Distribution Grid Electrification Model

Supplemental Study on Electric Vehicle Charging Location and Potential Cost Impacts

Our mission is to advocate for the lowest possible bills for customers of California's regulated utilities consistent with safety, reliability, and the state's climate goals.

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1 Executive Summary

The Public Advocates Office has undertaken a study on the impact of electric vehicle (EV) charging locations on distribution grid upgrade costs. The study comprises two approaches. One approach examines hypothetical locations of EV charging stations along Highway Interstate 5 (I-5) and another approach examines a state-wide study of the location of EV chargers. Both approaches evaluate load and cost impacts on the distribution grid. This study is a follow up to our earlier study, the 2023 Distribution Grid Electrification Model (DGEM),[1] which quantifies the impact of transportation electrification (TE) in California on distribution grid upgrade costs and electric rates.

For the first study approach we select three case studies. Each case study examines where EV charging stations may be located in an area along the I-5 corridor and the impact the charging stations may have on the distribution grid. For each case and for different EV charging station sizes, we calculate and compare the estimated costs to connect the EV charging station at different feeders in an area along I-5. This methodology allows us to determine the benefit that results from relatively small differences in the location of a charging station. For the second study approach, we use data from our DGEM study to compare the total available capacity on a state-wide basis of California's distribution grid. The total available capacity is then compared with the expected EV load if EVs charge only at ideal locations with available feeder and substation capacity.

From the first approach, we find that (1) charging stations may only need to adjust their location a short distance to minimize costs, (2) site selection impacts the cost of distribution upgrades triggered by a direct current fast charger (DCFC), and (3) the optimal site for charging stations sometimes depends on the scale of the proposed facility. The overall conclusion from the first approach is that coordination between developers and investor-owned utilities (IOUs)[2] can reduce costs to ratepayers by allowing developers to take advantage of feeders that already have available capacity to support an EV charging station.

From the second approach, we find that (1) California has a significant amount of available distribution grid capacity to accommodate EV charging if the location is optimized, and (2) California's available capacity for EV charging is dependent on the time that EVs charge. There are several constraints, however, that can limit the potential for strategically placing and timing EV charging to reduce grid investments. Primarily, not all EV charging stations will have the

[1] Public Advocates Office, *Distribution Grid Electrification Model – Study and Report*, June 2023 (DGEM). Available at: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-findings.

[2] Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE).

flexibility as to location, and not all EVs have flexibility as to charging time, in order to work optimally with the distribution grid. Additionally, there are constraints on generation and transmission level infrastructure, as well as secondary voltage infrastructure, apart from the primary distribution grid,[3] that may need additional investment due to EV growth. However, the charging capability of many EVs provides the potential flexibility and adaptability needed to optimize the capacity of the current distribution grid.

California should leverage and maximize the spatial and temporal flexibility of EV charging to use available capacity on the distribution system to the extent practical before building new capacity and ensure that planning is aligned with both existing transmission and generation capacity. This would reduce the need for grid upgrades to support transportation electrification and therefore minimize the cost burden on ratepayers.

2 Introduction

The Public Advocates Office's 2023 DGEM studied "the cost of upgrading California's three large electric IOUs' distribution grids to meet California's electrification goals."[4] The DGEM calculates the costs of grid upgrades and electric rate impacts for California's IOU customers,[5] and quantifies the impacts of factors such as EV charging load shape,[6] EV charging location, and infrastructure unit costs[7] on distribution grid upgrade costs.[8]

The Public Advocates Office issued a supplemental DGEM in March 2024, which refines the analysis of the impacts of EV charging load shape on distribution grid upgrade costs.[9] This report, the *Supplemental Study on Charging Location*, reviews the impact of EV charging location on distribution grid upgrade costs. This report studies the amount of money that could be saved by optimizing the locations of charging infrastructure, in particular by placing charging stations where there is grid capacity. We present three detailed case studies, and one less-detailed statewide study, to explore this issue.

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[3] Examples of secondary voltage infrastructure are service transformers, service drops, and networked secondary systems.

[4] DGEM at ES-2.

[5] DGEM at ES-2.

[6] DGEM at 34.

[7] DGEM at 38-40.

[8] This report is a companion report to the DGEM. As such, it does not include a comprehensive discussion of the methods applied in our DGEM analysis. Nor does it include a detailed background information. The reader should refer to the DGEM report for such information as needed. This report limits its discussion to the methods used to analyze the impact of EV charging location on distribution upgrade costs.

[9] Public Advocates Office, *Distribution Grid Electrification Model – Supplemental Analysis*, March 2024. Available at: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-findings.

2.1 Overview of methodology

The overall goal of the analysis within this report is to quantify the potential cost savings of locating charging stations, in consideration of available grid capacity. Calculating the sensitivity of cost to locations of EV charging stations is challenging for two reasons: (1) forecasting the locations of EV adoption is challenging and (2) the DGEM did not specifically model public charging locations.[10] Our analysis of the sensitivity of cost to locations of vehicle charging in this study comprises two approaches:

1. We analyze a sensitivity case study of infrastructure upgrade cost to charging location along three ten-to-fifteen mile stretches of Highway Interstate-5 (I-5) (the main north-south highway in the Pacific Northwest, and thus a key EV charging corridor in California). This approach is described in Section 2 of this report.
2. We perform a statewide calculation of how many vehicles the distribution grid of the three large IOUs can support if vehicles charge only at ideal locations.[11] This approach is described in Section 3 of this report.

The primary limitation of the second approach is that it does not thoroughly consider feasibility. The second approach only lightly touches on the question of "how feasible *is* it to move all charging to ideal locations?" The first approach is limited in its breadth: only one charging scenario is considered (corridor charging), and only at three locations. The first approach is more feasible because moving charging locations 10 to 15 miles along a highway would have little impact on drivers (though this study does not consider traffic patterns or feasibility of land procurement).

We could have used data from the IOUs' integration capacity analysis (ICA) maps for the first approach, rather than data from the DGEM. We chose to rely on the latter because these data are uniquely available to us. However, because ICA data were readily available, we took the opportunity to compare the DGEM result to the ICA result. Alignment between the two results can validate both the DGEM and the ICA maps because the methods and data sources are distinct. This comparison is made in Appendix A.

2.2 Scope of this analysis

When discussing distribution grid upgrade needs, this study analyzes distribution substations, substation transformer banks, and distribution feeders (unlike the DGEM, which analyzes service transformers). Figure 1 illustrates this infrastructure in the context of the distribution grid.

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[10] DGEM at 39-40 (Section 4.3).

[11] The ideal location considers only distribution feeder and substation capacity.

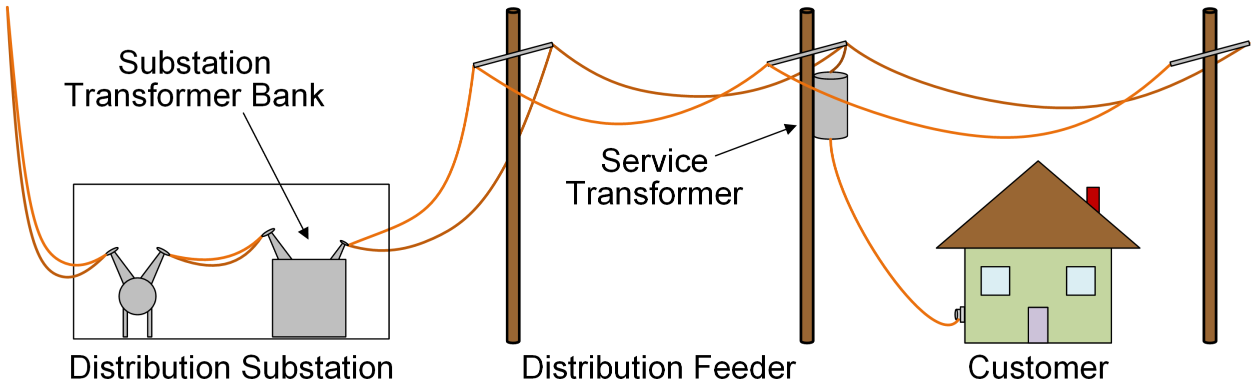

Figure 1. Distribution grid hardware.

3 First approach

The first approach includes three case studies of sites along I-5. Two sites are in PG&E's service territory, and one site is in SCE's service territory.

3.1 Case study locations

3.1.1 Case study one: Between Willows and Orland

The first case study is in the far-northern part of PG&E's service territory, along a sixteen-mile stretch of I-5 between Willows, California, and Orland, California. This area has a significant number of distribution grid sections that cross I-5, including four distribution feeders, each fed by a different substation. Figure 2 depicts this area, its distribution feeders and substations.

