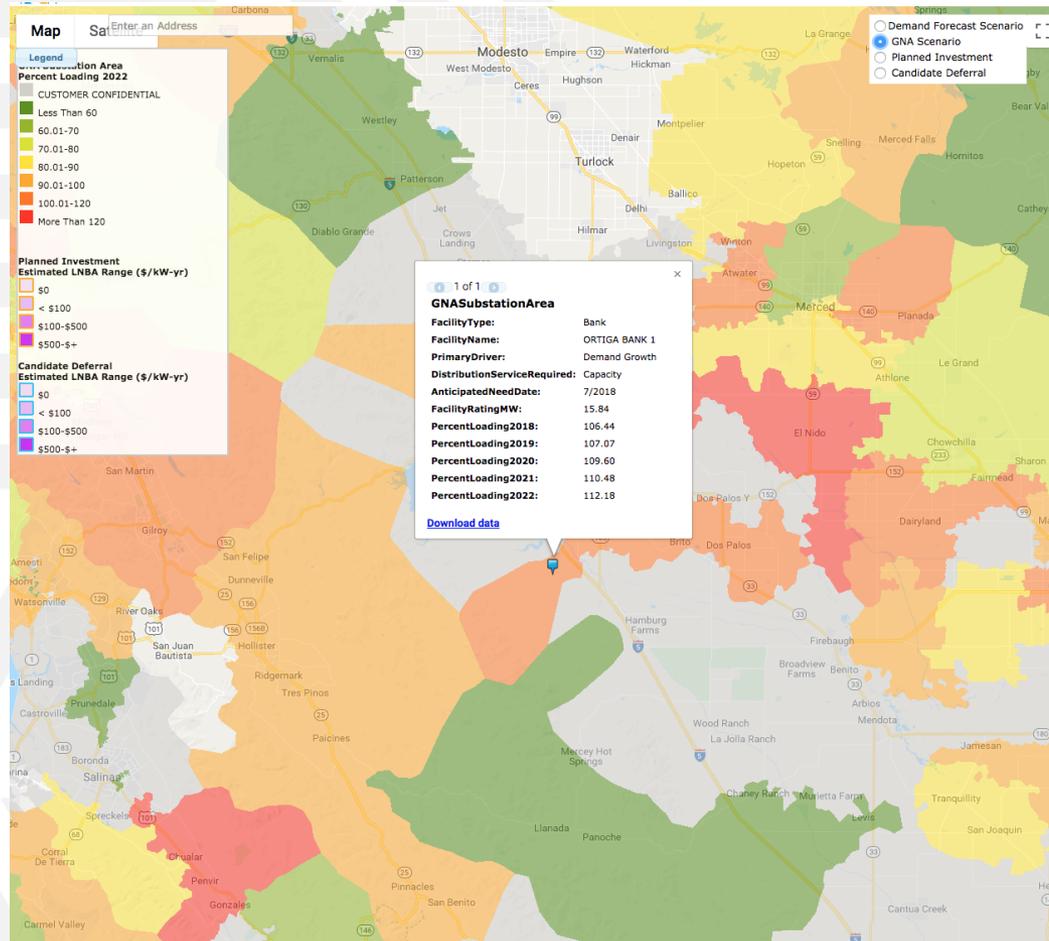


Candidate Deferral examples

Proposed Work	Dist. Service Req.	Est. LNBA Range (\$/kW-yr.)	Unit Cost of Trad. Mitigation (\$k)	Expected performance and operational requirements				
				Grid Need (MW)	Month	Days/Year	Hours	Duration (Hours)
Install new bank at Substation	Capacity	\$100-\$500	\$6,500	[CUSTOMER CONFIDENTIAL]				
Replace Bank #3	Capacity	\$100-\$500	\$5,500	[CUSTOMER CONFIDENTIAL]				
				1.50	Jun-Sep	12	8:00AM-4:00PM	8
Installation to reduce the number of customers on nearby feeder	Reliability / Other	\$100-\$500	\$1,485	1.20	Jan-Dec	365	12:00AM - 12:00AM	24
Replace recloser and booster to transfer and reduce number of customers	Reliability / Other	\$0-\$100	\$250	2.23	Jan-Dec	365	12:00AM - 12:00AM	24
Install new feeder to reduce the load on 2 other feeders	Reliability / Other	\$0-\$100	\$1,250	3.68	Apr-Aug	153	12:00AM - 12:00AM	24
				2.10	Jun-Aug	92	12:00AM - 12:00AM	24

