Advancing Distribution System Planning for a Changing Grid

ESIG Webinar

July 2026

Energy+Environmental Economics

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Perceived Utility Capabilities and Sophistication vs. Current Maturity

	Distribution Planning	Distribution Operations	Distribution Automation (DA)	DER Resources
Today	• Focus on peak days • Limited data from substation SCADA and AMI • Multiple tools to perform an increasing variety of analysis	• SCADA visibility and control at Substation • Inaccuracies in distribution network model	• Autonomous controls (reclosers, fuses, voltage regulators) • Advanced Metering Infrastructure (AMI) outage notifications (underutilized)	• Old direct load control programs and technology • Rely on 3rd party aggregators with proprietary solutions • Limited operational integration
Tomorrow	• Focus on monthly variability of both loads and distributed generation • 8760 data -> 576 analysis • Additional data from DA sensors • Tool integration to perform multivariable simulations with a range of possible outcomes	• Advanced Distribution Management System (ADMS) • Distributed Energy Resource Management System (DERMS) • “Digital Twin” connectivity model	• DA devices provide monitoring and control to distribution operator with ADMS • DA data provides additional data for Distribution Planning • AMI power quality and anomality notifications	• DERMS interface to utility scale DER (vendor or utility) • DERMS interface to aggregated customer DER (aggregator or customer) • Telecom & messaging protocol standard adoption

Evolving Distribution Planning Role

- **Distribution Planning and Engineering methodology is necessarily conservative to address safety and reliability priorities**
  - E.g. DER have not yet proven they can perform
- **Traditional approach focuses on system peak rather analyzing dynamic seasonal or monthly variables**
  - Increasing workload for substation and feeder analysis for capacity expansion and interconnection requests
  - E.g., minimum daily load and placement of distribution automation (DA) equipment
- **Limited data and visibility for analysis**
  - Substation SCADA
  - Advanced Metering Infrastructure (AMI)
    - 15 min – 1 hr. interval data
  - Lack of distribution sensor data
  - Inaccuracies in distribution network model
- **Multiple software applications to perform increasingly complex and intertwined functions**
  - Account for adoption of customer owned distributed generation and energy storage
  - Account for electrification of buildings and transportation

Distribution Planning Functions
1. Power Flow Studies
2. Grid Optimization
3. Resource and Economic Optimization
3. Fault & Protection Analysis
4. Integration Capacity Analysis
5. Forecasting Integration
6. Interconnection Integration
7. Reliability & Resilience Analysis
8. Locational Value Analysis
9. Power Quality Analysis
10. Electromagnetic Dynamic/Transient Analysis
11. Safety Analysis

Grid Needs, Solution Evaluation, and Feasibility

Consider whether the economically feasible idea is achievable, and what it will take to implement

Grid Needs & Solution Evaluation

- Distribution engineering, systems, and technology considerations for
  - Grid Needs Assessment
  - Cost Mitigation Opportunities
  - Solution Evaluation
    - e.g., Flexible Load, NWA, Flexible Interconnection, Distribution Automation, etc.

Feasibility Analysis

- Economic Feasibility
- Technical Feasibility
  - Systems and Technologies Required
  - Customer (DER) Program Considerations
  - Distribution Automation Capabilities
- Operational Feasibility

Planning to Operations

Distribution Planning

- Forecasts
- Solution Identification
  - Infrastructure,
  - Non-Wires Alternative (NWA)*
  - Distributed Energy Resource (DER)
    - Utility scale
    - Customer programs
      - Utility
      - 3rd Party

Solution Review & Approval

- Business Case (e.g., Cost Benefit Analysis - CBA)
- Internal Review
- Regulatory

Solution Implementation

- Planning
- Specification
- Procurement
- Deployment
  - Utility scale DER
  - Infrastructure
  - Customer DER & Programs

Distribution Operations

- Monitoring & Control
  - Supervisory control and data acquisition (**SCADA**)
  - Distribution Management System (**DMS**)
  - Outage Management System (**OMS**)
  - Distributed Energy Resource Management System (**DERMS**)
  - Advanced DMS (**ADMS**) = DMS + OMS + DERMS

Operational Data Warehouse

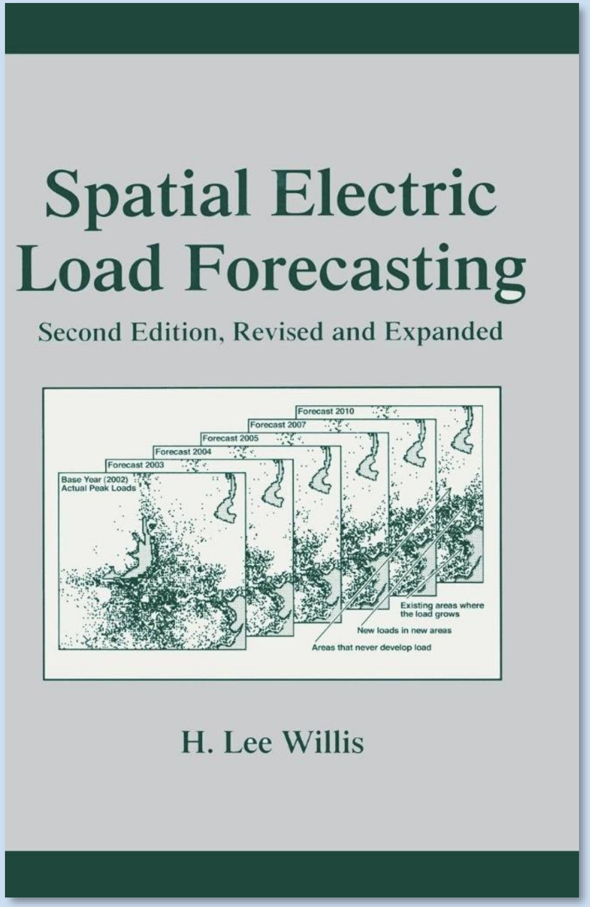
Advancing Distribution System Planning for a Changing Grid

Modern Approaches to Spatial Forecasting & Long-Term Planning

Jesse Fallick

July 14th 2026

Spatial forecasting is a discipline - not a black box



Where, how much, and when?