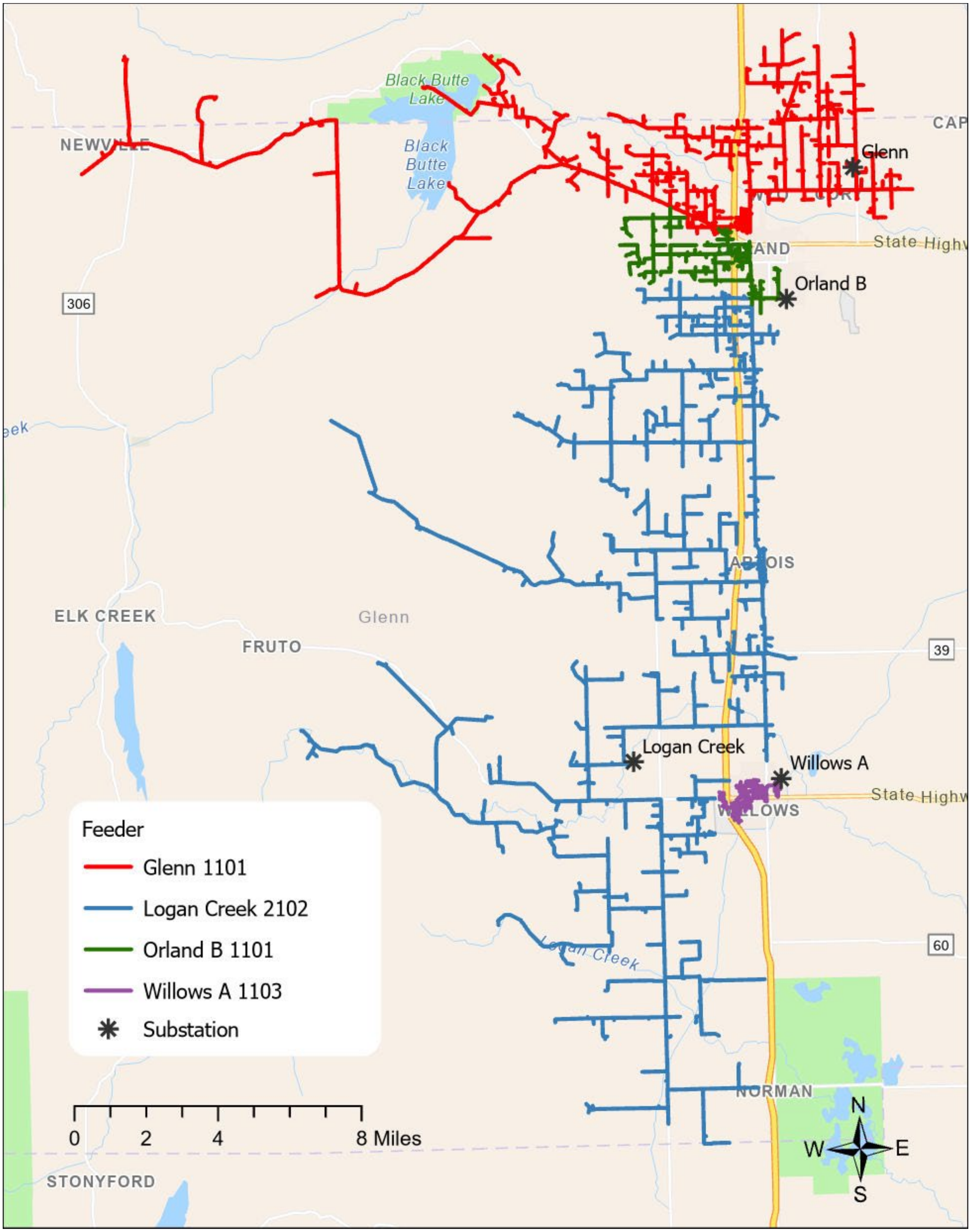

Figure 2. Case study one. Distribution grid along I-5 between Willows and Orland, California. I-5 is the yellow-colored line going in the north - south direction.

3.1.2 Case study two: From north of Wheeler Ridge to Orland

Case study two considers a thirteen-mile stretch of I-5 at the southern end of PG&E's service territory, from Wheeler Ridge south through Lebec. Figure 3 shows this area, which is crossed by only two distribution feeders, each fed by a different substation.

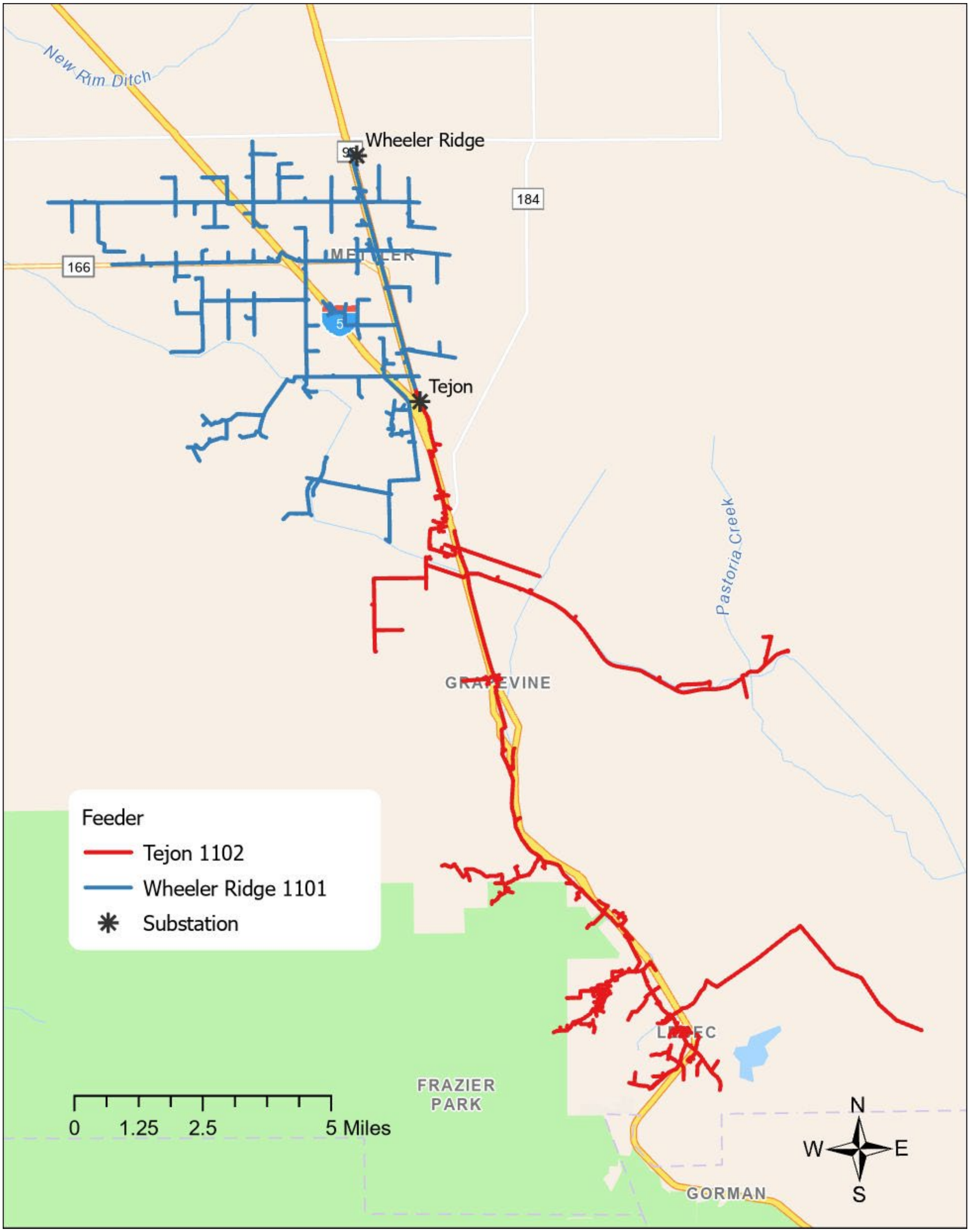

Figure 3. Case study two. Distribution grid along I-5 between Wheeler Ridge and Lebec, California. I-5 is the yellow-colored line going in the north - south direction.

3.1.3 Case study three: Santa Clarita

Case study three includes a 9.5-mile stretch of I-5 north of Los Angeles, and alongside Santa Clarita. This stretch runs from I-5's intersection with Highway 126 (at the northern end) to its intersection with Highway 14 (at the southern end). Figure 3 shows this stretch of I-5 and its nearby ten distribution feeders, which are fed by a total of four substations. Unlike in PG&E service territory, these feeders cross the interstate less often, but each run nearby the interstate.

