# Electrification Impacts Study (EIS) Part 1

## High Distributed Energy Resources (DER) Grid Planning Proceeding

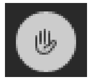
CPUC Energy Division

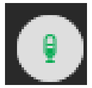
May 17, 2023

California Public Utilities Commission

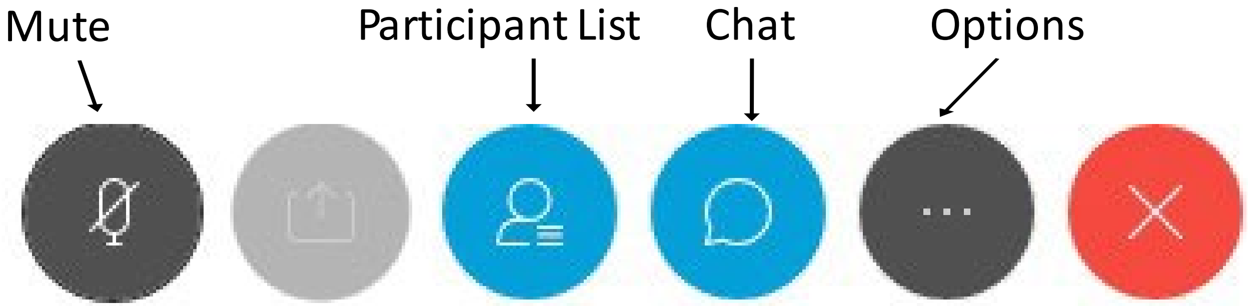
# This Event is Being Recorded

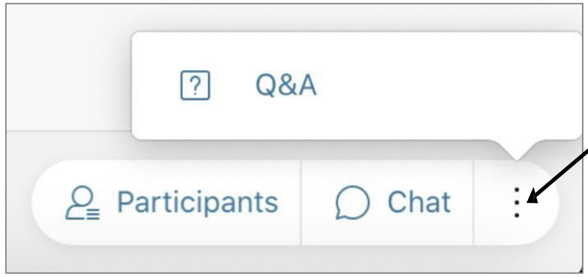
# Logistics

- All attendees have been muted.
- To ask questions, please "raise your hand"  and a panelist will unmute you so you can ask a question or make a comment.

  *Please press mute when done speaking. 
- If you would rather type, use the "Q&A" function. Q&A questions may also be read aloud by staff; attendees may be unmuted to further discuss the question.

  *Please select "all panelists" for submitting Q&A questions/comments.
- Questions asked in "Chat" will not be answered, please use Q&A or raise hand.
- Please identify your name and organization when speaking or providing written communication.




Click the "3 dots" on the bottom right of the screen to open the "Q&A" panel if not already showing.

# Agenda

1. Introduction and Opening Remarks
2. High DER Proceeding Overview
3. Electrification Impact Study (EIS) Part 1 Overview and Findings
4. EIS Part 1 Assumptions, Methods, and Limitations
5. EIS Part 1 Grid Impacts Cost Analysis
6. Stakeholder Discussion on EIS Part 1
7. EIS Part 2 Proposal
8. Stakeholder Discussion on EIS Part 2
9. Next Steps and Closing Remarks

# Workshop Objectives

1. Establish Electrification Impact Study (EIS) Part 1 context within the High DER proceeding and identify next steps.
2. Present the findings and methods described in EIS Part 1.
3. Discuss staff proposed plans for updating the study in EIS Part 2.
4. Receive stakeholder feedback on EIS Part 1 and staff proposed plans for Part 2.

# Opening Leadership Remarks

# Commissioner Darcie Houck

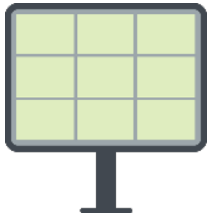
## Assigned Commissioner

# High DER Proceeding Overview

CPUC Energy Division

# About the High DER Grid Planning Proceeding

- The primary objective of the CPUC High DER proceeding is to prepare the electric grid for a high distributed energy resource (DER) future by determining how to improve distribution grid planning to maximize societal and ratepayer benefits from DERs while ensuring grid reliability and affordable rates.
- The proceeding opened in 2021, and the Scoping Ruling issued on November 15, 2021.
- What are DERs?
  - Pursuant to State Assembly Bill 327 and Public Utilities Code Section 769(a), DERs include:

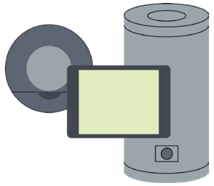


**Distributed Renewable Generation Resources (e.g., solar)**

**Energy Efficiency**

**Energy Storage**

**Electric Vehicles**



Examples: Thermostats, Internet-connected Water Heaters

**Demand Response/Flexible Load Management Technologies**

# California Anticipates High Adoption of Distributed Energy Resources (DER)

"This OIR anticipates a high-penetration DER future and seeks to determine how to optimize the integration of millions of DERs within the distribution grid while ensuring affordable rates."

– High DER OIR at p. 9

"This OIR neither seeks to set policy on the overall number of DERs nor does it seek to increase or decrease the desired level of DERs. This OIR focuses on preparing the grid to accommodate what is expected to be a high DER future and capture as much value as possible from DERs as well as mitigate any unintended negative impacts."

– High DER OIR at p. 10

# Three High DER Proceeding Tracks

## 1

### Distribution Planning Process and Data Improvements

- **Phase 1: Near-Term Actions**
- **Phase 2: Distribution Planning Process Improvements**
- Topics:
  - IOU Distribution Planning Processes
  - **Electrification Impacts** and Potential Mitigation
  - Data Portals
  - Community Engagement Needs Assessment for Distribution Planning

## 2

### Distribution System Operator (DSO) Roles and Responsibilities

- Long-term grid vision(s) and associated policy issues
- Investigation of grid operations models
- Future Grid Study development and public outreach
- Future actions identified that could lead to a successor proceeding

## 3

### Smart Inverter Operationalization and Grid Modernization Planning

- Phase 1: Smart Inverter Operationalization
- Phase 2: Grid Modernization Planning and Cost Recovery
- Topics:
  - Business Use Cases for Smart Inverters
  - DER Dispatchability
  - Smart Grid Investment Planning

# Track 1 Scoping Questions*

**Phase 1:** Should the Utilities' Distribution Planning Processes (DPPs) be modified to address policy-based issues such as forecasting scenarios for increased electrification, improved data sharing, electric vehicle adoption, adoption of real-time rates and related flexible load management technologies, and equity?

- Should policy-forecasting scenarios for higher electrification be used for determining potential grid investments needed to address electrification?

**Phase 2:** Should Utilities better integrate DERs into their standard annual DPP?

- If so, in what ways should the Utility DPPs improve with respect to planning for DERs (e.g., capturing additional value from these resources and optimizing resource siting)?
- How should Utility ownership of DERs be considered in these changes to DPP?

*The full list of scoping questions are provided in the proceeding's 11/15/2021 Scoping Ruling.

# Questions

# EIS Part 1 Overview and Findings

CPUC Energy Division

# Study Objectives and Scope

The study is intended to addresses two main objectives:

1. Exploring new planning and analytic methods, including scenario planning, that attempt to improve forecasting accuracy and granularity for estimating where and when electrification loads will occur, and the potential impact of DER growth on forecasts.
2. Estimating grid infrastructure costs associated with achieving California electrification policies over longer time frames than current distribution planning processes (inclusive of distribution grid requirements down to the service transformer level).

The Part 1 Study was prepared for review within the High DER Proceeding as a first step toward examining the potential impacts of high DER adoption on the distribution grid.

Broader impacts or policy implications of the preliminary results (such as potential rate or billing impacts or DER incentive programs) are not within the scope of the Part 1 Study.

# High-Level Preliminary Findings and Assumptions

- Potential for approximately $30-$50 billion for distribution grid investments by 2035 if measures are not taken to reduce costs and manage load
- Potential for approximately $15 billion of the $50 billion in secondary system upgrades (service transformers)
- Potential annual peak demand reaching about 70 gigawatts for the State's three largest electric utilities combined by 2035 (more than 12 million customer meters)
  - By comparison, 2022 IEPR Planning Forecast reaches about 55 gigawatts by 2035
- Assumed all grid needs would be met with traditional distribution investments
- Did not consider alternative new time-variant rates, dynamic rates, flexible load management, or other potential mitigation strategies
- All cost and load estimates are considered preliminary
- The best available data at the time of Research Plan completion in spring 2022 was used for EIS Part 1 development (e.g., adopted 2021 IEPR)

# Preliminary Distribution Cost Findings

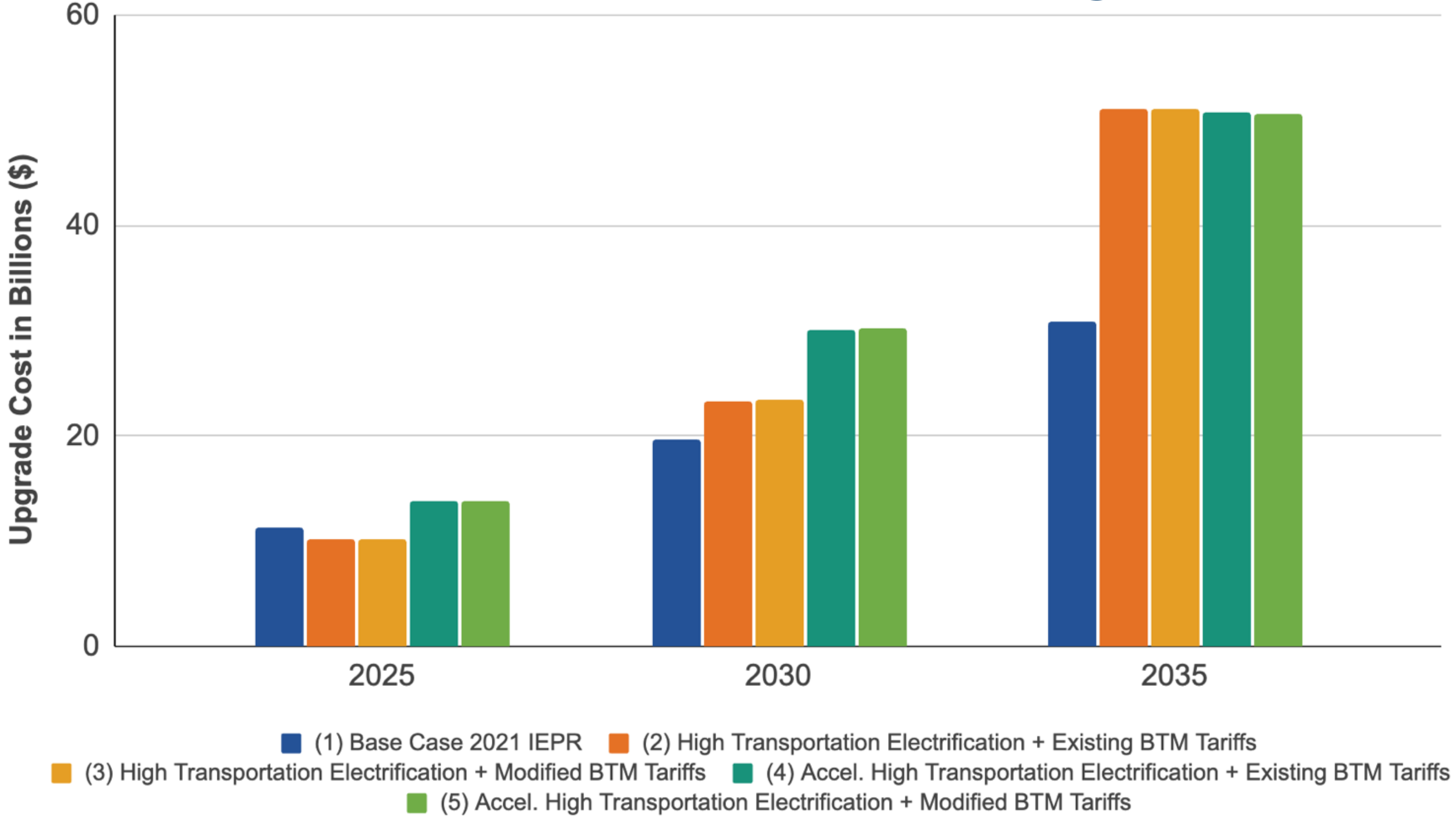



Figure ES-1: Estimated total capacity upgrade costs for the three large California IOUs, including new substations, transformer banks, feeders, and service transformers

# Secondary Findings

- Traditional and next-generation grid **investments need to be made as efficiently as possible** by improving grid planning methods, data collection, analytics, approaches to grid modernization, and DER integration.
- Missing the when and where of electrification loads could result in either **underbuilding or overbuilding the system**.
- Flexible **load management** strategies and **alternative rate design** are important strategies to consider for mitigating electrification-driven grid upgrade costs.
- Implementation of DER-based mitigation strategies in the near-term may be considered a **bridge solution** while longer-term traditional upgrades are in various planning and approval stages.

# Secondary Findings (Continued)

- **Secondary distribution system upgrades** may be significant grid upgrade costs and may be among the first grid components to require upgrade.
- Transmission, wildfire mitigation, and aging infrastructure cost data may need to be incorporated into a more **integrated distribution planning** process to better inform decision-making about optimal solutions including DER-based and load management solutions.
- Distribution planning processes may need to be expedited and modified such that **multiple demand scenarios** may be incorporated, **longer planning horizons** could be studied, and **greater amounts of grid data** may be linked and processed to inform decision making about long-lead grid upgrades.

***Additional analysis and stakeholder feedback is needed to identify and consider all the potential implications of the study and inform next steps in the proceeding.**

# Questions

# EIS Part 1 Assumptions, Methods, and Limitations

Kevala


kevala
GRID INTELLIGENCE, DELIVERED.

# Electrification Impacts Study (EIS) Part 1

**Explores a new, highly granular approach for identifying where and when the distribution grid will need enhancements under specific policy or planning scenario assumptions.**

## Forecasted Net Loads

- Estimate net loads at a premise level.
- Incorporate propensity to adopt modeling of PV, batteries, EVs, and building electrification.
- Aggregate premise load to locations on the grid.
- Generate DER adoption scenarios to test a range of outcomes.

## Capacity Needs

- Identify current capacity from secondary transformers to sub-transmission feeder banks.
- Determine additional capacity needs due to forecasted net loads.
- Determine range of capacity needs based on scenarios of DER adoption.

## Aggregated Costs

- Estimate unit costs to meet capacity needs.
- Determine incremental capital investments to meet capacity needs.
- Aggregate grid asset costs up to the system level by scenario.

# EIS Part 1 Is the When and the Where of California's Forecast, *Not the Actual Forecast*

## The EIS Part 1 IS/DOES:

**An approach to premise-level forecast analysis that identifies where and when the distribution grid will need enhancements under certain policy scenario assumptions to enable California to meet its electrification policy goals by 2035.**

- **Estimate the scope and scale of electrification impacts at the system level from the bottom up**
  - Leverage premise-specific information, including customer meter data from PG&E, SCE, and SDG&E, to develop circuit premise-specific forecasts
  - Performed scenarios to explore impact of different levels of transportation electrification and BTM structures
- **Enable premise- and circuit-specific grid integration analysis** (integration of EVs and other DER types) in the context of the distribution and sub-transmission grid infrastructure

## The EIS Part 1 is/does NOT:

**The EIS Part 1 is not an absolute prediction (revenue-grade investment forecast) of the level of electric distribution grid investment needed by 2035.**

- The EIS differs from the Integrated Energy Policy Report (IEPR) in important ways:
  - **Bottom-up, not top-down**
  - **Calibrated to state policy goals**, not based on what is likely to happen
  - Scenarios are limited to transportation electrification and BTM tariff sensitivities known as of Q2 2022
- **Does not include mitigations** like V1G (smart charging), rate design changes, etc.
- **Is limited to the electric distribution system up to the distribution substation**; excludes sub-transmission

# EIS Part 1 Overall Approach

**Part 1 starts at the premise level to explore a "distribution first" planning approach where distribution capacity expansion needs are met by an integrated and efficient distribution, and ultimately sub-transmission* and transmission* planning processes that anticipates the value of DERs and load management technologies in addressing a high electrification future.**

## What does premise-level (bottom-up) mean?

- Load and DER growth is disaggregated at the premise-level based on econometric modeling using socioeconomic data and bill savings, ***customer by customer***
- Apply the customer-by-customer forecast approach to the IEPR load and DER forecast, ***as well as state policy-driven targets***
- Analysis is structured to yield results for multiple scenarios, planning horizons, and utilities
    - **2025, 2030, 2035** planning horizons
    - PG&E, SCE, SDG&E
    - **One base case calibrated to the IEPR**
    - **Four alternate scenarios** calibrated to four combinations of State Agency Transportation Electrification assumptions and behind-the-meter tariff outcomes
- **Forecast Net Loads (Baseline Net Load) → Capacity Needs → Locational Costs**

kevala

*EIS Part 1 did not include sub-transmission or transmission network elements

# EIS Part 1 Costs: Comparison Against Past Studies

- **Previous electrification studies in PG&E territory estimate lower electrification costs by 2050 than PG&E's 5-year capacity planned investments of $5.3 billion are up to in 2026.**
- Bottom-up approach identifies substantial additional costs not captured in previous studies.
- NREL's LA100 was the first more granular study looking at 100% renewable energy (RE) targets.
  - LADWP unit-cost data is lower than the IOUs.

| | Distribution Assets Modeled | | | | Cost Inputs | | | Overload Calculation | | | Objective and DERs Modeled | Range of Costs |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Substation | Banks | Feeders | Service Transformers | DIDF In $/kW | GRC in $/kW | IOUs Unit Cost in $ | ICA | SCADA | AMI | | |
| **Kevala EIS Part 1** | ✓ | ✓ | ✓ | ✓ | | | ✓ | | ^ | ✓ | Electrification: baseline load, plus PV, BESS, EV (LD, MD, HD), EE, BE | $34-$55 billion by 2035 for 13 million customers (PG&E, SCE, SDG&E) |
| **Berkeley** | ✓ | | ✓ | | ✓ | | | ✓ | | | Electrification: heat pump, EVs (only LD) | $5 billion by 2050 for 5.7 million customers (PG&E only) |
| **NREL LA100** | | ✓ | ✓ | ✓ | | | ✓ | | ✓ | | 100 % RE: baseline load, plus PV, BESS, EV (LD, MD, HD), EE, BE | $1.5 billion by 2045 for 1.4 million customers (LADWP) |
| **Benefits to EIS Approach** | More detailed and precise capacity and cost analysis leads to better insights into the timing and scale of distribution planning needs. | | | | More granular, transparent, and accurate. | | | More accurate load allocation. | | | Provides locationally and temporally DER-specific insights that can inform planning activities and policy development. | Only study to analyze all three big IOUs. Forecast horizon informed by most believable inputs and assumptions. |

*^ SCADA data is not included in Part 1.*

# Advantages of EIS Methodology for Forecasting

### Uses AMI data for *each* premise for all three IOUs

- This differs from traditional "sampling" approaches, which assume similar customers have identical load profiles.
- Eliminates need to assume that average customer profiles are universally applicable

### Offers premise-level counterfactuals to compare scenarios

- Estimate of what would happen without DER based on the customer's actual historical behaviors allows
- Eliminates the need to find a sample of non-participating customers that are representative of the
- Allows for use cases in addition to grid-scale forecasting (e.g., rates or incentive designs at a community level or down to the individual customer level).