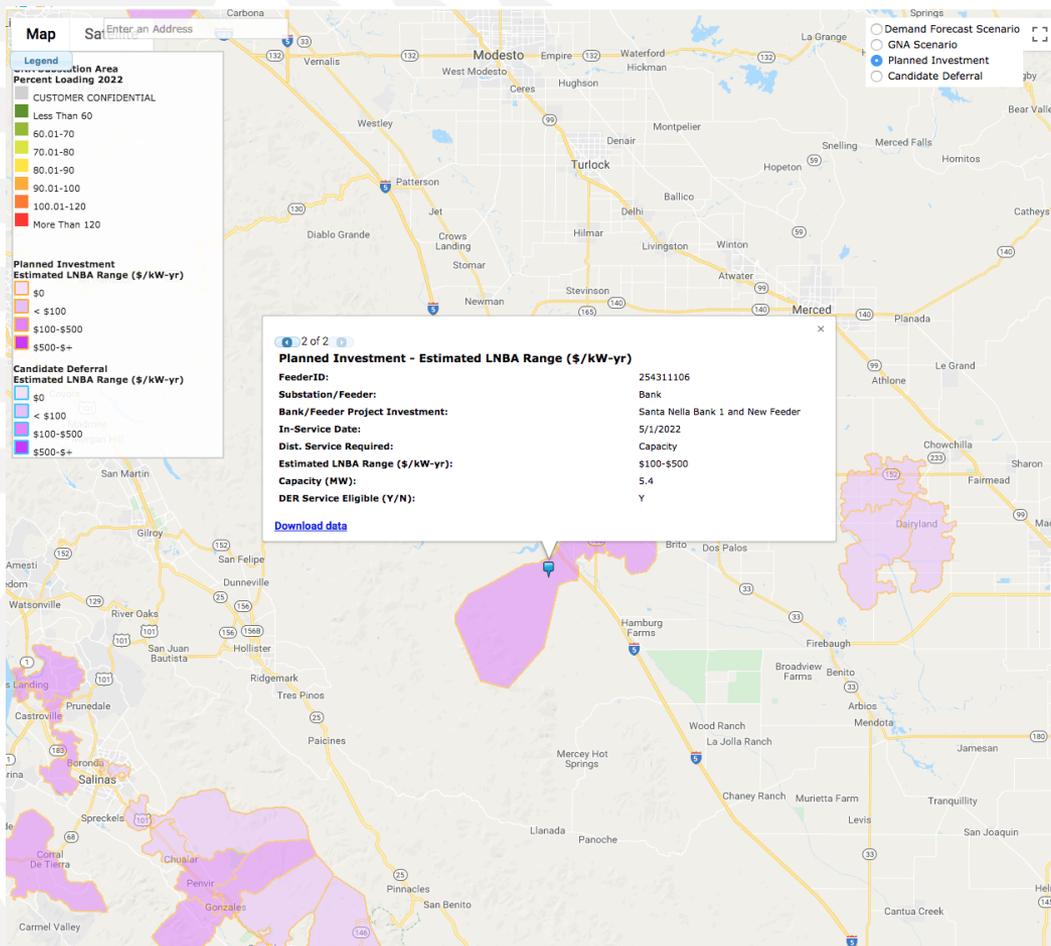
4. Distribution Deferrals

GNA



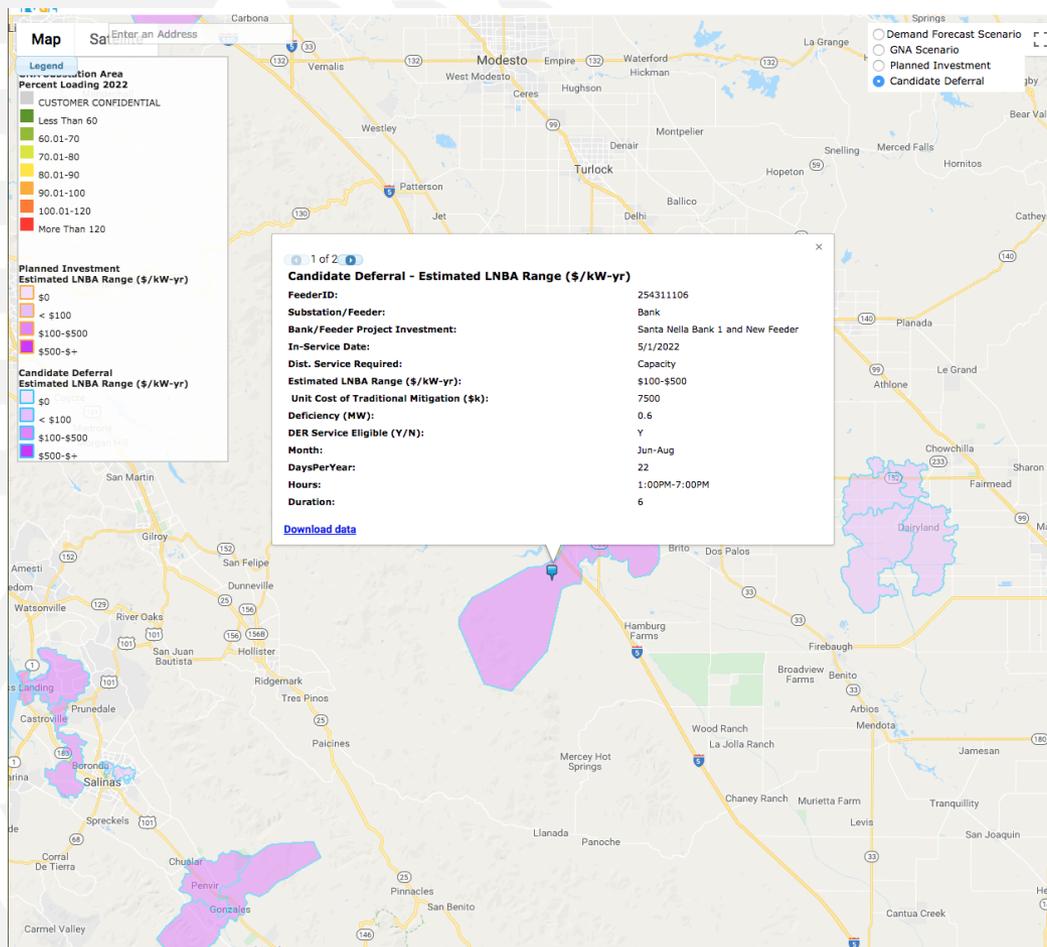
Source: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

Planned Investment



Source: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

Candidate deferral



Source: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

Questions to ask utilities

- ▶ What are your grid modernization goals?
- ▶ Which grid mod investments are foundational? And which build on those foundations?
- ▶ What are the costs and benefits of each grid mod investment?
- ▶ Have you considered time-series profiles (not just system peak) in your growth forecasts?
- ▶ Have you considered uncertainty and risk in your growth forecasts?
- ▶ Are your energy, capacity, loss calculations appropriate for the application?
- ▶ How do you consider the benefits from smart inverter capabilities such as voltage regulation?
- ▶ How do you screen and prioritize deferral projects?

Resources



- ▶ Xcel Energy's *Integrated Distribution Plan (2019-2028): Advancing the Grid at the Speed of Value*, Nov. 1, 2018.
- ▶ PG&E Distributed Resources Plan, 2015, <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5141>
- ▶ PG&E Maps https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page
- ▶ CA Distributed Resources Plan Working Groups <https://drpwg.org/>
- ▶ PG&E's 2018 Distribution Grid Needs Assessment June 1, 2018

Any Questions?

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