The Public ADVOCATES OFFICE

The Public Advocates Office's Distribution Grid Electrification Model (DGEM) Results

Distribution Planning and Policy

August 2023

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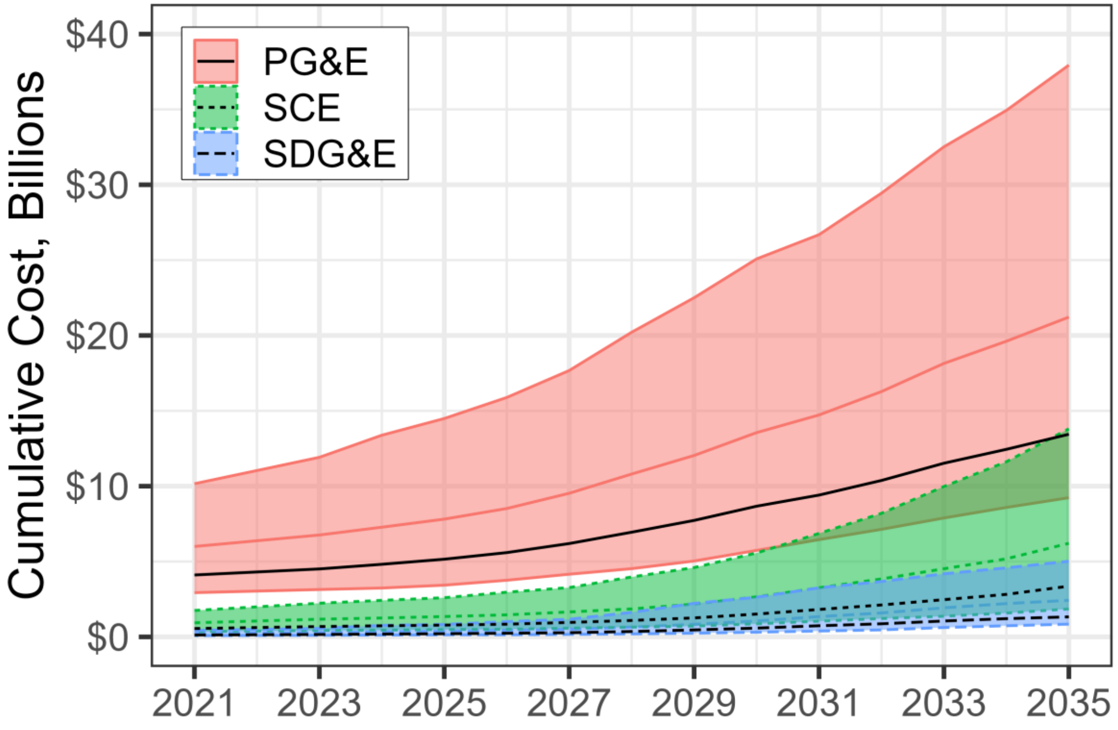
Introduction