### Creates transparency of results and ease of comparison

- Premise data to estimate future net-load allows for a simple visual comparison of the trend of a premise and verified as reasonable for that customer.
- Can directly compare feeder by feeder results (e.g., conduct a Grid Needs Assessment for comparison to utility Grid Needs Assessments either with a limited sampling approach or in full)

### Estimates both peak load, total energy and the load duration curve

- Most data science techniques focus on a single value (e.g., the peak), often sacrificing estimates of others
- Able to forecast a peak with increased accuracy, while also estimating hourly energy at all hours across the year (load duration curve) that accurately represents the customer's total annual use.

# Limitations of Methodology

**While the Part 1 Study may be among the most comprehensive distribution grid analyses made public to date, its scope was necessarily bounded by data and to align with state policy goals. The Part 2 study is proposed to expand the number of scenarios, enhance the precision of grid requirements with additional data, and examine potential mitigations that reduce the impacts on customers.**

- **The Part 1 premise-level forecast is based on advanced metering infrastructure (AMI) data**, which is the most robust dataset received and the most readily joinable with geospatial data. However, using AMI data alone risks missing specific grid requirements and costs. Using supervisory control and data acquisition (SCADA) and AMI datasets together for Part 2 will enable more accurate modeling and analysis.
- Part 1 scenarios are **managed** (via existing time-of-use (TOU) rates) **but are not mitigated.**
    - **Built solely on electric vehicle (EV) and behind-the-meter (BTM) tariff sensitivities.**
    - **Additional DER sensitivities and NWAs** (additional mitigations) are **<u>not</u>** included in Part 1 and are proposed for Part 2.
- Part 1 does not include considerations across **sub-transmission and primary and secondary lines.**
- Part 1 relies on **aggregated cost data provided by the utilities.**
- Part 1 relies on data provided by PG&E, SCE, and SDG&E to date; **other data—from CCAs, ISO, DMV, for example—will enable even more accurate and granular identification of grid needs**, especially for fleet identification.

# Context and Timing of EIS Part 1Assumptions

EIS Part 1 assumptions were driven by the **final 2021 IEPR Demand Forecast as well as regulatory and policy decision and rate designs in place** at the time of the research plan design

| 2020 | 2021 | 2022 |
| --- | --- | --- |

Executive Order N-79-20 (2020) established the goal for 100 percent of in-state sales of new passenger cars and trucks to be zero emissions by 2035

July 2021: High DER … CPUC opened High Distributed Energy Resources (DER) Grid Planning Proceeding (R.21-06-017)

2020-2022: California Air Resources Board's *Advanced Clean Cars II* (light-duty) regulations (adopted 11/22), and included innovated Clean Transit (buses), Advanced Clean Truckes (medium/heavy duty), and Advanced Clean Fleets

**EIS Study Research Plan Workshop (Dec 2021**

Special Interagency Working Group HE Demand Scenario adopted by CEC (5/22) (Resolution No. 22-0524-5)

2022 State Implementation Plan (SIP) which defines zero-emission standards for space and water hearting (9/22)

December 2022: Net Billing Tariff adopted (12/22) (D.22-12-056)

Updated Time-of-Use periods and corresponding rates accepted pre-2020

# Baseline Net-Load: Approach

## 1 Data Ingestion

**Import key data into the platform to include but not limited to:**

- AMI
- SCADA
- Weather (e.g., temperature),
- Rate schedules
- Electrical infrastructure
- Premise information (e.g., building characteristics, census data)
- Technology adoption (e.g., PV, EV and storage)
- EE programs
- Asset costs

## 2 Net-Load Baseline Simulation

**Create a baseline forecast of hourly net-load** (feeder-level load less feeder renewable generation)

- Simulate premise load and expected (current plus baseline projected growth) using AMI, weather, premise, and technology adoption information
- Using electric infrastructure data, aggregate loads by feeder then substation, etc.
- Generate IOU and cumulative IOU baselines
- Generate IEPR-scaled forecast for 2022

## 3 Hourly Demand-Side Modifiers

**Using available data, create hourly load modifiers for DER and EE technologies:**

- Develop a catalog of EE and BE end-use shapes, equipment specifications, and estimated savings
- Leveraging Kevala's bill impact analysis capabilities and NREL's PVWAtts, simulate PV or PV+storage profiles
- Calibrate EE, BE, PV, and storage using the IEPR targets
- Develop LDV, MDV, and HDV adoption and behavior impacts across CA and calibrating to current EV forecasts scenarios that reflect various policy ambitions and expectations.

## 4 Net-Load Impacts/Analysis

**Combine load and DER forecast to calculate the net-load at different grid aggregation levels:**

- Calculate energy and peak load at IOU and different grid asset levels by customer sector and DER of load and DER forecast scenarios
- Calculate grid upgrade costs at service transformer, feeder, transformer bank, and substation levels
- Calculate energy burden at the census block level using bill calculation costs and household income

# Data Ingestion Goals for Part 1

### IOU confidential data

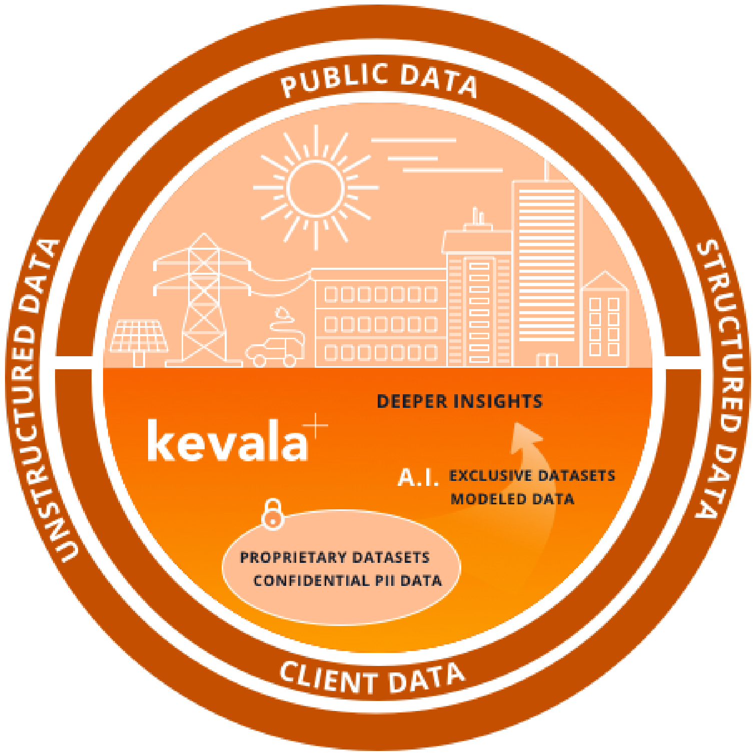
- GIS data for grid assets
- Hourly AMI per meter
- Meter rate code
- Hourly SCADA for distribution grid components
- Meter-level energy efficiency program participation
- Distribution planning design principles
- Grid infrastructure unit costs

### IOU non-confidential data

- GNA and ICA datasets
- IEPR forecast targets

### Publicly available data

- California forecast and building climate zones
- Cal-Adapt
- Traffic volumes AADT
- RASS survey statistics
- Energy efficiency program data (CEDARS)
- Socioeconomic data



# Utility Data Received for Part 1

**Data ingestion and joining, or linking, comprised the vast majority of the Part 1 analysis**

- 100 terabytes total, 64 terabytes in AMI data alone

| IOU | AMI Data (Terabytes) | No. of AMI Meters* (Millions) | No. of AMI Data Records (Millions) | No. of Distribution Assets** (Thousands) |
|---|---|---|---|---|
| PG&E | 31 | 6.07 | 318,347 | 916 |
| SCE | 25 | 5.3 | 251,145 | 753 |
| SDG&E | 7 | 1.51 | 75,949 | 171 |

*Combination of 15-minute and hourly meters
**Feeders, (service and bank) transformers, and substations

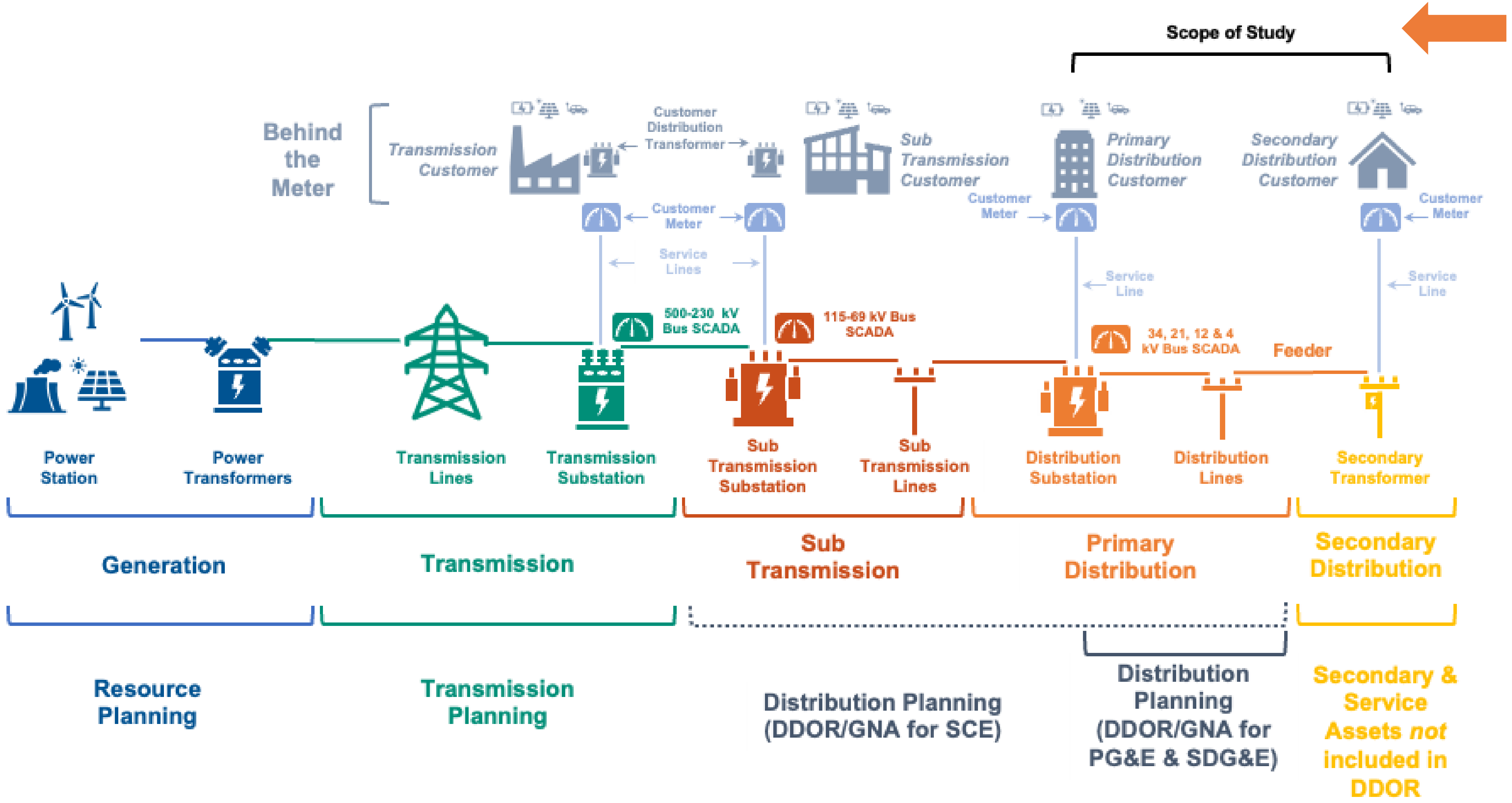
- Mapping geospatial grid infrastructure, AMI, and rates
    - Transformer bank rating and connectivity to feeders data received as late as September 26, 2022 for SCE and SDG&E
    - Gaps remain: feeder connectivity to transformer banks and asset ratings
- Data quality and completeness
    - AMI data: Outliers and missing time series data
    - Premises associated with multiple feeders, rates, billing, and interconnection data all had gaps

# Data Ingestion: Approach and Framework

## IOU Service Territory

- **Substation:** Lat/Long — Connectivity (Parent ID)
- **Transformer Bank:** Lat/Long, GNA loading, GNA rating, SCADA MW — Connectivity (Parent ID)
- **Feeder:** Lat/Long, GNA loading, GNA rating, SCADA MW — Connectivity (Parent ID)
- **Service Transformer:** Lat/Long, KVA rating — Connectivity (Parent ID)
- **Parcel:** Census, zip code, size — Polygon Geo-shape
- **Premise:** Lat/Long, kWh, rate, DER — Lat-long; Connectivity (Parent ID)

# Baseline Net-Load: Objective




**Study Hypothesis:**
The development of a baseline net-load forecast by premise that incorporates varied assumptions of demand modifiers is needed the most accurate way to generate esti**mates of the where and the when of capacity needs at a secondary transformer, feeder, feeder bank, and substation across all three large IOU service territories**.

# Five Scenarios Designed to Focus on the Impact of Transportation Electrification and BTM Tariffs

***All Transportation Electrification assumptions used in the Part 1 scenarios are consistent with state agency assumptions adopted and available at the time of study development as of Q2 2022. The Part 1 Study Base Case is based on the 2021 Integrated Energy Policy Report (IEPR) forecast assumptions (2021 IEPR adopted Q1 2022). For the 2022 IEPR, the CEC increased electrification assumptions the levels in the to the High Transportation Electrification.***

| Scenario | | (1) Base Case 2021 IEPR | (2) High Transportation Electrification + Existing BTM Tariffs | (3) High Transportation Electrification + Modified BTM Tariffs | (4) Accelerated High Transportation Electrification + Existing BTM Tariffs | (5) Accelerated High Transportation Electrification + Modified BTM Tariffs |
|---|---|---|---|---|---|---|
| **Input Name** | | **Demand Forecast/DER Growth Forecast Calibration Target** | | | | |
| **ZEV Adoption Forecast Source** | **LDV** | CEC 2021 IEPR mid scenario | CARB 2021 Advanced Clean Cars II (ACC II) | | CEC 2021 IEPR bookend scenario | |
| | **MDV/HDV** | | CARB 2020 State SIP Strategy (SSS) | | CEC 2021 IEPR high scenario | |
| **ZEV Adoption Total Vehicle Count (2022-2035, Three IOUs)** | **LDV** | 3,172,598 | 10,013,953 | | 9,530,034 | |
| | **MDV/HDV** | 227,140 | 218,710 | | 230,876 | |
| **BTM Rate Design** | | Existing BTM rate design | Existing BTM rate design | Modified BTM rate design | Existing BTM rate design | Modified BTM rate design |

- The 2022 IEPR Base Case is now equivalent to the High Transportation Electrification scenarios (2 and 3) in terms of EV adoption projections.
- Peak demand, energy efficiency, building electrification, solar PV, and BESS are **all calibrated to 2021 IEPR mid-mid case.**
- Except for BTM tariffs, **rate levels and design are held constant at early 2022 levels for each IOU;** modified BTM rate design based on the December 13, 2021, Proposed Decision for R.20-08-020. The Proposed Decision was not adopted; instead, D.22-12-056 adopted the Net Billing Tariff.
- **Demand response** is assumed to be included in the peak forecast to the extent it is reflected in historical AMI data. No future expansion of DR was incorporated..