Core Tenets:

+ **Where Detail Matters**

  Locate growth at a scale useful for T&D decisions

+ **Spatial ≠ Small-Area**

  Reflect neighboring areas and the system-wide allocation of growth

+ **Transparent Methods**

  Disclose assumptions, drivers, constraints and limits — no black boxes.

+ **Planning needs alternatives**

  Evaluate scenarios and tradeoffs before committing capital.

Key Question: How do you operationalize a long-standing planning discipline in a modern geospatial system?

Building a Foundation for Advanced Distribution Planning

Planning & Costing

- Distribution Planning
- Infrastructure Costing
- Scenario Comparison

Spatial-Temporal Forecasting

- Long-term load growth
- DER adoption scenarios
- Localized (grid-aligned or grid-agnostic)

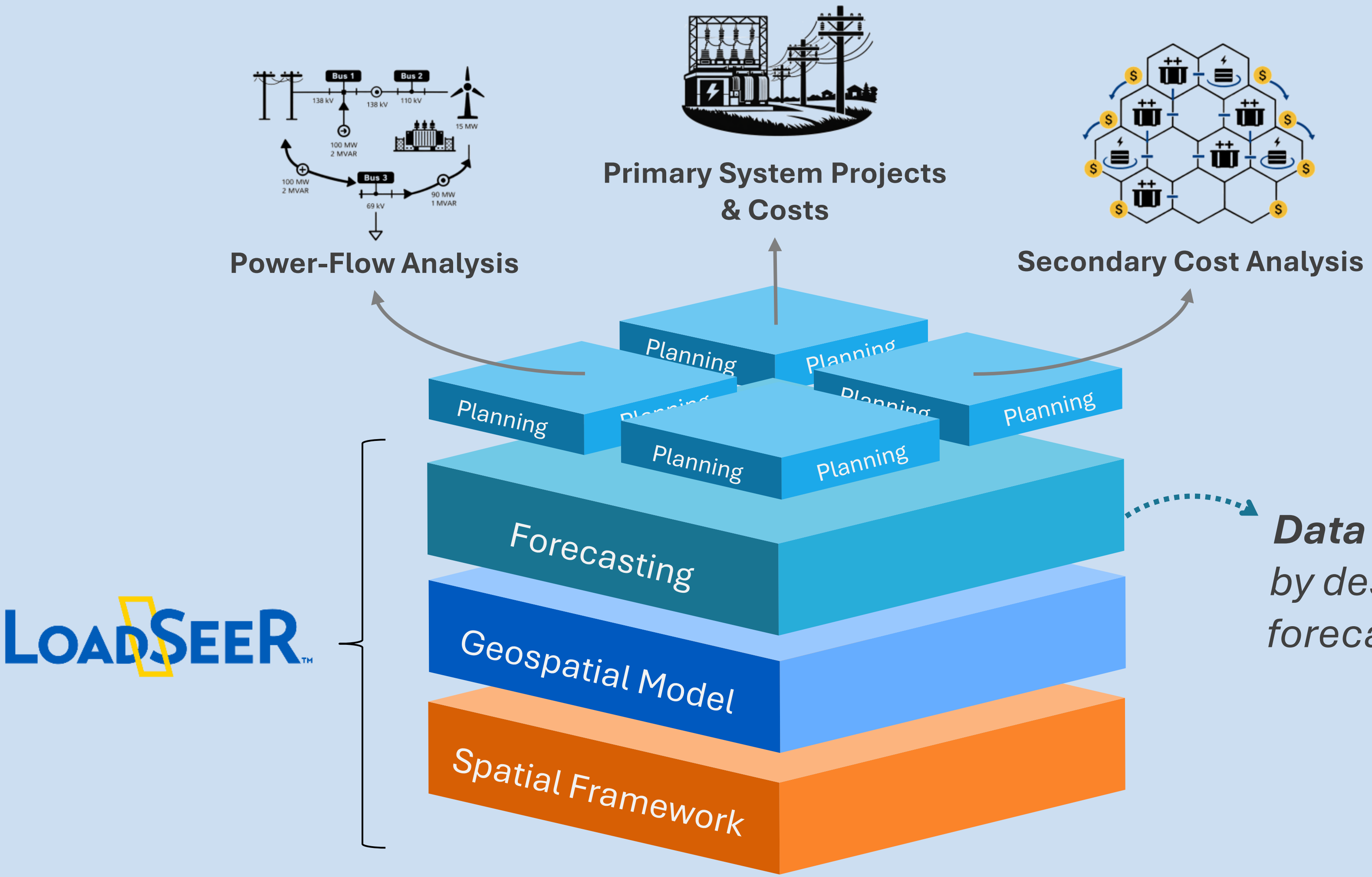
Standardized Geospatial Model

- 700+ spatial & building-level variables
- Land use, buildings, demographics
- National coverage

High-Resolution Spatial Framework

- H3 grids / flexible aggregation
- Aligns to feeders, substations, planning
- Supports non-grid growth (Land Use, EV corridors)