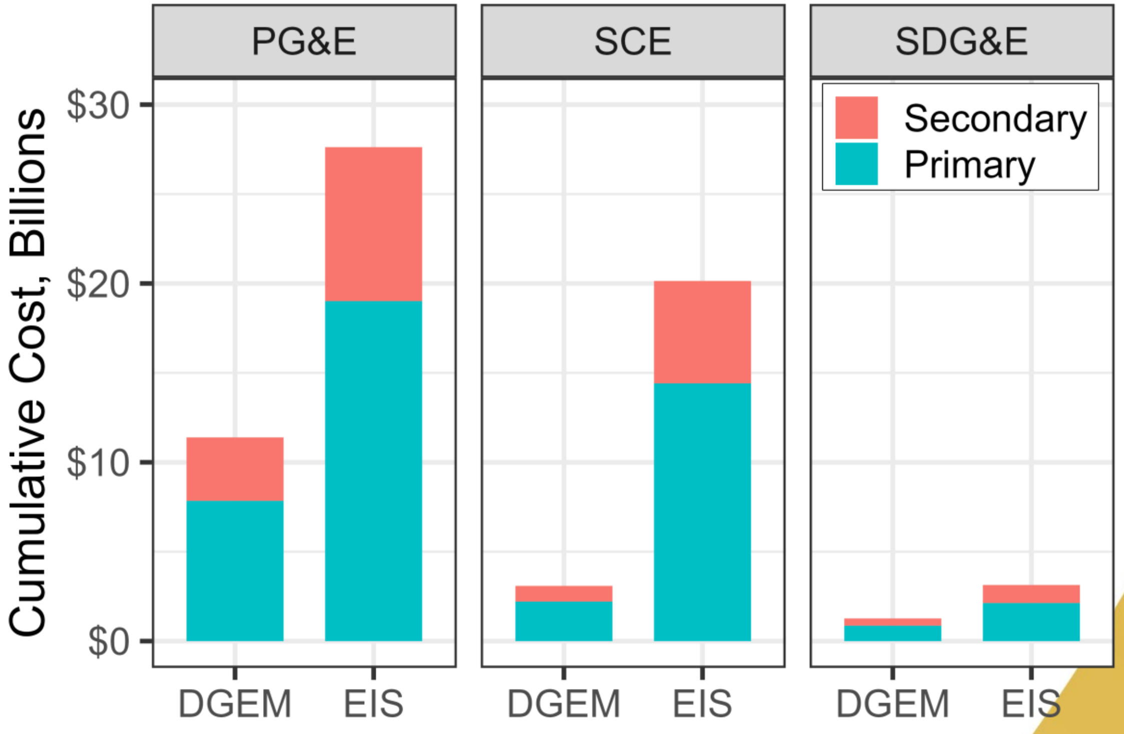
- The Public Advocates Office at the California Public Utilities Commission has developed a model of electrification load growth of similar purpose and scope to the *Electrification Impacts Study Part 1* (EIS) developed by the California Public Utilities Commission's consultant, Kevala.[1]
- Our model disaggregates forecasted transportation and non-transportation load growth estimates through 2035 to feeders, adds this load growth to baseline feeder loads provided by the Utilities,[2] and then calculates where upgrades are needed on feeders and substations and the cost and rate impacts.
- Our research has four primary objectives:
  1. Understand the distribution infrastructure cost and residential rate impact of electrification.
  2. Identify the key drivers of the cost and residential rate impacts and the key uncertainties.
  3. Compare the pace at which the utilities will need to upgrade primary distribution assets to support electrification to their recent upgrade paces.
  4. Understand the potential for mitigation strategies to reduce the cost and rate impacts (e.g., shifting EV charging to outside of peak load hours).
- We provide results for items 1 - 3 and a first-order result for item 4; we plan to more fully address item 4 in a subsequent study.

[1] Docketed at: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=509105421.
[2] Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE).

Total cost of distribution upgrades

- We estimate the cost to upgrade the distribution grids of the three Utilities through 2035 to be:
  - **$26 billion** (this figure and all other costs and rates are in present-day dollars).
- Due to study uncertainties, the total cost could be as low as $8 billion or as high as $57 billion.
- If we use the same infrastructure unit costs as the EIS (right plot and black lines in left plot), we calculate a total cost of $16 billion compared to $51 billion in the EIS (discussed later).



