Planning for Electrification on the Distribution Grid

PG&E High DER Electrification Impact Study Part 2

May 11th, 2026

For full report, see: *PG&E's Electrification Impacts Study (EIS) Part 2 – Final Report*, filed Jan. 28, 2026, R.21-06-017, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907812.PDF

Agenda

Topic	Time	Presenter
Overview of EIS and Key Findings	15 minutes	Tom Huynh Bill Peter
Analytical Methods	5 minutes	Caitlin McMahon
Load Flexibility	10 minutes	Caitlin McMahon
Secondary Distribution System Modeling & Costing	10 minutes	Jesse Fallick
Conclusion and Q&A	20 minutes	All

Overview of EIS Findings and Integration into DPP

Accelerating Electricity Demand for PG&E

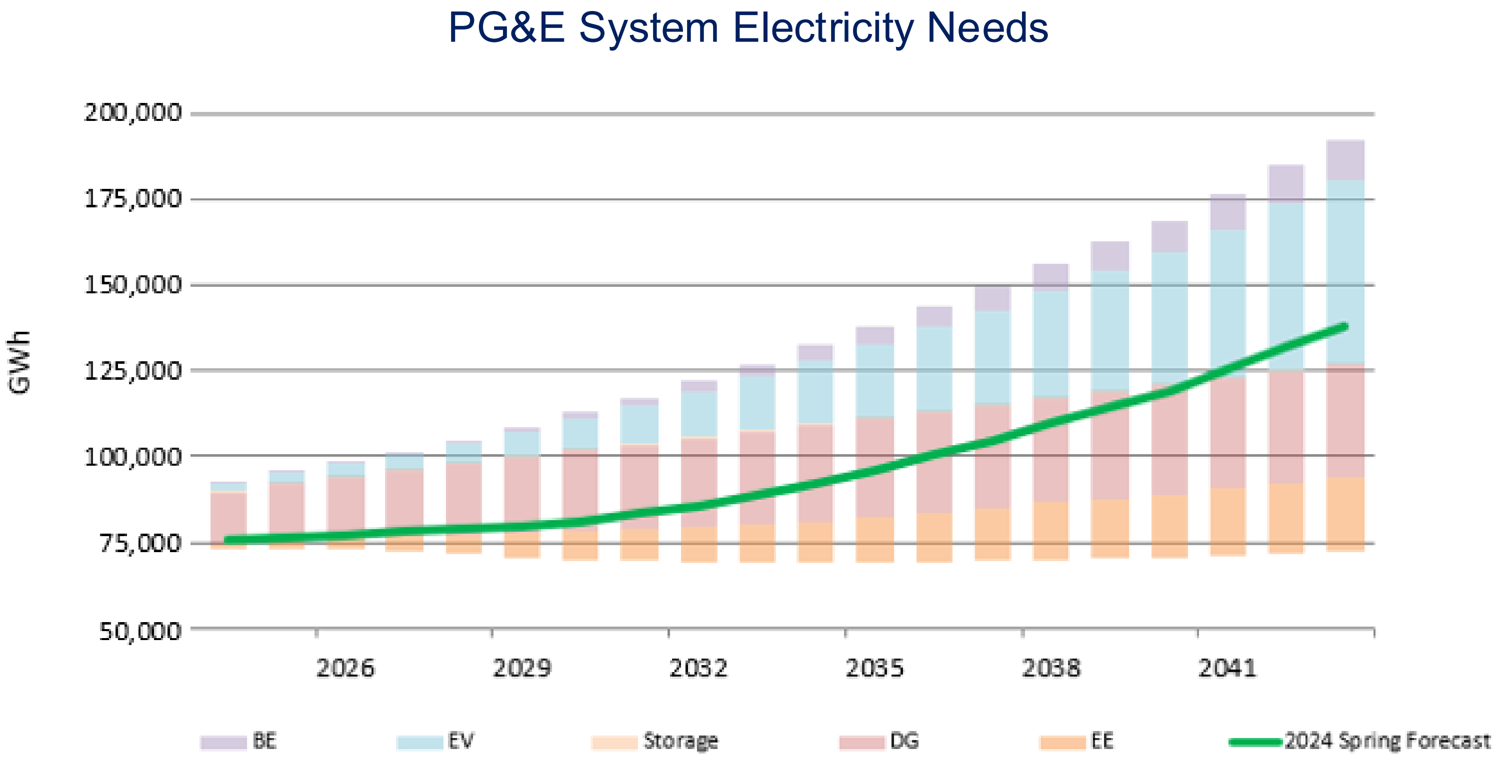
PG&E's grid is facing load growth driven by transportation and building electrification, new business growth (e.g., data centers) and continued adoption of distributed solar, storage and flexible loads.

80% energy needs

10X EV

7X Behind-The-Meter (BTM) Storage

2X Distributed Generation (DG)



Building Electrification (BE); Electric Vehicle (EV); Distributed Generation (DG); Energy Efficiency (EE)

Source: PG&E's Spring 2024 Annual Load Forecast

PG&E Electrification Impact Study (EIS)
Overview

The EIS estimates long-term distribution grid infrastructure costs associated with achieving California's electrification goals through 2040.

- A comprehensive assessment of a high electrification future:
  - Forecast grid impacts across the required scenarios for 2030, 2035, 2040
  - Estimate costs across the distribution and secondary grid[1] through solutioning
  - Examine DER adoption for DAC customers using equity ratio provided by the Energy Division
  - Examine the impact of enhanced demand flexibility
- Additional study requirements:
  - Includes historical and resource impact for PG&E
  - Provides transparency of data of DER disaggregation
  - Provides Equity and Demand Flex takeaways
  - Aligns closely to existing planning process and mitigations

Scenario 1	• Base Case (Mitigated 2023 IEPR)
Scenario 2	• Base Case + Equity DER Dispersion (e.g., DAC)
Scenario 3	• Base Case + Enhanced Demand Flexibility (e.g., Load Management)
Sensitivity Scenario	• EV Capacity Demand Forecast

Study performed in support of California Public Utility Commission (CPUC) proceeding to Modernize the Electric Grid for a High Distributed Energy Resources Future ("High DER Proceeding"):