One Geospatial Foundation, Many Planning Applications



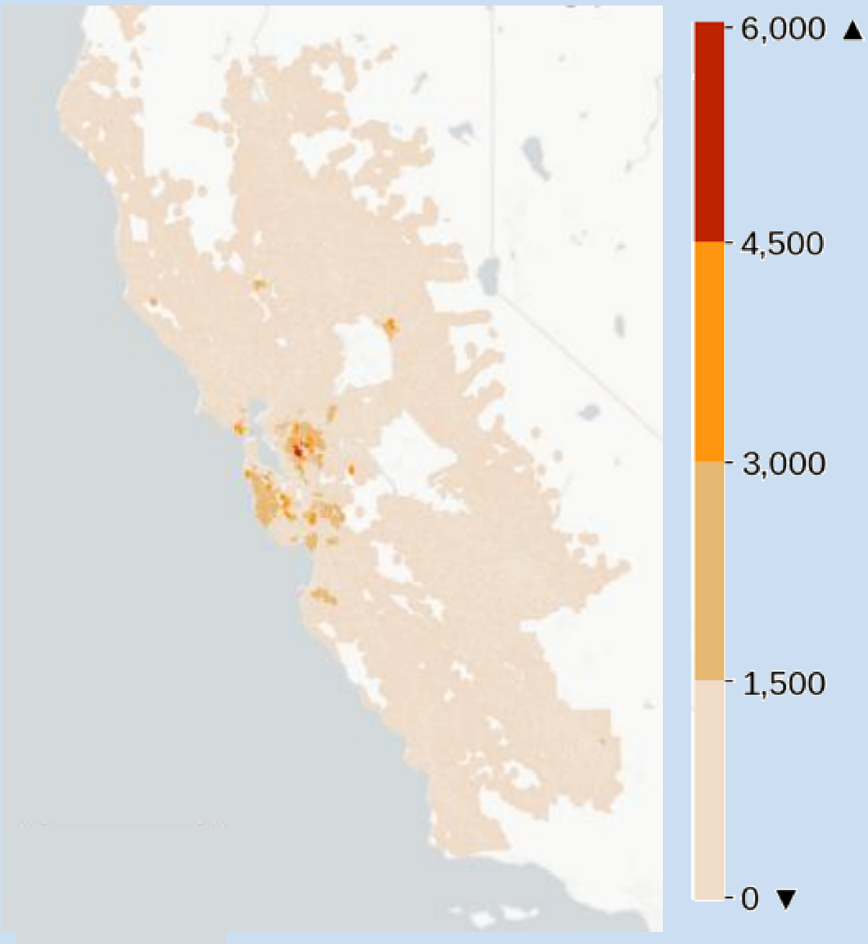
Data and method-agnostic *by design. Supports multiple forecasting and load shaping methodologies.*

Example – Electrification Impact Study (PG&E)

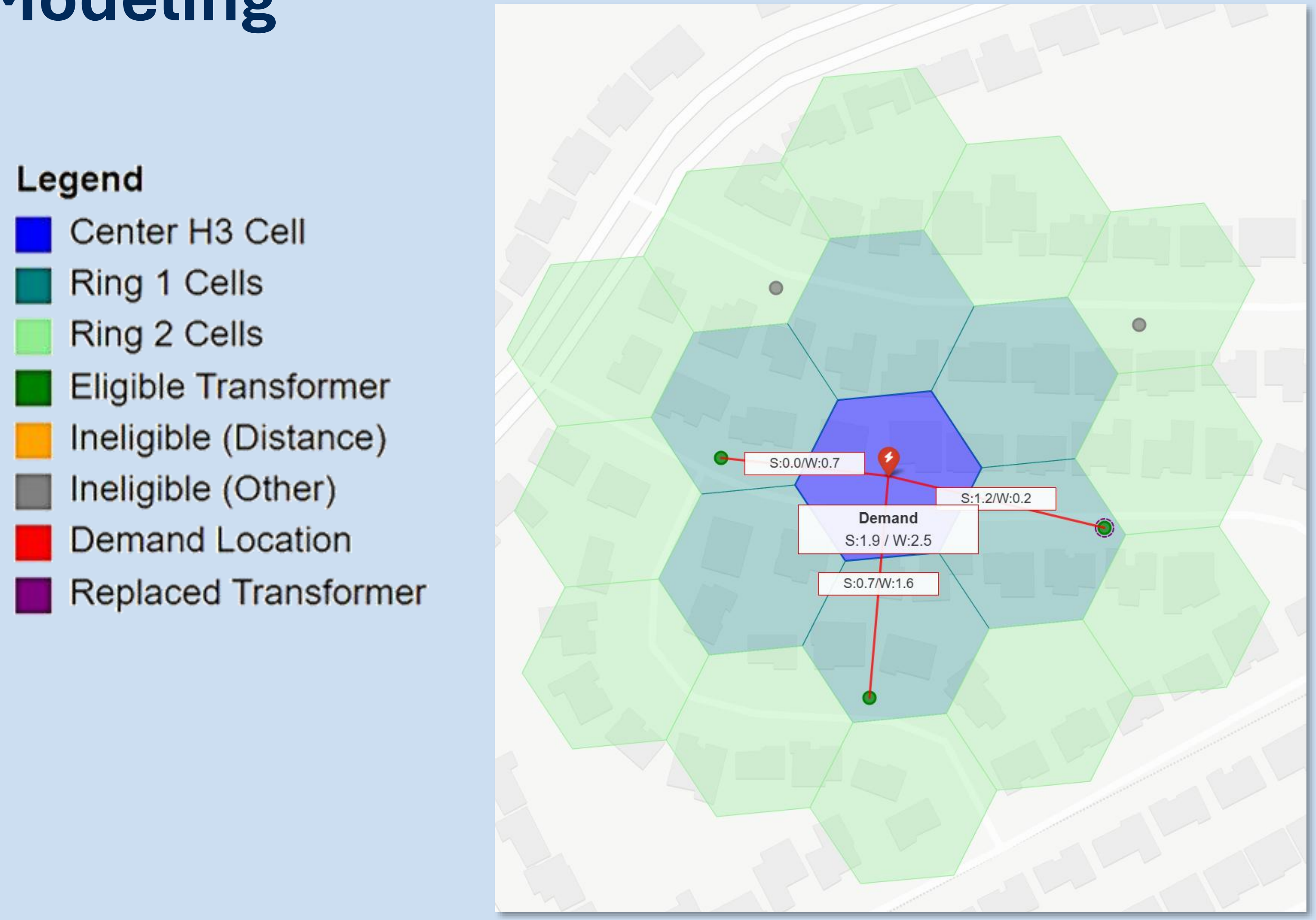
1. For each technology modeled, E3 calculated the maximum adoption at every possible location in PG&E's territory, and the likeliness of adoption at each of those locations
2. LoadSEER then geospatially allocated the adoption forecast based on those datasets and applied the technology-specific load shapes to the adoption sites to model the impacts on the distribution system