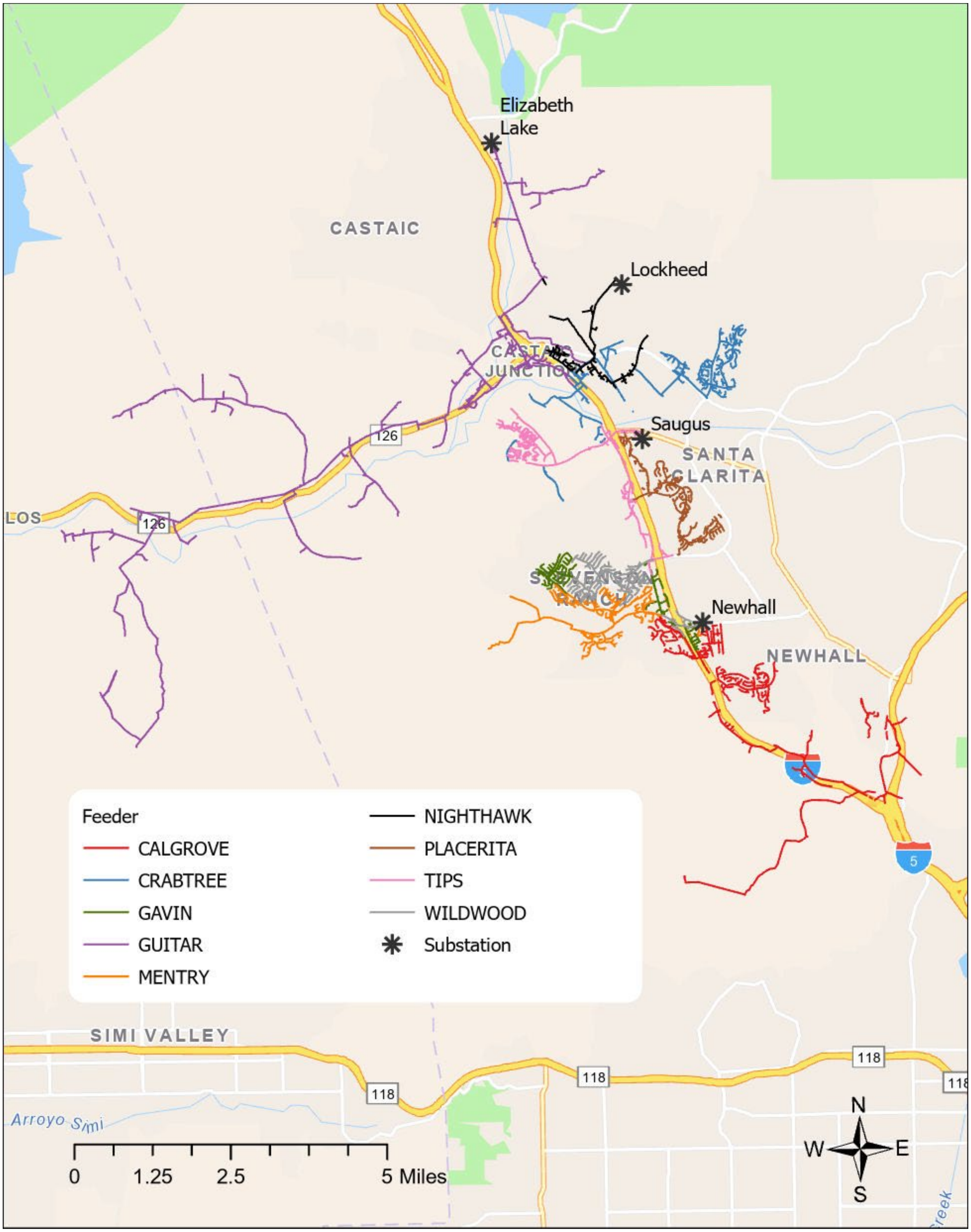

Figure 4. Case study three. Distribution grid along I-5 adjacent Santa Clarita, California. I-5 is the yellow-colored line going in the north - south direction.

3.2 Methods for the first approach

3.2.1 Calculating feeder headroom

We calculated the minimum available capacity on each feeder, the headroom (MW), as:

$$headroom = \min_{hours}[Capacity - Load]$$

This equation calculates the minimum headroom on the distribution grid across all hours in the year of capacity. Headroom is the amount of available capacity on feeders and substations in reference to the peak load meaning that higher headroom corresponds to more available capacity to accommodate new load. For SCE, headroom is constant across the year as SCE has one consistent rating for its facilities regardless of season. PG&E, however, has two rating values (one for winter and one for summer), which results in two values for headroom that subtracts the existing load (which varies across the hours of the year).[12]

The equation below reflects the headroom calculation for each substation, with the complication that the load on the substation is the sum of the load of each distribution feeder connected to the substation:[13]

$$headroom = \min_{hours}\left[Capacity - \sum_{Feeders} L_F\right]$$

In the above equation, L_F is the load on feeder F.

3.2.2 Calculating the impact of charging on feeders and substations

We consider two sizes of direct-current fast charging (DCFC) corridor charging stations (A and B below). We assume that each charging station's energization agreement allows every charger at that site to simultaneously operate at full power. The stations differ in their number of chargers and charger power.[14]

A. Forty DCFCs, each with a capacity of 50 kilowatts (kW). Thus, the charging site requires two megawatts (MW) of power and is referred to as the "2-MW site."

B. Eighty DCFCs with a capacity of 200 kW each. Thus, this site has a total power requirement of 16 MW and is referred to as the "16-MW site."

A feeder upgrade is triggered if the connecting feeder has less capacity than the power requirement of the charging station.

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[12] See DGEM at 48-53 (Appendix A.1) for details on how feeder capacity and load were calculated.

[13] The DGEM already calculated $\sum_F L_F$ for each substation.

[14] Charger sizes and quantities are based upon those in Gamage, T., Tal, G., and Jenn, A. *The costs and challenges of installing corridor DC Fast Chargers in California*, Case Studies on Transport Policy, March 2023 at 10.

A new substation transformer bank is triggered if the downstream substation has less aggregate transformer bank capacity than the power requirement of the charging station. A new substation transformer bank is also triggered if a new feeder is triggered and there is no physical space remaining on the existing substation transformer banks at which to connect a new feeder.[15]

A new substation is triggered if a transformer bank is triggered and there is no room for additional transformer banks at the existing substation. This study assumes that PG&E has capacity for three substation transformer banks.[16]

3.2.3 Upgrade costs

For simplicity, this study uses infrastructure unit costs from the *Electrification Impacts Study* (EIS).[17] Table 1 summarizes these costs.

Table 1. Infrastructure unit costs. Figures in $ million.

Infrastructure	PG&E	SCE
Feeder	$6.4	$5.5
Transformer Bank	$11.8	$2.0
Substation	$27.0	$39.6

3.3 Results from the first approach

3.3.1 Case study one

The corridor charging site in case study one can be connected to one of four feeders, each connected to a different substation. Table 2 lists each of these feeders and substations, along with its headroom (i.e., the minimum value of unused capacity). In short, feeders at sites B-D can accommodate the smaller charging station, no feeders can accommodate the larger charging station, substations A-C can accommodate the smaller charging station, and only substation A can accommodate the larger EV charging station. Furthermore, Willows A 1103 feeder has sufficient existing capacity to support the 2-MW charging site. However, the Willows A substation is at capacity with three transformer banks already installed, while the other

[15] PG&E's standard 45-MVA transformers accommodate five feeders. However, data from PG&E show that many existing substations use much smaller transformers, some of which accommodate only a single feeder. For simplicity, this study assumes that each transformer accommodates four feeders. SCE's 28-MVA transformers accommodate four feeders.

[16] PG&E states that its typical substation accommodates three 45-MVA substation transformer banks. SCE's substation capacity is not clear, but since no substation transformer banks were triggered in case study three, this was left unsolved.

[17] Issued as an attachment to *Administrative Law Judges' Ruling Setting a Workshop, Admitting Into the Record Part 1 of the Electrification Impacts Study and Research Plan, and Seeking Comments,* May 9, 2023; filed in Rulemaking (R). 21-06-017. Available at: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=508423139.

substations have one or two. Therefore, if a new transformer bank is triggered by installing a charging site at site D, it could cost $27 million in costs for a new substation and $11.8 million for a new transformer bank at that new substation.

Table 2. Summary of feeders and substations in case study one.

Site	Feeder	Feeder headroom (MW)	Substation	Substation headroom (MW)
A	Glenn 1101	0.76	Glenn	19.77
B	Logan Creek 2102	5.58	Logan Creek	3.07
C	Orland B 1101	2.84	Orland B	3.33
D	Willows A 1103	5.13	Willows A	0

Table 3 summarizes the resulting costs for case study one. The result for case study one is informative: Site selection drives significant variance in distribution grid costs (up to a difference of $38.8 million depending on the scenario), with the optimal site depending upon the scale of the facility (B or C are optimal for two MW of charging capacity; A is optimal for 16 MW of charging capacity). The fact that optimal site selection depends upon both the current conditions of the site and the scale of the prospective facility shows that capacity data are insufficient for planning purposes. A developer should know the types (or at least the costs) of triggered upgrades to choose an optimal site. For example, site B has the most feeder capacity available before triggering any upgrades (3.07 MW), but site A is the optimal site at which to deploy a 16-MW charging station (or any charging station between 3.07 MW and 19.77 MW) at the substation level.