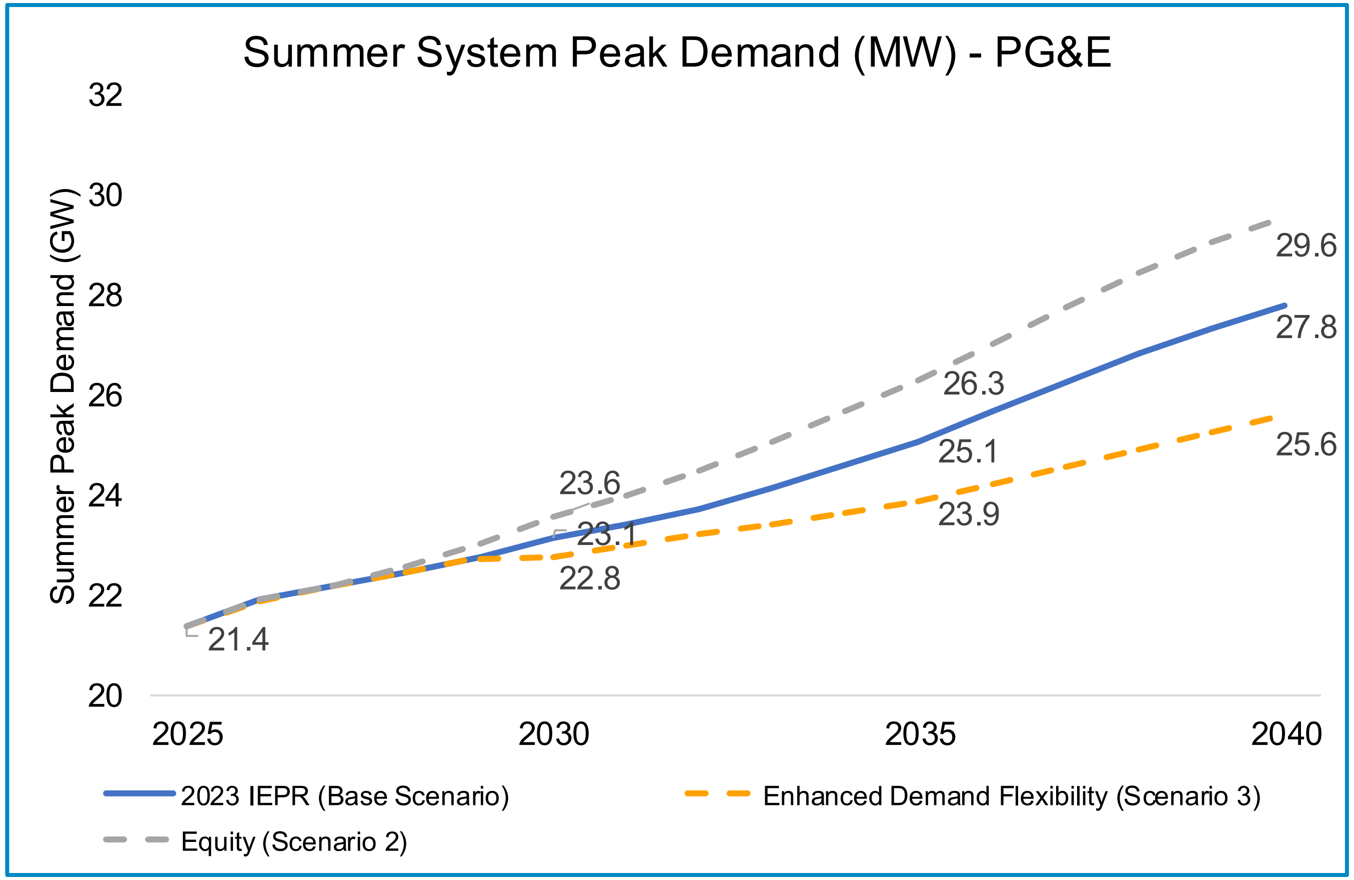
Scenarios of Electrification Growth

Electrification growth results in increased Summer System Peak Demand of ~6.4 GW by 2040 and demand flexibility can reduce it by 2.2 GW.

- Base Scenario leverages the state forecast (2023 *Integrated Energy Policy Report* or IEPR)[1] and is "mitigated" consistent with current distribution planning processes: includes engineering solutions (e.g., load transfers) and load shapes that reflect evolving policy (e.g., Time of Use (TOU) rates).

- The Equity Scenario scales up electrification loads in Disadvantaged Communities (DACs) to model new policy that encourages higher DER adoption which results in about 1.8 GW of additional summer peak load.

- The Enhanced Demand Flexibility Scenario assumes orchestrated load management down to the secondary level,[2] reducing the summer peak load by ~2.2 GW



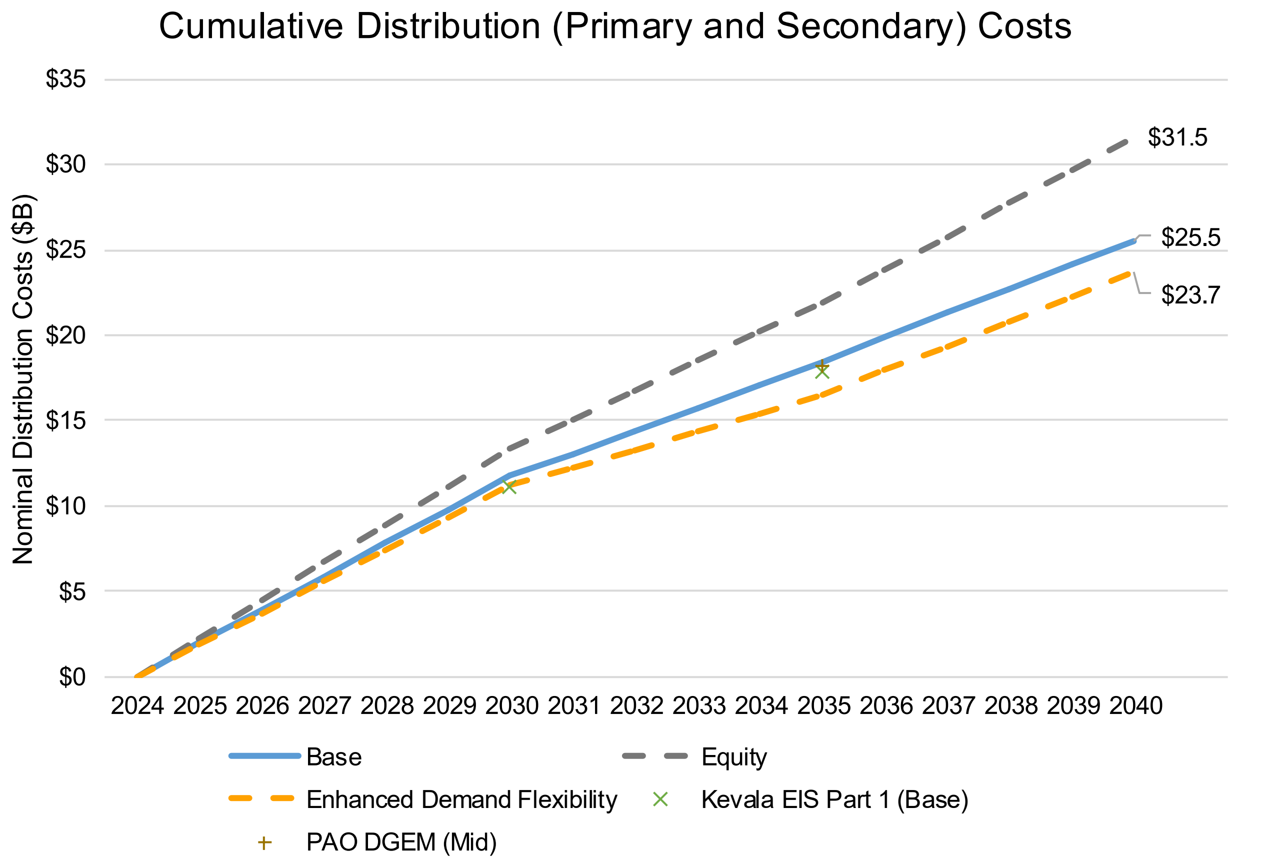
[1]2023 IEPR only includes a small amount of embedded data center load (versus 2024 IEPR).
[2]~2.2GW of Incremental Load Flexibility by 2040 is consistent than the CEC DFLEX assessment of technical potential and model is also consistent with our share of the CEC's goal of 7GW by 2030.