+ Technologies modeled:
  - Solar PV
  - Battery storage
  - Energy efficiency
  - Building electrification
  - Light-duty EV charging
  - Medium- and heavy-duty EV charging

Residential EV Charger Adoption Through 2040



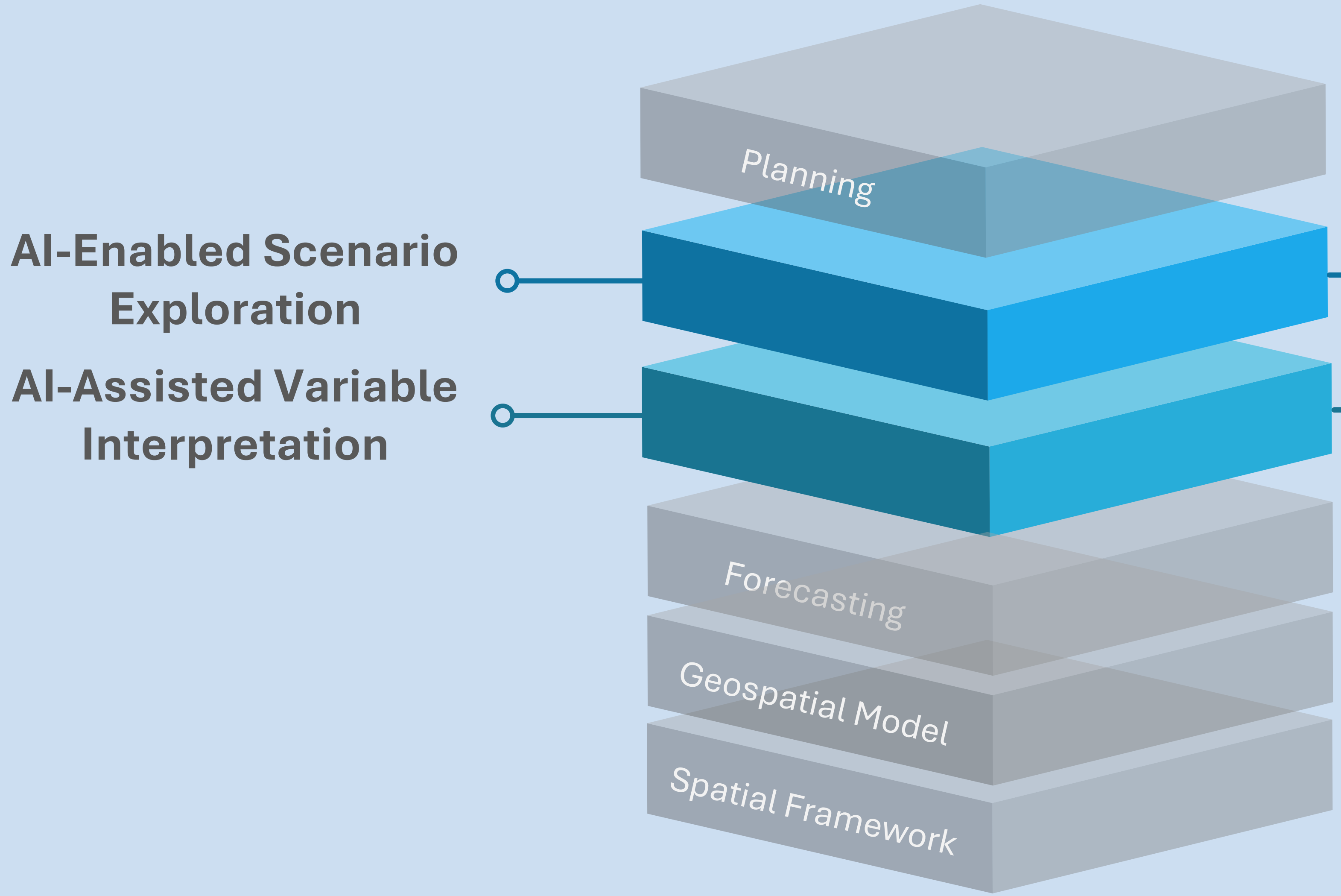
Example: PG&E EIS - Grid-Independent Secondary System Modeling



General logic:

- Check within a predefined radius if existing capacity is available to support load growth
- If not, replace or build new transformers, sized based on user-input planning assumptions

AI-Enabled Scenarios, Grounded in Geospatial Reality



- User-defined scenario prompts
- Rapid exploration of assumptions
- Consistent, explainable outputs

- Learns relationships across variables
- Adjusts weights within guardrails
- Preserves physical & policy constraints

"Generate a scenario reflecting accelerated EV adoption in lower-income communities, while respecting observed land use, building stock, and infrastructure constraints."