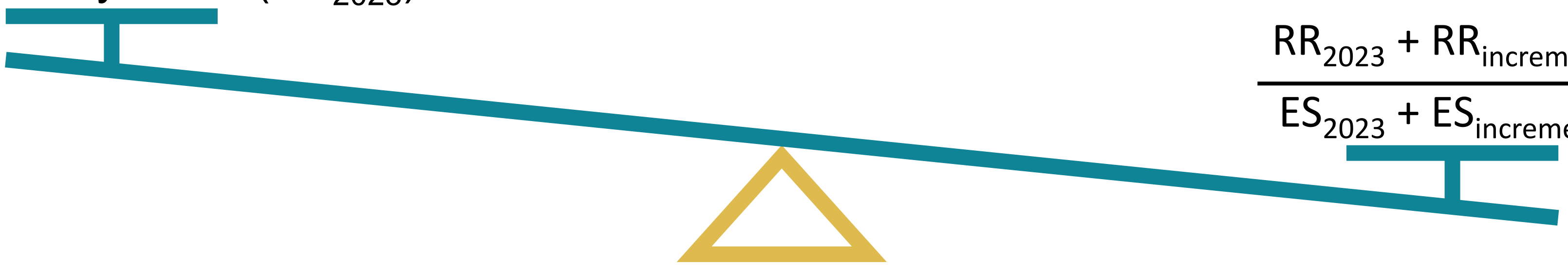


Primary distribution infrastructure consists mainly of substations and feeders. Secondary distribution infrastructure consists mainly of service transformers.

Residential rate impact

- We calculated average rates by dividing the residential revenue requirement by residential sales. We compared 2023 rates to hypothetical rates with electrification.

$$\frac{\text{2023 revenue requirement } (RR_{2023})}{\text{2023 electricity sales } (ES_{2023})}$$



$$\frac{RR_{2023} + RR_{incremental}}{ES_{2023} + ES_{incremental}}$$

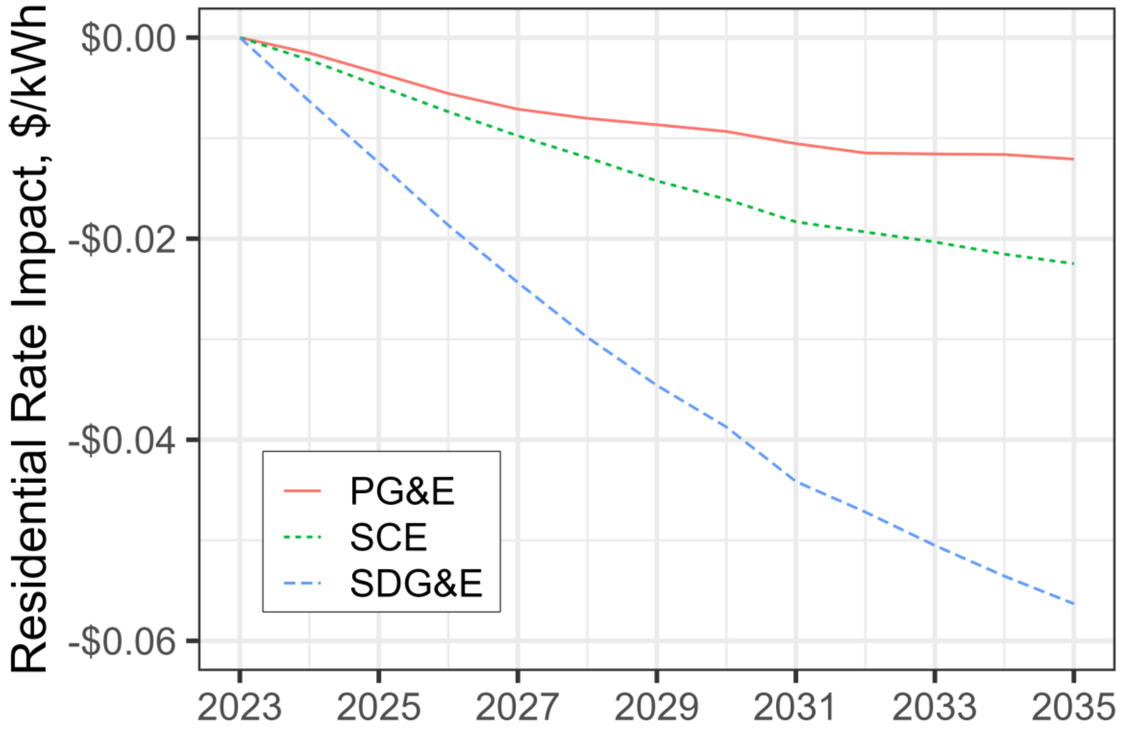
- Incremental revenue requirement includes:
  - Distribution capital depreciation (2.5%) and return on capital (7 - 8%).
  - Distribution O&M (estimated at 3.5% of undepreciated capital).
  - Transmission cost (from forecasted Transmission Access Charges).
  - Generation cost (from avoided cost calculator, excluding transmission and distribution costs).