Table 3. Summary of upgrade costs in case study one. All figures in $ million.

Site	Feeder	2-MW site	16-MW site
A	Glenn 1101	$6.4	$6.4
B	Logan Creek 2102	$0	$18.2
C	Orland B 1101	$0	$18.2
D	Willows A 1103	$38.8	$45.2

3.3.2 Case study two

The corridor charging site in case study two can be connected to one of two feeders, each connected to a different substation. Table 4 lists these feeders and substations and their headroom.

Table 4. Summary of feeders and substations in case study two.

Site	Feeder	Feeder headroom (MW)	Substation	Substation headroom (MW)
E	Tejon 1102	2.89	Tejon	8.75
F	Wheeler Ridge 1101	0	Wheeler Ridge	2.76

In short, the feeder and substation at site E can accommodate the smaller EV charging station, the substation at site F can accommodate the smaller EV charging station, and neither feeder nor substation can accommodate the larger EV charging station. Furthermore, both substations can accommodate a new transformer if needed. Table 5 summarizes the resulting costs for case study one.

Table 5. Summary of costs in case study two. All figures in $ million.

Site	Feeder	2-MW site	16-MW site
E	Tejon 1102	$0.0	$18.2
F	Wheeler Ridge 1101	$18.2	$18.2

The result for case study two is simpler than that of case study one mainly because, for both sites E and F, a new feeder and transformer bank is all that is needed to accommodate the larger EV charging station. Site E feeder is optimal for a small EV charging station (2-MW) with no needed upgrades. However, from a distribution cost perspective, both sites are equally good hosts for a 16-MW charging station as they would both require the same scale of distribution upgrades.

3.3.3 Case study three

The corridor charging site in case study three can be connected to ten possible feeders, each connected to one of three substations. Table 6 depicts these feeder and substations, along with their headroom.

Table 6. Summary of feeders and substations in case study three.

Site	Feeder	Feeder headroom (MW)	Substation	Substation headroom (MW)
G	Guitar	7.12	Elizabeth Lake	47.34
H	Nighthawk	3.95	Lockheed	18.11
I	Calgrove	4.14	Newhall	32.65
J	Gavin	7.76	Newhall	32.65
K	Mentry	6.42	Newhall	32.65
L	Wildwood	5.88	Newhall	32.65
M	Crabtree	5.67	Saugus	49.76
N	Placerita	3.66	Saugus	49.76
O	Tips	10.22	Saugus	49.76
P	Val Verde	8.35	Saugus	49.76

In short, each feeder can accommodate a 2-MW charging station, no feeder can accommodate a 16-MW development, and all substations can accommodate both developments with no new transformers needed. Table 7 summarizes costs for case study three.

Table 7. Summary of costs in case study three. All figures in $ million.

Sites	2-MW site	16-MW site
All sites	$0.0	$5.5

The result for case study three is simplest of all with all sites having available headroom at the feeder level to accommodate the 2-MW station. At scales of 2-MW and 16-MW, site selection is inconsequential from a distribution grid upgrade cost perspective because all feeders can accommodate 2MW and none can accommodate 16MW. At a scale of 4-MW for example, sites H and N would trigger new feeders while other sites would not. At a scale of 6-MW, sites G, J, K, O, and P would not trigger new feeders, while all other sites in this case study would. At a scale of 20-MW, site H would trigger a new substation bank, while the other sites would not. At a scale of 40-MW, sites H-L would trigger new transformer banks, while the other sites would not. So once again, the optimal site depends upon the scale of development, just not at scales of 2-MW and 16-MW.

3.4 Conclusions from first approach

3.4.1 Site selection impacts the cost of distribution upgrades triggered by a DCFC station

Some sites can accommodate 2-MW of DCFC capacity with no upgrades,[18] while other sites would trigger tens of millions of dollars in upgrades with even modest DCFC installations (well below 2-MW). However, actual cost variability is likely greater than that calculated herein, because this study did not consider that each substation is a unique distance from I-5. Thus, this study did not consider that the length of new or upgraded feeders and the resulting cost will vary between sites.[19] So too will the cost of substation upgrades, though caused by different factors.

The primary conclusion of the first approach is that coordination between developers and IOUs can reduce costs to ratepayer by allowing developers to take advantage of feeders that already have available capacity to support a EV charging station. Siting EV charging stations at locations with feeders that have available capacity will reduce the amount of infrastructure upgrades needed. Less infrastructure upgrades needed means less total costs to be subsequently recovered by ratepayers. It also suggests, conversely, that DCFCs can be significant cost drivers for distribution grid upgrades.

3.4.2 The optimal site for charging stations sometimes depends upon the scale of the facility

In case study one, sites B or C is the optimal site for 2-MW of EV charging capacity, while site A is optimal for 16-MW of EV charging capacity and site D is not optimal for either size EV

[18] This only includes feeder and substation upgrades. New service transformers and line extensions would likely be needed, and equipment may be needed to maintain voltage stability.

[19] See DGEM at 42 and 76-79. The costs in this study are consistent with two total miles of feeder. The end-to-end length as the crow flies would be much shorter since feeders are highly branched.

charging facility. This demonstrates that the optimal site for Ev charging locations is dependent on the scale of the proposed charging facility. Therefore, grid capacity data alone is not a complete guide for planning purposes; however, grid capacity data provides a good starting point for finding a location that may require less distribution grid upgrades. A developer would need to know the types (or at least the costs) of upgrades triggered by the proposed facility to choose an optimal site which would require, as suggested above, close coordination between the IOU and developers.

4 Second approach

The second approach uses DGEM data to calculate the capacity of the IOUs' distribution grids to host EVs if they are charged in the most optimal locations (from a distribution grid perspective, not from a customer or transmission grid perspective).

4.1 Methods for the second approach

Methods for the second approach are more complicated than those of the first approach. In short, the second approach methods entail calculating:

1. An average charging load shape (24 hourly values) for EVs in California.
2. The headroom on substations in the IOU service territory (24 hourly values) considering constraints on associated feeder capacity.
3. The number of EVs that can be accommodated at each substation by dividing the result of step 2 by the result of step 1.

4.1.1 Average charging load shape

To calculate integration capacities (in terms of number of EVs), without having to incorporate heterogeneity among vehicles, we first calculated an average EV charging load shape for vehicles in the IOUs' territories. This long-term load shape is based upon all current vehicles in the Department of Motor Vehicles (DMV) registration dataset within the IOUs' territories, assuming that all vehicles become EVs at some point. We then calculated the hourly charging demand of this average vehicle in each hour as follows:

$$Power_h = \frac{\sum_{Classes} Q_c \cdot kWh_c \cdot \frac{kW_{c,h}}{kWh_c}}{\sum_{Classes} Q_c}$$

Table 8. Variable definitions and sources for methods step 1.

Variable	Definition	Source
$Power_h$	Average hourly charging demand for all vehicles within the IOU's service territory.	Calculation
$\sum_{Classes}$	Sum across all vehicles in class C	Calculation
Q_c	Quantity of vehicles in class *C*	DMV registration dataset[20] (2021)
kWh_c	Annual charging energy consumption of each class *C* vehicle	Integrated Energy Policy Report (IEPR) data[21] for 2035
$\frac{kW_{c,h}}{kWh_c}$	Charging load shape in hour *h* of class C vehicles	IEPR data[22] for 2035

Figure 5 shows the resulting average state-wide vehicle charging load shape—an aggregate across all vehicles in the dataset, including light-duty, medium-duty, and heavy-duty vehicles.

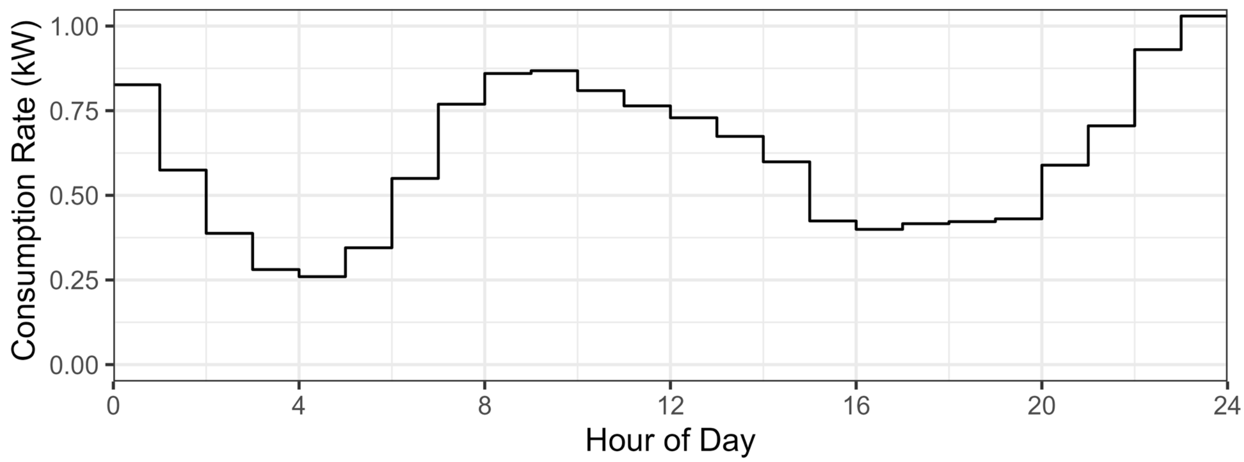

Figure 5. Long-term average charging load shape for EVs in the combined territories of PG&E, SCE, and SDG&E.