# Definition of Demand Modifiers Applied to EIS Part 1

## Demand Modifiers Included

**Behind-the-Meter Photovoltaics** (PV)

**Behind-the-Meter Battery Energy Storage System** (BESS)

**Energy Efficiency** (EE)

**Building Electrification** (BE)

**Electric Vehicles** (EV) **and Electric Vehicle Service Equipment** (EVSE)

## Demand Modifiers Excluded

**Demand Response*** (DR)

**Pricing & Programs** (P&P)

**Smart Controls** (A subset of P&P)

*To the extent DR is reflected in historical AMI, DR events are included in baseline forecasts, however this study did not address explicit DR programs or impacts nor forecast the impact of previous DR impacts

# DER Modeling Basis

## Size

- **Output** is an estimate of the capacity of the DER, such as the appropriate capacity or nameplate rating of the DER for a given premise, or percent change in premise load
- Determined based on characteristic of a premise, such as baseline load (e.g., to get 'net zero' for PV), historical DER sizing (e.g., historical percent savings from EE) or technology adoption (e.g., Level 1 vs Level 2 charger)

## Behavior

- **Output** is the hourly resolution (8760 profile) behavior of the DER over the course of a year
- Determined based on either engineering algorithms (e.g., PV based), statistical relationships (e.g. EE) or a combination of premise characteristics and customer behaviors (e.g., EV)

## Adoption

- **Output** is an estimate of the likelihood that a premise will adopt the DER (specifically an adoption propensity score between 0 (definite non-adoption) and 1 (definite adoption)
- Determined using statistical modeling techniques that examine the relationships among certain premise (or customer) attributes and historical adoptions

## Target

- **Output** is an estimate of the level of adoption of a DER in terms of capacity (e.g., kW of PV installed) or number DERs adopted (e.g., numbers of EVs)
- **Input** is an external forecast, such as medium case scenario from Integrated Energy Policy Report (IEPR) 2021, for the DER levels by year
- Determined using medium case scenario from Integrated Energy Policy Report 2021 mid-case forecast for base case and other targets for specific EV scenarios

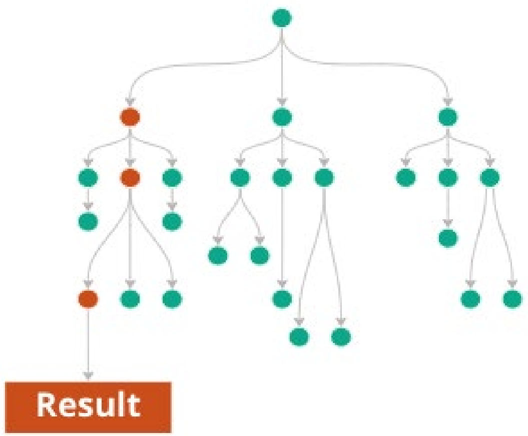
# DER Modeling Assumptions and Limitations

- DER adoption is highly dependent upon available data that reflects historical propensity to adopt
- Reliance on historical data to reflect future behaviors relies on the assumption that the past will reflect the future
- No assumptions about future regulatory, legislative, rate design, or rate levels were made
    - Future, not yet drafted, codes and standards were not included in the baseline load forecast
    - Proposed (published), not yet final, Behind-the-Meter tariff assumptions were made for PV adoption

# Baseline Net-Load

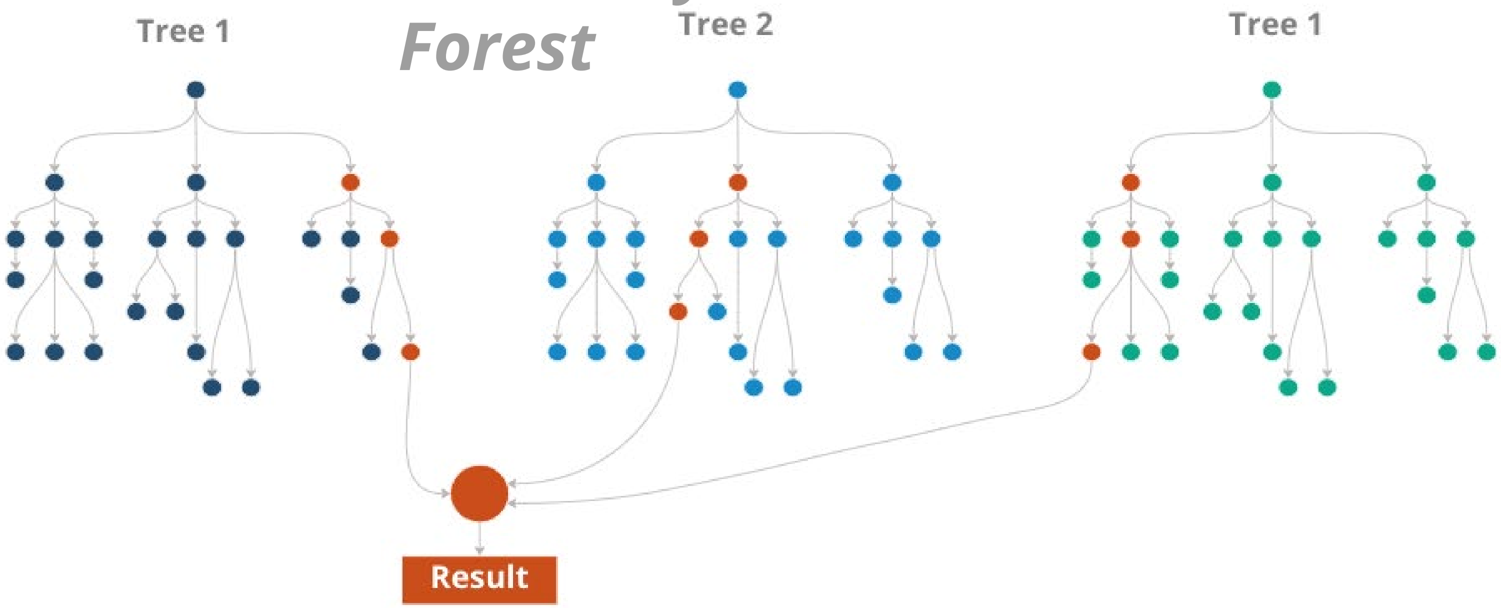
Hybrid methodology - combined method to reach objectives

## *Decision Tree*




- The **decision tree** approach predicts the dependent variable by learning rules that split the training data into successively smaller and more homogenous groups.
- The decision tree approach tends to overfit and performs best in predicting the peak but underperforms on estimating energy levels.

## *Extremely Randomized Forest*




- The **extremely randomized forest** technique generates many decision trees based on different inputs and starting points for the trees, with decision tree branches splitting randomly.
- The average outcome of the many trees is used as an estimate.
- The extremely random forest approach tends to underfit the idiosyncratic observations in the training data and thus is a poor predictor of peaks.

# Net-Load Baseline: Approach

**Baseline Net-Load**
Address-specific hourly forecast of expected load served by the IOU

- Assumed baseline Net-Load represents the expected address-level energy use served by the IOU.
- Assumed AMI data represents historical net-load at the premise
- Trained model for **each** premise based on historical AMI, weather and other factors
- Forecasted hourly load at each premise for the study period and incorporated any weather changes over that same period.

**Baseline Load**
Address-specific hourly forecast of net-load less impact of PV, calibrated to IEPR

- Assumed baseline net-load less PV is the best representation of the premises hypothetical demand.
- Estimated the load profile of any adopted PVs at a premise (based on interconnection data)
- Removed estimated PV generation from hourly net-load forecasts to create baseline load forecasts.

**Load Growth**
Estimate of known and unknown load growth applied to actual or hypothetical addresses

- Broke load growth down into ‘known’ and ‘unknown’
- Assumed ‘known’ is new load predicted through interconnection request or other internal indications of load growth in a particular area
- Assumed ‘Unknown’ for residential is based on population growth and average load profiles
- Assumed ‘Unknown’ load growth was based on economic growth and applied to existing loads

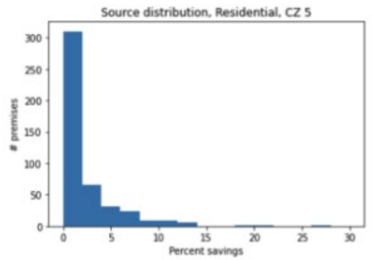
## Net-Load Baseline Objectives

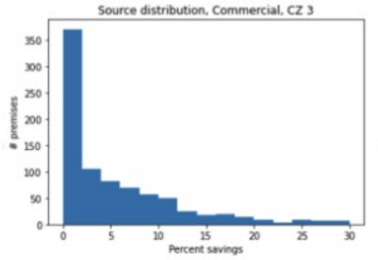
- **Inclusive.** Use as much of the advanced metering infrastructure (AMI) data provided by the utilities as possible.
- **Flexible**. Address potential sparsity in the net-load input data, as AMI data sources can contain missing values.
- **Holistic.** Incorporate complex interactions between seasonal components that drive load demand, such as hourly, weekly, and yearly effects.
- **Transparent**. The forecast model should not be a black box—model output should be interpretable with respect to its inputs.

# EE Modeling Summary

## Size

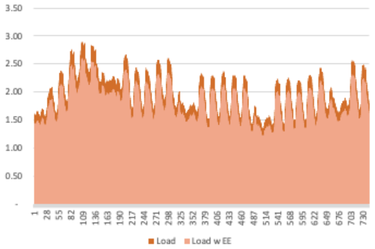
- **Output** is a percent savings expected at the premise
- Determined based historical savings from EE installations



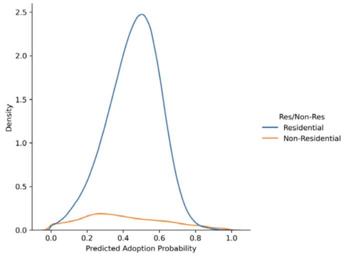

## Behavior

- **Output** is the hourly resolution (8760 profile) of savings over the year
- Determined by multiplying premise baseline load forecast by percent savings
  - Resulting the same percent savings in all hours
  - Different levels of energy savings depending on the baseline load levels



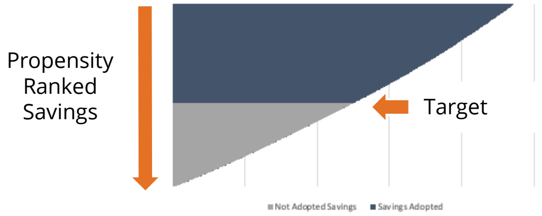

## Adoption

- **Output** is percent likelihood of adopting EE measures
- Determined by analyzing data from historical EE program participation and premise characteristics
  - Tested based on the area under the receiver operating characteristic curve (AUC ROC) metric



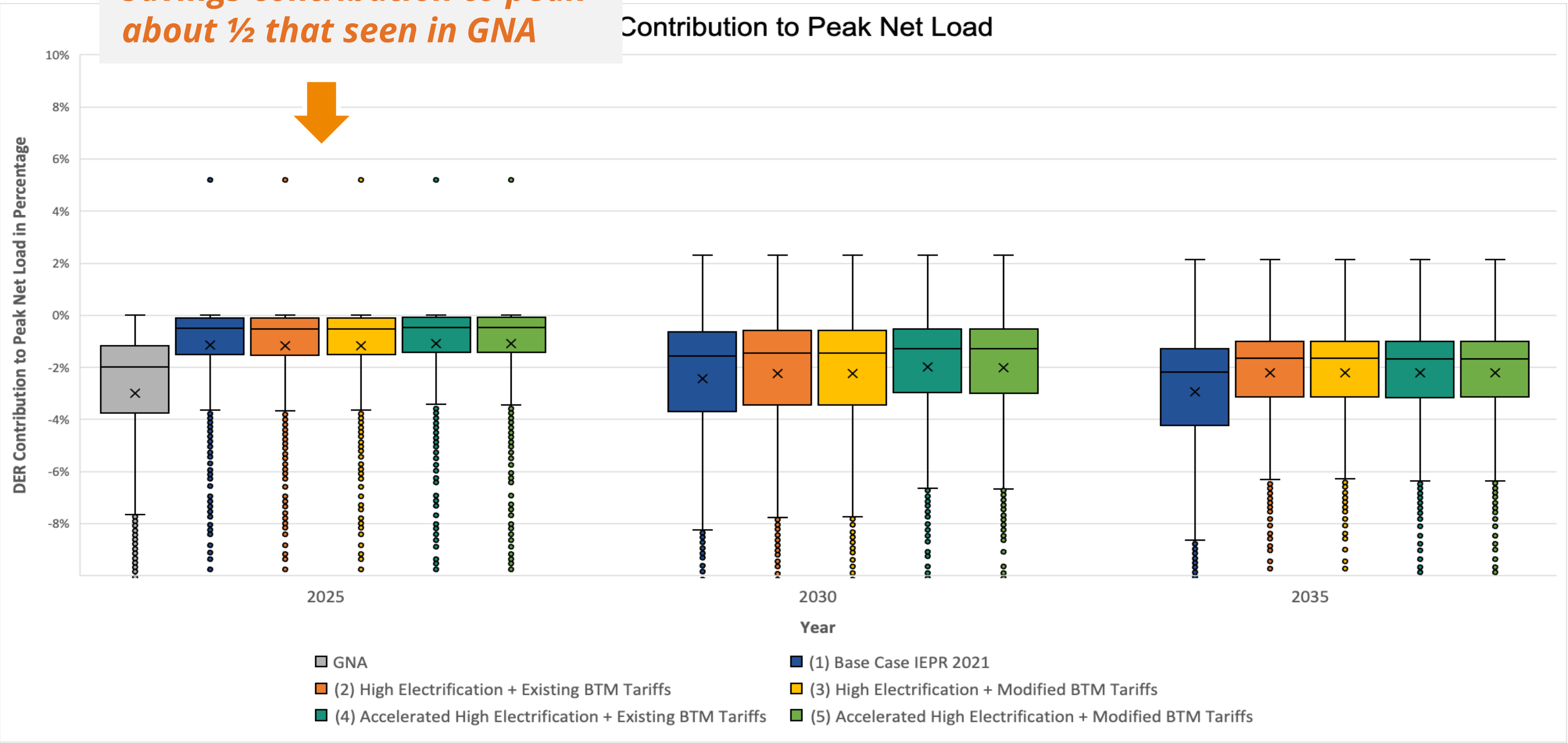

## Target

- **Output** is an EE adoption for residential and non-residential customer groups
- **Input** is an EE adoption forecasted for residential and non-residential from the medium case scenario from the 2021 IEPR
- Determined by ranking each premise from highest to lowest propensity, then adopting each premise size up to the target of EE



# EE Contribution to Peak

***Savings contribution to peak about ½ that seen in GNA***




***By 2035, the contribution to reduction in peak from EE stabilizes between 1-3% of peak load, in part driven by the even allocation of savings across all hours***

**EE provides some relief to electrification**, but still a low percentage of peak across all scenarios and all years

kevala

# BE Modeling Summary

## Size

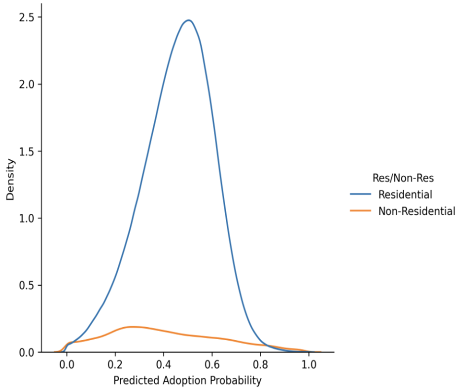
- **Output** is a percent increase in baseline load due to electrification
- Determined by calculating BE load ratios (BE load divided by baseline load) for the residential and commercial sectors by climate zone
    - California Residential Appliance Saturation Survey (RASS)
    - 2012 Pacific Region Commercial Buildings Energy Consumption Survey (CBECS)

## Behavior

- **Output** is the hourly increase in load from BE
- Determined by randomly selecting an electricity load profile, by class, using National Renewable Energy Laboratory's (NREL's) ResStock and ComStock databases, and applying that load shape to the estimated BE load increase

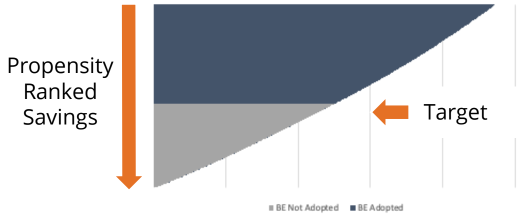
## Adoption

- **Output** is percent likelihood of adopting BE measures
- Determined by using same adoption propensity model used for EE



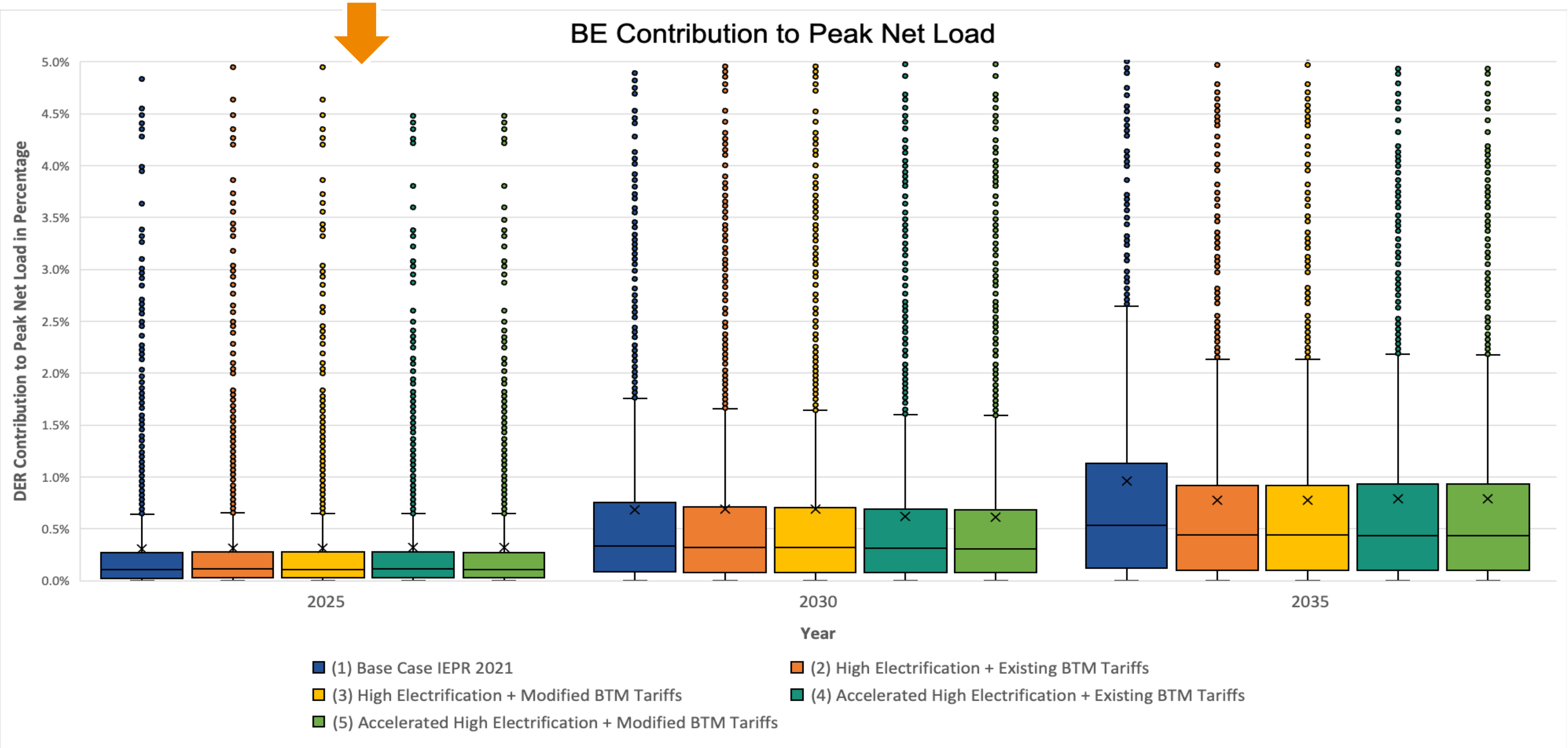

## Target

- **Output** is an BE adoption for residential and non-residential customer groups
- **Input** is a BE adoption forecast from the medium case scenario from the 2021 IEPR
- Determined by ranking each premise from highest to lowest propensity, then adopting each premise size up to the target of BE