Residential rate impact

- We predict that electrification will result in downward pressure on residential rates for each Utility.
  - Upward pressure on rates due to infrastructure investment is more than offset by downward pressure on rates due to the increased consumption of electricity resulting from electrification.
  - All ratepayers, even those who do not electrify, could financially benefit from electrification.
- Downward pressure on rates is not the same as decreasing rates; rates may still increase in net due to other costs.
- Achieving this downward pressure on residential electricity rates is contingent upon five key model assumptions; downward pressure on residential rates might not be achieved if:
  1. Electric vehicles (EVs) mostly charge in the evening, near peak hours.
  2. Electric rates are used to fund additional EV-related programs (e.g., deploying EV chargers).
  3. New feeders and substations are more expensive than our central estimate assumes.
  4. Expected load growth due to electrification does not occur.
  5. Utilities build more infrastructure than is needed or build infrastructure in the wrong locations.

Residential rate impact

- We predict that electrification will result in downward pressure on residential rates for each Utility.
- All scenarios show downward pressure for SDG&E and SCE; most show downward pressure for PG&E.



2035 residential rate impact ($/kWh) compared to 2023 rates

IOU	High cost	Central	Low cost
PG&E	$0.013	-$0.012	-$0.028
SCE	-$0.006	-$0.022	-$0.030
SDG&E	-$0.026	-$0.056	-$0.069

Core message on rates

1) The total cost of distribution grid upgrades through 2035 will be $26 billion (under our modeling assumptions).

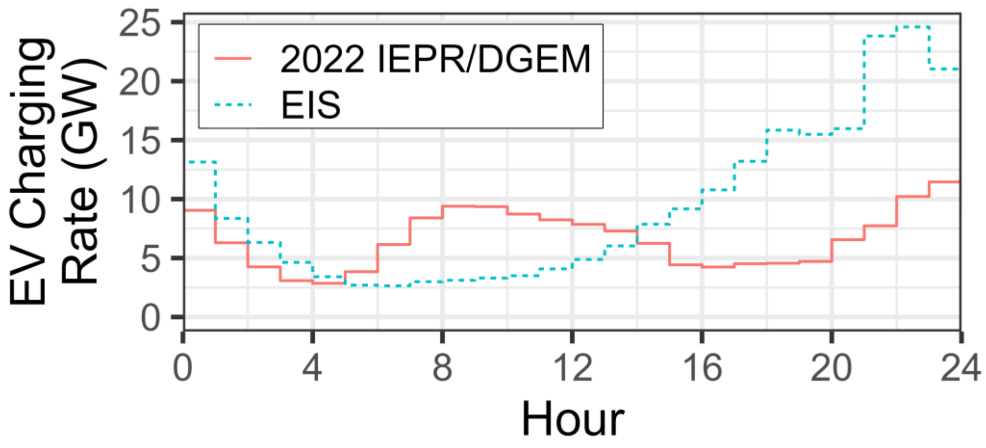
2) Electrification causes downward pressure on rates (under our modeling assumptions) when considering the increased volume of energy sales.

3) There is a potential for upward pressure instead, if infrastructure is overbuilt relative to actual future load.

4) Distribution planning should be flexible, adaptable, and incremental so that investment plans can be reshaped if load does not appear. This can reduce the risk of upward rate pressure.

Value of load management

- Load management includes any strategy to adjust the time at which load occurs. Time-of-use rates are a prominent form of load management.
- We developed a “Replicate” scenario, which uses infrastructure unit costs duplicated from the EIS.
- The primary difference between the EIS and the DGEM Replicate scenario is that the EIS forecasts that EVs charge nearer to peak demand hours than does the DGEM.
  - The difference between the two study results is our estimate of the value of load management.