Coordinating Overlapping Interconnection Improvements

Flexibility, Proactive Investment, and "Reactive" Cost Sharing

Cody Davis
Assoc. Director, Grid Modernization, Electric Power Engineers

Integrated Planning – Key Emerging Areas

Several emerging strategies for effective load and DER integration can have similar types of impacts but widely varying risk profiles to different stakeholders

- **Proactive Investment** – Construct new load or DER capacity further ahead of anticipated needs, rather than waiting for certainty[1]
- **Flexible Connections** – Modify the performance of loads or DERs connecting to the grid to avoid triggering grid constraints[2]
- **"Reactive" Cost Sharing** – Facilitating system capacity expansion after sufficient interest is demonstrated via contributions from (generally DER) applicants

Key Resource #1: CHARGED Initiative Proactive Investment Framework
Key Resource #2: CHARGED Initiative Flexible Grid Connection Implementation Guide
Access via ChargedInitiative.org/Resources

Proactive Investment

Overview

<u>Proactive Investment Characteristics:</u>

- Investments made **<u>before growth is certain</u>**, based on longer-term forecasts
  - Higher risk of inaccurate timing or location of investments
- Generally intended to **<u>reduce customer wait times</u>** for new connections
- Can improve lifecycle cost by considering long-term needs

Low Medium High

RISK FACTOR	CURRENT INVESTMENT APPROACHES	PROACTIVE INVESTMENT APPROACHES
Lifecycle Cost Impact	higher unit costs, recurring work/ revisit assets, and lost synergies between investments	minimizes potential repeated work and prevents urgency-based inefficiencies
Stranded/ Underutilized Asset Risk	investments made after growth is known	risks driven by potential for forecast inaccuracies
Utility Cost Recovery Risk	investments justified by known load growth	depends on Regulatory Process Design
Dissatisfaction of Customers Adopting Electrification Measures	delays in new connections likely due to lack of capacity	capacity available for new / upgraded connections without delays
Policy Alignment Risk	lags policy timelines	removes barriers to achieving policy goals
Execution Complexity	simpler planning, but requires rapid mobilization under pressure; fewer complex forecasting models	requires complex forecasting, integrated processes, and robust project justification

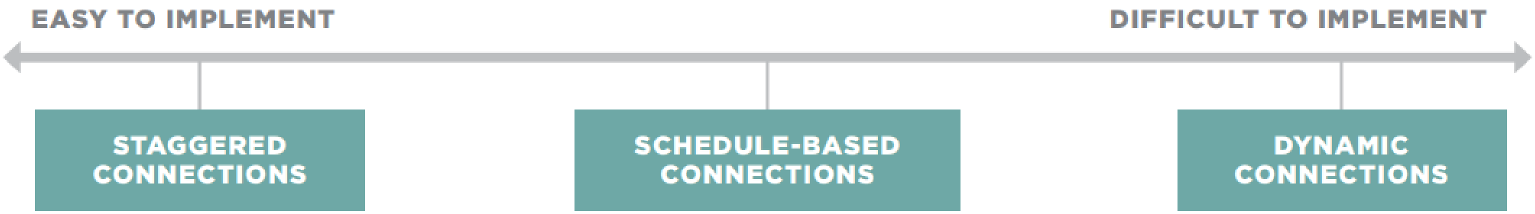
<u>Traditional Vs Proactive Investment Risk Dimensions</u>

Source: CHARGED Initiative Proactive Investment Framework

Flexible Connections

Overview

- **<u>Flexible Grid Connections –</u> Incorporating new control systems or operational capabilities to connect new loads and/or DER to the distribution system more efficiently**
    - Several methods available using different control philosophies
- **Generally used to avoid triggering the need for distribution upgrades**
- **Benefits:**
    - ✓ Faster Energization
    - ✓ Lower Connection Costs
- **Challenges:**
    - ❖ Increased Study Complexity
    - ❖ Additional Site Equipment
    - ❖ Protection Against Non-Compliance