# BE Contribution to Peak

There is no estimate of BE in GNA Forecasts



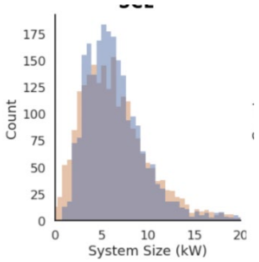

By 2035, the contribution to increase in peak from BE remains low relative to total load on the feeder but with significant tail events

IEPR forecast shows minimal impact from BE, and not considered in GNA, **highlighting need for BE scenarios**

# BTM PV Modeling Summary

## Size

- **Output** is system size in kW DC
- Determined by taking tract-level typical annual production of a 1 kW DC system in PVWatts and then scale PV system size to offset a fraction of the 2022 annual consumption of the premise and restrict size to building footprint.
- Validated by comparing estimated sizes to interconnection data




## Behavior

- **Output** is the hourly generation profile for the
- Determined by estimating the behavior of a 1 kW PV generation system for each Census tract for two customer groups (Residential and C&I) using NREL's PVWatts. Restricted size to building footprint, assuming 100 sqft per kW is needed and 75% of building footprint is usable for the system

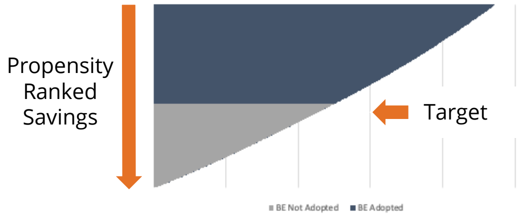
| | Resi | C&I |
|---|---|---|
| Tilt | 19° | 12° |
| DC/AC | 1.13 | 1.13 |
| Load Offset Ratio | 100% | 84% |

## Adoption

- **Output** is percent likelihood of adopting BE measures
- Determined by a Multi-level logistic regression, with predictors include payback period and demographics
- Trained based on historical data using calculate historical bills and PV payback periods (2016 prices)
- Validated based on historical data using an "Out-of-sample" data
- Prediction based on forecast data including estimating future bills and PV payback period (2022 prices)

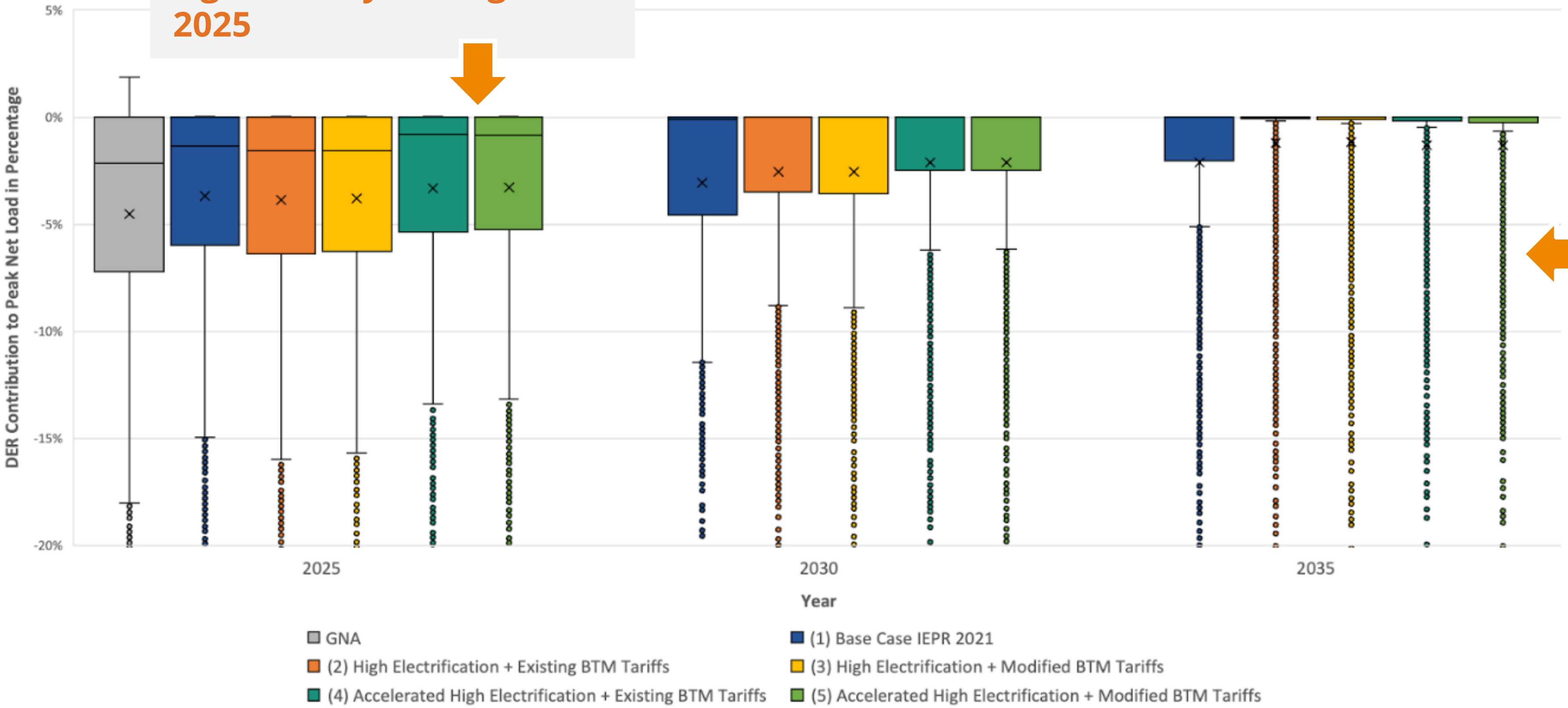
## Target

- **Output** is an PV adoption for residential and non-residential customer groups
- **Input** is a PV adoption forecast from the medium case scenario from the 2021 IEPR
- Determined by ranking each premise from highest to lowest propensity, then adopting each premise size up to the target of PV



# PV Contribution to Peak

PV Contributes significantly through 2025




By 2035, the peak hour migrates from late afternoon to 9 pm due to EV evening charging

Even as PV capacity increases, **PV's impact on peak load decreases by 2035**

# BTM BESS Modeling Summary

## Size

- **Output** is determining the commercially available battery modules installed
- Determined by adjusting the battery features for capacity (kWh) and power (kW) to a set of standard commercially available batteries (see Table
- For residential systems, sized to meet a defined percentage of maximum daily energy consumption.
- For non-residential premises, sized to reduce demand charges over a given duration

## Behavior

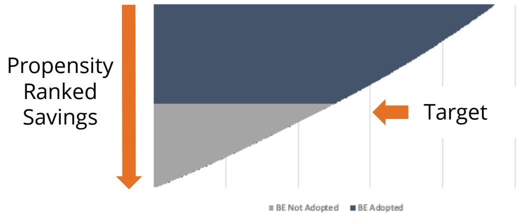
- **Output** is the change in load from BESS
- For Residential, assumed the premise is maximizing its self-consumption of PV. by charging when net-load was negative, and discharging when net-load was positive (typically in the early evening hours)   assuming 90% efficiency
- For non-residential, assumed the premise reducing demand charges by reducing its peak periods. The algorithm selected the ‘n’ lowest hourly intervals in the net-load data to charge and the ‘n’ highest hourly intervals to discharge.

## Adoption

- **Output** is percent likelihood of adopting BE measures
- Trained a multilevel logistic regression (MLR) models grouped by customer class and with or without PV then trained a regression model on other features such as, maximum load, and demographics
- Due to small number of BESS systems in CA from which to train, the data science technique know as “under-sampling” was used to mitigate the impacts of unbalanced training data.

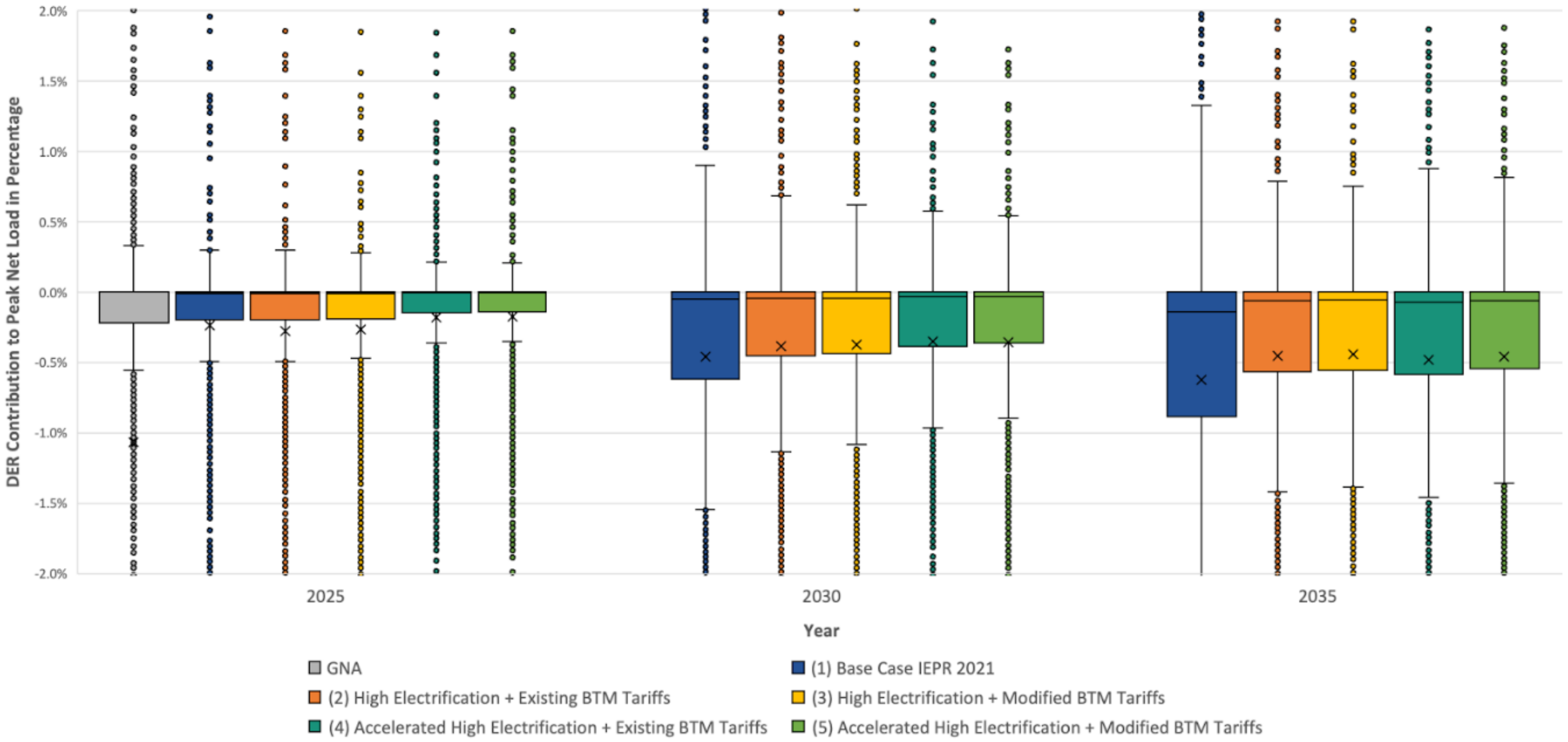
## Target

- **Output** is an BESS adoption for residential and non-residential customer groups
- **Input** is a BES adoption forecast from the medium case scenario from the 2021 IEPR
- Determined by ranking each premise from highest to lowest propensity, then adopting each premise size up to the target of BESS



# BESS Contribution to Peak

Significant ranges due to aggregate charging & discharging decisions




By 2035, reduction in peak load increases as deployment of BESS continues and the contribution is relatively constant across all scenarios

## BESS shows potential for mitigating peaks

# EV/EVSE Modeling Summary

**EVs**

## Target

- **Input** is a target of vehicle counts
- This target varied by each EV scenario

## Size

- **Output** is total count of vehicles for a premise
- Determined the type of vehicles (personal, light-duty (LD), battery electric vehicle (BEV), small car, or fleet)
- Personal EV types based on market share forecast of vehicle types
- Fleet EV types based on existing internal combustion engine fleets in a given census tract

## Adoption

- **Output** is ranked likelihood of adopting EV
- For personal EVs, applied a MLR technique segment by urban, suburban, and rural and applied demographic and behavior features
- For Fleet, ranking was based on ratio of non-building to total area at the premise

## Behavior

- **Output** is the increase in load from EV charging
- Developed a simulation model to develop hourly EVSE behavior load curves based on features such as EVSE characteristics, vehicle departure and arrival times, and vehicle miles traveled
- For primary charging also incorporated known charging behavior (e.g., residential charging in the evenings) and price signals (e.g., TOU)
- For secondary charge points, the number of assumed charging events was used to simulate the charger's behavior curve

**EVSEs**

### EVSE TARGET

- **Input** is adopted EVs and Fleets
- **Output** number of EVSEs
- Used a ratio of how many EVSE charging ports are assumed to be required to support targeted ZEVs

### Size (EVSEs)

- **Output** is type and quantity of chargers at premise
- Determined an eligible premise's charger type
- Primary charging (home and fleet) quantity based on EVs at premise
- Secondary charging (public, workplace, corridor) quantity based on existing station trends

### EV ADOPTION

- **Output** is type and quantity of chargers at premise
- Primary charging was based on the count/type of premise EV adopted
- Secondary Charging based on premise-level features including available land and local density of retail and traffic volumes

# Impact of EV Charging Modeling Approach

**Adding between 3 and 10 million light-duty (LD) ZEVs by 2035 across the three IOUs has roughly the same energy impacts as adding 3 to 9 million residential customers.**

## Base Case

- **ZEV adoption sources:**
  - **LD:** CEC 2021 IEPR Base Case
  - **Medium duty/heavy duty (MD/HD):** CEC 2021 IEPR Base Case
- **2035 ZEV-equivalent energy:**
  - **3.2M LDs:** 2.9M residential customers
  - **227k MD/HDs:** 173k commercial customers

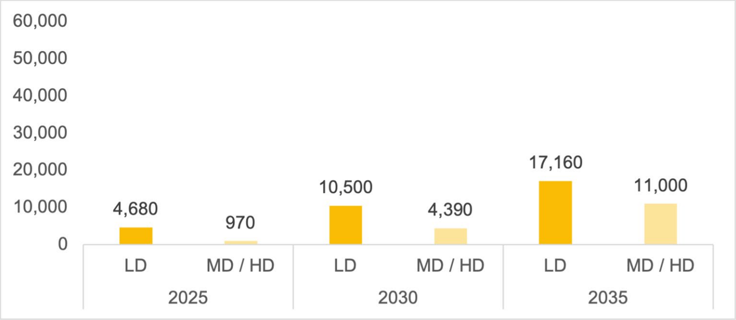
## High Electrification

- **ZEV adoption sources:**
  - **LD**: CARB ACC II
  - **MD/HD**: CARB 2020 SSS (ACT & ACF)
- **2035 ZEV-equivalent energy:**
  - **10.0M LDs:** 8.7M residential customers
  - **219k MD/HDs:** 198k commercial customers

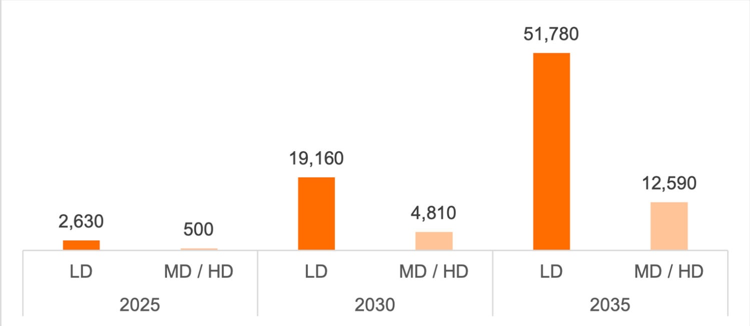
## Accelerated High Electrification

- **ZEV adoption sources:**
  - **LD**: CEC 2021 IEPR Bookend Case
  - **MD/HD**: CEC 2021 IEPR High Case
- **2035 ZEV-equivalent energy:**
  - **9.5M LDs:** 8.2M residential customers
  - **231k MD/HDs:** 164k commercial customers