2035 cost, DGEM, Replicate	**2035 cost, EIS Part 1**	**Approximate savings**
$16 billion	$51 billion	$35 billion

- Approximately two thirds of the costs in the EIS are eliminated with reduced near-peak charging.
- We plan to further explore how load management can reduce the necessary infrastructure investment associated with electrification in a future study.

IEPR: The Integrated Energy Policy Report published by the California Energy Commission

Primary distribution upgrade pace

- Our modeled required pace of primary distribution upgrades is generally close to the past planned pace of upgrades; SDG&E's forecasted pace of upgrades most greatly exceeds its past planned pace of upgrades.
- Main caveats:
  - Planned investments receive more scrutiny than our forecasted upgrades. Utilities will consider alternatives like load transfers before planning an upgrade.
  - We did not consider the scope of upgrades; future feeder or substation upgrades may tend to be larger than past upgrades.

Facility Type	IOU	Forecasted Annual Upgrades		Historic Planned Investments*		
		2023 – 2035	2030 – 2035	2020	2021	2022
Feeders	PG&E	46	58	18 - 68	21 - 49	40 - 90
Feeders	SCE	19	32	22 - 49	15 - 36	15 - 56
Feeders	SDG&E	7	12	2 - 7	4 - 15	1 - 10
Substations	PG&E	10	13	1	4	13
Substations	SCE	5	7	9	6	8
Substations	SDG&E	2	2	1	0	0

*For feeders, the low value includes only new feeders; the high value includes all feeder projects (e.g., reconductoring).

Key takeaways

1. Electrification will require $26 billion in distribution infrastructure through 2035 without additional mitigations.
2. Increased energy sales due to electrification could put downward pressure on residential rates despite additional infrastructure investment.
3. We estimate a significantly lower distribution investment cost than the EIS's preliminary estimate of $51 billion.
4. Reducing charging during peak load hours could avoid $35 billion or more in distribution investments.
5. The present planned pace of primary distribution upgrades is nearly sufficient for future grid needs.
6. Better data can improve study accuracy.

Appendix

Study comparison

- There are many differences between the DGEM and the EIS.
- The EIS's results show that non-EV assumptions have little impact on upgrades.
- Our analysis (see next slide) shows that charging load shape explains most of the difference between the upgrades identified in the DGEM and the EIS.

Model parameter	DGEM	EIS	Impact
PV/BE/EE/BESS Forecasts	From 2022 IEPR (planning) hourly load growth profiles	From 2021 IEPR (mid-mid) deployment forecasts	Low
EV forecasts (2035, IOU area)	11,700,000 LD 300,000 MD+HD	10,000,000 / 9,500,000 LD 220,000 / 230,000 MD+HD	Medium
EV forecast source	2022 IEPR (planning)	CARB / 2021 IEPR (high/bookend)	Medium
Charging pattern	2022 IEPR (planning)	Modeled from non-EV TOU rates	High
Public charging	Not included	Included	Low
Baseline load data	Feeder level	Premises level	Low

BE = building electrification
BESS = battery energy storage system
CARB = California Air Resources Board
DER = distributed energy resource

EE = energy efficiency
IEPR = Integrated Energy Policy Report
LD = light-duty
MD+HD = medium duty + heavy duty

PV = photovoltaic
TOU = time-of-use

Charging profile comparison

- The EIS model forecasts much more afternoon and evening (4 pm to 11 pm) EV charging than the load forecasts presented in the California Energy Commission's 2022 IEPR.
- Furthermore, the EIS predicts 43% more peak day charging energy than the 2022 IEPR.
- Greater evening charging predicted by the EIS (from different time of charging and more total charging energy) drives significantly higher peak load growth estimates than the IEPR predicts.
- The DGEM's load growth forecast aligns more closely with the IEPR than does the EIS.