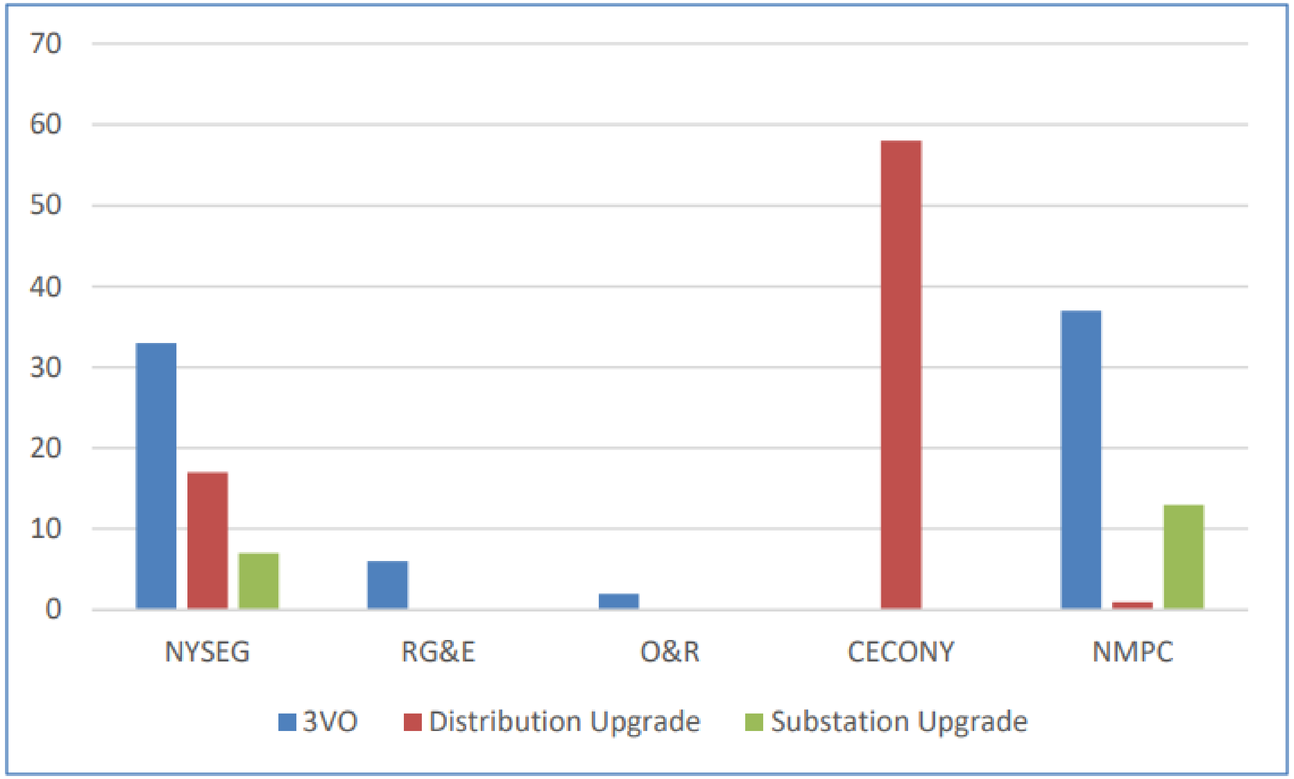


Source: CHARGED Initiative Flexible Grid Connection Implementation Guide

“Reactive” Cost Sharing

Overview

- **Allows applicants to pool funding for upgrades to enable new DER interconnections**
  - Load applicant costs often already socialized via revenue contribution credit / allowance
- **Reduces “first mover” problem for high-cost upgrades**
- **Does not directly improve speed to power for individual applicants**
  - “Never” to “when we get enough” is still an improvement in concept
- **Example: NY Cost Share 2.0**



[# of Projects Funded Via NY Cost Share 2.0 Mechanism]

Source: NY DPS - https://dps.ny.gov/system/files/documents/2026/06/review-of-cost-sharing-2.0-program-ipwg-presentation.pdf

Interconnection Improvement Pathways

Summary Table

	Flexible Connections	Proactive Investment	Reactive Cost Sharing
Increases Speed to Power	+	+	
Avoids Upgrade Costs	+		
Provide Pathway to Efficient Upgrades		+	+
Provide More Predictable Interconnection Costs		+	+
Reduces “First Mover” Problem		+	+
Ratepayer Cost Risk (Relative)	Minimal	High	Low
Applicant Operational Risk	Varies	None	None

Integrating Key IX Improvement Efforts

Considerations for Deployment Options

- **Proactive Investment and Flexible Connections are different ways of achieving speed to power**
  - Different Risk Dimensions – Ratepayer cost Vs Applicant Feasibility & Cost
  - Different Benefit Dimensions – Upgrades + Speed Vs Just Speed
- **Flexible Connections, where viable, reduce the need for Proactive Investments**
  - Feasibility of flexibility should be a key input to proactive investment decisions
- **Reactive Cost Sharing provides an upgrade pathway with less ratepayer cost risk/responsibility than Proactive Investment**
  - Reduces the need for proactive investments to remove constraints
  - No impact on speed to power **unless paired with Flexible Connection pathway**

Expanding the Context of Distribution Planning

Advancing Distribution System Planning for a Changing Grid
ESIG Webinar

14 July 2026 | Sean Morash

TELOS ENERGY

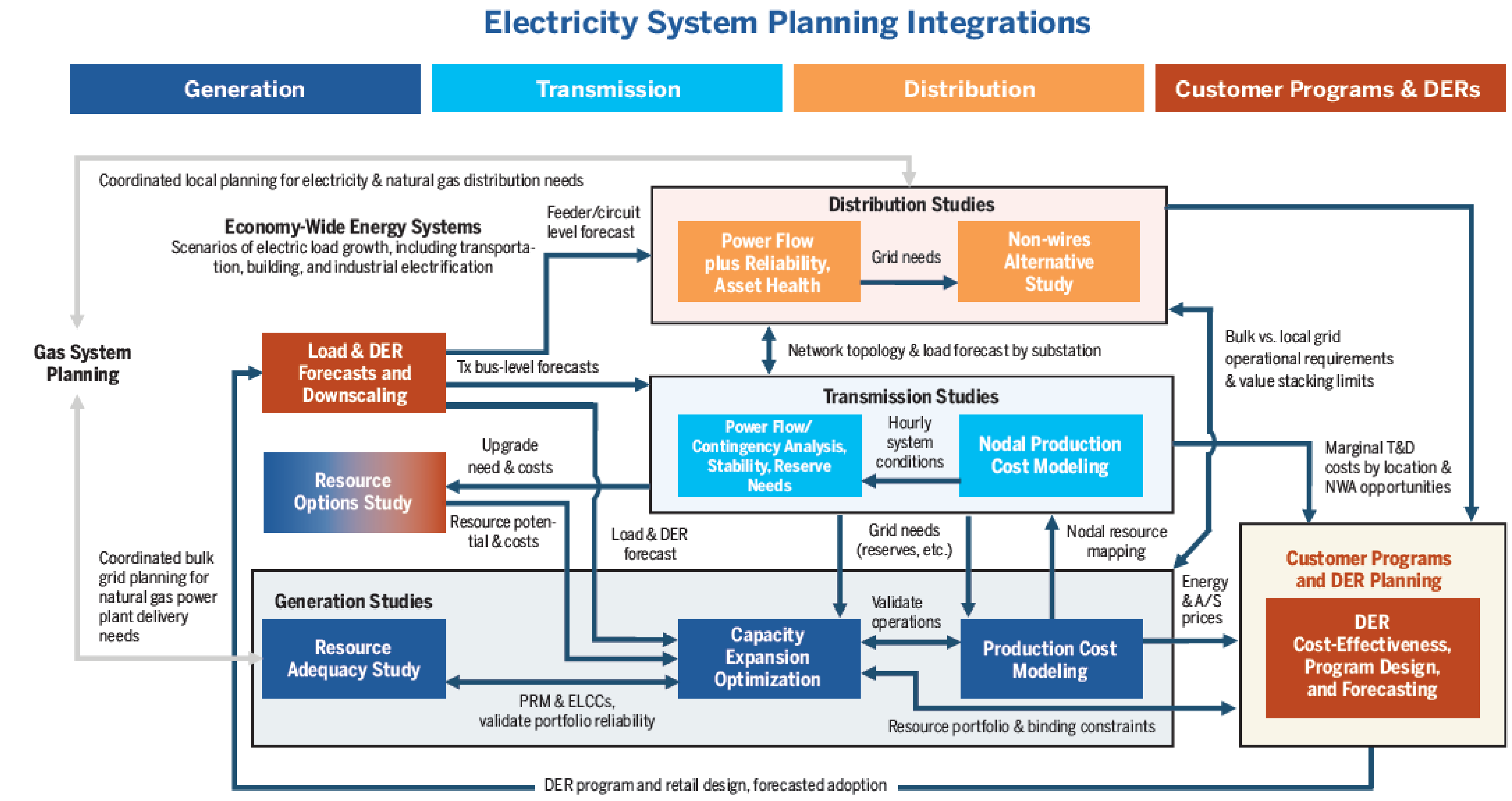
Utility planning grew up as parallel processes