Electrification Distribution Infrastructure Costs

Electrification Requires ~$23B to ~$32B in Distribution (Primary and Secondary) Investment by 2040

Distribution (Primary and Secondary) Upgrade Costs ($B)				
Scenario	***2030***	***2035***	***2040***	***Delta***
Base Case	11.0	18.5	25.5	--
Equity	12.6	22.0	31.6	$6.00
Enhanced Demand Flexibility	10.4	16.5	23.7	($1.80)

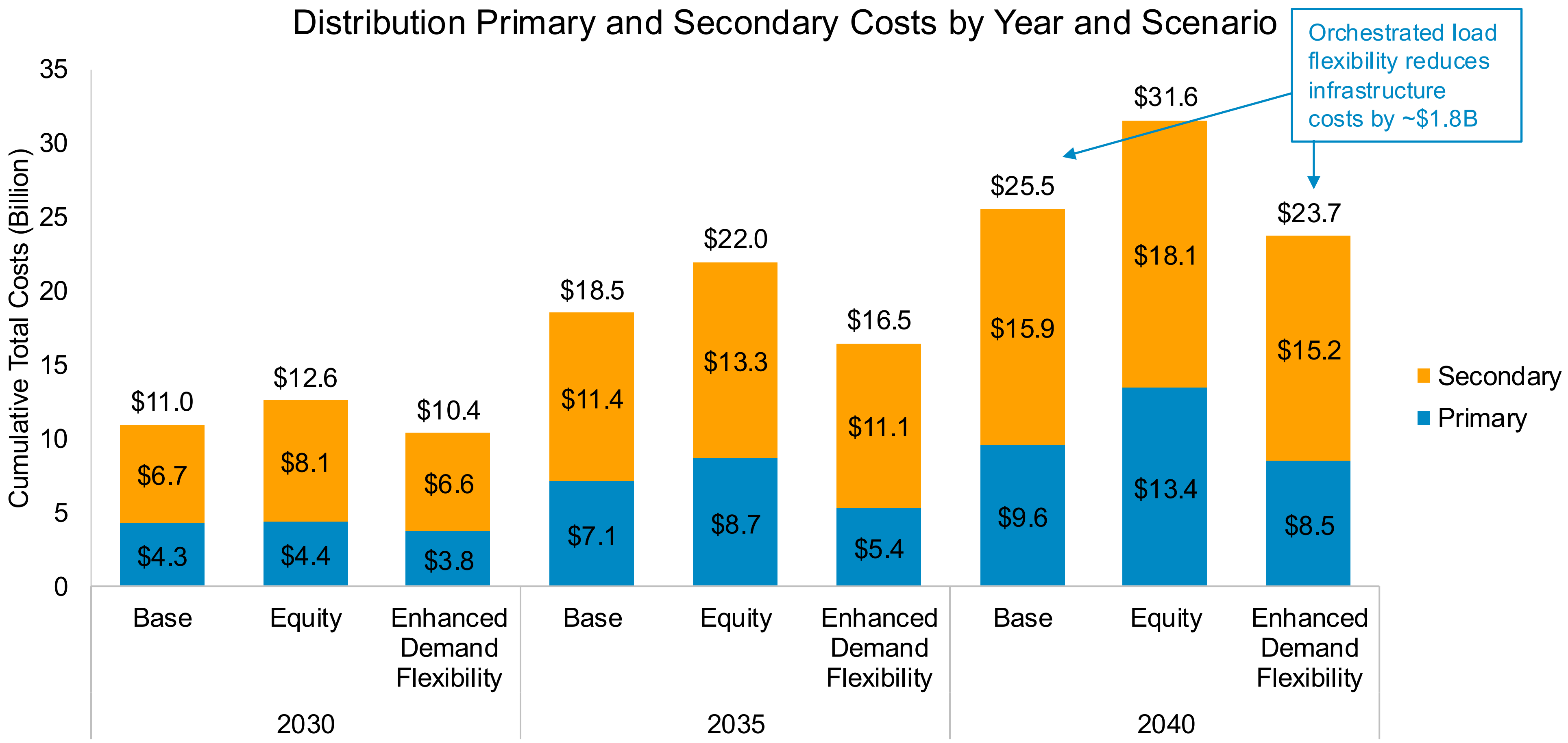
- **Rate of investment slows down slightly after 2030 and is relatively consistent across the study period**
- **The equity scenario requires $6B additional investment consistent with higher electrification loads.**
- **The enhanced load management scenario reduces infrastructure costs by $1.8B through 2040.**
- **All costs include inflation of 2.6% and exclude project contingency dollars**



Linear Interpolation of costs used between study years.

Distribution System Infrastructure Costs – Primary and Secondary

By 2040, costs will range between $8.5B -$13.5B in Primary and $15B-$18B in Secondary infrastructure costs.



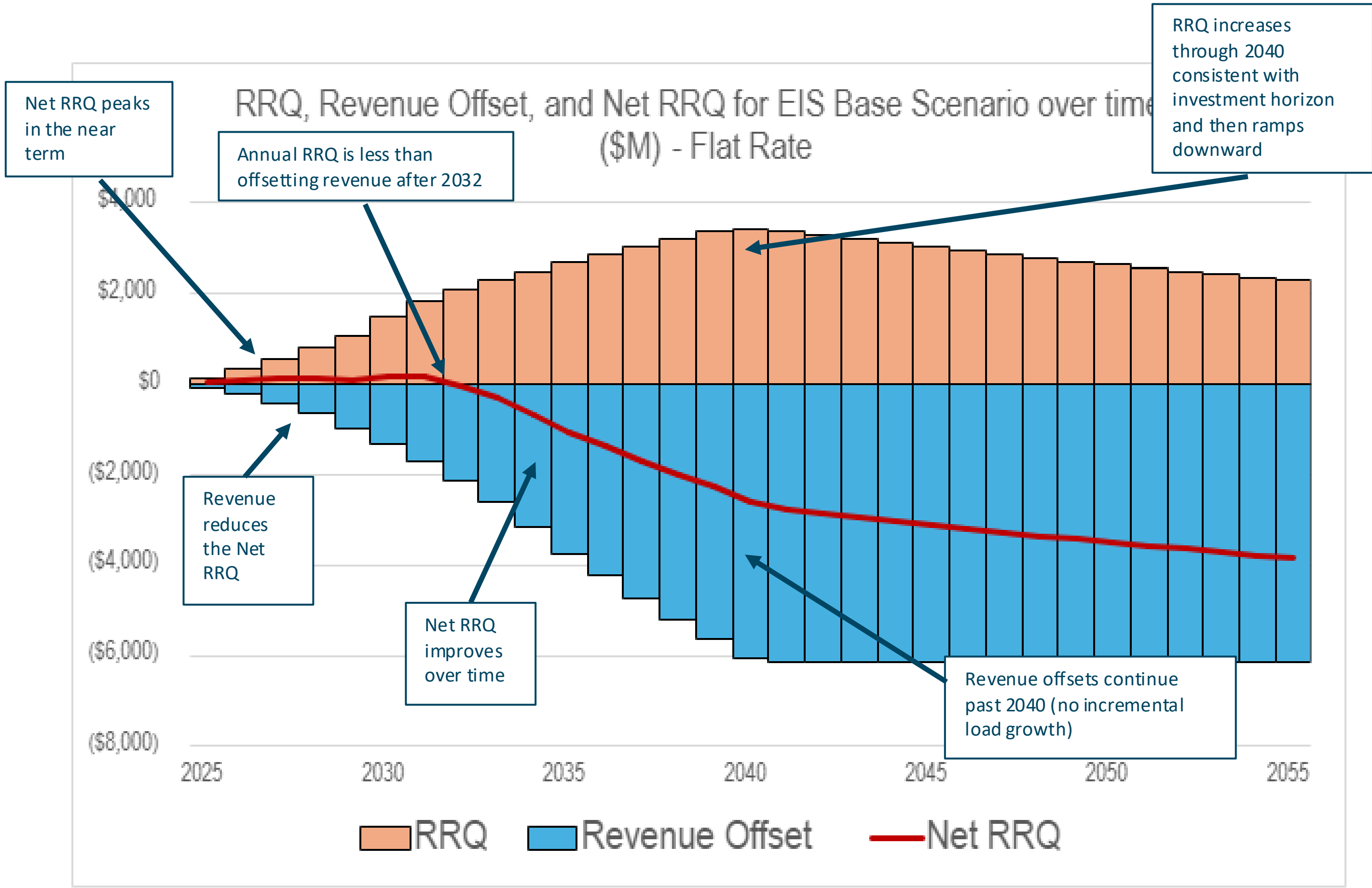
The EV Capacity Sensitivity Scenario (not shown) only modeled secondary costs, with total secondary costs of $7.3B, $12.5B, and $17.5B through 2030, 2035, and 2040, respectively.