4.1.2 Headroom on IOU substations

Next, we calculated the headroom[23] on each IOU substation, the lesser of the headroom on the substation's transformers and the headroom on the substation's feeders:[24]

[20] See DGEM at 56 (Table A-3).

[21] See DGEM at 67 (Table A-8).

[22] See DGEM at 71 (Figure A-6).

[23] Headroom is equal to capacity minus load.

[24] The load on substation *S* in hour *h* is the sum of the loads in hour *h* on feeders connected to substation *S*. This equation can also be written as: $\min_{C_F, C_S} [\sum_F(C_F), C_S] - L_{S,h}$.

$$H_{S,h} = \min_{F,S}\left[\sum_{Feeders}[C_F - L_{F,h}], [C_S - L_{S,h}]\right]$$

Table 9. Variable definitions and sources for step two of the methods for the second approach.

Variable	Definition	Source[25]
$\min_{F\ S}$	Minimum value across sum of feeder headroom and substation headroom	IOU data
C_F	Capacity of feeder *F*	IOU data
$L_{F,h}$	Maximum load on feeder *F* in hour *h*	IOU data
C_S	Total capacity of transformer banks in substation *S*	IOU data
$L_{S,h}$	Maximum load on substation *S* in hour *h*	IOU data

For each hour in the day, we then calculated the minimum headroom across the days of the year, resulting in 24 values per substation.[26] Figure 6 depicts this effective headroom curve for one substation. This substation's transformer banks and feeders have a maximum of 9 MW of available capacity from 3 a.m. to 5 a.m., and as little as 2 MW of capacity between 5 p.m. and 6 p.m.

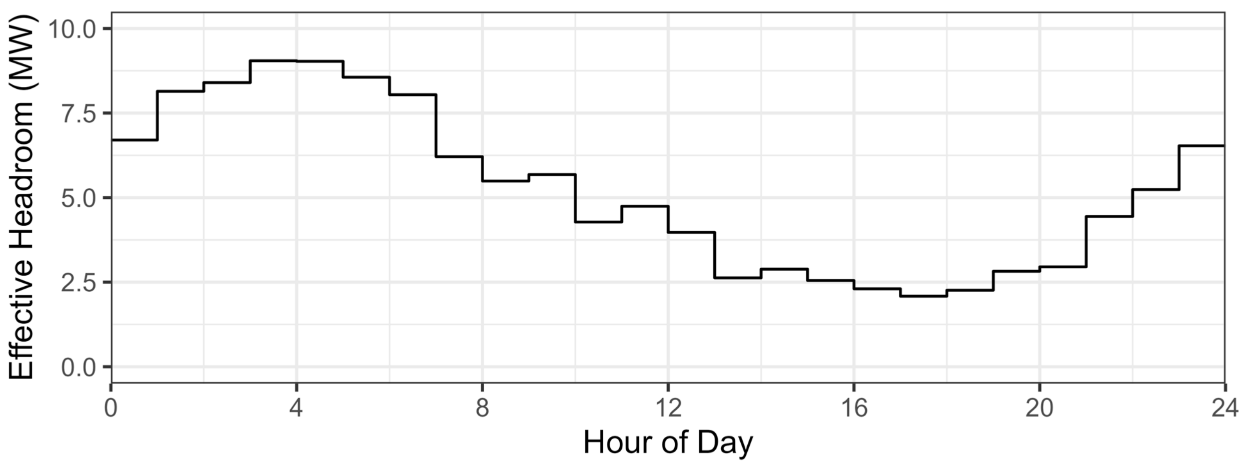

Figure 6. Headroom profile for the Oroville substation in PG&E's service territory, including both the 12-kV kilovolt (kV) and 4-kV systems.

The aggregate headroom across the combined service territories of PG&E, SCE, and SDG&E takes on a similar shape, though with greater magnitude. Like the Oroville substation (Figure 6), combined service territories substation headroom peaks at 4 a.m. and reaches its minimum headroom at 5 p.m.

[25] See DGEM at 48-53 (Appendix A.1).

[26] This calculation would find the minimum headroom between 1 a.m. and 2 a.m. across all 365 days of the year and do the same for each hour throughout the day.

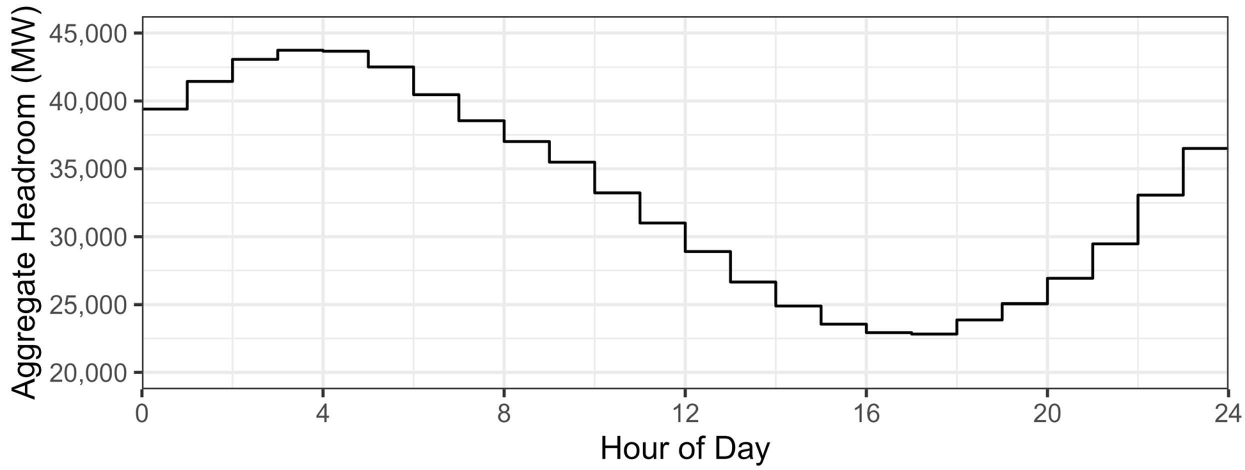

Figure 7. Headroom profile for the combined service territories of PG&E, SCE, and SDG&E.

Figure 8 breaks down available headroom across all 1,396 substations in this study. A small but significant number of distribution substations (102 substations) are already over capacity according to our analysis in the DGEM. Many substations (639 substations) have between 0 and 10 MW of available capacity, and the remaining 655 substations have available capacities of 10 or more MW. In short, there are many substations across the IOUs' territories with significant unused feeder and transformer bank capacity.

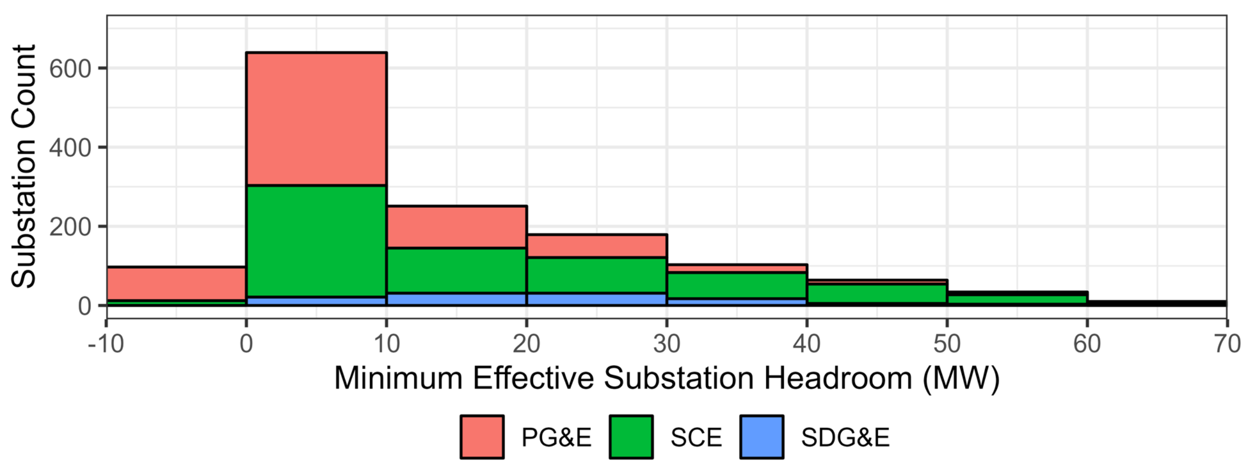

Figure 8. Histogram of minimum substation headroom for substations in PG&E, SCE, and SDG&E service territories. A few substations with very high and very low capacity are left off this chart for viewability.