The core questions are changing and merging, necessitating new processes and new challenges.

- FERC 2222 allows for DER aggregation participation models, but questions about effectiveness of DER remain.
- Whose load and DER forecast to use? What DER characteristics to represent as endogenous or exogenous parameters?

Planning Process	Core Question (Historically)	Typical Horizon	Regulatory Home
Generation (Resource)	What supply- and demand-side resources are required at what time?	15–20+ years	IRP dockets, procurements, long-term market auctions
Transmission	What bulk-system upgrades are required given my resource mix to reliably serve load?	10–20+ years	RTO/ISO processes, IRP dockets, FERC
Distribution	What distribution upgrades are required to reliably serve load?	1–10 years	DSP filings, rate cases
Customer programs	How can customers change load to make things more affordable for everyone?	1–5 years	Program approvals, rate cases
Long-term Load Forecasting	What will peak demand for electricity be in the future?	1-20+ years	Embedded across dockets and processes

What does one integrated process look like?



Key Outcome

Right investments…

…in the **right places…**

… at the **right times**.

Images via Energy Systems Integration Group. 2025. Foundations of Integrated Planning: Defining a Framework for Comprehensive Energy System Planning. A report by the Integrated Planning Task Force.

HECO's Integrated Grid Planning Process

- **Better inclusion of DER in solving bulk system challenges.** DER as a located grid asset to meet bulk system models.
- Inclusion of distribution planning via Location-Based Distribution Grid Needs and NWA
  - **DER forecasts from IGP used as an input to the distribution planning analyses**

Image Via HECO Grid Modernization Strategy (2017)

New York’s Coordinated Grid Planning Process

Why one statewide process

- One model across the seams of the IOU’s to avoid multiple projects from different utilities to serve the same needs of the state.
- Plan to a common set of scenarios; needs that persist across three scenarios carry less stranded-asset risk.
- Local transmission and distribution needs are also borne by ratepayers.

Scenarios & Capacity Expansion
Zonal

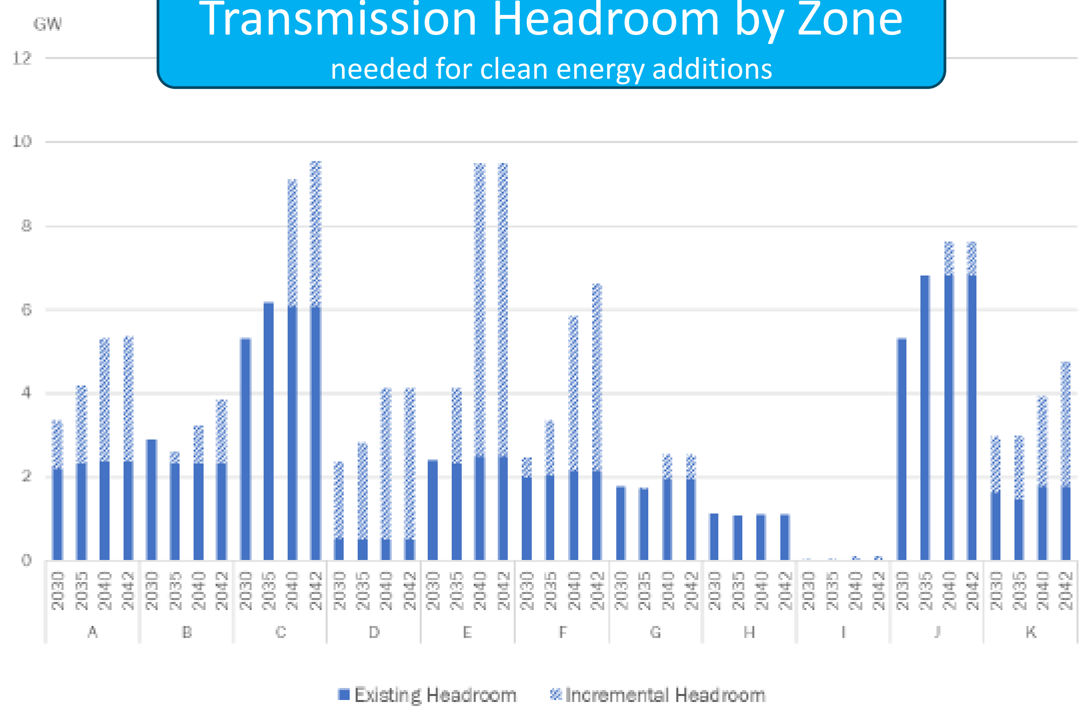
Network model development
Allocate zonal results to Nodal Transmission

Local T&D assessment
Where, when, and what upgrades are needed?