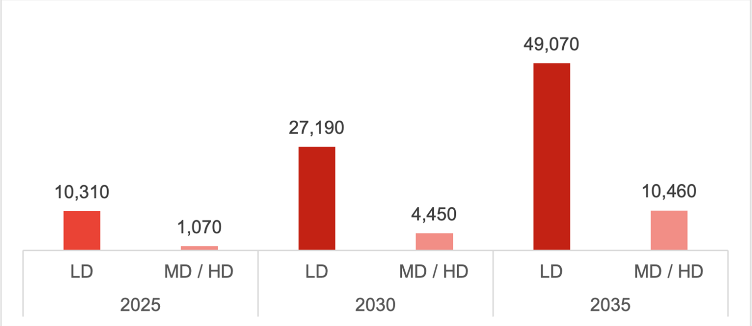
**Three IOUs' Total EV Energy (GWh)**
**Base Case**




**Three IOUs' Total EV Energy (GWh)**
**High Electrification**

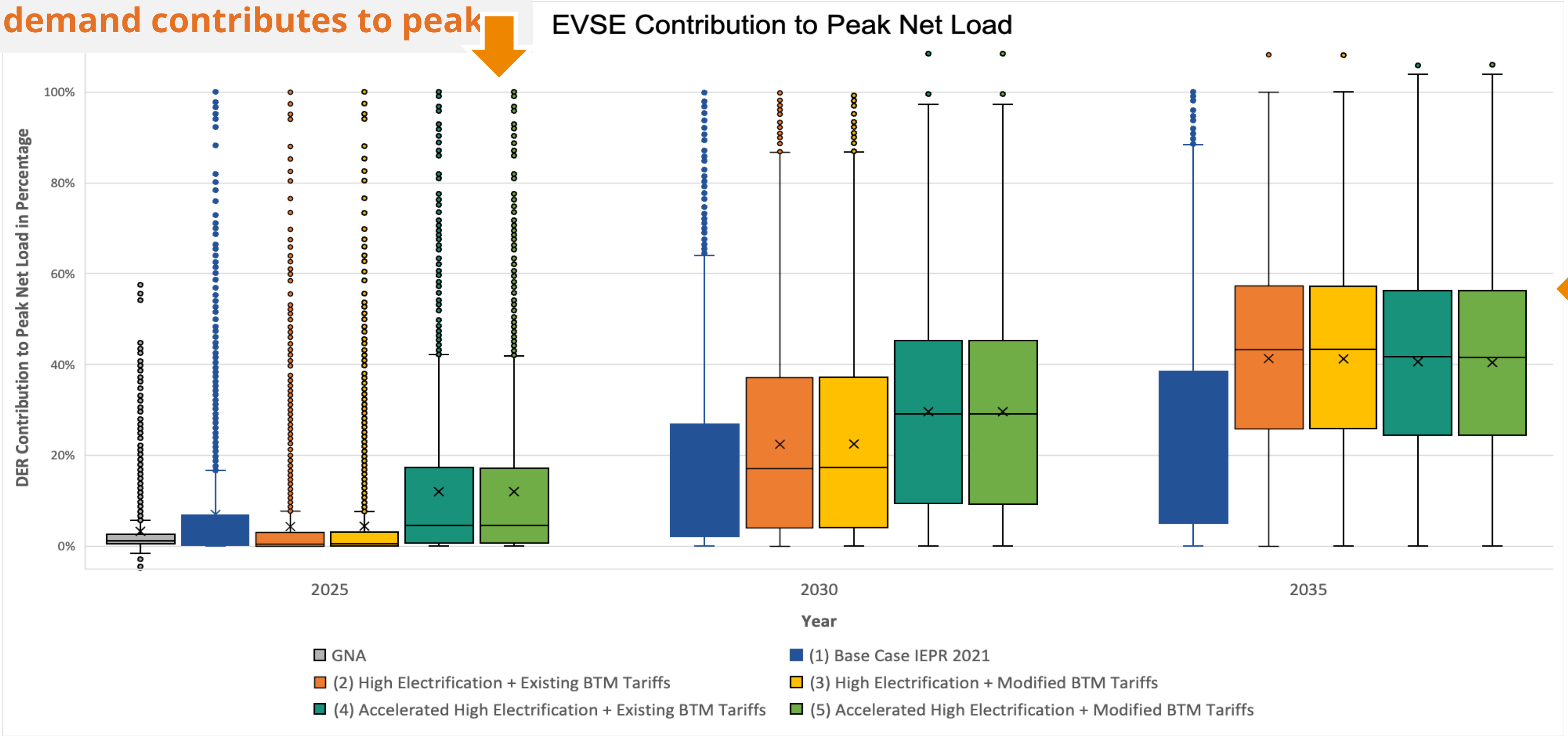



**Three IOUs' Total EV Energy (GWh)**
**Accelerated High Electrification**



# EV/EVSE Contribution to Peak

In 2025, EVSC charging demand contributes to peak



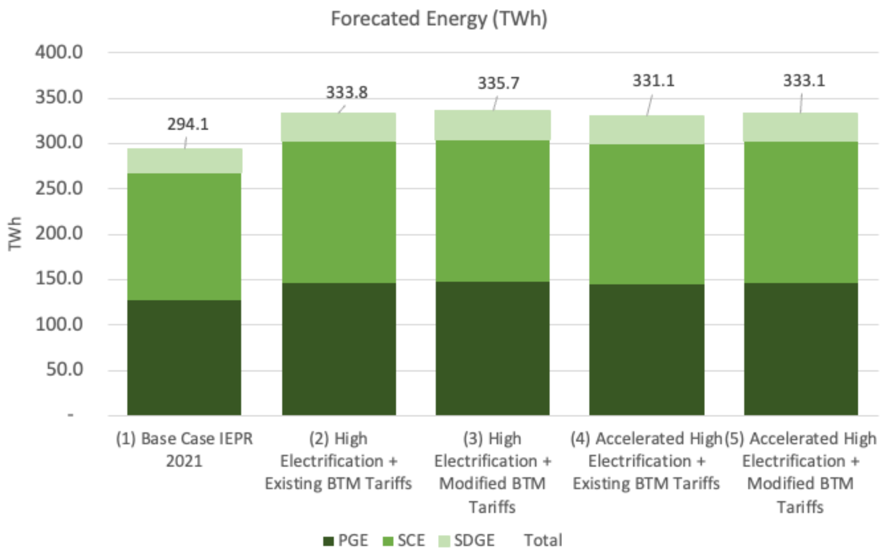

By 2035, EV charging can be as much as 40% of the average feeder peak net load under high EV penetration scenarios

For all scenarios, **EVSE charging contributes greatly to the** of average feeder peak net load

# Load Increases ~70GW by 2035


All scenarios result in peak demand increasing to between **55 and 70 GW by 2035**

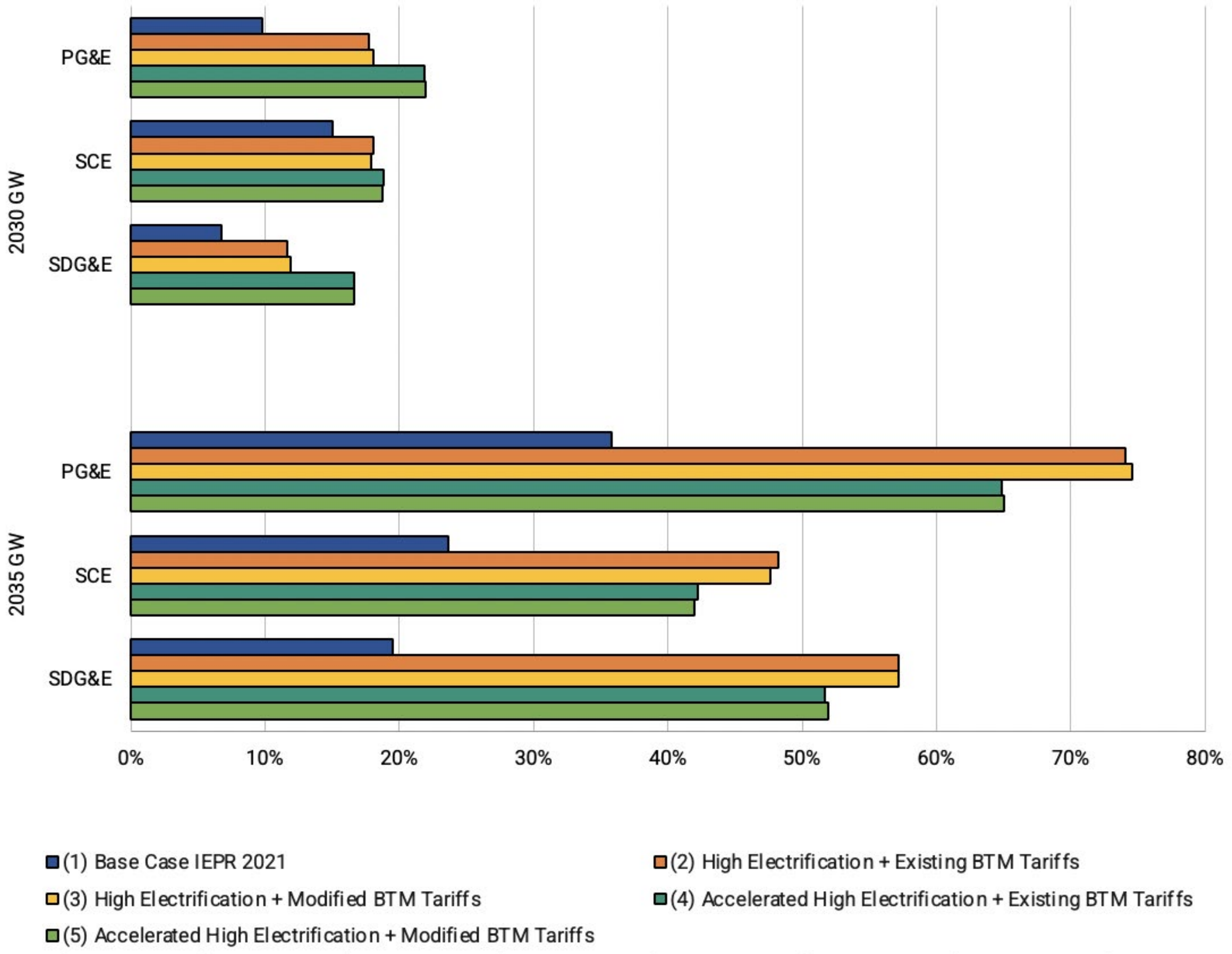
- 2035 electric vehicle projections appear counterintuitive (High vs. Accel.) but are based on the adoption curves available in the agency projections applied and timing of agency projection availability, with both scenarios reaching about 70 GW by 2035.
- All scenarios increase energy use by between 180% and 210% of current, providing additional 'sales' to aid in collecting additional costs



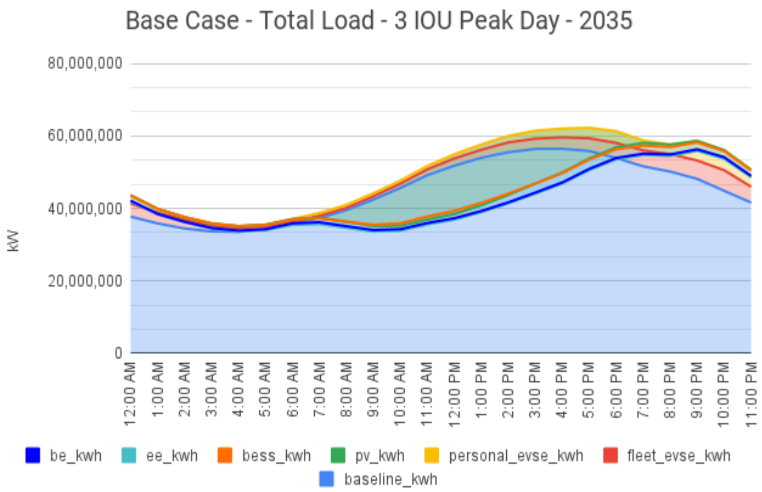
# Forecasted Peak Load by IOU

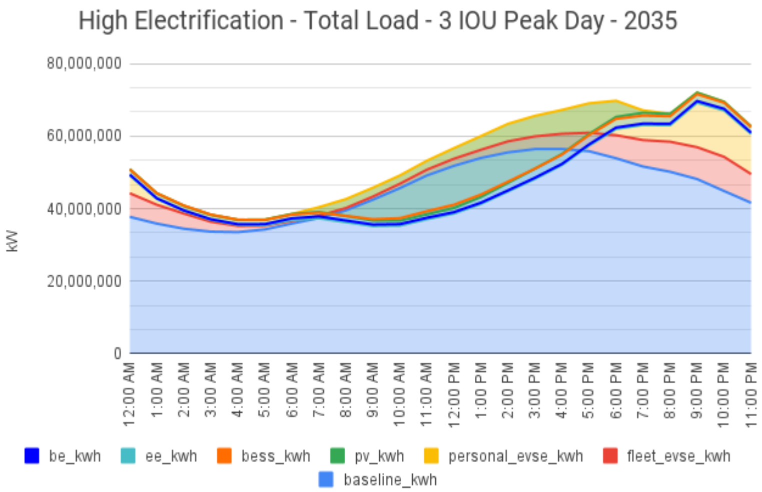
- Significant projected percent **change in peak load** for all scenarios, but especially for HE and Accelerated HE scenarios
- Peak-load **time shift to 9pm** in 2030 and 2035

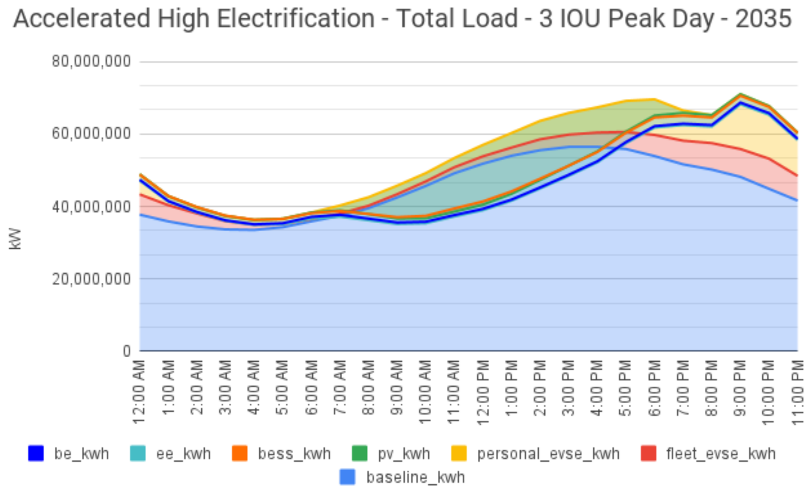
| | 2025 | | | 2030 | | | 2035 | | |
|---|---|---|---|---|---|---|---|---|---|
| | PGE | SCE | SDGE | PGE | SCE | SDGE | PGE | SCE | SDGE |
| (1) Base Case IEPR 2021 | Aug. 7pm | Oct. 4pm | Oct. 4pm | Aug. 7pm | Sep. 5pm | Sep. 6pm | Aug. 9pm | Aug. 6pm | Aug. 9pm |
| (2) HE + Existing BTM Tariffs | Aug. 7pm | Oct. 4pm | Oct. 4pm | Aug. 9pm | Sep. 5pm | Sep. 6pm | Aug. 9pm | Aug. 9pm | Aug. 9pm |
| (3) HE + Modified BTM Tariffs | Aug. 7pm | Oct. 4pm | Oct. 4pm | Aug. 9pm | Sep. 5pm | Sep. 6pm | Aug. 9pm | Aug. 9pm | Aug. 9pm |
| (4) Accelerated HE + Existing BTM Tariffs | Aug. 7pm | Oct. 5pm | Oct. 4pm | Aug. 9pm | Sep. 5pm | Sep. 9pm | Aug. 9pm | Aug. 9pm | Aug. 9pm |
| (5) Accelerated HE + Modified BTM Tariffs | Aug. 7pm | Oct. 5pm | Oct. 4pm | Aug. 9pm | Sep. 5pm | Sep. 9pm | Aug. 9pm | Aug. 9pm | Aug. 9pm |