Preliminary Analysis shows significant downward pressure on Distribution Rates over time

All scenarios show a long-term downward pressure on distribution rates from energization investments that drive electrification growth.

Year	2030	2035	2040
Annual Revenue Requirement (RRQ) [$B]	$1.5	$2.7	$3.4
Annual Offsetting Revenue [$B]	$1.3	$3.7	$6.1
Net Annual RRQ [$B]	$0.2	($1.1)	($2.6)
Rate Pressure (%)	1.6%	(10%)	(25%)
Net Present Value (NPV) [$B]	$14.2		

- Near-term rate increases due to capital outlays are offset by sustained revenue growth from increased energization, indicating long-term value of energization investments.
- Net Present Value of Energization of $14.2B, showing a small upward rate pressure in the near term followed by downward distribution rate pressure from 2031 onwards.
- Costs are ***solely*** for Distribution Energization Investments and does not include other incremental costs (e.g., safety, reliability, etc.). This is not a rate forecast.



Key Strategic Findings

Electrification Requires ~$23B to ~$31B in Distribution Investment by 2040, in line with current investment trends

KEY FINDINGS

Distribution Engineering Mitigations

- PG&E’s Base Scenario includes mitigations (e.g., load transfers, TOU rates) by distribution engineers to optimize infrastructure investments that resulted in as much as $3.4B in primary savings through 2040.

New Approach to Long-Term Secondary Planning

- The EIS represents a pioneering, data-driven evaluation of secondary system planning, establishing a foundational framework to optimize our secondary investments for serving load energizations.

Enhanced Demand Flexibility with Orchestration

- Enhanced demand flexibility reduces system peak demand between 2.2 and 3.1 GW and reduces distribution infrastructure costs by an additional $1.8B (7%) through 2040 but only if orchestrated to avoid triggering new investments.

Electrification Provides a Downward Distribution Rate Pressure

- Electrification growth may provide downward pressure on distribution rates by as much as 25% (~3.5 cents/kWh) by 2040.

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Analytical Methods

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Methodology – Overview

1

GEOSPATIAL ADOPTION FORECASTING

IA + E3 + PG&E

Modeled where customers are likely to adopt electrification and DER technologies using geospatial propensities and technical potentials in E3's *Forecasting Anywhere* Tool

2

LOAD IMPACTS

E3 + PG&E

Developed technology-specific hourly and flexible load shapes using E3's EV Grid model, NREL's *ResStock* and *ComStock*, PG&E meter data, and IEPR data

3

DISTRIBUTION PLANNING, SOLUTIONING, & COSTING

IA + PG&E

Simulated distribution system impacts and identified overloads and solutions within *CYME* and *LoadSEER*

Methodology – Forecasting Workflow

Forecasting Anywhere

Scenario-based generation of technical potentials, propensities, and adoption forecasts at H3 level

- IEPR Load Forecast → Disaggregated by charger type or end use → Adoption Forecast
- Geospatial Datasets → Machine learning and heuristics → Propensities; Technical Potential

Load Shapes

- **BE load shapes** from NREL's *ResStock* and *ComStock*
- **EV charging load shapes** generated from E3's *EVLST*
- **PV, Storage, EE load shapes** are directly from *IEPR*

LoadSEER

Distribution planning tool used by PG&E for secondary load impacts, siting and sizing

1. Map H3 to Premise
2. Spatial Allocation
3. Load Impacts
4. Secondary Capacity Planning

CYME

Power flow model used by PG&E for distribution planning at the feeder level

1. Primary Conductor Loading and Voltage
2. Load Flow Model with Service Point Level Forecasting
3. Integrated Known Loads
4. Integrated GNA Capacity Solutions

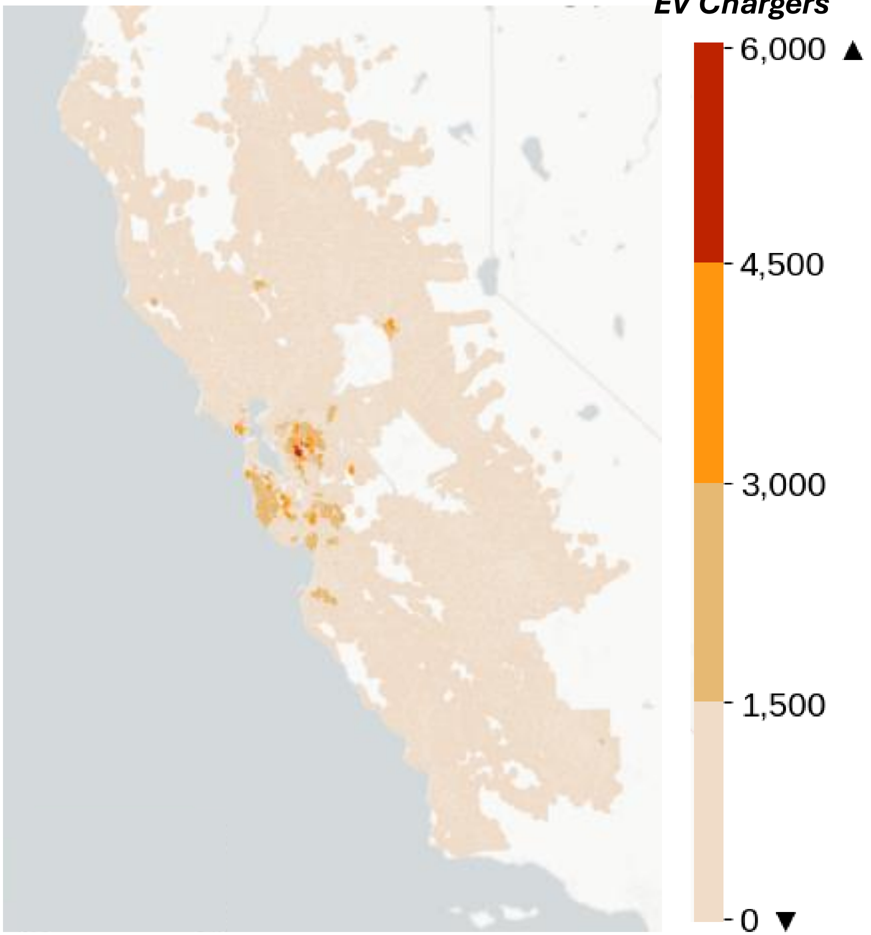
Methodology – Forecasting Anywhere & LoadSEER

1. **For each technology modeled, FA calculates 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 allocates the adoption forecast based on those datasets and applies 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