Review preferred solutions
Size & cost the upgrade portfolio

Least-cost planning assessment
Re-run CEM with local costs, reconcile

Transmission Headroom by Zone
needed for clean energy additions



NY PSC Case 20-E-0197 (CGPP)
Image via Joint Utilities CGPP Cycle 1 Report (May 2026), Figure 17

The CGPP Cycle 1 focus narrowed over time

THE STATED OBJECTIVE

"…capture the interdependence of distribution, local transmission, and bulk transmission…"

NY PSC Phase 2 Order, Case 20-E-0197 (September 2021) — required of the utilities' plans

FOCUS ON LOCAL TRANSMISSION NEEDS

"…incorporating the conceptual LT&D cost estimates into the capacity expansion model…"

CGPP Order approving the Process (August 2023)

WHERE DISTRIBUTION COMES IN

"…apply DERs and load assumptions developed in Stage 1 to utility distribution network models…"

CGPP Order approving the Process (August 2023), Stage 3 process description

FIRST CYCLE RESULTS

"The Joint Utilities are not proposing standalone distribution upgrade projects in this CGPP cycle."

Joint Utilities CGPP Cycle 1 Report (May 2026)

Bulk System Needs Met with Distributed Storage

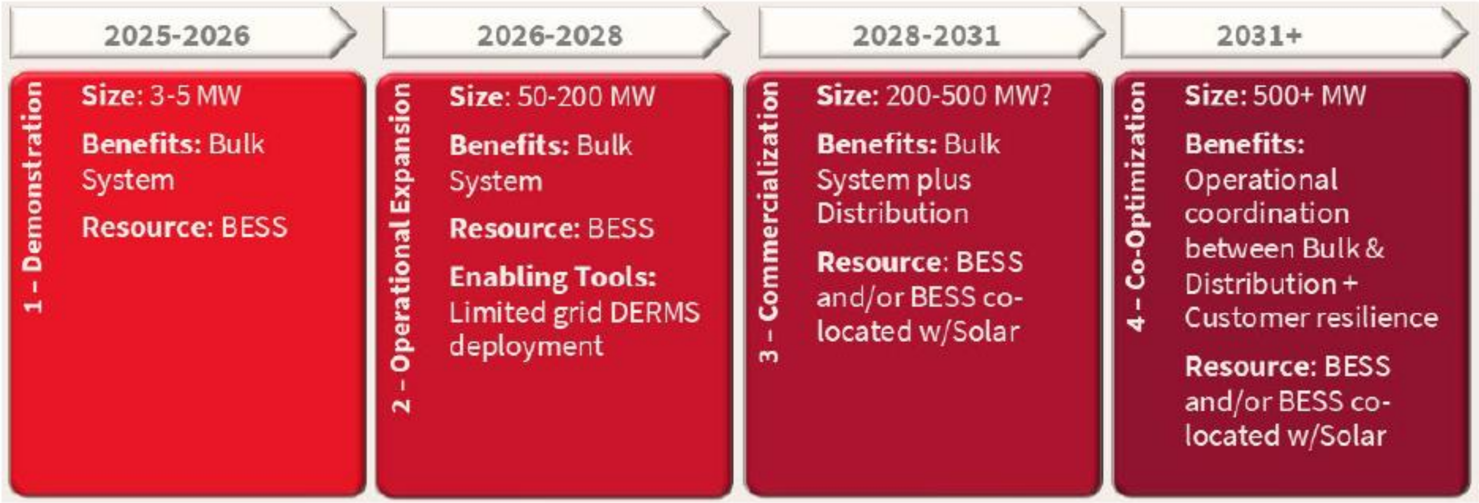
Xcel Minnesota's Capacity*Connect Program

Why distributed and why 1-3 MW?

- Prove capabilities in integration/coordination between resource and distribution planning and operations.
- Address the intersecting operational needs of distribution systems, markets, and customer benefits.
- Working theory is that 1-3 MW represents a reasonable tradeoff across deployment speed, costs, experience.

Why target bulk system benefits first?

- Targeting "bulk system use cases with the highest value (e.g., MISO energy and capacity market participation)"
- "As we validate program assumptions and deploy more distributed BESS, we will seek to expand and optimize opportunities to [value stack]"



Quotes and image pulled directly from Xcel's Petition for approval of Capacity*Connect (Oct 2025) MN PUC Docket E002/M-25-378. Approved April 2, 2026.

Observations and Summary

Sequencing continues to repeat	Start from an integrated process design, but then complexity forces prioritization
Bulk value is the entry point	Established markets and processes create clear value signals.
Missing constraints at the early planning stage	Appending distribution costs later, or failing to align operating assumptions across planning surely leads to suboptimal solutions, costing ratepayers money.
Planning questions or operational challenges?	Many of these concepts are driven by real-world DER deployment and opportunity. It's not theoretical anymore. There's also *some* urgency given the load growth moment.

Thank You!

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