Figure 8 also reflects the trend in substation capacity that was shown in the small sample in the first approach. The columns between 20 MW and 60 MW show that SCE has the highest share of under-utilized substations.[27] PG&E has an outsized share of low-headroom substations, as shown in the columns from 0 MW to 20 MW, and over-capacity substations (with load greater than capacity in some hours), as shown in the column between -10 MW and 0 MW.

4.1.3 EV integration capacity

The final methodological step in the second approach was to divide the headroom curve on each substation by the EV charging curve, to determine the maximum number of EVs that each substation's feeders and transformer banks can accommodate without overloading the infrastructure. This calculation was performed as follows:

$$I_S = \min_{hours} \left[\frac{H_{S,h}}{Power_h} \right]$$

That is, the number of EVs that can be accommodated at a given substation (I_S) is the minimum number of hours across the 24 hours of the day of substation headroom ($H_{S,h}$), divided by charging power ($Power_h$). Figure 9 shows the result of this calculation in the form of a histogram for all substations in the combined service territories of PG&E, SCE, and SDG&E. Over 100 substations can accommodate more than zero and up to 2,000 EVs, 2,000 to 4,000 EVs, and 4,000 to 6,000 EVs. At least 50 substations can accommodate 6,000 to 8,000 EVs, 8,000 to 10,000 EVs, and 10,000 to 12,000 EVs. Over 75 substations can accommodate 12,000 or more EVs.

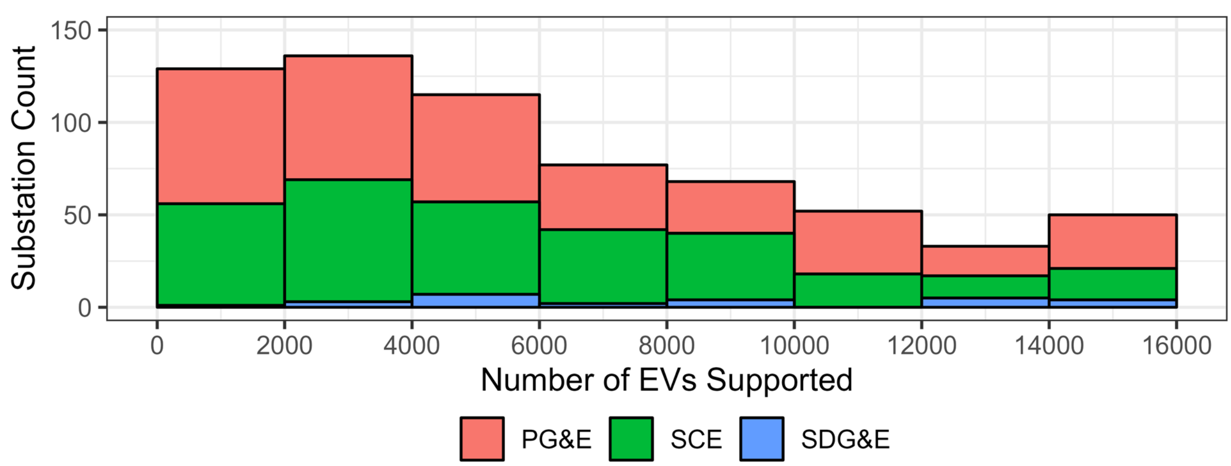

Figure 9. Histogram of EV integration capacity at substations in PG&E, SCE, and SDG&E service territories. Substations with very high and low capacity are left off this chart for viewability.

[27] SDG&E has a high proportion of high-capacity substations. Its largest histogram slice is for 20-30 MW of capacity.

4.2 Results from the second approach

Figure 10 shows that the existing distribution grid of the three large IOUs can accommodate over 31 million EVs (incidentally, almost exactly the total number of vehicles registered in the entire state of California) under typical charging patterns, and if their charging occurs in the locations with spare capacity. This is twice the number of EVs anticipated in 2035 by the California Energy Commission's (CEC) IEPR across the state of California.[28]

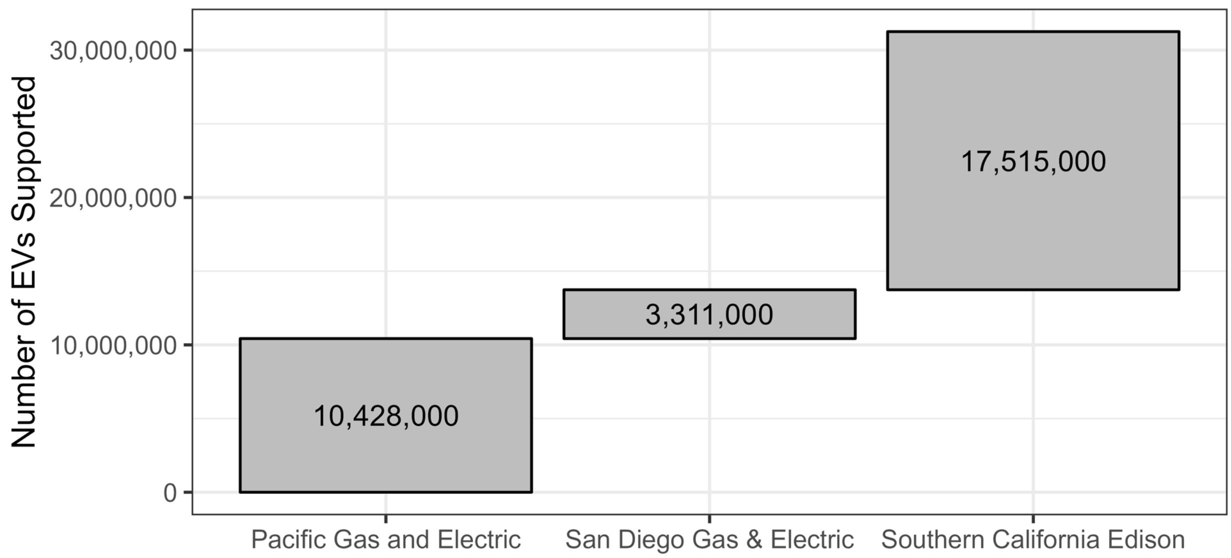

Figure 10. Number of EVs that each IOUs' service territory can accommodate. These counts include only substations that can accommodate at least 100 EVs.

Typical charging pattern, in this context, means that when aggregated, EVs have the impact on the distribution grid corresponding to the charging pattern shown in Figure 5. Of course, no vehicle is expected to always charge according to this load shape, but when aggregated to hundreds and thousands, these load shapes are expected to converge upon the shape shown in Figure 5.

The number of EVs that each IOU's service territory can accommodate varies significantly across the IOUs; including between PG&E and SCE, which have similar numbers of customers and vehicles. Table 10 breaks this down, showing that PG&E has enough distribution grid to accommodate only 2% more EVs than it has vehicles at present, while SCE can accommodate more than 1.6 EVs for each vehicle currently present in its service territory (i.e., SCE has a significant margin).

[28] See DGEM at 3 (Figure 1-1).

Table 10. Number of EVs that can be charged on existing feeders and substations compared to present vehicle populations.

IOU	Available EV Capacity	Current Vehicles	Available EV Capacity / Current vehicles
PG&E	10,428,000	10,192,000	102%
SDG&E	3,311,000	2,922,000	113%
SCE	17,515,000	10,782,000	162%

Next, we take a closer look at the spatial dimension of EV charging capacity availability at substations, particularly as it relates to the locations of IOU customers (i.e., population density excluding population in regions like Los Angeles, which are served by municipal utilities).

Figure 10 compares the IOU-served population of each California county (left) with the capacity to integrate EVs at substations (right). Counties that can integrate more than one vehicle per person have a darker fill on the right plot than on the left plot.