Load Flexibility

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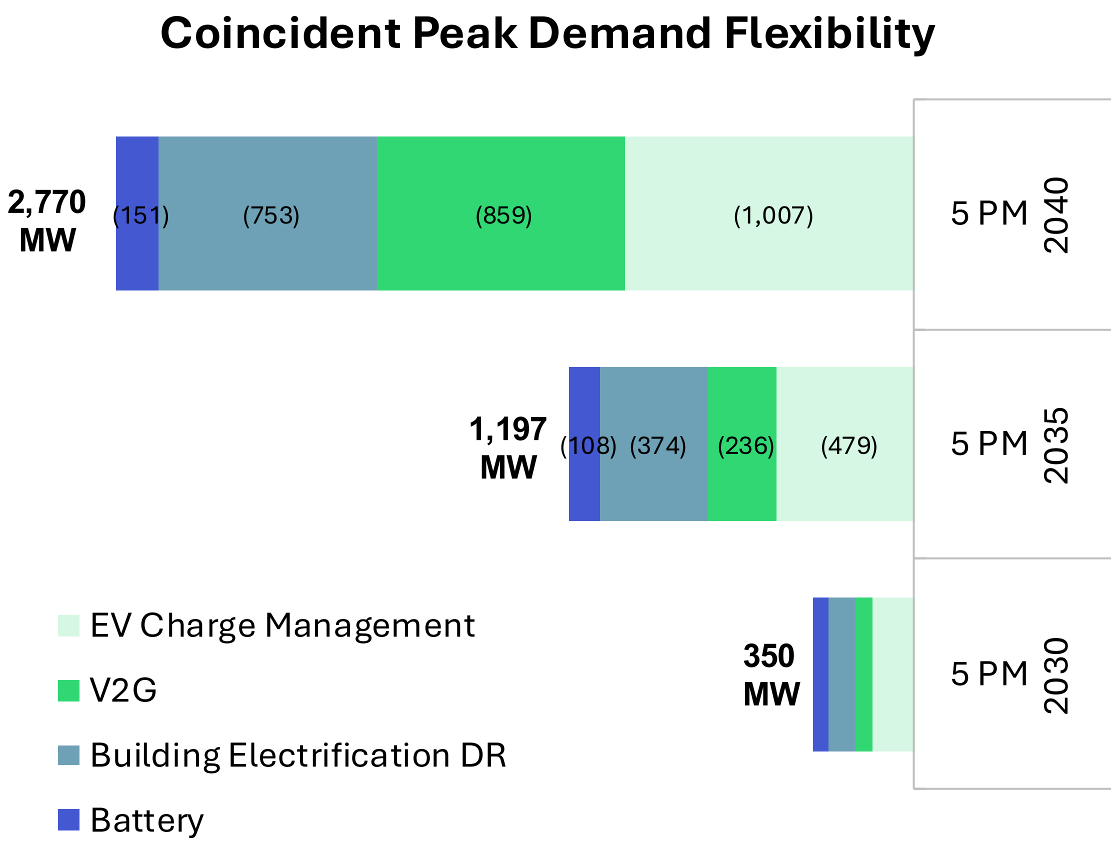
Enhanced Demand Flexibility Scenario

- **The Base Scenario includes business-as-usual demand flexibility, including passive managed charging (TOU rates)**
- **The Enhanced Demand Flexibility Scenario applies incremental technology specific managed load, benchmarked to the CEC's D-Flex tool**
- **EV Charge Management + V2G**
  - Increased charge management participation, introduces more active charge management to feeder-specific needs, and vehicle-to-grid (V2G)
- **Building Electrification Demand Response (DR)**
  - Model shed + shift DR events based on LBNL CA DR Potential Study
- **Battery**
  - Increased utilization of storage for enhanced demand flex



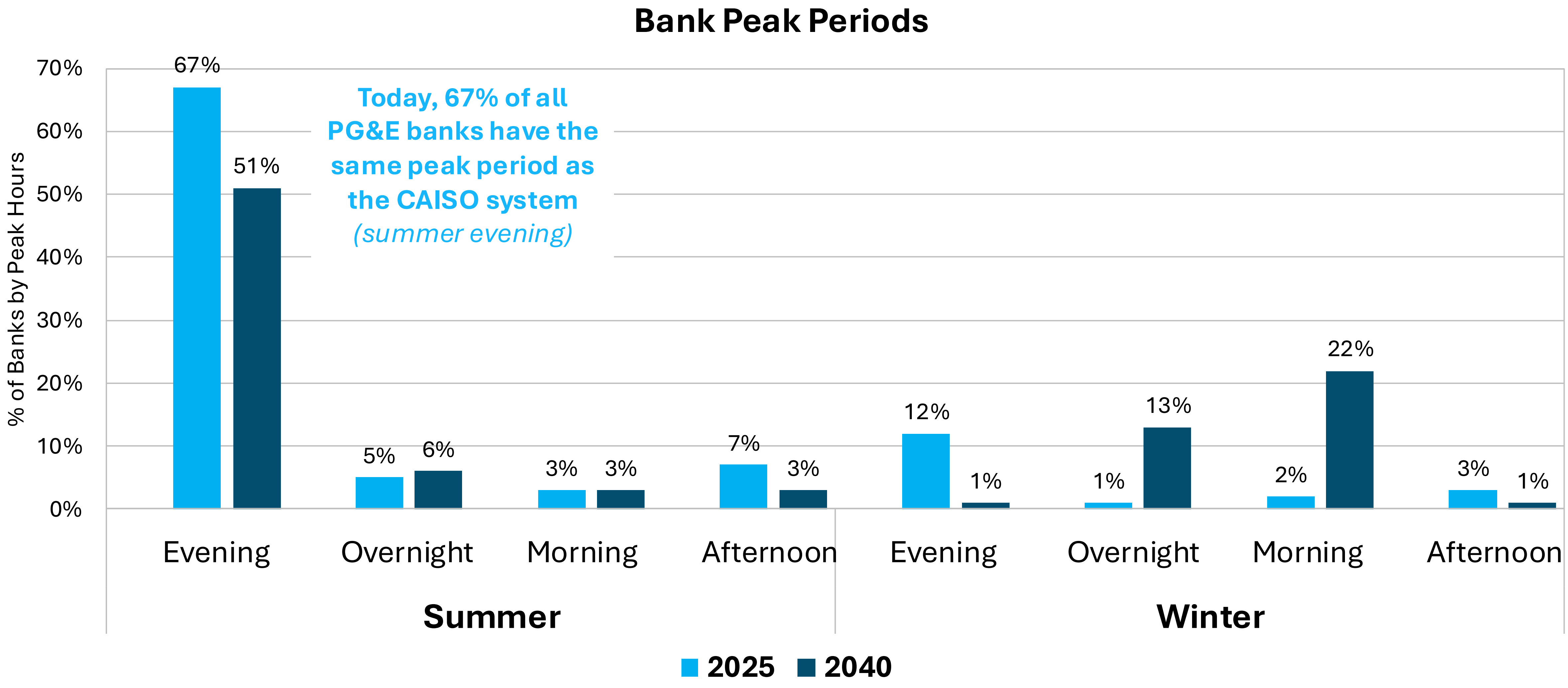
Orchestration to local constraints required to avoid triggering additional upgrades

- **Sensitivity performed without Demand Flexibility Orchestration results lowered the system peak but did not account for local (e.g., secondary) constraints**
  - "Orchestration" in the context of the EIS study refers to the ability to manage the electric load in response to local grid constraints, in a manner that can be relied upon for planning purposes using firm, dispatchable load management.
- **Non-orchestrated sensitivity did not reduce long-term distribution infrastructure costs**
- **Reduction in infrastructure costs required orchestration to avoid triggering new upgrades**

Scenario	2040 Total Cost ($M)	Difference from Base ($M)	Difference from Base (%)
Base	$25,526	-	-
Enhanced Demand Flexibility **Orchestrated**	$23,713	$1,813	**7.10%**
Enhanced Demand Flexibility **Non-Orchestrated**	$25,387	$139	**0.50%**