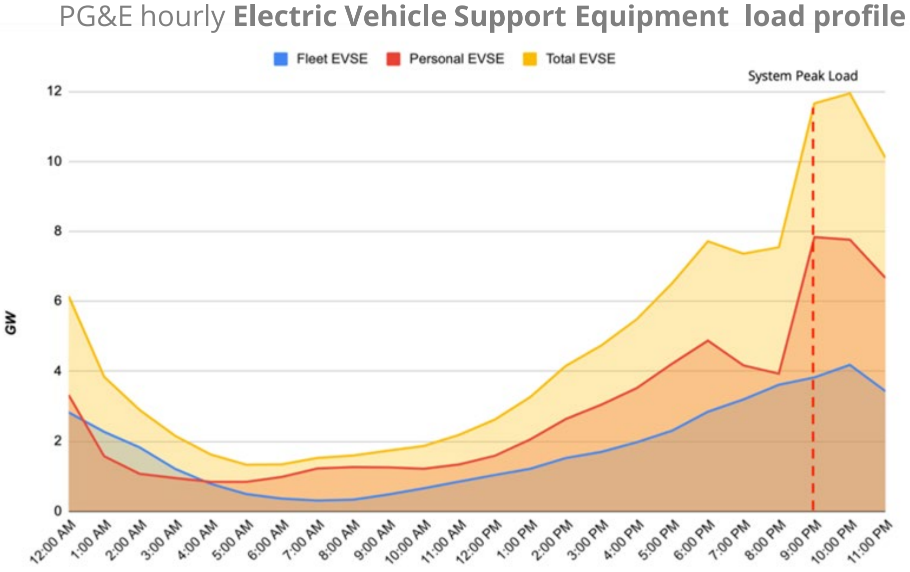
# Peak Load Change Driven by EV/EVSE



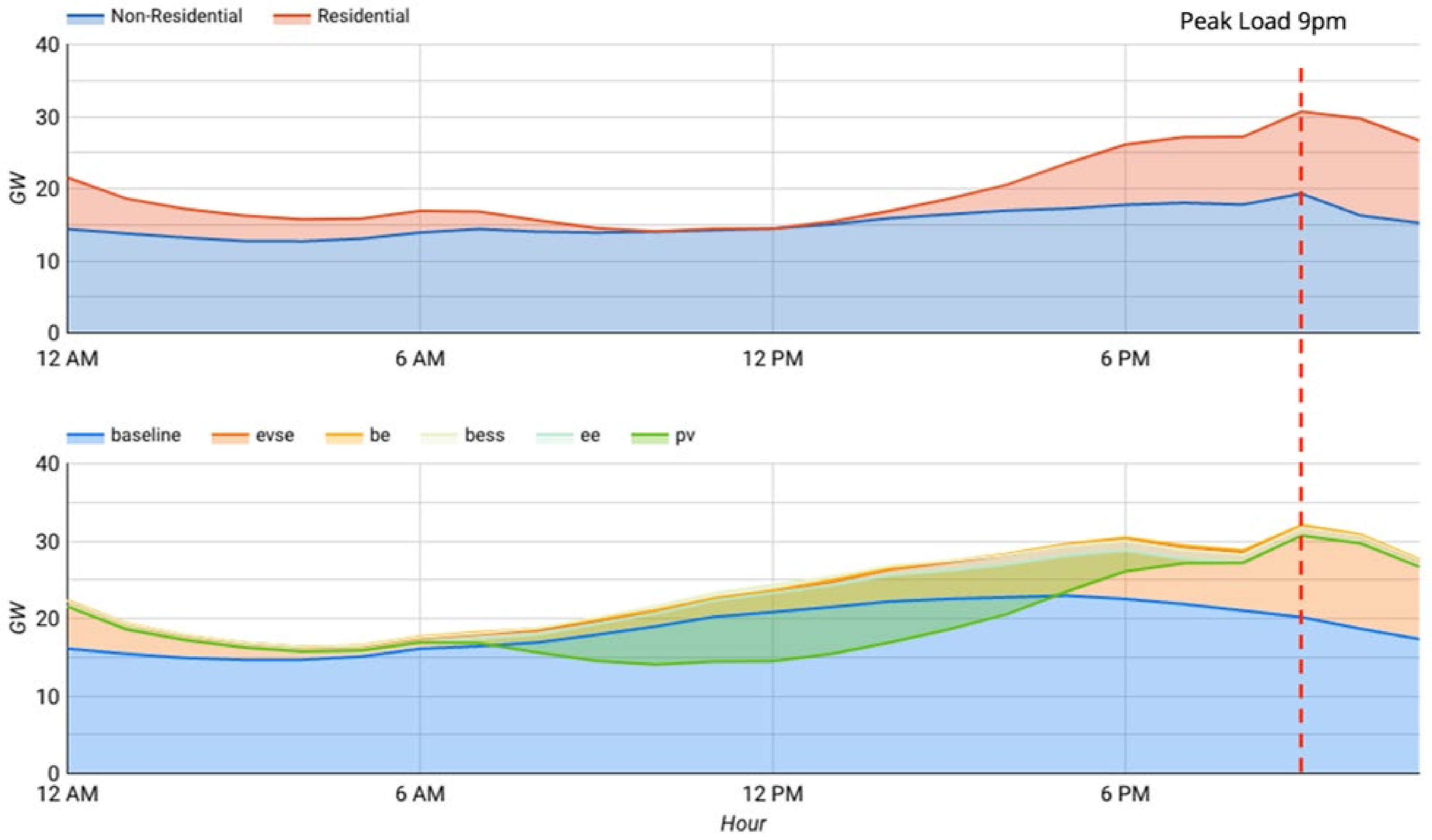




- The study assumed **adherence to existing time-of-use (TOU) periods** through 2035 to study what may be a worst-case scenario for peak load impacts from concurrent vehicle charging *(orange chart area)*.
- As a result, the **system peak shifts to 9 pm**, which is the current end of the peak period for most of the IOU's TOU rates
- EIS Part 2 is expected to explore alternative assumptions about customer charging behavior



# Solar Generation (Alone) Does Not Reduce Peak

PG&E hourly **net-load profile** by customer sector and by load type for Scenario 2




Given expected shift to a 9pm peak, **there is a limit to what solar generation can achieve to reduce the peak** and meeting renewable energy targets without battery storage.

# Questions

# 10 Minute Break

# EIS Part 1 Grid Impacts and Cost Analysis

Kevala

# Upgrade Costs Approach

## Capacity Expansion Grid Needs

Identify likely **infrastructure upgrades needed** including service transformers, feeders, transformer banks, and new distribution substations. **Equipment upgrade hierarchy** considers **thermal capacity constraints*** and depends on the overload amount and typical number of feeders and banks in a substation.

## Unit Cost

Costs reflect unit costs received from and used by PG&E, SCE, and SDG&E, respectively, and are consistent with each utility's unique design principles.

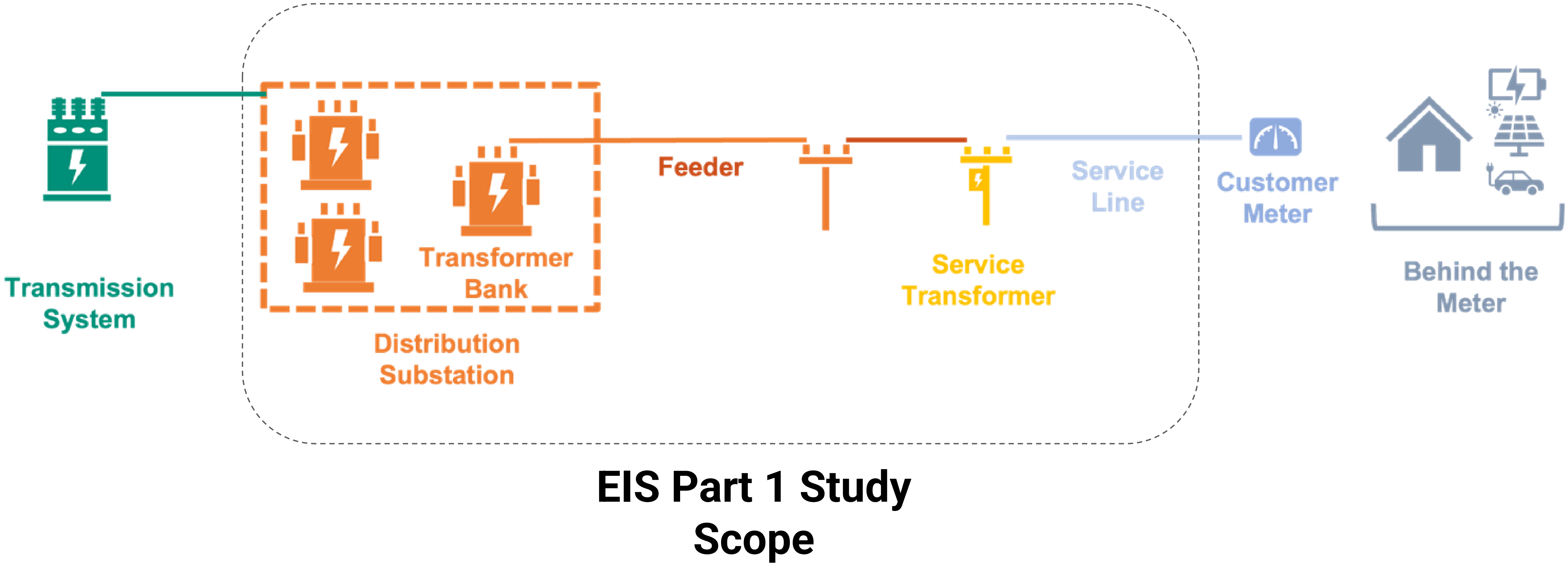
## Estimated Upgrade Costs

Total estimated costs vary by utility depending on the type of infrastructure upgrade required. Unit cost differences vary widely across utilities, contributing to differences in total costs between them.

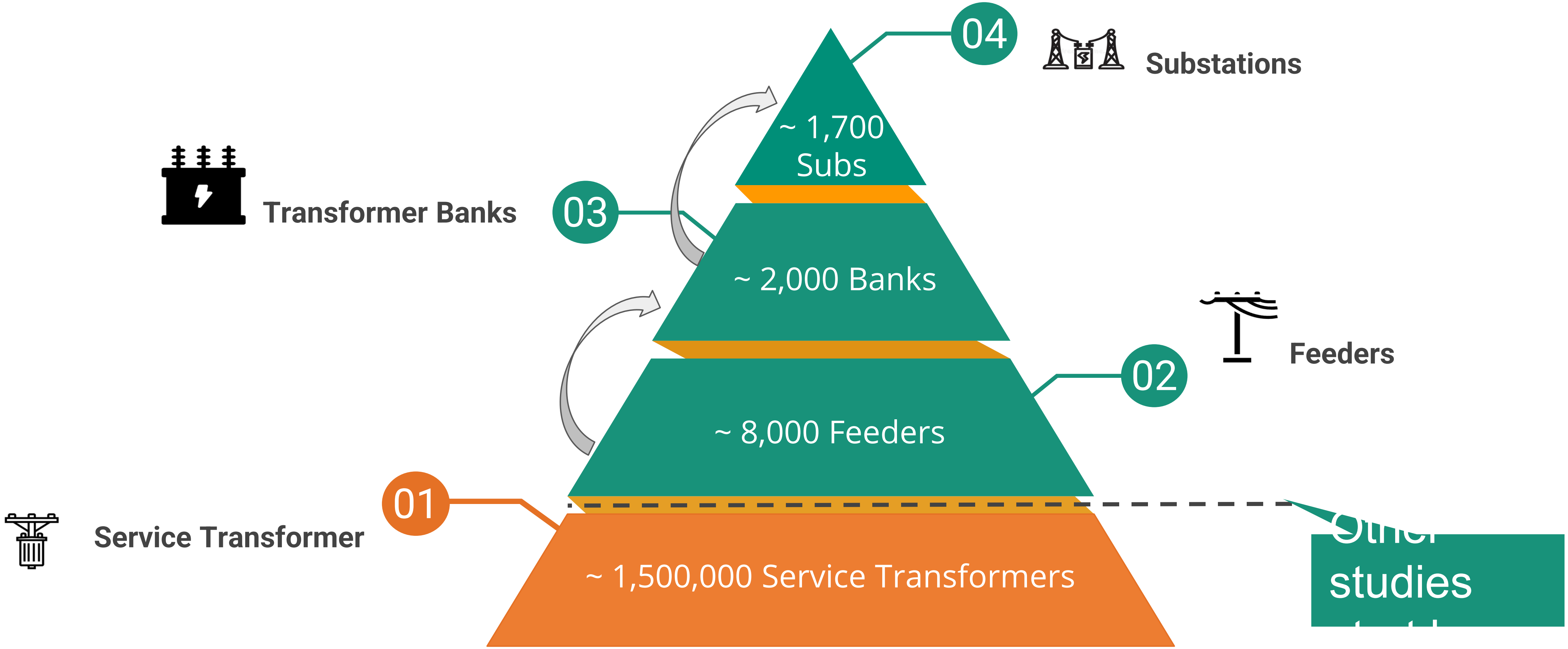
* Cost estimates are based on an assessment of thermal capacity constraints; N-1 thermal reliability was not considered in Part 1.

# Grid Assets Studied: An Overview

**Distribution substation, transformer bank, feeders, and service transformers were included in the upgrade cost analysis.**

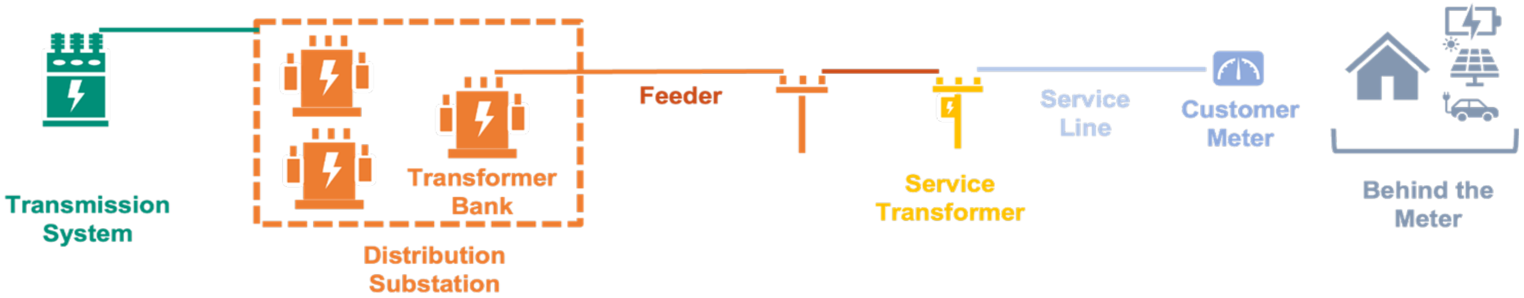


# Infrastructure Upgrade Costs Approach




Notes: The numbers in the pyramid are the number grid assets by category for the three IOUs.

# Approach on Infrastructure Upgrade Costs




**Step 1: Calculate overload at the substation level**

- If spare space in substation, build a new transformer bank
- Else, trigger a new substation upgrade

**Step 2: Calculate overload at the feeder level**

- If space in transformer bank, build new feeder(s)
- Else, if a new transformer bank or substation is built in Step 1, build a new feeder(s)
- Else, trigger a new transformer bank or substation upgrade

**Step 3: Calculate overload at the service transformer**

- If service transformers size < 100 KVA, required number of 50 KVA service transformers
- If service transformers size >100 KVA, a new service transformer that mitigates the overload is chosen

# Unit Cost Summary: IOU-Provided Data

| | Substation | Transformer Bank | Feeder |
|---|---|---|---|
| **PG&E** | $27,000,000 | $11,800,000 (45 MVA) | $6,363,200 |
| **SCE** | $39,663,589 | $2,019,011 (28 MVA) | $5,473,094 |
| **SDG&E** | $20,912,000 | $4,685,000 (28 MVA) | $6,689,760 |

- Key **differences in substation unit costs:**
  - ***PG&E:*** Based on Table 17-27 of the 2023 General Rate Case and includes land, regulatory, material, and construction costs for assets n the substation fence.
  - ***SDG&E:*** Based on the installation of four 69/12 kV transformers (each rated at 28 MVA) and four quarter section switchgear; they do not include cost estimates for other requirements and factors such as land acquisition, site development, environmental permits, T&D infrastructure, control shelter, protection equipment, and relays.
  - ***SCE:*** Based on the average cost of five historical substation projects and includes distribution substation installed equipment costs and land.
- Key **differences in feeder unit costs:**
  - ***PG&E*** included the fixed feeder breaker costs of $1.4 million and the primary conductor cost for which Kevala used the average of overhead and underground runs, resulting in $470/foot.
  - ***SDG&E*** included the per distance cost of primary trench and conduit and primary cable adding up to $601/foot.
  - ***SCE*** provided a typical cost for primary feeder by voltage class, and Kevala used the average cost; it includes all equipment and labor to construct the entire circuit, including the primary distribution line.