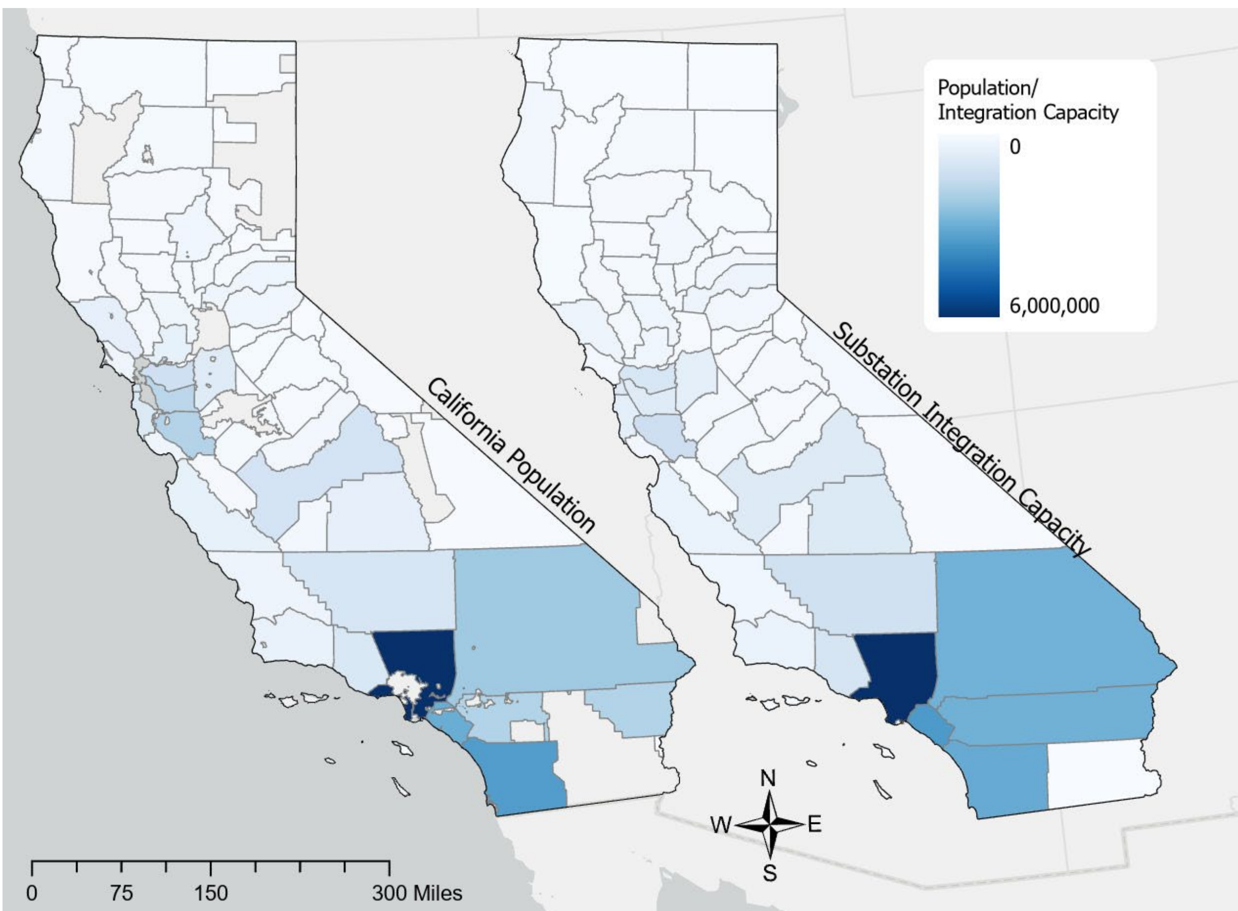

Figure 11. Population within IOU-served census blocks by county at left, aggregated substation integration capacity (i.e., the number of typical EVs that can be charged at IOU-operated substations within each county) at right. This count includes only substations that can accommodate at least 100 EVs. Cutouts in population (left) show areas not served by the three large IOUs.

In general, California counties can accommodate charging for close to or more than one EV per person.[29] This likely exceeds the state's long-term needs because, at present, California has about 30% more people than cars. The upshot is that the above observation that the *state* has enough capacity on distribution feeders and substations filters down to counties. Each California county has enough distribution feeder and substation capacity to charge EVs (depending on where EVs locate within the county and when EVs charge).

This trend of generally sufficient capacity for EV charging continues at a more granular level, as shown in Figure 12. Figure 12 depicts the scale of available capacity for California's most populous region, the greater Los Angeles and San Diego metropolitan areas. In this figure, the size of population blocks correlates to population density (because census tracts are designed to contain about 4,000 people). Areas with densely fitted census tract polygons are all characterized by densely grouped circles of substations with available capacity for, typically, tens of thousands of EVs. The areas without many substations, mostly the northern and eastern parts of the figure, are all areas with low population density. Figure 12 shows that areas with high population density also have the highest density of substations with available capacity to support more EV charging.

[29] The most notable exceptions are Alameda, Contra Costa, Fresno, Santa Clara, and San Diego Counties. The first four have populations over one million and capacity for 0.4 to 0.8 EVs per person (all within PG&E's service territory). San Diego County has over three million SDG&E customers and can support just over 0.9 EVs per person.

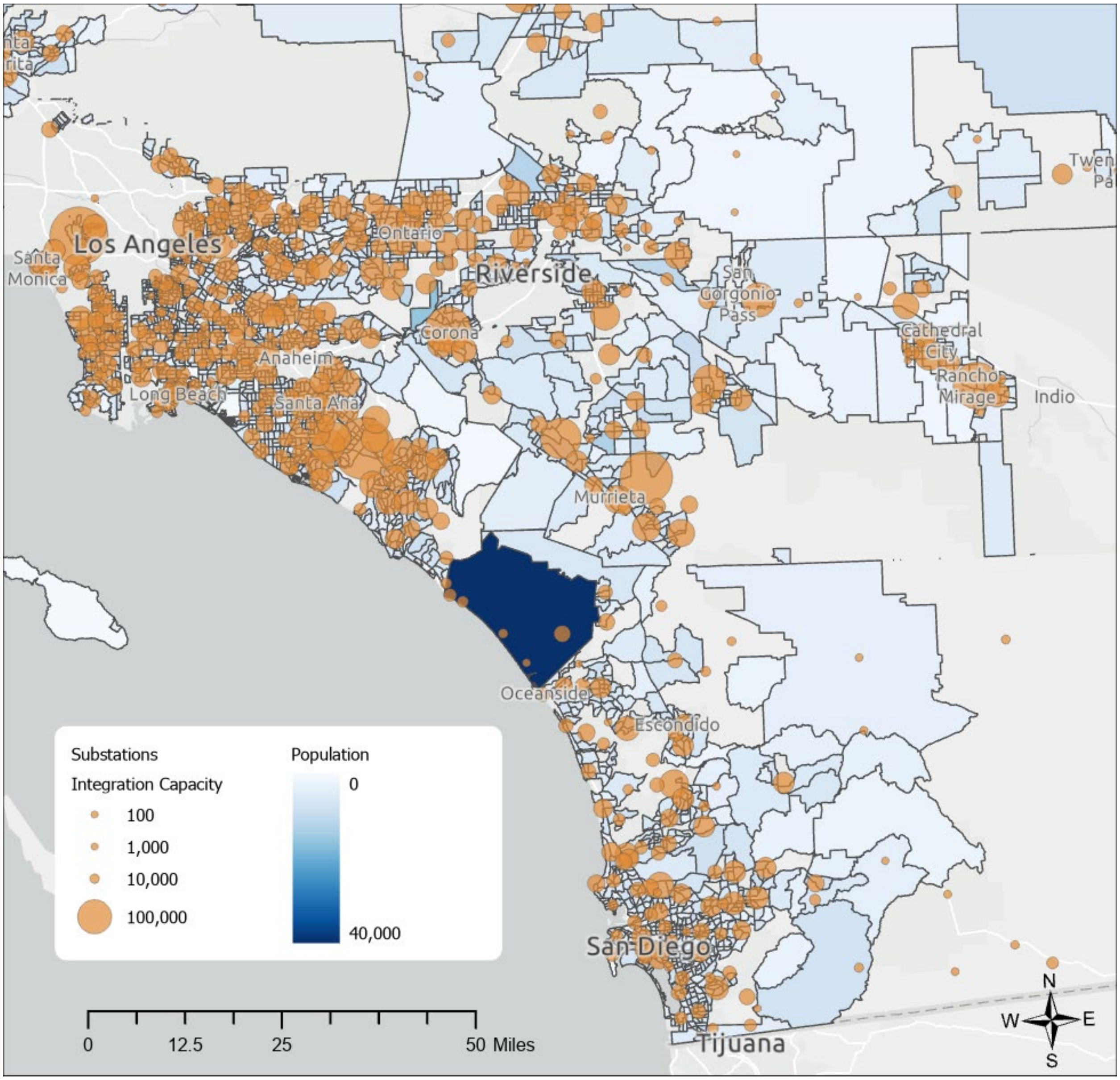

Figure 12. Population within IOU-served census tracts compared to substation integration capacity for substations able to accommodate at least 100 EVs. Areas not showing population are outside of the service territories of the three IOUs.

This trend also carries across the state, which is too large to depict fully, with PG&E's service territory having generally less capacity than SCE's service territory. That substation capacity correlates with population is not surprising – substations were located to serve people's needs, so capacity and excess capacity tend to be most common in the most populated areas of the state.