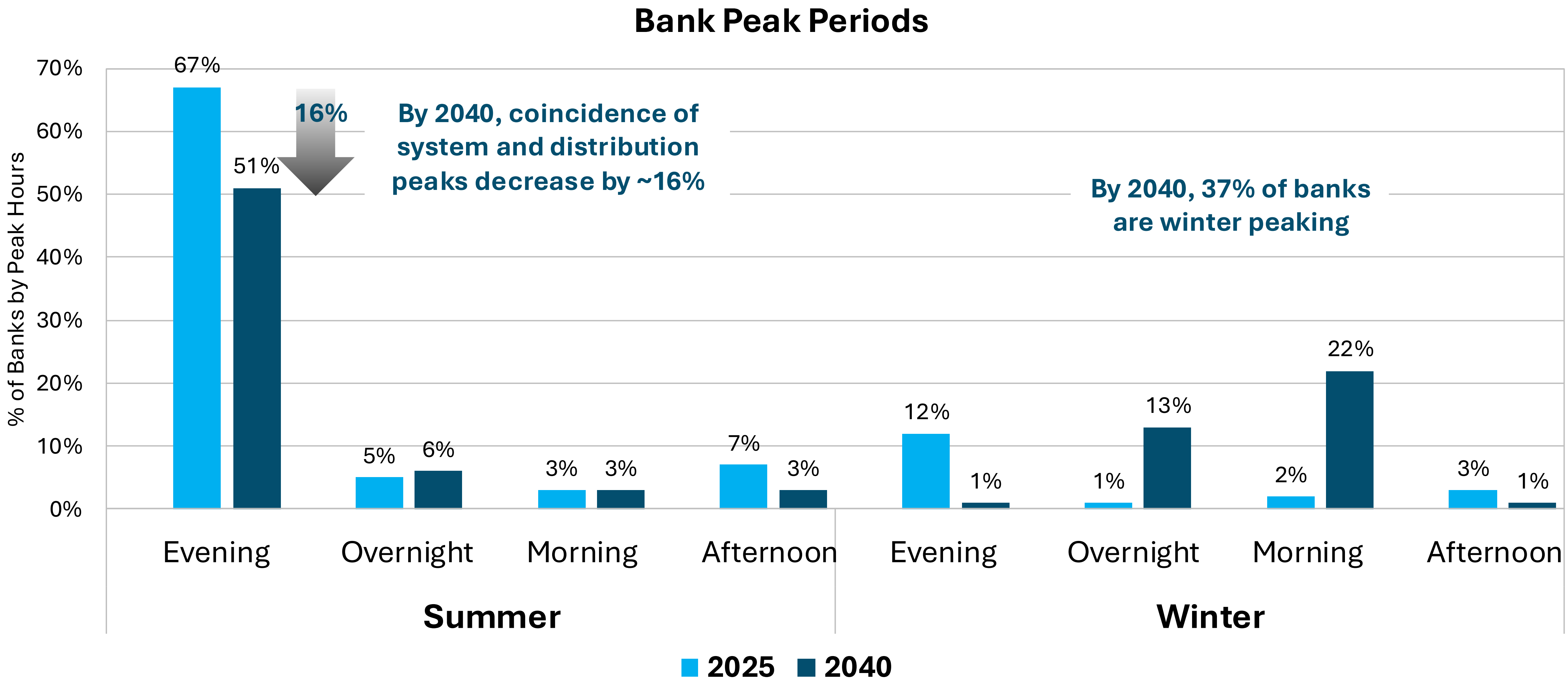
- *Costs to achieve orchestrated enhanced load flexibility are not included and are not evaluated for affordability.*
- *Orchestration of load flexibility down to the premise level was not studied nor were customer infrastructure (e.g., panel upgrades) considered*

Distribution constraints forecasted to become more local, more seasonal, and less aligned with the bulk system peak



Morning (5-10), Afternoon (11-15), Evening (16-21), Overnight (22-4)

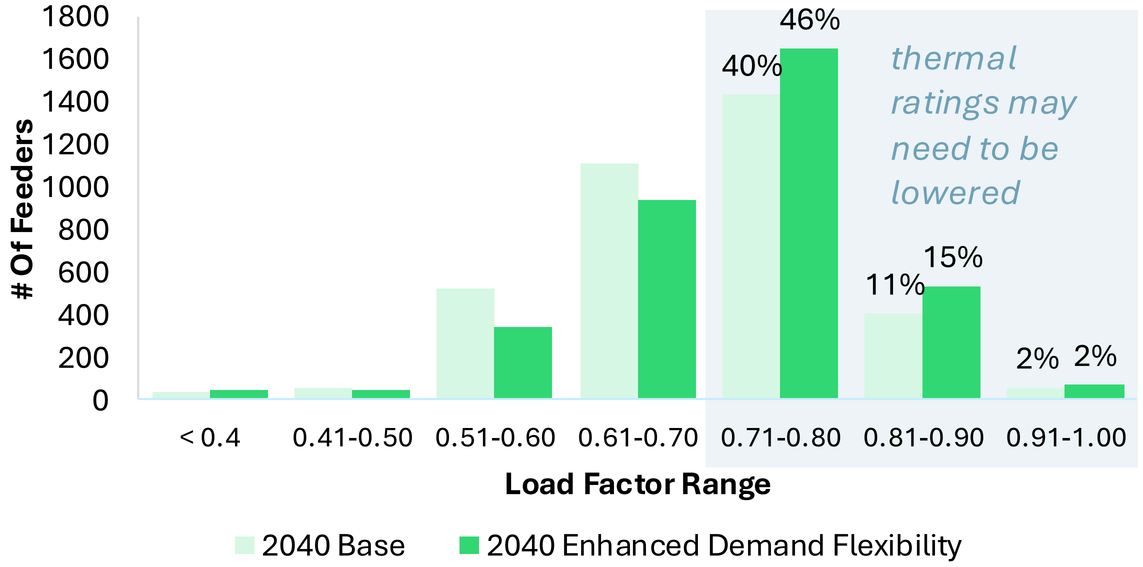
Distribution constraints forecasted to become more local, more seasonal, and less aligned with the bulk system peak



Morning (5-10), Afternoon (11-15), Evening (16-21), Overnight (22-4)

Load Factor Increases in the Enhanced Demand Flexibility Scenario

Higher load factors may result in lower thermal capability and reduced operational flexibility



$$\textit{Load Factor} = \frac{\textit{Average Demand (over peak day)}}{\textit{Peak Demand}}$$

- Average load factor is ~70%, including ~500 feeders with a load factor greater than 80%.
- The load factor does not change substantially between 2025 and 2040 in the Base Case, indicating that electrification does not increase the load factor.
- Enhanced demand flexibility flattens the load – consequently increasing the load factor and potentially decreasing the facility rating.
- **Orchestration of load flexibility and distribution planning should start incorporating load factors into their processes as increased electrification and load management flattens the load profile.**

Secondary Distribution System Modeling & Costing

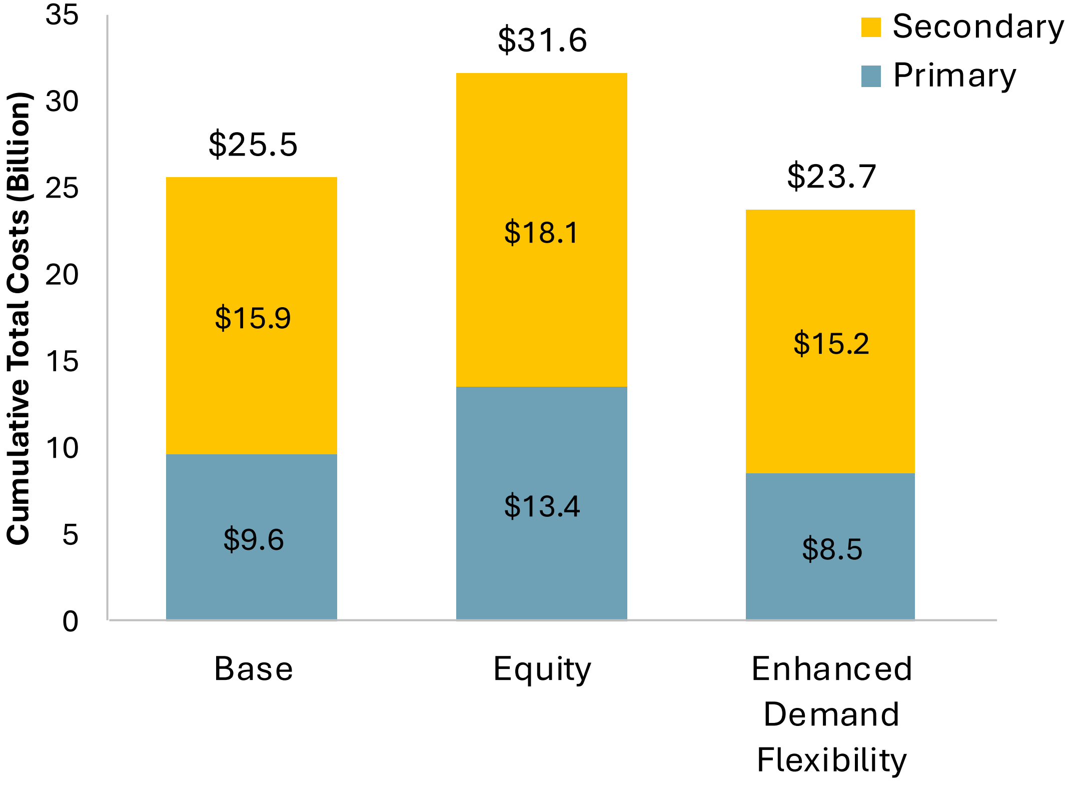
Goals and Challenges of Modeling Secondary Distribution Costs