# Unit Cost Summary: IOU-Provided Data

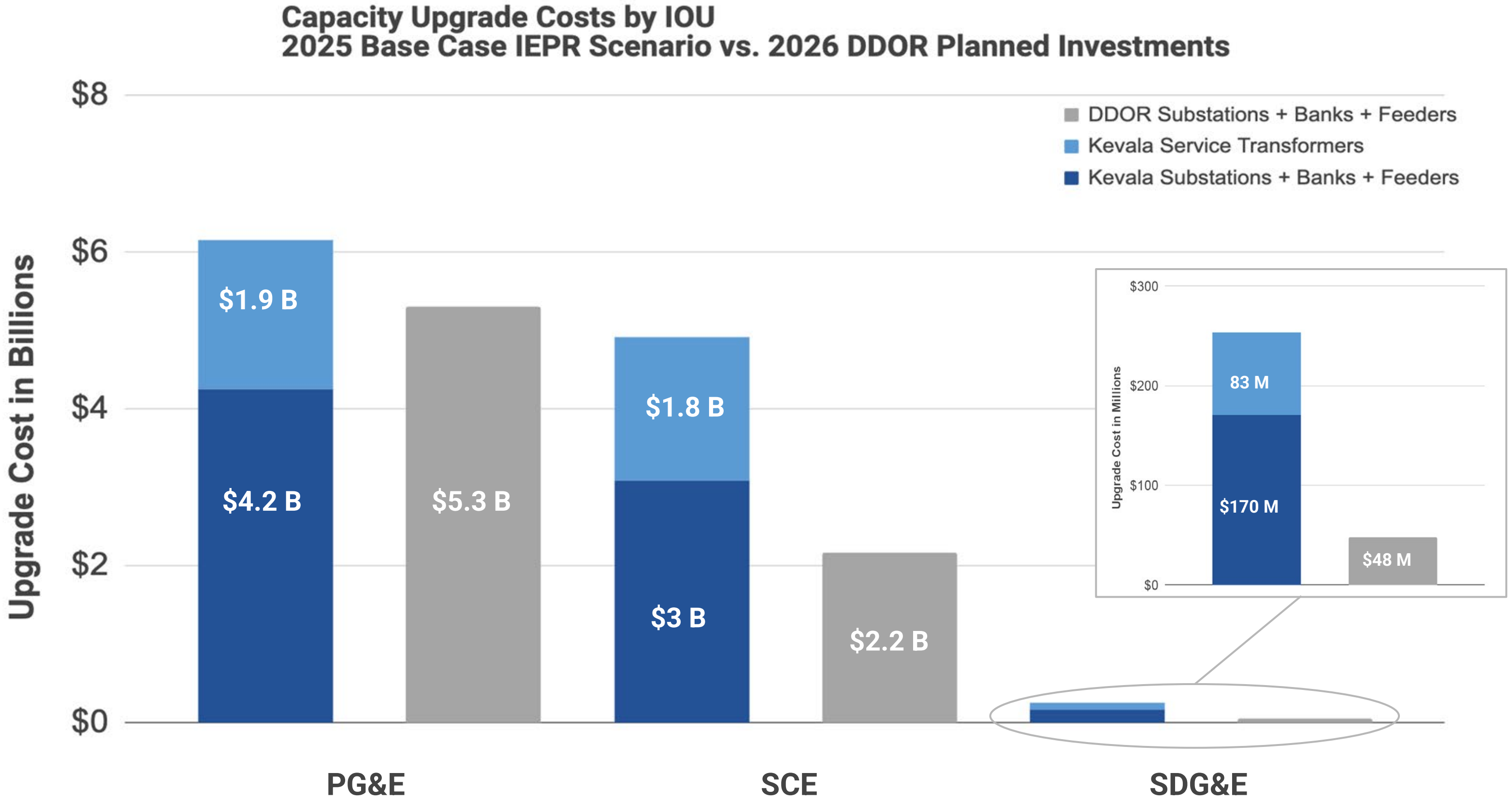
| Service Transformer Size (KVA) | PG&E | SCE | SDG&E |
|---|---|---|---|
| <150 (Residential) | $22,000 | $19,000 | $22,000 |
| 150 (C&I) | $39,000 | Not standard size | $59,700 |
| 300 (C&I) | $47,000 | $39,140 | $61,600 |
| 500 (C&I) | Not standard size | $50,470 | $67,500 |
| 750 (C&I) | $58,000 | $58,710 | $74,000 |
| 1,000 (C&I) | $72,000 | $74,160 | $126,100 |
| 1,500 (C&I) | $98,000 | $101,970 | $133,400 |
| 2,500 (C&I) | Not standard size | $193,640 | $152,100 |

# Distribution Planning Assumptions

- **Standard power transformer sizes**
  - 230/21 kV : 75 MVA
  - 230/12 kV : 45 MVA
  - 115/12 kV : 45 MVA
  - 70/12 kV : 30 MVA
  - 60/12 kV : 30 MVA
- **Max loading criteria**
  - <= 3 distribution transformers per substation
  - Nameplate rating at 100%
- **Typical number of circuits per transformer**
  - 75 MVA = 3 circuits
  - 45 MVA = 4 circuits
  - 30 MVA = 3 circuits
- **Service transformer loading criteria** *(PG&E did not provide)*
  - Residential ~150%
  - Commercial & industrial ~125%

# EIS Benchmarking – 2025 Projected Upgrade Costs Compared to the IOUs Planned Investments

- **Part 1 Study approximates the IOUs' DDOR planned investments costs for substations + banks + feeders in the *short term***
- Study shows that there are **additional costs** in replacing hundreds of thousands of **service transformers** that are currently not included in the IOUs distribution planning filings (planned investments list in the DDORs)
- *Caveat*: Part 1 analysis does not include primary line upgrades

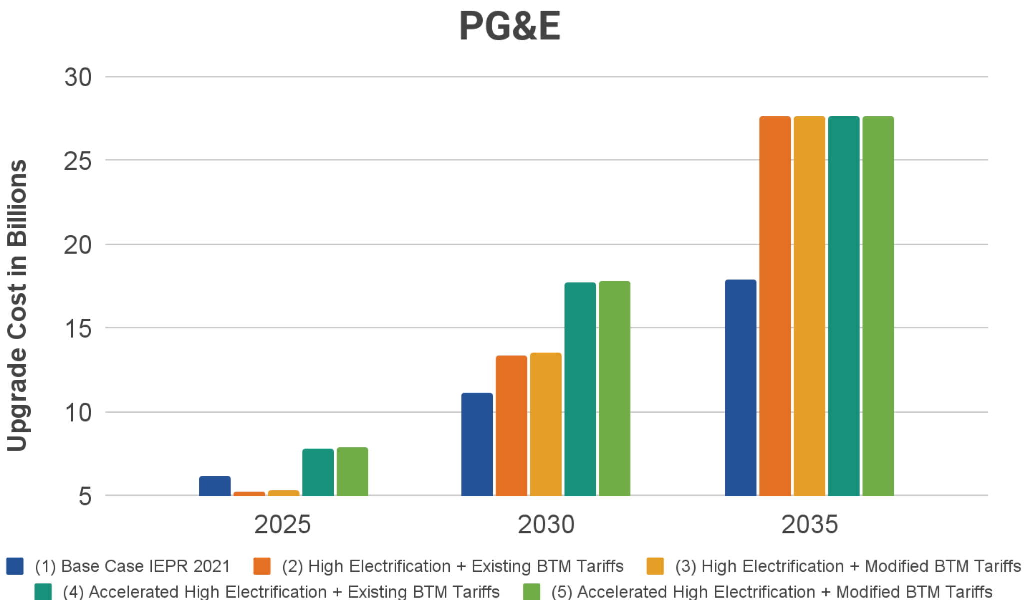


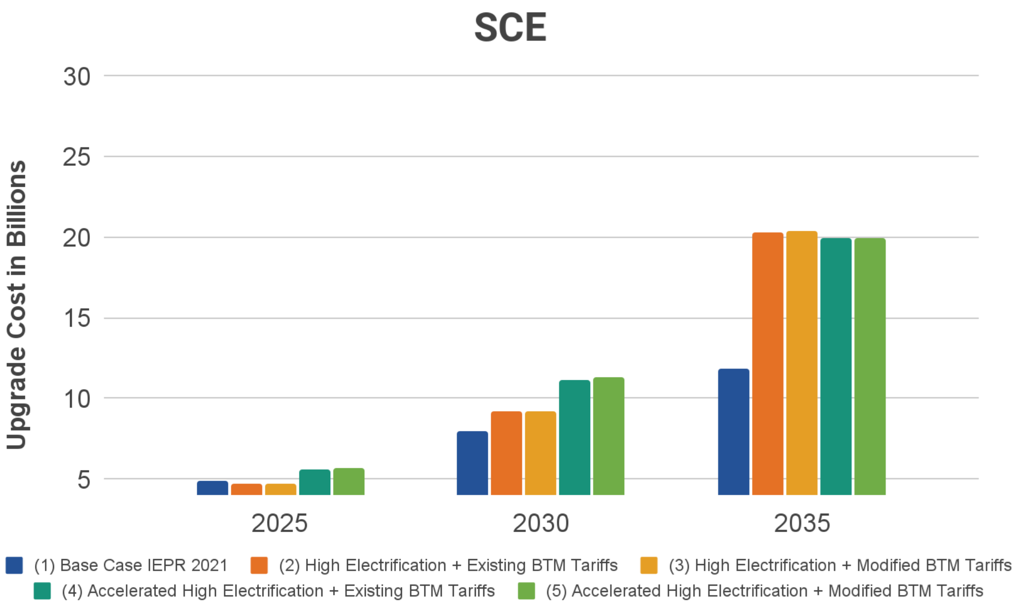

**DDOR planned investment cost totals are significantly lower than Kevala's cost data indicate.**

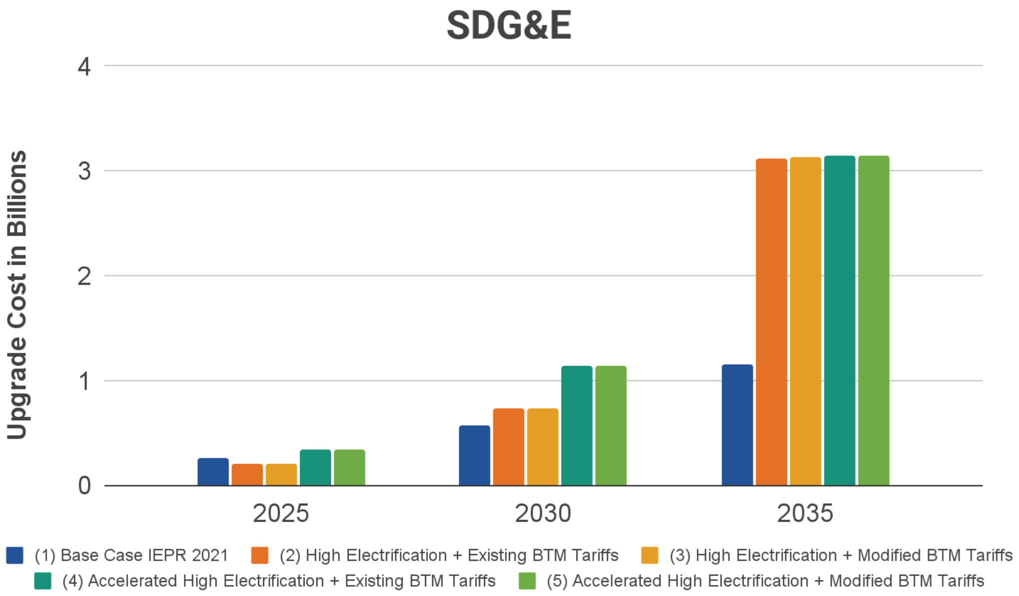
# Differences in Electrification Impacts Costs by IOU

Given the **current distribution planning process** and the **utility-provided distribution asset unit cost data**, the EIS Part 1 Study projected costs could **be up to $50 billion**.*

- PG&E's grid is more stressed in all scenarios and costs are higher.
- SDG&E's grid requires the least number of upgrades.

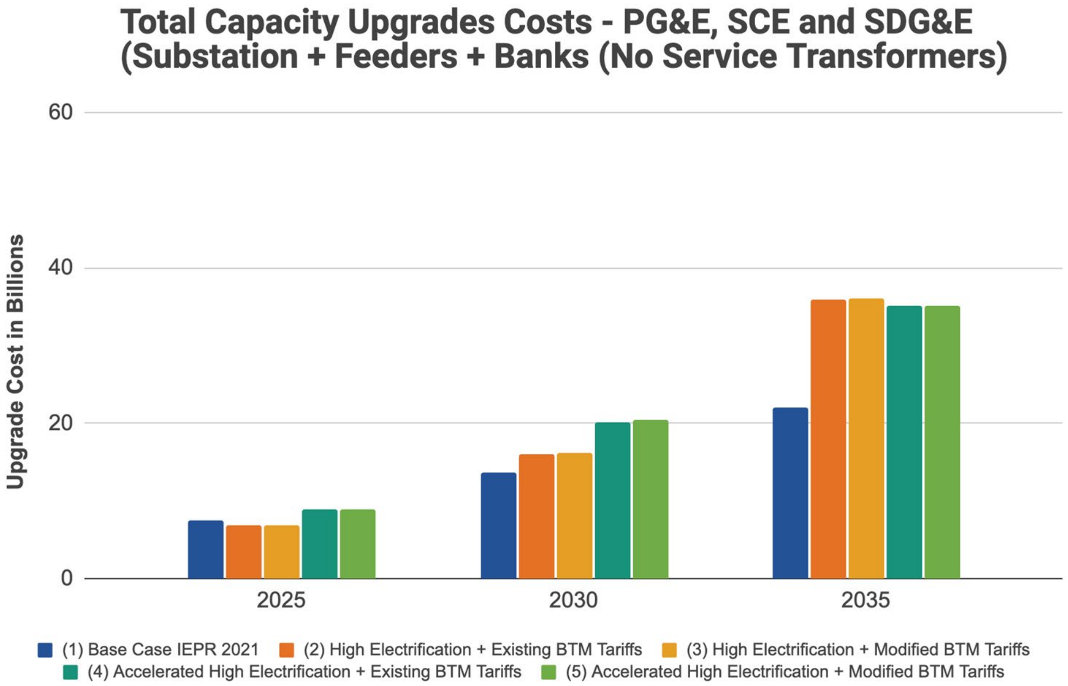


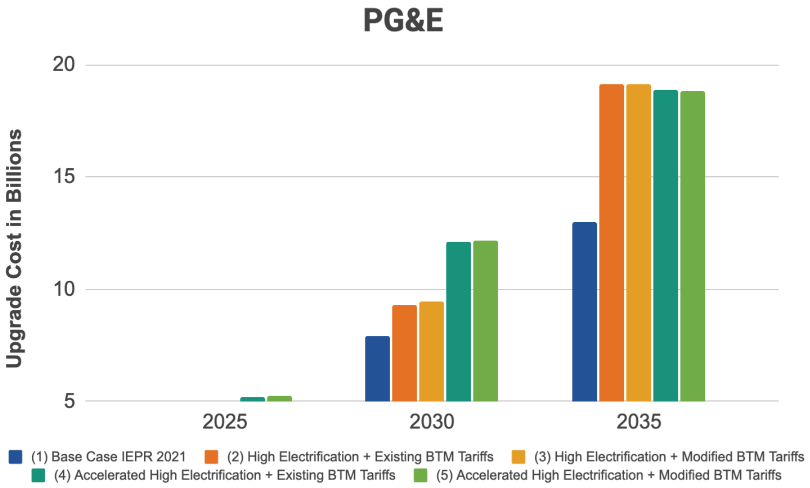



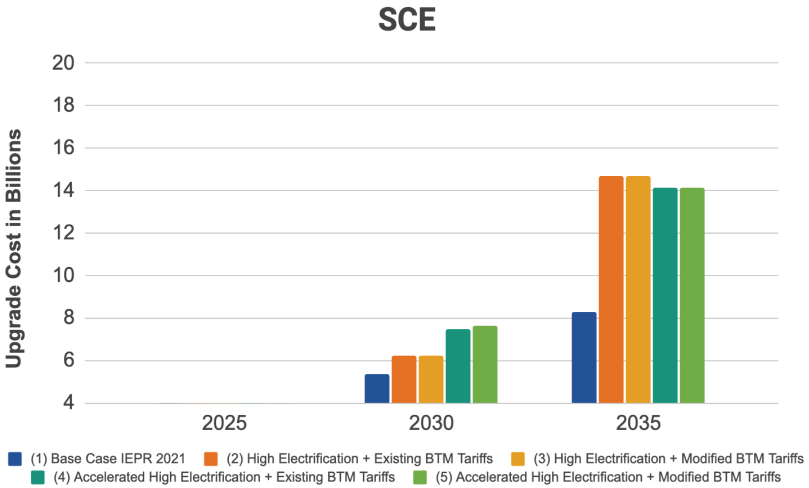



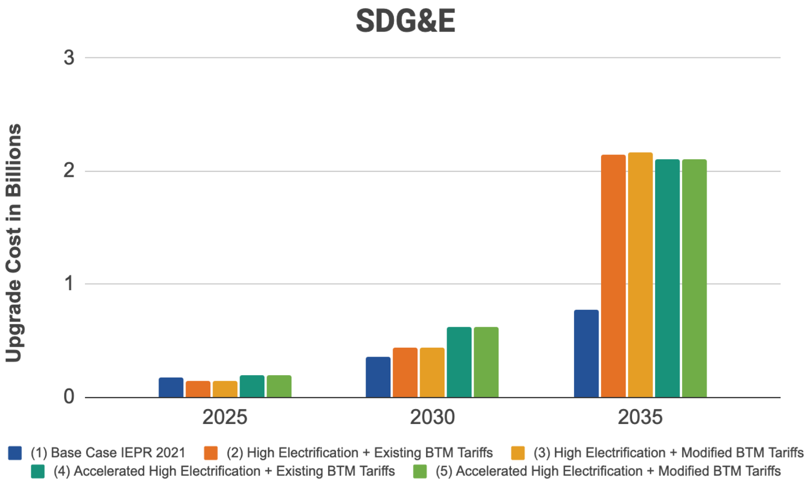

*The EIS Part 1 Study ***does not include*** **non-wires alternatives (NWAs), mitigations, or alternatives.**