4.3 Conclusions from the second approach

4.3.1 California has a significant amount of available distribution grid capacity

There is a tremendous amount of available distribution grid capacity within the IOUs' territories – enough to accommodate California's entire vehicle fleet were it to electrify tomorrow. Grid investment can be minimized, but the ability to do so is constrained by three main factors.

The first constraint is how flexible EV charging locations will be and how much of this potential flexibility is utilized. Not all chargers have locational flexibility. For example, it would be unrealistic to expect a homeowner who is thinking of installing charging infrastructure to buy a new house on a distribution feeder with spare capacity. Second, this study does not consider transmission and generation constraints as well as access to chargers and secondary voltage infrastructure[30] – this study looks only at distribution substations and feeders within IOU territories. Even if the entire primary distribution investment were avoided, generation and transmission infrastructure, secondary voltage infrastructure, and EV chargers would all require investment. Third, regarding charging load shape,[31] grid costs will increase if EVs are charged simultaneously or nearer to the grid peak than assumed in this study.

4.3.2 EV hosting capacity will depend upon when EVs charge

A worse time-of-charge would reduce the number of EVs that the current distribution infrastructure can host. Conversely a better time-of-charge can increase the number of EVs beyond what was studied here. A comparison of Figure 5 and Figure 7 shows that the EV charging load shape is not optimal for the distribution grid. Low charging around 5 p.m. reflects the strained condition of the distribution grid at that time, but the ample capacity of the distribution grid at 4 a.m. remains largely unused. EV charging is at the lowest at 4 a.m. Shifting EV charging toward the 4 a.m. window would unlock distribution grid capacity. However, this may not be optimal from a generation resource perspective because generation resources may have to ramp up at an unusual time to meet the new demand. Additionally, there is limited ability in the flexibility of renewable generation resources to accommodate a 4 a.m. spike. In the end, planning must be integrated across distribution, transmission, and generation to determine the entire systems' ideal hours for EV charging (which could be expressed as hourly costs for energy and capacity, as in the Avoided Cost Calculator)[32].

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[30] Secondary voltage infrastructure includes service transformers, service drops, and networked secondary systems.

[31] See also DGEM at 37 and 40 (Sections 4.1.1 and 4.4).

[32] See CPUC, *DER Cost-Effectiveness*. Available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/der-cost-effectiveness.

4.3.3 This study does not consider the feasibility of vehicle charging in the locations imagined

It could be that certain drivers would have to drive dozens of miles to charge their EVs in this model, a clear implausibility. That said, regarding the feasibility of moving EV charging stations to where the grid can accommodate them, we look to the first study approach, which suggests that chargers, at least EV chargers located along a highway corridor, only need to locate optimally over a short distance to minimize costs.

5 Overall conclusions

In summary, the first approach led to the following conclusions regarding the site selection process for EV chargers:

- Charging stations may only need to adjust their location a short distance to minimize costs.
- Site selection impacts the cost of distribution upgrades triggered by a DCFC station.
- The optimal site for charging stations sometimes depends upon the scale of the facility.

Additionally, the second approach led to the following conclusions regarding EV charging more generally:

- California has a significant amount of available distribution grid capacity to accommodate EV charging.
- In addition to site location, EV hosting capacity will depend upon when EVs charge.

Overall, the main conclusion of this study is that there is physical primary distribution grid capacity across California that can be used to integrate electric vehicles. California should leverage the spatial and temporal flexibility of EV charging to use this capacity to the extent practical before building new capacity. This would reduce the need for grid upgrades to support transportation electrification and therefore minimize the cost burden on ratepayers.

Appendix A. Comparison between DGEM and ICA data

After producing headroom estimates for feeders using the DGEM, we compared our results to those of the IOUs' ICA maps.[33] ICA maps are hosting capacity maps produced and hosted by the IOUs, which "assist developers [to] find information on the grid where capacity is available to site Distributed Energy Resource (DER) projects"[34] including both generation resources and load projects such as EV charging stations. Alignment between the two can validate both the DGEM and the ICA maps because the methods and data sources are distinct.

Table 11 compares the headroom calculated from the DGEM to the headroom shown on PG&E's ICA for feeders in case studies one and two. There is little alignment between the results for these feeders. The DGEM calculates the same (zero) or more capacity than the ICA for all feeders. This could be caused by inaccuracies in load ICA data,[35] inaccuracies in the DGEM, or misalignment between what is measured. Specifically, the DGEM analyzes only thermal constraints, not voltage constraints.

Table 11. Comparison of headroom calculated by the DGEM and from PG&E's ICAs (i.e., load integration capacity).

Site	Feeder	DGEM Headroom (MW)	ICA Headroom[36] (MW)
A	Glenn 1101	0.76	0
B	Logan Creek 2102	3.07	0
C	Orland B 1101	2.84	0.51-0.86
D	Willows A 1103	0	0
E	Tejon 1102	2.89	0
F	Wheeler Ridge 1101	0	0

Table 12 compares headroom for SCE's ICA with that of the DGEM for feeders in case study 3. These results are more closely aligned. Many feeders have similar capacity across the two models; several feeders show zero capacity in the ICA but non-zero capacity in the DGEM.

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[33] These maps may be found at:

- PG&E: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page.
- SCE: https://drpep.sce.com/drpep.

[34] CPUC, *Load Integration Capacity Analysis Refinements Workshop*, March 8 2023. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-action-plan/load-ica-refinements-workshop-slides.pdf.

[35] For example, 69% of recent applications for PG&E that exceeded ICA capacity did not require an upgrade, while 34% of applications that did not exceed ICA capacity required upgrades. See CPUC Energy Division, *Staff Proposal for the High DER Proceeding*, April 5, 2024 at 159 (Table 6-4). Available at: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=528884800.

[36] Note that ICA headroom varies by feeder segment, whereas DGEM looks only at feeder-level capacity.

Table 12. Comparison of headroom calculated by the DGEM and from SCE's ICAs (i.e., load integration capacity). N/A = data not available.

Site	Feeder	DGEM Headroom (MW)	ICA Headroom (MW)
G	Guitar	7.12	1.49
H	Nighthawk	3.95	4.36
I	Calgrove	4.14	2.71
J	Gavin	7.76	0
K	Mentry	6.42	0
L	Wildwood	5.88	N/A
M	Crabtree	5.67	0
N	Placerita	3.66	4.07
O	Tips	10.22	6.96
P	Val Verde	8.35	5.82

Figure 13 shows alignment between the DGEM and SCE's ICA result directly. Two sites (Nighthawk and Placerita) were extremely close in capacity, three sites (Calgrove, Tips, and Val Verde) were reasonably close, and the remaining four sites were quite different—these four sites all had near-zero capacity shown in SCE's ICA, and three had exactly zero. This supports the view that some (or many) zeros in ICA load data are erroneous.

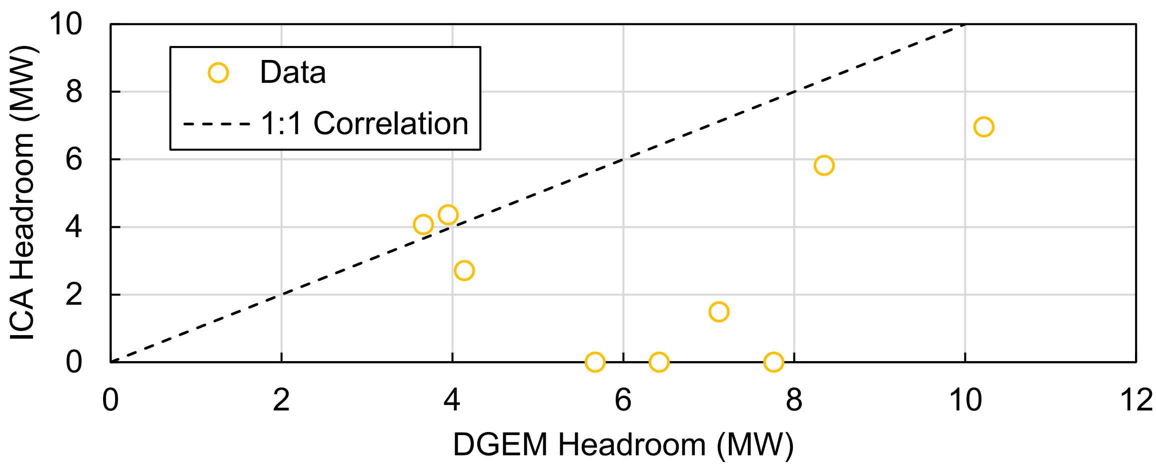

Figure 13. Correlation between DGEM result and ICA result for case study three (SCE).

For SCE, several of the feeders analyzed showed similar capacity in the DGEM and the ICA, while several had zero capacity in the ICA and non-zero capacity in the DGEM. This supports the view that some (or many) zeros in SCE's (and potentially the other IOU's) ICA load data are erroneous.