+ **Goal:**
  - Develop a granular, transparent estimate of secondary distribution system costs across all EIS scenarios aligned with PG&E distribution planning standards and assumptions.
+ **Challenges:**
  - Secondary distribution systems are often less comprehensively modeled and documented than primary systems.
  - Even with complete system data, detailed engineering-level solutioning of the secondary system is impractical for a systemwide study of this magnitude.
  - Many forecasted new loads occur beyond the service radius of existing secondary assets, requiring the model to:
    - install new service transformers where needed, and
    - preserve and utilize the installed capacity throughout the forecast horizon.

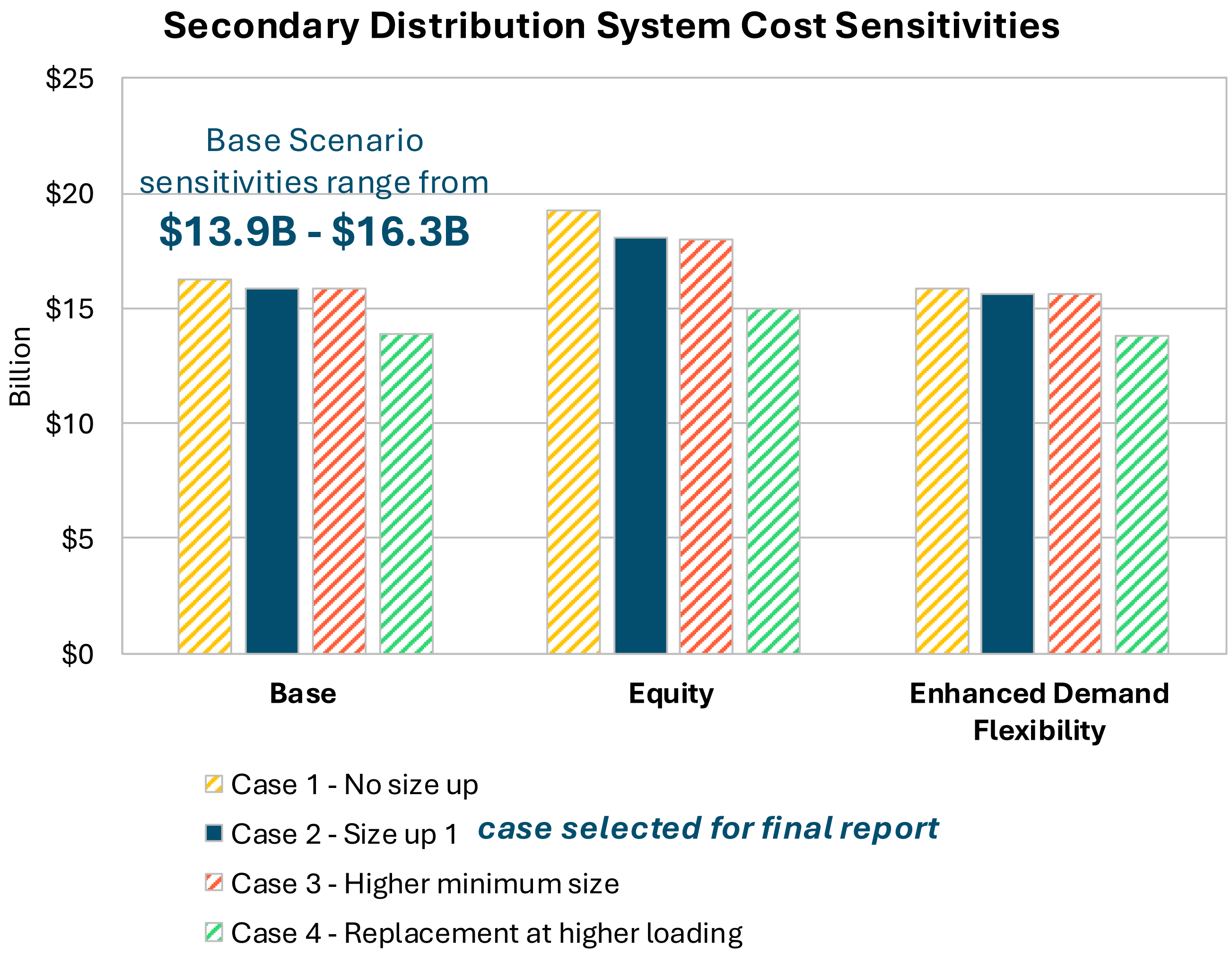
PG&E EIS found that secondary costs for energization are ~62% of total energization distribution infrastructure costs

- **Secondary costs for energization are ~62% of total energization distribution infrastructure costs**
  - Consistent with the historical costs to energize customers
  - Majority of secondary costs were new services versus replacements (78% of total secondary costs)
- **This is higher than EIS Part 1 study because of expanded scope including new service connections and detailed secondary analysis**