# Long-Term Upgrade Costs of IEPR 2021 Base Case and Electrification Scenarios (Excluding Service Transformers)



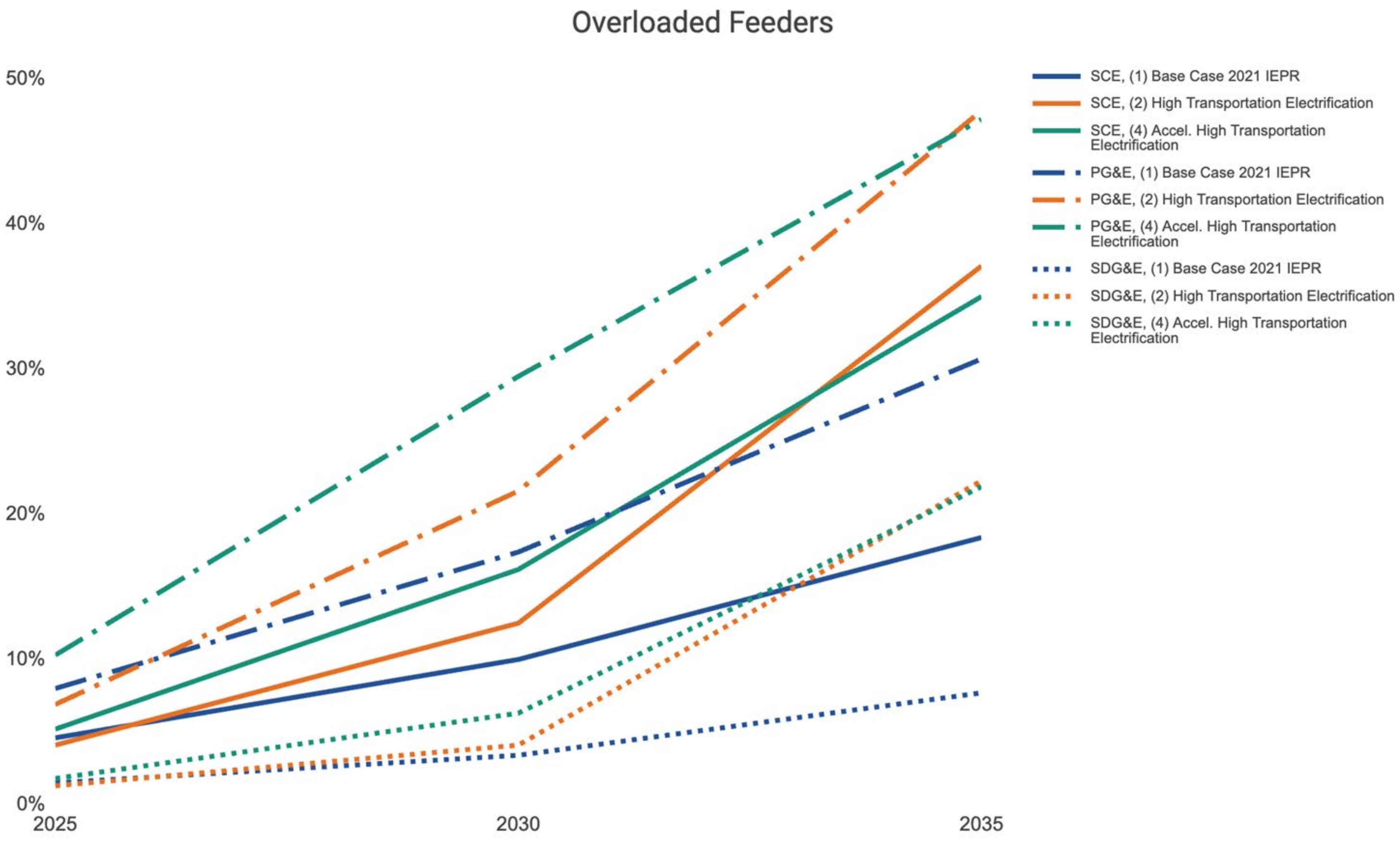



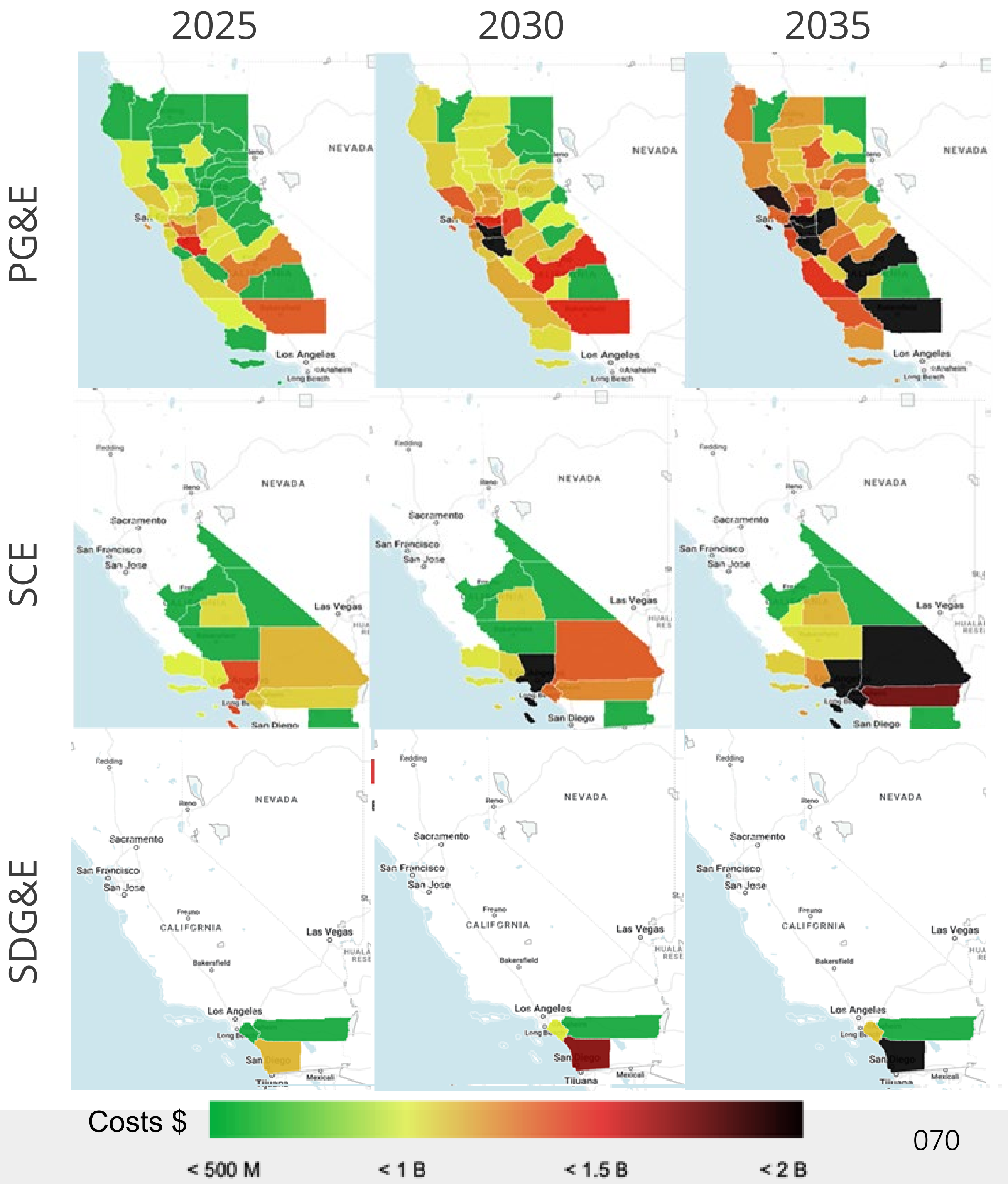
# Percent Overloaded Feeders by IOU and Scenario

- PG&E's grid is more stressed in all scenarios and costs are higher.
- SDG&E's grid requires a significantly fewer number of upgrades.



# Upgrade Costs by County

- Upgrade costs are not homogenous across counties, geographies and demographics
- This diversity illustrates the importance of looking at regional and local planning needs



# Questions

# Stakeholder Discussion on EIS Part 1

CPUC Energy Division

# Discussion

1. Comments and questions on the methodology, analysis, and findings of the Part 1 Study.

2. What are the strengths and weaknesses of the Part 1 Study in comparison to the utilities' approach to distribution planning processes?

# Comments/Questions About EIS Part 1

1. Comments and questions on the methodology, analysis, and findings of the Part 1 Study.

# EIS Part 1 Methods/Assumptions Compared to Current Utility Distribution Planning Processes

2. What are the strengths and weaknesses of the Part 1 Study in comparison to the utilities' approach to distribution planning processes?

# Lunch

# EIS Part 2 Proposal

Kevala

# EIS Part 2

**Updates and expands Part 1 EIS study to determine the customers and exploring potential mitigations to reduce costs and identify synergies with other utility operations.**

## Forecasted Net Loads

- Estimate net loads at a premise level.
- Incorporate propensity to adopt modeling of PV, batteries, EVs, and building electrification.
- Aggregate premise load to locations on the grid.
- Generate DER adoption scenarios to test a range of outcomes.

## Capacity Needs

- Identify current capacity from secondary transformers to sub-transmission feeder banks.
- Determine additional capacity needs due to forecasted net loads.
- Determine range of capacity needs based on scenarios of DER adoption.

## Aggregated Costs

- Estimate unit costs to meet capacity needs.
- Determine incremental capital investments to meet capacity needs.
- Aggregate grid asset costs up to the system level by scenario.

## Impacts & Mitigations

- Estimate revenue requirement, rate and bill impacts.
- Quantify marginal costs by location using study capital costs by asset
- Examine mitigation options using case studies

# Proposed Refinements, Scenarios, and Case Studies

- Updated assumptions and additional data
- Methodological refinements
    - Ability to improve understanding and visualization of the economic impacts of electrification across customer classes and geographies, as well as disadvantaged communities
    - Refinements to baseline load forecast methodology, BE methodologies, and EV methodologies
- Developing scenarios that:
    - Are likely to reflect the range of potential impacts on the distribution grid, and/or
    - Reflect DER programs or technologies that are more nascent or have relatively less available actual program data
- Up to five case studies—and at least one each across the PG&E, SCE, and SDG&E service territories—to develop a range of targeted case studies on localized DER adoption, grid impacts, and mitigation strategies

# Proposed Part 2 Core Elements

## Case Studies Objective

Understand the specific location and timing of future distribution grid requirements for select geographic areas (case studies) under different distributed energy resource (DER) adoption scenarios to propose changes to distribution planning that result in a robust and integrated distribution planning framework.

## Scenarios, Case Studies, and Final Report

1. **Statewide Electrification Scenarios Analysis, with added emphasis on building electrification**
   - Estimate future DER adoption and behavior under multiple electrification scenarios (electrification includes BE adoption and EV adoption)
   - Analyze granular impact of electrification on the grid
   - Update EIS Part 1 system-level cost estimates
2. **Complete Regional Case Studies** designed to identify the efficacy of and customer responsiveness to NWAs and various other potential mitigation measures
3. **Develop Electrification Grid Impacts Report** (i.e., EIS Part 2) with recommendations for future distribution planning process enhancements

# Proposed Scenarios

Proposed Scenarios are designed to create 'bookends' on possible outcomes

| Part 2 Component | Statewide Electrification Scenarios |
|---|---|
| **Statewide Electrification Scenarios Definition** | Analyze the specific location, timing, and aggregate cost of future distribution grid requirements across **all 12 million+ premises for PG&E, SCE, and SDG&E** under multiple **High Building Electrification (BE) and Updated High EV Electrification Scenarios** in 2025, 2030, and 2035. |
| **Reference Case** | All alternate scenarios are compared to a reference case that is based on the 2022 Integrated Energy Policy Report (IEPR) Local Reliability case (same as the 2024 Grid Needs Assessment (GNA)/Distribution Deferral Opportunity Report (DDOR)). |
| **Scenarios** | Eight different scenarios are designed to identify the range of electrification impacts of **different combinations of High BE and Updated High EV adoption outcome assumptions** defined by California state agencies relative to the Reference Case. |
| **"Optimal" versus Business as Usual charging profiles** | Developing "Optimal Managed Charging" Updated High EV and High BE profiles for comparison to the charging profiles assumed in the IEPR will enable Kevala to bookend the range of electrification for High BE, Updated High EV, and combinations. It also should indicate how effective TOU price signals may be for BE and EV. |

# For Example: Eight Statewide Electrification Scenarios

| Part 1 Scenarios | Proposed Part 2 Scenarios | |
|---|---|---|
| 1. Base Case 2021 IEPR (mid-mid case)<br>2. High Transportation Electrification + Existing Behind-the-Meter (BTM) Tariffs<br>3. High Transportation Electrification + Modified BTM Tariffs<br>4. Accelerated High Transportation Electrification + Existing BTM Tariffs<br>5. Accelerated High Transportation Electrification + Modified BTM Tariffs | **Reference**<br>*2022 IEPR Local Reliability (= 2024 GNA/DDOR)* | 1. Optimal managed charging profiles (best case)<br>2. IEPR/National Renewable Energy Laboratory (NREL)-based load profiles (reference case) and current TOU periods |
| | **High BE Adoption** | 3. Managed charging profiles (e.g., grid-enabled buildings)<br>4. IEPR/NREL-based load profiles and current TOU periods |
| | **High EV Adoption** | 5. Optimal managed charging profiles (e.g., charging signals optimize peak circuit capacity – does not correspond to current TOU Rate design periods)<br>6. IEPR/NREL-based load profiles |
| | **High BE + High EV Adoption** | 7. Optimal managed charging profiles<br>8. IEPR/NREL-based load profiles |

# Proposed Case Studies

| Part 2 Component | Case Studies |
|---|---|
| **Case Studies Definition** | Select up to **five regional case studies that test multiple potential mitigation measure(s) against the results of the Statewide Electrification Scenarios analysis**. The case studies aim to identify the efficacy of and customer responsiveness to various potential mitigation measures. |
| **Mitigation Measure Definition** | A **mitigation measure is a technology, program, rate design, or other non-wires alternative (NWA) solution that could mitigate the expected grid impacts and associated costs** of any given electrification scenario across different geographic, climate, and socio-economic regions. Mitigation measures analysis includes their respective associated costs in order to enable a directional understanding of the economic and service-level impacts. |
| **Example Case Study Mitigation Measures** | How would the following **mitigation measures perform in Fresno versus Oakland?**<br>• Mandatory demand response<br>• Utility battery share program<br>• Managed charging by location for medium-duty vehicles (MDVs) or heavy-duty vehicles (HDVs) |

# Possible Case Study Locations and Design

## Up to five locations designed to reflect diverse geographies, climates, demographics (e.g., rural/urban) and socioeconomic factors, for example:

1. City of Fresno
2. City of Oakland
3. Port of Long Beach
4. North Coast
5. City or County of San Diego

## Mitigation measures designed to assess the impact of regionally appropriate load mitigation and management approaches, for example:

- Mandatory demand response
- Utility battery share program
- Targeted additional rooftop solar (battery paired)
    - For Fresno and Oakland: Both residential and commercial and industrial (C&I)
    - Include option for utility financed and owned on customer premises, particularly in disadvantaged communities
- Active managed charging for MDVs/HDVs
    - Price signal driven
    - Controls designed to optimize IOU distribution operations (VGI)

# Questions

# 10 Minute Break

# Stakeholder Discussion on EIS Part 2

CPUC Energy Division

# Discussion Questions

1. How should the approach and information used in the Part 1 Study be updated for developing and improving the methodology, analysis, and scenarios for the Part 2 Study?
2. The Part 1 Study proposes developing scenarios focused on building electrification and electric vehicle adoption for the Part 2 Study.
   - What other scenarios, if any, should the Part 2 study consider?
   - How should the study design these scenarios?
3. The Part 1 Study proposes developing case studies for specific grid locations in Part 2.
   - How should Part 2 case studies be identified to support building a location-specific distribution planning framework?
   - How should these case studies be designed?
4. What additional topics should be considered in developing the scope for the Part 2 Study?

# Part 1 Versus Part 2 Approach

1. How should the approach and information used in the Part 1 Study be updated for developing and improving the methodology, analysis, and scenarios for the Part 2 Study?

# Part 2 Scenarios

2. The Part 1 Study proposes developing scenarios focused on building electrification and electric vehicle adoption for the Part 2 Study.
    - What other scenarios, if any, should the Part 2 study consider?
    - How should the scenarios be designed for Part 2?

# Part 2 Case Studies

3. The Part 1 Study proposes developing case studies for specific grid locations in Part 2.
    - How should Part 2 case studies be identified to support building a location-specific distribution planning framework?
    - How should these case studies be designed?

# Part 2 Additional Topics to Cover

4. What additional topics should be considered in developing the scope for the Part 2 Study?

# Next Steps and Closing Remarks

CPUC Energy Division

# Track 1, Phase 1 Activities 2023/2024

**March 9, 2023, Ruling** (Utilities Existing Distribution Planning Processes)

- April 10, 2023: Utilities filed responses to questions on their distribution planning processes and preparedness for electrification loads.

**April 6, 2023, Ruling** (Proposed Improvements to Distribution Planning Processes)

- May 22, 2023: Opening comments are due.

**May 9, 2023, Ruling**

- Entered EIS Part 1 and the EIS Research Plan into proceeding record.
- Requested comments on EIS Part 1 and proposed plans for EIS Part 2 (due in June)

**Upcoming Activities**

- Staff Proposal Development – Near Term Distribution Planning Improvements
- Staff Proposal Issuance (by Ruling)
- Staff Proposal Workshop
- Party Comments
- Proposed Decision

# Staff Proposal (Track 1, Phase 1)

The Energy Division will prepare a Staff Proposal that, based on party feedback, may consider, among other things:

- Integrating **longer planning horizons** and **multiple demand scenarios** into utility distribution planning to ensure grid preparedness for electrification loads
- Proposing cost recovery mechanisms for electrification-related investments and addressing **near-term capacity constraints** impacting electrification progress
- **Improving alignment of annual utility distribution planning process with quadrennial General Rate Cases** and the CEC IEPR Forecast
- Improving utility data management and database systems integration
- Applying advanced analytics to utility distribution planning
- Updating **Integration Capacity Analysis data** and data portals
- Alignment with Energy Division's pending Freight Infrastructure Planning proposal (workshop on 5/22/2023)
- Enhancing utility local planning engagement

# Next Steps

- May 22, 2023: Party comments due on distribution planning process preparedness for electrification loads (April 6, 2023, Ruling)
- May 22, 2023 (2pm to 5pm): Freight Infrastructure Planning workshop
- June 9, 2023 (Utilities), and June 19, 2023 (All Parties): Comments due on EIS Part 1 and proposed plans for EIS Part 2 (May 9, 2023, Ruling)
  - June 26, 2023: Reply comments due

# Thank You!

# Contact Information

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# Additional Slides

# DER Action Plan

**Track 2: Grid Infrastructure**
The Infrastructure Track is focused on CPUC actions to guide utility infrastructure planning and operations to maximize the value of DERs interconnected to the electric grid.

**Vision Element 2D**
Utilities integrate the anticipated impacts of electrification into distribution planning to maximize public benefits and minimize costs and to optimize deployment of complimentary and supporting infrastructure and distributed energy resources.

**Action Element 1**
By 2023, CPUC staff completes a comprehensive, data-driven electrification impacts study to estimate the scope of distribution grid buildout and identify opportunities to mitigate costs.

EIS Part 1 is responsive to Action Element 1.

The full DER Action Plan is available here.