Distribution Primary and Secondary Costs by Scenario

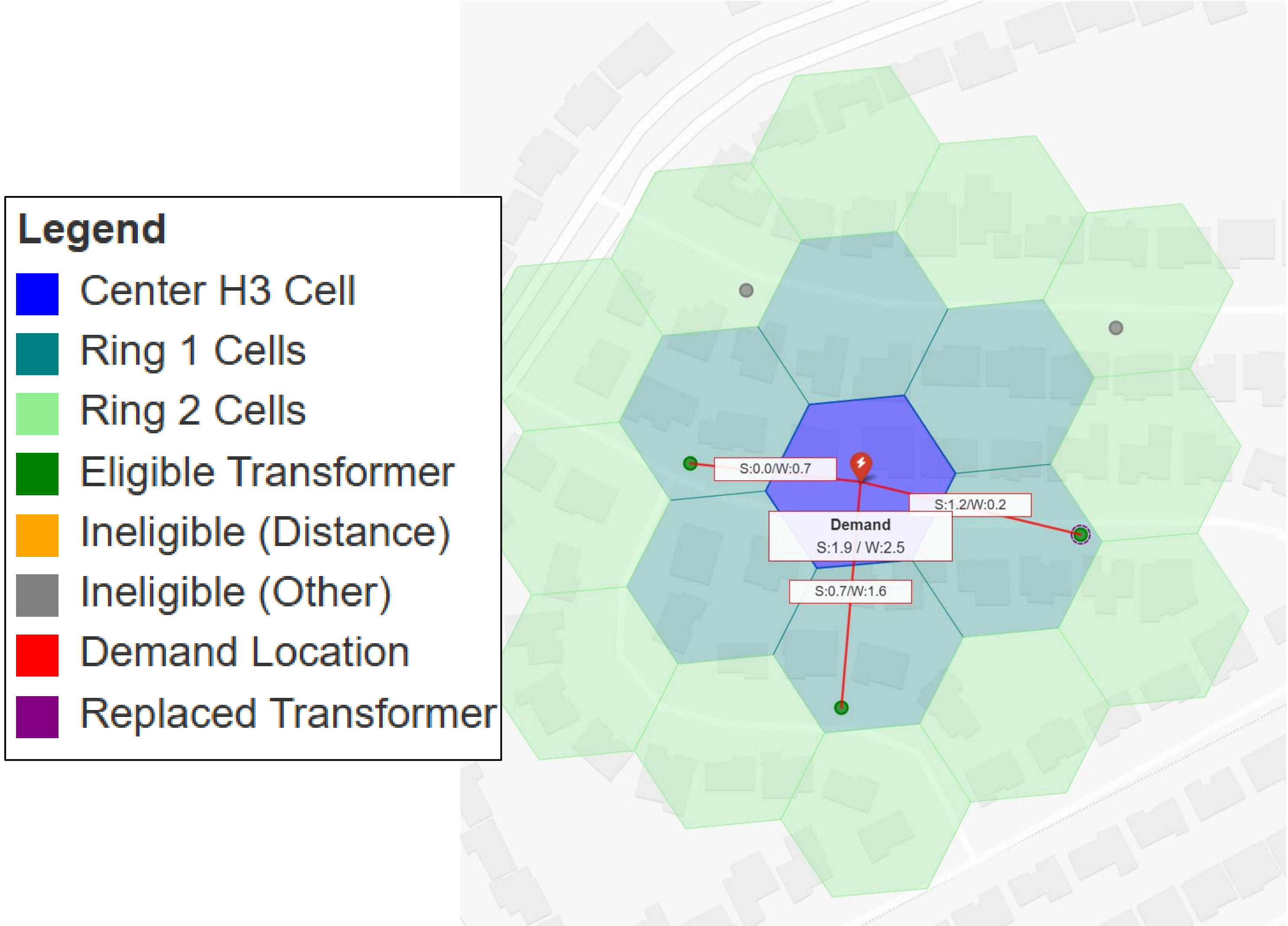


Secondary sensitivities capture different engineering assumptions and stress-tested the tool



- **The analysis modeled costs assuming a range of inputs for key distribution planning assumptions.**
- **The costs estimates vary from $13.9 B to $16.3 B depending on the investment strategy of replacing transformers**

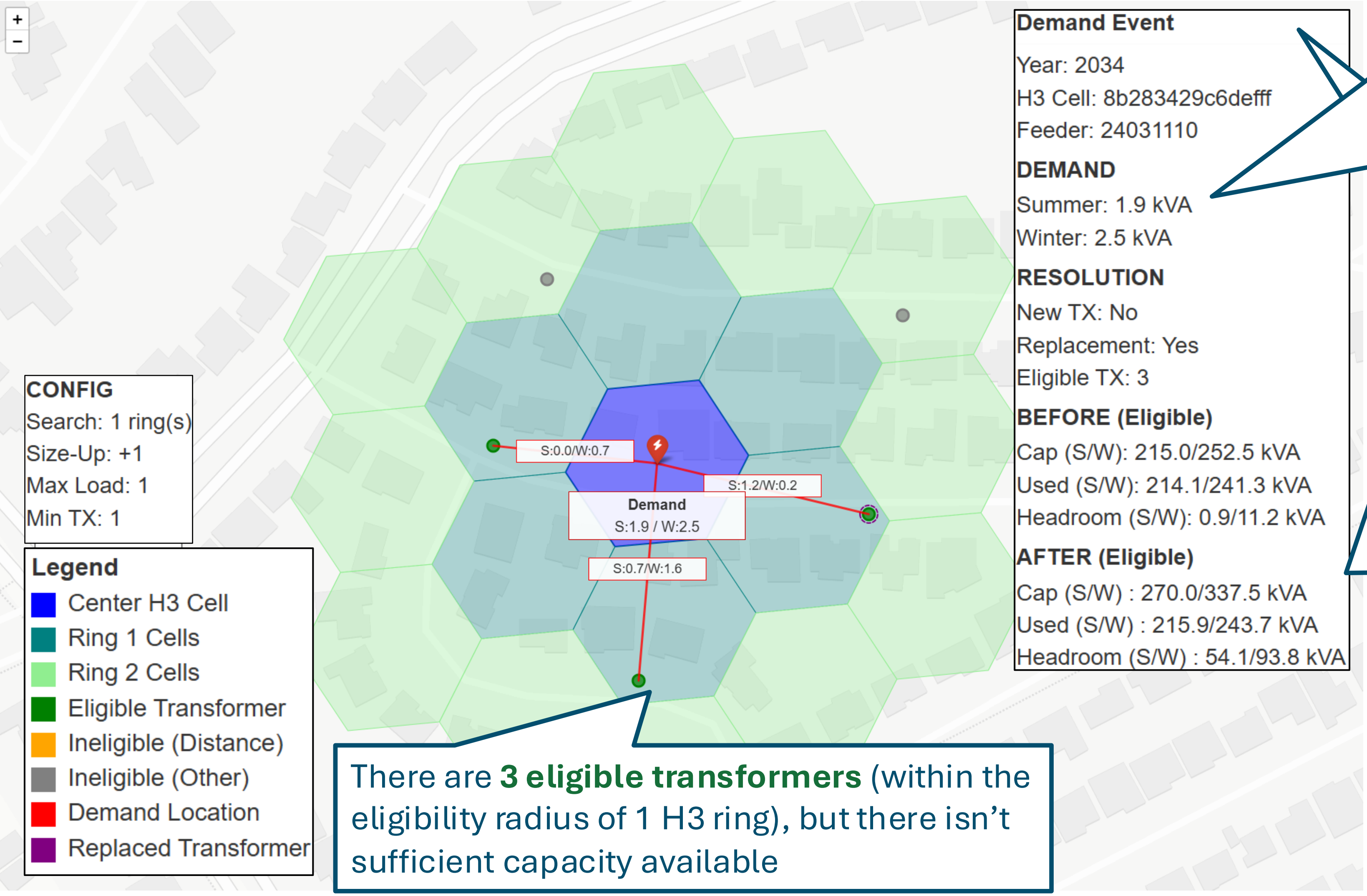
A new, automated approach to solution-oriented secondary system modeling and costing in LoadSEER



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

Example: transformer replacement triggered by insufficient available capacity



"Demand Event" added 1.9 kVA of new **coincident summer load** and 2.5 kVA of new **coincident winter load.**

The original 65 kVA unit is **replaced,** and consistent with the configured **one size-up policy, a 100 kVA transformer is installed**

There are **3 eligible transformers** (within the eligibility radius of 1 H3 ring), but there isn't sufficient capacity available

Conclusion

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Summary of Key Findings for Preparing the Grid for a High Electrification Future

Electrification Requires ~$23B to ~$32B in Distribution Investment by 2040

Planning and Engineering

- New planning tools: Integration of machine learning, can help prepare the grid for a high electrification future.
- Distribution engineering matters: Distribution engineering and planning mitigations resulted in $3.4B in primary savings through 2040.
- Secondary Planning: The EIS represents a pioneering, geographic-based evaluation of secondary system planning, establishing a foundational framework to optimize our secondary investments for serving load energizations.

Orchestrated Demand Flexibility

- Enhanced demand flexibility reduced distribution infrastructure costs by an additional $1.8B (7%) through 2040 but only if orchestrated to avoid triggering new investments.

Opportunity: Electrification Provides a Downward Distribution Rate Pressure

- Electrification growth may provide downward pressure on distribution rates by as much as 25% (~3.5 cents/kWh) by 2040.

High Electrification Future

Discussion and Q&A

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Thank You

Caitlin McMahon: caitlin.mcmahon@ethree.com

Tom Huynh: txhu@pge.com

Bill Peter: wxpx@pge.com

Jesse Fallick: jesse.fallick@integralanalytics.com

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